State of the Market Report for PJM

Volume 2: Detailed Analysis

Monitoring Analytics, LLC
Independent Market Monitor for PJM

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Preface

The PJM Market Monitoring Plan provides:

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

Accordingly, Monitoring Analytics, LLC, which serves as the Market Monitoring Unit (MMU) for PJM Interconnection, L.L.C. (PJM),[2] and is also known as the Independent Market Monitor for PJM (IMM), submits this *2015 State of the Market Report for PJM*.[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 State of the Market Report for PJM*.

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Introduction

2015 in Review

The results of the energy market, the results of the capacity market and the results of the regulation market were competitive in 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.

Competitive markets were introduced as an alternative form of regulation to ensure that wholesale power is provided at the lowest possible price. The PJM market design does not incorporate a laissez faire approach. The PJM market remains regulated. The PJM market design incorporates a variety of rules designed to help ensure competitive outcomes. When basic elements of those rules are modified, e.g. the raising of the overall $1,000 per MWh offer cap and the introduction of hourly offers in place of daily offers, it is essential that effective market power mitigation be maintained. While the three pivotal supplier test addresses local market power associated with transmission constrained markets, it does not address aggregate market power. Aggregate market power exists when generation owners have the ability to raise market prices above competitive levels in the absence of transmission constraints, for example when demand is high and market conditions are tight. A direct and effective substitute for the current market power mitigation rule limiting units to one offer per day would be to limit any hourly offer changes during the day to changes in the cost of fuel. The failure to maintain limits on aggregate market power will lead to the exercise of market power and the associated negative impacts on the competitiveness of PJM markets.

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 high demand hours. 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 aggregate market power, or 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.

One of the benefits of competitive power markets is that changes in input prices and changes in the balance of supply and demand are reflected immediately in energy prices. Energy market prices in 2015 decreased by almost a third from 2014 as a combined result of lower fuel prices and lower demand. The load-weighted average real-time LMP was 31.9 percent lower in 2015 than in 2014, $36.16 per MWh versus $53.14 per MWh. The load-weighted average price in 2015 was about 20 percent lower than the average of annual prices in all years from 1999 through 2015. If fuel costs in 2015 had been the same as in 2014, holding everything else constant, the load-weighted average LMP would have been higher, $41.91 per MWh instead of the observed $36.16 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 $3.32 in 2014 to $1.75 in 2015. The markup decreased from 6.2 percent of real-time LMP in 2014 to 4.8 percent in 2015. Although markups continued to be significant in 2015, participant behavior was evaluated as competitive because marginal units generally made offers at, or close to, their short run marginal costs. But the markup results are a reminder that aggregate market power remains an issue when market conditions are tight and that market design choices must account for the potential to exercise aggregate market power. There are also generation owners who routinely include high markups in price based offers on some units. These markups do not affect prices under normal conditions.

The three pivotal supplier (TPS) 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. The TPS test is a flexible, targeted real-time measure of market structure which replaced the prior approach of offer capping all units required to relieve a constraint. But there are some issues with the application of mitigation when market sellers fail the TPS test. There is no tariff or manual language that defines in detail the application of the TPS test and mitigation in the Day-Ahead Energy Market and the Real-Time Energy Market. In both the Day-Ahead and Real-Time Energy Markets, generators have the ability to avoid mitigation by using varying markups in their price-based offers, offering different operating parameters in their price-based and cost-based offers, and using different fuels in their price-based and cost-based offers. These issues with mitigation can and should be resolved by simple rule changes requiring that markup be constant across price and cost offers, that there be at least one cost-based offer using the same fuel as the available price-based offer, that the price-MW pairs in the price based PLS offer be exactly equal to the price based non PLS offer, and requiring cost- based and price-based PLS offers to be at least as flexible as price-based non-PLS offers. The significance of implementing these rule changes is substantially increased with the introduction of hourly offers.

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 2015 than in 2014. Net revenues from the energy market for all plant types were affected by the lower energy and fuel prices. Capacity prices for calendar year 2015 were higher than in 2014 in the western zones.

In 2015, average energy market net revenues decreased by 23 percent for a new peaker (CT), 27 percent for a new combined cycle unit, 53 percent for a new coal plant and 38 percent for a new nuclear plant. The comparisons to 2014 reflect the very high net revenues in January 2014.

Despite lower net revenues, the market signals were still positive for new investment in gas-fired units, particularly in eastern PJM zones. But market signals continued to be negative for coal and nuclear units. In 2015, a new peaker (CT) would have received sufficient net revenue to cover levelized total costs in six of the 20 zones and more than 90 percent of levelized total costs in an additional six zones. In 2015, a new combined cycle unit would have received sufficient net revenue to cover levelized total costs in nine of the 20 zones and more than 90 percent of levelized total costs in an additional four zones.

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 quasi-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. While there are entities in the PJM markets that continue to operate under the quasi-market paradigm, they have made a long term decision on a regulatory model and the PJM rules generally limit any associated, potential negative impacts on markets. That consistent approach to the regulatory model is very different from current attempts to subsidize specific uneconomic market assets using various planning concepts as a rationale. The subsidy model is inconsistent with the PJM market design and inconsistent with the market paradigm and constitutes a significant threat to both.

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 resulted in a substantial suppression of capacity market prices for multiple years.

These market design choices have substantial impacts. Capacity prices that were suppressed substantially below the level consistent with supply and demand fundamentals affected some participants' long term decisions. PJM has addressed the fundamental issues of the capacity market design in its Capacity Performance design, 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.

Load pays for the transmission system and contributes all congestion revenues. For that reason, FTRs and later ARRs were intended to return congestion revenues to load. The annual ARR allocation should be designed to return congestion revenues to load, without requiring contract path physical transmission rights that are difficult or impossible to define and enforce in LMP markets. The current ARR/FTR design does not serve as an efficient or effective way to ensure that load receives all the congestion revenues or has the ability to receive the auction revenues associated with all the potential congestion revenues.

In recent planning years, ARRs did not serve as an effective way to return congestion revenues to load. Total ARR and self scheduled FTR revenues offset only 42.1 percent of total congestion costs for the 2013 to 2014 planning period and only 59.8 percent of total congestion costs for the 2014 to 2015 planning period. In the first seven months of the 2015 to 2016 planning period, total ARR and self scheduled FTR revenues offset 85.8 percent of total congestion costs.

If the original PJM FTR design had simply been designed to return congestion revenues to load, many of the subsequent issues with the FTR design would have been avoided. Now is a good time to address the issues of the FTR design and to return the design to its original purpose. This would eliminate much of the complexity associated with ARRs and FTRs and eliminate unnecessary controversy about the appropriate recipients of congestion revenues.

On January 25, 2016, the U.S. Supreme Court voted 6-2 to reverse the decision of the lower court in the EPSA case. The Supreme Court's decision was about jurisdiction over demand side resources and not about the substance of Order 745. In resolving the uncertainty about jurisdiction, the decision creates an opportunity to rethink the ways in which demand side resources can most effectively participate in wholesale power markets based on market principles. The Commission has the clear authority to modify or reverse Order 745.

The long term appropriate end state for demand resources in the PJM markets should be comparable to the demand side of any market. Rather than demand response programs, with their 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. Customers should use energy as they wish and that usage will determine the amount of capacity and energy for which each customer pays. There is no need for counterfactual and inaccurate 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 customers based on actual load on the system during these hours. Customers that wish 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.

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 discretion. Customers would pay for capacity and energy depending solely on metered load.

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.

PJM Market Summary Statistics

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

Table 1-1 PJM Market Summary Statistics, 2014 and 2015[1]

	2014	2015	Percent Change
Load	780,505 GWh	776,083 GWh	(0.6%)
Generation	807,986 GWh	786,698 GWh	(2.6%)
Net Actual Interchange	(324) GWh	15,368 GWh	4,843%
Losses	17,150 GWh	16,241 GWh	(5.3%)
Regulation Requirement*	664 MW	641 MW	(3.5%)
RTO Primary Reserve Requirement	2,063 MW	2,175 MW	5.4%
Total Billing	$50.03 Billion	$42.63 Billion	(14.8%)
Peak	**Jun 17, 2014 16:00**	**Jul 28, 2015 16:00**	
Peak Load	141,673 MW	143,697 MW	1.4%
Load Factor	0.63	0.62	(2.0%)
Installed Capacity	**As of 12/31/2014**	**As of 12/31/2015**	
Installed Capacity	184,400 MW	177,683 MW	(3.6%)

* 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 December 31, 2015, had installed generating capacity of 177,683 megawatts (MW) and 957 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).[2 3 4]

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.

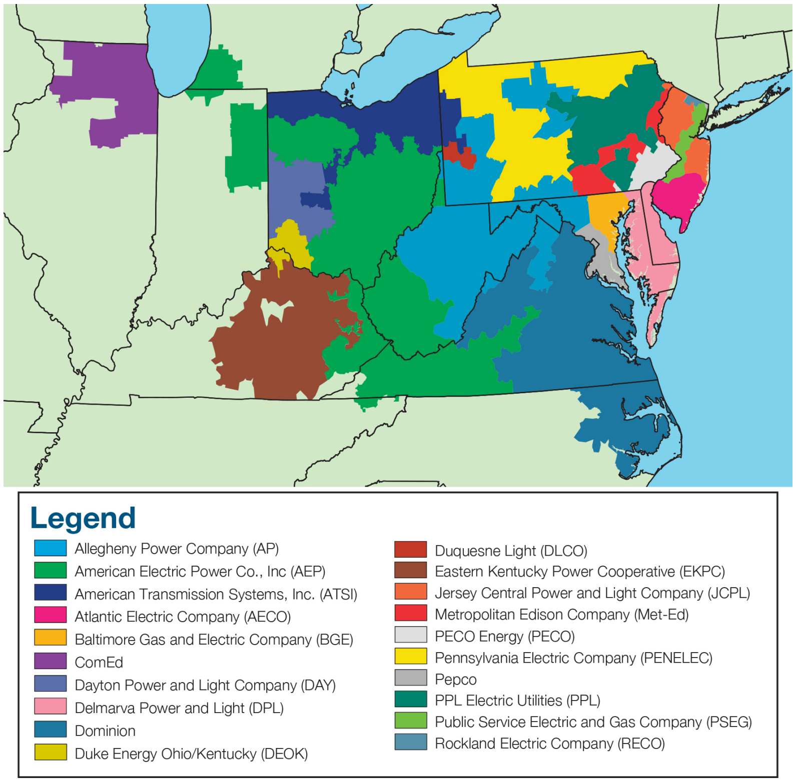
1 The load reported in this table is the accounting load plus net withdrawals at generator buses. The average hourly accounting load is reported in Section 3, "Energy Market."

2 See PJM's "Member List," which can be accessed at: <http://pjm.com/about-pjm/member-services/member-list.aspx>.

3 See PJM's "Who We Are," which can be accessed at: <http://pjm.com/about-pjm/who-we-are.aspx>.

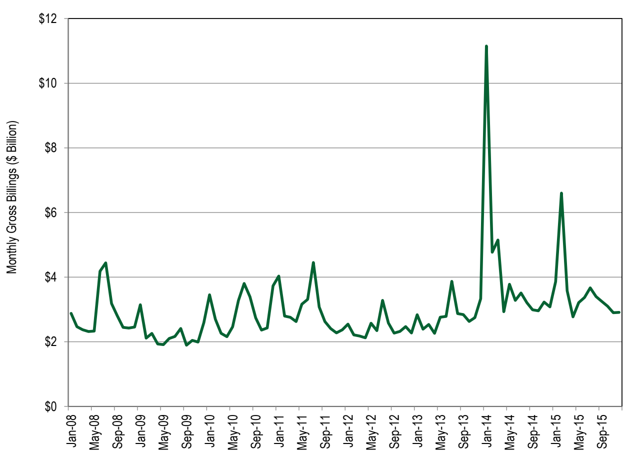
4 See the *2015 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography" for maps showing the PJM footprint and its evolution prior to 2015.

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



In 2015, PJM had total billings of $42.62 billion, down 15 percent from $50.04 billion in 2014 (Figure 1-2).[5]

Figure 1-2 PJM reported monthly billings ($ Billion): 2008 through 2015



5 Monthly billing values are provided by PJM.

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 Financial Transmission Rights (FTRs) Markets.

PJM introduced energy pricing with cost-based offers and market-clearing nodal prices on April 1, 1998, and market-clearing nodal prices with market-based offers on April 1, 1999. PJM introduced the Daily Capacity Market on January 1, 1999, and the Monthly and Multimonthly Capacity Markets for the January through May 1999 period. PJM implemented FTRs 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.[6 7] PJM introduced the Capacity Performance capacity market design effective on August 10, 2015, with the Base Residual Auction for 2018/2019.

Conclusions

This report assesses the competitiveness of the markets managed by PJM in 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.

6 See also the *2015 State of the Market Report for PJM*, Volume II, Appendix B, "PJM Market Milestones."

7 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."

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 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 2015 was moderately concentrated. Average HHI was 1096 with a minimum of 879 and a maximum of 1468 in 2015. The fact that the average HHI was in the moderately concentrated range does not mean that the aggregate market was competitive in all hours. The PJM Energy Market intermediate and peaking segments of supply were highly concentrated.
- 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 identified local market power and resulted in offer capping to force competitive offers, correcting for structural issues created by local transmission constraints. There are, however, identified issues with the application of market power mitigation to resources whose owners fail the TPS test that need to be addressed.
- 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 both routinely and during periods of high demand is consistent with 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 general, 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 identifies 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.

PJM markets are designed to promote competitive outcomes derived from the interaction of supply and demand in each of the PJM markets. Market design itself is the primary means of achieving and promoting competitive outcomes in PJM markets. One of the MMU's primary goals is to identify actual or potential market design flaws.[8] The approach to market power mitigation in PJM has focused on market designs that promote competition (a structural basis for competitive outcomes) and on limiting market power mitigation to instances where the market structure is not competitive and thus where market design alone cannot mitigate market power. In the PJM energy market, this occurs primarily in the case of local market power. When a transmission constraint creates the potential for local market power, PJM applies a structural test to determine if the local market is competitive, applies a behavioral test to determine if generator offers exceed competitive levels and applies a market performance test to determine if such generator offers would affect the market price.[9] There are, however, identified issues with the application of market power mitigation to resources whose owners fail the TPS test that can result in the exercise of local market power. These issues need to be addressed. There are issues related to the definition of gas costs includable in energy offers that need to be addressed. There are currently no market power mitigation rules in place that limit the ability to exercise market power when aggregate market conditions are tight. If market-based offer caps are raised, or if generators are allowed to modify offers hourly, market design must reflect appropriate incentives for competitive behavior and aggregate market power mitigation rules need to be developed.

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

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

Table 1-3 The Capacity Market results were competitive

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

- The aggregate market structure was evaluated as not competitive. For almost all auctions held from 2007 to the present, the PJM region failed the three pivotal supplier test (TPS), which is conducted at the time of the auction.[10]
- The local market structure was evaluated as not competitive. For almost every auction held, all LDAs have failed the TPS test, which is conducted at the time of the auction.[11]
- Participant behavior was evaluated as competitive. Market power mitigation measures were applied when the Capacity Market Seller failed the market power test for the auction, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, would increase the market clearing price. Market power mitigation rules were also applied when the Capacity Market Seller submitted a sell offer for a new resource or uprate that was below the Minimum Offer Price Rule (MOPR) threshold.
- Market performance was evaluated as competitive. Although structural market power exists in the Capacity Market, a competitive outcome resulted from the application of market power mitigation rules.
- Market design was evaluated as mixed because while there are many positive features of the Reliability Pricing Model (RPM) design and the

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

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

Capacity Performance modifications to RPM, there are several features of the RPM design which still threaten competitive outcomes. These include the definition of DR which permits inferior products to substitute for capacity, the replacement capacity issue, the definition of unit offer parameters and the inclusion of imports which are not substitutes for internal capacity resources.

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 2015 because the Regulation Market failed the three pivotal supplier (TPS) test in 97.8 percent of the hours in 2015.
- Participant behavior in the Regulation Market was evaluated as competitive for 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, 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 design has failed to correctly incorporate a consistent implementation of the marginal benefit factor in optimization, pricing and settlement. The market results continue to include the incorrect definition of opportunity cost.

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 Tier 2 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, although there is concern about failure to comply with the must offer requirement.
- 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 nonzero 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 6.4 percent of all cleared hours in 2015.
- Participant behavior was evaluated as mixed because while most offers were equal to marginal costs, a significant proportion of offers reflected economic withholding.
- Market performance was evaluated as competitive because there were adequate offers in every hour to satisfy the requirement and the clearing prices reflected those offers, although there is concern about offers above the competitive level affecting prices.
- Market design was evaluated as mixed because while the market is functioning effectively to provide DASR, the three pivotal supplier test and appropriate market power mitigation 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	Flawed

- 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 flawed because there are significant flaws with the basic ARR/FTR design which need to be addressed. The market design is not an efficient way to ensure that congestion revenues are returned to load.

Role of MMU

The FERC assigns three core functions to MMUs: reporting, monitoring and market design.[12] These functions are interrelated and overlap. The PJM Market Monitoring Plan establishes these functions, providing that the MMU is responsible for monitoring: compliance with the PJM Market Rules; actual or potential design flaws in the PJM Market Rules; structural problems in the PJM Markets that may inhibit a robust and competitive market; the actual or potential exercise of market power or violation of the market rules by a Market Participant; PJM's implementation of the PJM Market Rules or operation of the PJM Markets; and such matters as are necessary to prepare reports.[13]

Reporting

The MMU performs its reporting function primarily by issuing and filing annual and quarterly state of the market reports; regular reports on market 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.[14] The MMU has direct, confidential access to the FERC.[15] The MMU may also refer matters to the attention of state commissions.[16]

The MMU monitors market behavior for violations of FERC Market Rules.[17] The MMU will investigate and refer "Market Violations," which refers to any of "a tariff violation, violation of a Commission-approved order, rule or regulation, market manipulation, or inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies…"[18 19 20] The MMU also monitors PJM for compliance with the rules, in addition to market participants.[21]

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

12 18 CFR § 35.28(g)(3)(ii); see also *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, FERC Stats. & Regs. ¶31,281 (2008) ("Order No. 719"), *order on reh'g*, Order No. 719-A, FERC Stats. & Regs. ¶31,292 (2009), r*eh'g denied*, Order No. 719-B, 129 FERC ¶ 61,252 (2009).

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

14 OATT Attachment M § IV.

15 OATT Attachment M § IV.K.3.

16 OATT Attachment M § IV.H.

17 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.")

18 The FERC defines manipulation as engaging "in any act, practice, or course of business that operates or would operate as a fraud or deceit upon any entity." 18 CFR § 1c.2(a)(3). Manipulation may involve behavior that is consistent with the letter of the rules, but violates their spirit. An example is market behavior that is economically meaningless, such as equal and opposite transactions, which may entitle the transacting party to a benefit associated with volume. Unlike market power or rule violations, manipulation must be intentional. The MMU must build its case, including an inference of intent, on the basis of market data.

19 OATT Attachment M § II(h-1).

20 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.

21 OATT Attachment M § IV.C.

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).[22] 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.[23]

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.[24] [25] [26] [27]

The MMU reviews offers and inputs in order to evaluate whether those offers raise market power concerns.[28] Market participants, not the MMU, determine and take responsibility for offers that they submit and the market conduct that those offers represent.[29] If the MMU has a concern about an offer, the MMU may raise that concern with the FERC or other regulatory authorities. The FERC and other regulators have enforcement and regulatory authority that they may exercise with respect to offers submitted by market participants. PJM also reviews offers, but it does so in order to determine whether offers comply with the PJM tariff and manuals.[30] 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.[31] [32] 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.[33]

Market Design

In order to perform its role in PJM market design, the MMU evaluates existing and proposed PJM Market Rules and the design of the PJM Markets.[34] The MMU initiates and proposes changes to the design of such markets or the PJM Market Rules in stakeholder or regulatory proceedings.[35] In support of this function, the MMU engages in discussions with stakeholders, State Commissions, PJM Management, and the PJM Board; participates in PJM stakeholder meetings or working groups regarding market design matters; publishes proposals, reports or studies on such market design issues; and makes filings with the Commission on market design issues.[36] The MMU also recommends changes to the PJM Market Rules to the staff of the Commission's Office of Energy Market Regulation, State Commissions, and the PJM Board.[37] The MMU may provide in its annual, quarterly and other reports "recommendations regarding any matter within its purview."[38]

New Recommendations

Consistent with its core function to "[e]valuate existing and proposed market rules, tariff provisions and market design elements and recommend proposed rule and tariff changes,"[39] the MMU recommends specific enhancements to existing market rules and implementation of new rules that are required for competitive results in PJM markets and for continued improvements in the functioning of PJM markets.

In this *2015 State of the Market Report for PJM*, the MMU includes 27 recommendations that were new in 2015, ten of which are evaluated as high priority. Seventeen of the 27 new recommendations for 2015 are reported for the first time in this annual state of the market report. For a complete list of all MMU recommendations, see Section 2, Recommendations.

22 See OATT Attachment M–Appendix § II.A.
23 OATT Attachment M–Appendix § II.E.
24 OATT Attachment M–Appendix § II.B.
25 OATT Attachment M–Appendix § II.C.
26 OATT Attachment M–Appendix § IV.
27 OATT Attachment M–Appendix § VII.
28 OATT Attachment M § IV.
29 OATT § 12A.
30 OATT § 12A.
31 See OATT Attachment M–Appendix § II(p).
32 See OATT Attachment M–Appendix § III.
33 OA Schedule 6 § 1.5.
34 OATT Attachment M § IV.D.
35 *Id.*
36 *Id.*
37 *Id.*
38 OATT Attachment M § VI.A.
39 18 CFR § 35.28(g)(3)(ii)(A); see also OATT Attachment M § IV.D.

New Recommendation from Section 3, Energy Market

- The MMU recommends, in order to ensure effective market power mitigation when the TPS test is failed, that markup be constant across price and cost offers, that there be at least one cost-based offer using the same fuel as the available price-based offer. (Priority: High. New recommendation. Status: Not adopted.)
- The MMU recommends that in order to ensure effective market power mitigation when the TPS test is failed, the operating parameters in the cost-based offer and the price-based parameter limited schedule (PLS) offer be at least as flexible as the operating parameters in the available non-PLS price-based offer, and that the price-MW pairs in the price based PLS offer be exactly equal to the price based non PLS offer. (Priority: High. New recommendation. Status: Not adopted.)
- The MMU recommends that under the Capacity Performance construct, PJM recognize the difference between operational parameters that indicate to PJM dispatchers what a unit is capable of during the operating day and the parameters that are used for capacity performance assessment as well as uplift payments. The parameters which determine non-performance charges and the amount of uplift payments to those generators should reflect the flexibility goals of the capacity performance construct. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that capacity performance resources and base capacity resources (during the June through September period) be held to the OEM operating parameters of the capacity market CONE reference resource for performance assessment and energy uplift payments. (Priority: Medium. New recommendation. Status: Not adopted.)
- 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. (Priority: Medium. First reported Q2, 2015. Status: Not adopted.)
- The MMU recommends that PJM explicitly state its policy on the use of transmission penalty factors including the level of the penalty factors, the triggers for the use of the penalty factors, the appropriate line ratings to trigger the use of penalty factors, and when the transmission penalty factors will be used to set the shadow price. (Priority: Medium. New recommendation Status: Not adopted.)

New Recommendations from Section 4, Energy Uplift

- The MMU recommends that PJM not use price setting logic to artificially override the nodal prices that are based on fundamental LMP logic in order to reduce uplift. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that units scheduled in the Day-Ahead Energy Market and not committed in real time should be compensated for LOC based on their real-time desired and achievable output, not their scheduled day-ahead output. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that only flexible fast start units (startup plus notification times of 30 minutes or less) and short minimum run times (one hour or less) be eligible by default for the LOC compensation to units scheduled in the Day-Ahead Energy Market and not committed in real time. Other units should be eligible for LOC compensation only if PJM explicitly cancels their day-ahead commitment. (Priority: Medium. First reported 2015. Status: Not adopted.)

New Recommendations from Section 6, Demand Response

- The MMU recommends that PJM require nodal dispatch of demand resources with no advance notice required or, if nodal location is not required, subzonal dispatch of demand resources with no advance notice required. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM eliminate the measurement of compliance across zones within a compliance aggregation area (CAA). 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. (Priority: High. First reported 2015. Status: Not adopted.)

- The MMU recommends that the Net Benefits Test be eliminated and that demand response resources be paid LMP less any generation component of the applicable retail rate. (Priority: Low. New recommendation. Status: Not adopted.)
- 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 because load has been reduced or eliminated, such as in the case of bankrupt and/or out of service facilities. (Priority: Medium. First reported Q2, 2015. Status: Not adopted.)

New Recommendations from Section 9, Interchange Transactions

- The MMU recommends that PJMSettlement Inc. immediately request a credit evaluation from all companies that engaged in up to congestion transactions between September 8, 2014, and December 31, 2015. If PJM has the authority, PJM should ensure that the potential exposure to uplift for that period be included as a contingency in the companies' calculations for credit levels and/or collateral requirements. If PJM does not have the authority to take such steps, PJM should request guidance from FERC. (Priority: High. New recommendation. Status: Not adopted.)
- The MMU recommends that the emergency interchange cap be replaced with a market based solution. (Priority: Low. New recommendation. Status: Not adopted.)

New Recommendations from Section 10, Ancillary Services

- The MMU recommends that a reason code be attached to every hour in which PJM market operations adds additional DASR MW. (Priority: Medium. First reported Q2, 2015. Status: not adopted.)

New Recommendations from Section 12, Planning

- The MMU recommends that rules be implemented to require that project cost caps on new transmission projects be part of the evaluation of competing projects. (Priority: Low. New recommendation. Status: Not adopted.)
- 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. First reported Q2, 2015. Status: Not adopted.)
- The MMU recommends consideration of changing the minimum distribution factor in the allocation from .01 to .00 and adding a threshold minimum impact on the load on the line. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that PJM draft a clear definition of the congestion analysis required for transmission outage requests to include in Manual 3 after appropriate review. (Priority: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM modify the rules to reduce or eliminate the approval of late outage requests submitted or rescheduled after the FTR auction bidding opening date. (Priority: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM not permit transmission owners to divide long duration outages into smaller segments to avoid complying with the requirements for long duration outages. (Priority: Low. New recommendation. Status: Not adopted.)

New Recommendations from Section 13, Financial Transmission Rights

- The MMU recommends that the ARR/FTR design be modified to ensure that all congestion revenues are returned to load. (Priority: High. New recommendation. Status: Not adopted.)
- The MMU recommends that all FTR auction revenue be distributed to ARR holders. (Priority: High. New recommendation. Status: Not adopted.)

- The MMU recommends that historical generation to load paths be eliminated as a basis for allocating ARRs. (Priority: High. New recommendation. Status: Not adopted.)
- The MMU recommends that counter flow FTRs be eliminated. (Priority: High. New recommendation. Status: Not adopted.)
- The MMU recommends that FTR auction revenues not be used to buy counter flow FTRs with the purpose of improving FTR payout ratios.[40] (Priority: High. 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 2014 and 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 95.6 percent of the total price per MWh in 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 M Wh of network integration charges, and firm and non firm point to point transmission service.[41]
- The Energy Uplift (Operating Reserves) component is the average price per MWh of day-ahead and balancing operating reserves and synchronous condensing charges.[42]
- The Reactive component is the average cost per MWh of reactive supply and voltage control from generation and other sources.[43]
- The Regulation component is the average cost per MWh of regulation procured through the Regulation Market.[44]
- The PJM Administrative Fees component is the average cost per MWh of PJM's monthly expenses for a number of administrative services, including Advanced Control Center (AC2) and OATT Schedule 9 funding of FERC, OPSI and the MMU.
- The Transmission Enhancement Cost Recovery component is the average cost per MWh of PJM billed (and not otherwise collected through utility rates) costs for transmission upgrades and projects, including annual recovery for the TrAIL and PATH projects.[45]
- The 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.[46]
- The Emergency Load Response component is the average cost per MWh of the PJM Emergency Load Response Program.[47]
- 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.[48]
- 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.[49]
- The Synchronized Reserve component is the average cost per MWh of synchronized reserve procured through the Synchronized Reserve Market.[50]

40 See PJM. "Manual 6: Financial Transmission Rights" Revision 16 (June 1, 2014), p. 56.
41 OATT §§ 13.7, 14.5, 27A & 34.
42 OA Schedules 1 §§ 3.2.3 & 3.3.3.
43 OATT Schedule 2 and OA Schedule 1 § 3.2.3B. The line item in Table 1-8 includes all reactive services charges.
44 OA Schedules 1 §§ 3.2.2, 3.2.2A, 3.3.2, & 3.3.2A; OATT Schedule 3.
45 OATT Schedule 12.
46 Reliability Assurance Agreement Schedule 8.1.
47 OATT PJM Emergency Load Response Program.
48 OA Schedules 1 §§ 3.2.3A.01 & OATT Schedule 6.
49 OATT Schedule 1A.
50 OA Schedule 1 § 3.2.3A.01; PJM OATT Schedule 6.

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

Table 1-8 Total price per MWh by category: 2014 and 2015

Category	2014 $/MWh	2014 Percent of Total	2015 $/MWh	2015 Percent of Total	2014 to 2015 Percent Change Totals
Load Weighted Energy	$53.14	74.2%	$36.16	63.6%	(31.9%)
Capacity	$9.01	12.6%	$11.12	19.6%	23.5%
Transmission Service Charges	$5.95	8.3%	$7.08	12.5%	19.0%
Transmission Enhancement Cost Recovery	$0.42	0.6%	$0.51	0.9%	19.2%
PJM Administrative Fees	$0.44	0.6%	$0.44	0.8%	0.1%
Energy Uplift (Operating Reserves)	$1.18	1.6%	$0.38	0.7%	(67.7%)
Reactive	$0.40	0.6%	$0.37	0.7%	(6.0%)
Regulation	$0.33	0.5%	$0.23	0.4%	(28.8%)
Capacity (FRR)	$0.20	0.3%	$0.13	0.2%	(38.7%)
Synchronized Reserves	$0.21	0.3%	$0.12	0.2%	(41.4%)
Day Ahead Scheduling Reserve (DASR)	$0.05	0.1%	$0.10	0.2%	115.5%
Transmission Owner (Schedule 1A)	$0.09	0.1%	$0.09	0.2%	1.2%
Black Start	$0.08	0.1%	$0.06	0.1%	(15.5%)
NERC/RFC	$0.02	0.0%	$0.03	0.0%	19.5%
Non-Synchronized Reserves	$0.02	0.0%	$0.02	0.0%	2.1%
Load Response	$0.02	0.0%	$0.02	0.0%	(15.2%)
RTO Startup and Expansion	$0.01	0.0%	$0.01	0.0%	(49.0%)
Transmission Facility Charges	$0.00	0.0%	$0.00	0.0%	134.6%
Emergency Load Response	$0.06	0.1%	$0.00	0.0%	(98.9%)
Emergency Energy	$0.01	0.0%	$0.00	0.0%	(100.0%)
Total	$71.62	100.0%	$56.86	100.0%	(20.6%)

Section Overviews

Overview: Section 3, "Energy Market"

Market Structure

- **Supply.** Supply includes physical generation and imports and virtual transactions. Average offered real-time generation increased by 4,490 MW, or 2.8 percent, in the summer months of 2015 from an average maximum of 160,190 in the summer of 2014 to 164,680 MW in the summer of 2015 of 160,190 MW to 164,680 MW. In 2015, 3,041.2 MW of new capacity were added to PJM. This new generation was more than offset by the deactivation of 9,897.2 MW.

  PJM average real-time generation in 2015 decreased by 2.5 percent from 2014, from 90,894 MW to 88,628 MW.

  PJM average day-ahead supply in 2015, including INCs and up to congestion transactions, decreased by 21.7 percent from 2014, from 146,672 MW to 114,889 MW, primarily as a result of decreases in UTC volumes.

- **Market Concentration.** The PJM energy market was moderately concentrated overall with moderate concentration in the baseload segment, but high concentration in the intermediate and peaking segments.
- **Generation Fuel Mix.** During 2015, coal units provided 36.6 percent, nuclear units 35.5 percent and gas units 23.4 percent of total generation. Compared to 2014, generation from coal units decreased 17.8 percent, generation from gas units increased 27.7 percent and generation from nuclear units increased 0.5 percent.
- **Marginal Resources.** In the PJM Real-Time Energy Market, in 2015, coal units were 51.74 percent of marginal resources and natural gas units were 35.52 percent of marginal resources. In 2014, coal

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

units were 52.90 percent and natural gas units were 35.81 percent of the marginal resources.

In the PJM Day-Ahead Energy Market, in 2015, up to congestion transactions were 76.1 percent of marginal resources, INCs were 5.1 percent of marginal resources, DECs were 8.9 percent of marginal resources, and generation resources were 9.6 percent of marginal resources. In 2014, up to congestion transactions were 91.0 percent of marginal resources, INCs were 2.3 percent of marginal resources, DECs were 3.3 percent of marginal resources, and generation resources were 3.3 percent of marginal resources.

- **Demand.** Demand includes physical load and exports and virtual transactions. The PJM system peak load during 2015 was 143,697 MW in the HE 1700 on July 28, 2015, which was 2,023 MW, or 1.4 percent, higher than the PJM peak load for 2014, which was 141,673 MW in the HE 1700 on June 17, 2014.

  PJM average real-time load in 2015 decreased by 0.6 percent from 2014, from 89,099 MW to 88,594 MW. PJM average day-ahead demand in 2015, including DECs and up to congestion transactions, decreased by 21.5 percent from 2014, from 142,644 MW to 111,644 MW.

- **Supply and Demand: Scarcity.** There were no shortage pricing events in 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 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 0.5 percent in 2014 to 0.4 percent in 2015.

  In 2015, 15 control zones experienced congestion resulting from one or more constraints binding for 100 or more hours. The analysis of the application of the TPS test to local markets demonstrates that it is working successfully to identify 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. There are, however, identified issues with the application of market power mitigation to resources whose owners fail the TPS test that can result in the exercise of local market power. These issues need to be addressed.

- **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 remained at 0.4 percent in 2014 and 2015. In the Real-Time Energy Market, for units committed for reliability reasons, offer-capped unit hours increased from 0.3 percent in 2014 to 0.4 percent in 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, when using unadjusted cost offers, in 2015, 85.9 percent of marginal units had average dollar markups less than zero and had an average markup index less than zero. Using adjusted cost offers, in 2015, 47.1 percent of marginal units had average dollar markups less than zero and average markup index less than or equal to zero. Some marginal units did have substantial markups. Using unadjusted cost offers, 0.17 percent of offers had offer prices greater than $400 per MWh with average dollar markup of $56.87 per MWh.

  In the PJM Day-Ahead Energy Market, when using unadjusted cost offers, in 2015, 3.2 percent of marginal generating units had an average markup index less than or equal to zero. Using adjusted cost offers, in the 2015, 3.2 percent of marginal units had an average markup index less than or equal to zero.

- **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. There were no units eligible for an FMU or AU adder in 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 but there was an increase in up to congestion volume in December 2015, coincident with the expiration of the fifteen month resettlement period for the proceeding related to uplift charges for UTC transactions.[58 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. 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 2015, 56.1 percent were offered as available for economic dispatch, 23.8 percent were offered as self scheduled, and 20.1 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 changes in supply and demand, generation fuel mix, the cost of fuel, emission related expenses, markup and local price differences caused by congestion. PJM also may administratively set prices with the creation of a closed loop interface related to demand side resources or reactive power or the application of price setting logic.

  PJM Real-Time Energy Market prices decreased in 2015 compared to 2014. The load-weighted average real-time LMP was 31.9 percent lower in 2015 than in 2014, $36.16 per MWh versus $53.14 per MWh.

  PJM Day-Ahead Energy Market prices decreased in 2015 compared to 2014. The load-weighted average day-ahead LMP was 31.5 percent lower in 2015 than in 2014, $36.73 per MWh versus $53.62 per MWh.

- **Components of LMP.** In the PJM Real-Time Energy Market, for 2015, 43.2 percent of the load-weighted LMP was the result of coal costs, 27.2 percent was the result of gas costs and 2.32 percent was the result of the cost of emission allowances.

  In the PJM Day-Ahead Energy Market for 2015, 29.6 percent of the load-weighted LMP was the result of the cost of coal, 22.5 percent was the result of DECs, 14.3 percent was the result of the cost of gas, 11.6 percent was the result of INCs, and 4.3 percent was the result of up to congestion transactions.

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

  In the PJM Real-Time Energy Market in 2015, the adjusted markup component of LMP was $1.75 per MWh or 4.8 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 PJM Day-Ahead Energy Market, marginal INCs, DECs and UTCs have zero markups. In 2015, the adjusted markup component of LMP resulting from generation resources was $0.78 per MWh or 2.1 percent of the PJM day-ahead load-weighted average LMP. The month of February had the highest adjusted markup component, $2.81 per MWh or 3.6 percent of the day-ahead load-weighted average LMP. In 2015, the highest hourly adjusted markup was $710.63.

  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 is consistent with economic withholding.

- **Price Convergence.** Hourly and daily price differences between the Day-Ahead and Real-Time Energy

58 148 FERC ¶ 61,144 (2014).
59 16 U.S.C. § 824e.

Markets fluctuate continuously and substantially from positive to negative. The difference between the average day-ahead and real-time prices was -$0.93 per MWh in 2014 and -$0.73 per MWh in 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 2015.

Section 3 Recommendations

- The MMU recommends that PJM retain the $1,000 per MWh offer cap in the PJM energy market except when cost-based offers exceed $1,000 per MWh, and other existing rules that limit incentives to exercise market power. (Priority: High. First reported 1999. Status: Partially adopted, 1999.)
- The MMU recommends that the rules governing the application of the TPS test be clarified and documented. (Priority: High. First reported 2010. Status: Not adopted.)
- The MMU recommends, in order to ensure effective market power mitigation when the TPS test is failed, that markup be constant across price and cost offers, that there be at least one cost-based offer using the same fuel as the available price-based offer. (Priority: High. New recommendation. Status: Not adopted.)
- The MMU recommends that in order to ensure effective market power mitigation when the TPS test is failed, the operating parameters in the cost-based offer and the price-based parameter limited schedule (PLS) offer be at least as flexible as the operating parameters in the available non-PLS price-based offer, and that the price-MW pairs in the price based PLS offer be exactly equal to the price based non PLS offer. (Priority: High. New recommendation. Status: Not adopted.)
- 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 under the Capacity Performance construct, PJM recognize the difference between operational parameters that indicate to PJM dispatchers what a unit is capable of during the operating day and the parameters that are used for capacity performance assessment as well as uplift payments. The parameters which determine non-performance charges and the amount of uplift payments to those generators should reflect the flexibility goals of the capacity performance construct. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that capacity performance resources and base capacity resources (during the June through September period) be held to the OEM operating parameters of the capacity market CONE reference resource for performance assessment and energy uplift payments. (Priority: Medium. New recommendation. Status: Not adopted.)
- 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. (Priority: Medium. First reported Q2, 2015. Status: Not 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 rather than indicating its availability to supply energy on an emergency basis. (Priority: Low. First reported 2009. Status: Not Adopted.)
- The MMU recommends that PJM explain how LMPs are calculated when demand response is marginal. The LMPs in excess of $1,800 per MWh on January 7, 2014, were potentially a result of the way in which PJM modeled zonal (not nodal) demand response as a marginal resource. (Priority: Low. First reported Q1, 2014. Status: Not Adopted.)
- The MMU recommends that PJM explicitly state its policy on the use of transmission penalty factors including the level of the penalty factors, the triggers for the use of the penalty factors, the appropriate line ratings to trigger the use of penalty factors, and when the transmission penalty factors will be used to set the shadow price. (Priority: Medium. New recommendation 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: Partially 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.[60] (Priority: Medium. First reported 2012. 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.)
- 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.[61] There is currently no PJM documentation in the tariff or manuals explaining how hubs are created and how their definitions are changed.[62] (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 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: Partially adopted.)
- The MMU recommends that PJM continue to enhance its posting of market data to promote market efficiency. (Priority: Medium. First reported 2005. Status: Partially Adopted.)
- The MMU recommends the elimination of FMU and AU adders. 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.)

Section 3 Conclusion

The MMU analyzed key elements of PJM energy market structure, participant conduct and market performance in 2015, including aggregate supply and demand, concentration ratios, three pivotal supplier test results, offer capping, participation in demand response programs, loads and prices.

Average PJM real-time generation increased by 4,490 MW, or 2.8 percent, in the summer of 2015 compared to the summer of 2014, and peak load increased by 2,023 MW. Market concentration levels remained moderate although there is high concentration in the intermediate and peaking segments of the supply curve 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 the 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 aggregate market power does exist during high demand hours.

60 PJM. OATT Section: 6A.1.3 Maximum Emergency, (February 25, 2014), p. 1740, 1795.

61 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.

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

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 2015 generally reflected supply-demand fundamentals, although the behavior of some participants during high demand periods is consistent with economic withholding. Economic withholding is the ability to increase markups substantially in tight market conditions. There are additional issues in the energy market including the uncertainties about the pricing and availability of natural gas, the way that generation owners incorporate natural gas costs in offers, and 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.[63] 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 for most hours to exempt owners when the local market structure is competitive and to require offer capping of owners when the local market structure is noncompetitive.

However, there are some issues with the application of mitigation in the Day-Ahead Energy Market and the Real-Time Energy Market when market sellers fail the TPS test. There is no tariff or manual language that defines in detail the application of the TPS test and offer capping in the Day-Ahead Energy Market and the Real-Time Energy Market. In both the Day-Ahead and Real-Time Energy Markets, generators have the ability to avoid mitigation by using varying markups in their price-based offers, offering different operating parameters in their price-based and cost-based offers, and using different fuels in their price-based and cost-based offers. These issues can be resolved by simple rule changes requiring that markup be constant across price and cost offers, that there be at least one cost-based offer using the same fuel as the available price-based offer, that the price-MW pairs in the price based PLS offer be exactly equal to the price based non PLS offer, and requiring cost- based and price-based PLS offers to be at least as flexible as price-based non-PLS offers.

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.

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 based on measured reserve levels and transparent prices and that there are strong incentives for competitive behavior

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

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 net 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. There are also significant issues with PJM's scarcity pricing rules, including the absence of a clear trigger based on measured reserve levels (the current triggers are based on estimated reserves) and the lack of adequate locational scarcity pricing options.

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 2014 or 2015. 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 is consistent with economic withholding. Given the structure of the energy market which can permit the exercise of aggregate market power at times of high demand, the tighter market conditions 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 2015.

Overview: Section 4, "Energy Uplift"

Energy Uplift Results

- **Energy Uplift Charges.** Total energy uplift charges decreased by $646.3 million, or 67.3 percent, in 2015 compared to 2014, from $960.5 million to $314.2 million.
- **Energy Uplift Charges Categories.** The decrease of $646.3 million in 2015 is comprised of a $12.6 million decrease in day-ahead operating reserve charges, a $587.0 million decrease in balancing operating reserve charges, an $18.8 million decrease in reactive services charges, a $0.1 million decrease in synchronous condensing charges and a $27.7 million decrease in black start services charges.
- **Average Effective Operating Reserve Rates in the Eastern Region.** Day-ahead load paid $0.115 per MWh, real-time load paid $0.050 per MWh, a DEC paid $1.187 per MWh and an INC and any load, generation or interchange transaction deviation paid $1.072 per MWh.
- **Average Effective Operating Reserve Rates in the Western Region.** Day-ahead load paid $0.115 per MWh, real-time load paid $0.042 per MWh, a DEC paid $1.151 per MWh and an INC and any load, generation or interchange transaction deviation paid $1.036 per MWh.
- **Reactive Services Rates.** The DPL, ATSI and Dominion control zones had the three highest local voltage support rates: $0.124, $0.056 and $0.027 per MWh. The reactive transfer interface support rate averaged $0.0019 per MWh.

Characteristics of Credits

- **Types of units.** Combined cycles received 24.0 percent of all day-ahead generator credits and 39.1 percent of all balancing generator credits. Combustion turbines and diesels received 85.6 percent of the lost opportunity cost credits. Coal units received 39.6 percent of all reactive services credits.
- **Concentration of Energy Uplift Credits.** The top 10 units receiving energy uplift credits received 34.2 percent of all credits. The top 10 organizations received 78.0 percent of all credits. Concentration indexes for energy uplift categories classify them as highly concentrated. Day-ahead operating reserves HHI was 5828, balancing operating reserves HHI was 3740, lost opportunity cost HHI was 3788 and reactive services HHI was 9093.
- **Economic and Noneconomic Generation.** In 2015, 88.0 percent of the day-ahead generation eligible for operating reserve credits was economic and 73.2 percent of the real-time generation eligible for operating reserve credits was economic.
- **Day-Ahead Unit Commitment for Reliability.** In 2015, 1.9 percent of the total day-ahead generation MWh

was scheduled as must run by PJM, of which 44.0 percent received energy uplift payments.

Geography of Charges and Credits

- In 2015, 88.4 percent of all uplift 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, 3.2 percent by transactions at hubs and aggregates and 8.3 percent by interchange transactions at interfaces.
- Generators in the Eastern Region received 68.2 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.
- Generators in the Western Region received 31.5 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.
- External generators received 0.2 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.

Energy Uplift Issues

- **Lost Opportunity Cost Credits.** In 2015, lost opportunity cost credits decreased by $71.1 million compared to 2014. In 2015, resources in the top three control zones receiving lost opportunity cost credits, AEP, Dominion and ComEd, accounted for 47.1 percent of all lost opportunity cost credits, 41.9 percent of all day-ahead generation from pool-scheduled combustion turbines and diesels, 39.6 percent of all day-ahead generation not committed in real time by PJM from those unit types and 39.0 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 were not economic. These black start units provided black start service under the ALR option, which means that the units had to run in order to provide black start services even if the units were not economic. PJM replaced all ALR units as black start resources as of April 2015. In 2015, the cost of the noneconomic operation of ALR units in the AEP Control Zone was $4.8 million, a decrease of $27.8 million compared to 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 2015, the average rate paid by a DEC in the Eastern Region would have been $0.149 per MWh under the MMU proposal, which is $1.038 per MWh, or 87.4 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 interface constraints to artificially override the nodal prices that are based on fundamental LMP logic in order to: accommodate rather than resolve the inadequacies of the demand side resource capacity product; address the inability of the power flow model to incorporate the need for reactive power; accommodate rather than resolve the flaws in PJM's approach to scarcity pricing; or for any other reason. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM not use price setting logic to artificially override the nodal prices that are based on fundamental LMP logic in order to reduce uplift. (Priority: Medium. New recommendation. Status: Not adopted.)

- The MMU recommends that PJM initiate an analysis of the reasons why some combustion turbines and diesels scheduled in the Day-Ahead Energy Market are not called in real time when they are economic. (Priority: Medium. First Reported 2012. Status: Not adopted.)
- 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 2014.)
- 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. Stakeholder process.)
- 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 2009. 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 seven modifications to the energy lost opportunity cost calculations:
  - The MMU recommends that the lost opportunity cost in the energy market be calculated using the schedule on which the unit was scheduled to run in the energy market. (Priority: High. First reported 2012. Status: Adopted 2015.)
  - 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: Adopted 2015.)
  - 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: Adopted 2015.)
  - The MMU recommends calculating LOC based on 24 hour daily periods or multi-hour segments of hours for 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 units scheduled in the Day-Ahead Energy Market and not committed in real time should be compensated for LOC based on their real-time desired and achievable output, not their scheduled day-ahead output. (Priority: Medium. First reported 2015. Status: Not adopted.)
  - The MMU recommends that units scheduled in the Day-Ahead Energy Market and not committed in real time be compensated for LOC incurred within an hour. (Priority: Medium. First reported 2013. Status: Not adopted.)
  - The MMU recommends that only flexible fast start units (startup plus notification times of 30 minutes or less) and short minimum run times (one hour or less) be eligible by default for the LOC compensation to units scheduled in the Day-Ahead Energy Market and not committed in real time. Other units should be eligible for LOC compensation only if PJM explicitly cancels their day-ahead commitment. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that up to congestion transactions be required to pay energy uplift charges. (Priority: High. First reported 2011. 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. Stakeholder process.)
- 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 solely to real-time RTO load. (Priority: Low. First reported 2013. Status: Not adopted. Stakeholder process.)
- 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 Q2, 2012. 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.

In PJM all energy payments to demand response resources are also uplift payments. The energy payments to these resources are not part of the supply and demand balance, they are not paid by LMP revenues and therefore the energy payments to demand response resources have to be paid as out of market uplift. The energy payments to economic DR are funded by real-time load and real-time exports. The energy payments to emergency DR are funded by participants with net energy purchases in the Real-Time Energy Market.

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.

One part of addressing the level and allocation of uplift payments is to eliminate all day-ahead operating reserve credits. It is illogical and unnecessary to pay units day-ahead operating reserve credits because units do not incur any costs to run and any revenue shortfalls are addressed by balancing operating reserve credits.

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'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. 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. 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.

But it is also important that the reduction of uplift payments not be a goal to be achieved at the expense of the fundamental logic of an LMP system. For example, the use of closed loop interfaces to reduce uplift should be eliminated because it is not consistent with LMP fundamentals and constitutes a form of subjective price setting. The same is true of what PJM terms its price setting logic.

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.[64]

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.[65] 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.[66] 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.[67]

The 2016/2017 RPM Second Incremental Auction, 2018/2019 RPM Base Residual Auction, 2016/2017 Capacity Performance Transition Incremental Auction, 2017/2018 Capacity Performance Transition Incremental Auction, and 2017/2018 RPM First Incremental Auction were conducted in 2015. The Base Residual Auction for the 2018/2019 Delivery Year had been delayed.[68] The Capacity Performance (CP) Transition Incremental Auctions (IAs) were held as part of a five year transition to a single capacity product type in the 2020/2021 Delivery Year. Participation in the CP Transition IAs was voluntary. If a resource cleared a CP Transition IA and had a prior commitment for the relevant Delivery

64 The terms *PJM Region*, *RTO Region* and *RTO* are synonymous in the *2015 State of the Market Report for PJM*, Section 5, "Capacity Market," and include all capacity within the PJM footprint.
65 See 126 FERC ¶ 61,275 (2009) at P 86.
66 See *PJM Interconnection, L.L.C.*, Letter Order in Docket No. ER10-366-000 (January 22, 2010).
67 See 126 FERC ¶ 61,275 (2009) at P 88.
68 151 FERC ¶ 61,067 (2015).

Year, the existing commitment was converted to a CP commitment which is subject to the CP performance requirements and Non-Performance Charges. The Transition IAs were not designed to minimize the cost of purchasing Capacity Performance resources for the two delivery years and were not designed to maximize economic welfare for the two delivery years.[69]

One June 9, 2015, FERC accepted changes to the PJM capacity market rules proposed in PJM's Capacity Performance (CP) filing.[70] For a transition period during the 2018/2019 and 2019/2020 Delivery Years, PJM will procure two product types, Capacity Performance and Base Capacity. PJM also procured Capacity Performance resources in two transition auctions for Delivery Years 2016/2017 and 2017/2018. Effective with the 2020/2021 Delivery Year, PJM will procure a single capacity product, Capacity Performance. CP Resources are expected to be available and capable of providing energy and reserves when needed at any time during the Delivery Year.[71] Effective for the 2018/2019 through the 2019/2020 Delivery Years, a Base Capacity Demand Resource Constraint and a Base Capacity Resource Constraint are established for each modeled LDA. These maximum quantities are set for reliability purpose to limit the quantity procured of the less available products, including Base Capacity Generation Resources, Base Capacity Demand Resources, and Base Capacity Energy Efficiency Resources.

RPM prices are locational and may vary depending on transmission constraints.[72] Existing generation capable of qualifying as a capacity resource must be offered into RPM Auctions, except for resources owned by entities that elect the fixed resource requirement (FRR) option. Participation by LSEs is mandatory, except for those entities that elect the FRR option. There is an administratively determined demand curve that defines scarcity pricing levels and that, with the supply curve derived from capacity offers, determines market prices in each BRA. RPM rules provide performance incentives for generation, including the requirement to submit generator outage data and the linking of capacity payments to the level of unforced capacity, and the performance incentives have been strengthened significantly under the Capacity Performance modifications to RPM. Under RPM there are explicit market power mitigation rules that define the must offer requirement, that define structural market power based on the marginal cost of capacity, that define offer caps, 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 2015, PJM installed capacity decreased 6,043.2 MW or 3.3 percent, from 183,726 MW on January 1 to 177,682.8 MW on December 31. 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 December 31, 2015, 37.5 percent was coal; 34.0 percent was gas; 18.6 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.
- **Supply.** Total internal capacity available to offer in the Base Residual Auction for the relevant Delivery Year increased 8,321.5 MW from 196,235.8 MW on June 1, 2014, to 204,557.3 MW on June 1, 2015. This increase was the result of new generation (6,786.1 MW), net generation capacity modifications (cap mods) (-5,118.9 MW), Demand Resource (DR) modifications (5,441.4 MW), Energy Efficiency (EE) modifications (220.1 MW), the EFORd effect due to lower sell offer EFORds (938.4 MW), and lower load management UCAP conversion factor (54.4 MW).
- **Demand.** There was a 902.4 MW decrease in the RPM reliability requirement from 178,086.5 MW on June 1, 2014, to 177,184.1 MW on June 1, 2015. The 902.4 MW decrease in the RTO Reliability Requirement was a result of a 1,718.2 MW decrease in the forecast peak load in UCAP terms holding the Forecast Pool Requirement (FPR) constant at the 2014/2015 level offset by a 815.8 MW increase attributable to the change in FPR. On June 1, 2015, PJM EDCs and their affiliates maintained a large market share of load obligations under RPM,

69 The MMU will publish a detailed report on the operation and design of the transition auctions in 2016.

70 See Docket No. ER15-623-000 (December 12, 2014) and 151 FERC ¶ 61,208 (2015).

71 See PJM. "Manual 18: PJM Capacity Market," Revision 30 (December 17, 2015), p. 7.

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.

together totaling 65.1 percent, down from 71.1 percent on June 1, 2014.

- **Market Concentration.** In the 2016/2017 RPM Second Incremental Auction, the 2018/2019 RPM Base Residual Auction, and the 2017/2018 RPM First Incremental Auction all participants in the total PJM market as well as the LDA RPM markets failed the three pivotal supplier (TPS) test.[73] The TPS test was not applied in the 2016/2017 Capacity Performance (CP) Transition Incremental Auction and the 2017/2018 CP Transition Incremental Auction. All offers in the Transition Auctions were subject to overall offer caps. Offer caps were applied to all sell offers for resources which were subject to mitigation when the Capacity Market Seller did not pass the test, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, increased the market clearing price.[74 75 76]

- **Imports and Exports.** Of the 5,135.8 MW of imports in the 2018/2019 RPM Base Residual Auction, 4,687.9 MW cleared. Of the cleared imports, 2,509.1 MW (53.5 percent) were from MISO.

- **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

- **2015/2016 RPM Base Residual Auction.** Of the 1,168 generation resources which submitted offers, unit-specific offer caps were calculated for 196 generation resources (16.8 percent). The MMU calculated offer caps for 670 generation resources (57.4 percent), of which 478 were based on the technology specific default (proxy) ACR values.

- **2015/2016 RPM First Incremental Auction.** Of the 131 generation resources which submitted offers, unit-specific offer caps were calculated for 20 generation resources (15.3 percent). The MMU calculated offer caps for 45 generation resources (34.4 percent), of which 25 were based on the technology specific default (proxy) ACR values.

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

- **2015/2016 RPM Third Incremental Auction.** Of the 214 generation resources which submitted offers, unit-specific offer caps were calculated for seven generation resources (3.3 percent). The MMU calculated offer caps for 23 generation resources (10.7 percent), of which 16 were based on the technology specific default (proxy) ACR values.

- **2016/2017 RPM Base Residual Auction.** Of the 1,199 generation resources which submitted offers, unit-specific offer caps were calculated for 152 generation resources (12.7 percent). The MMU calculated offer caps for 638 generation resources (53.2 percent), of which 491 were based on the technology specific default (proxy) ACR values.

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

- **2016/2017 RPM Second Incremental Auction.** Of the 101 generation resources that submitted offers, the MMU calculated offer caps for 45 generation resources (44.6 percent), of which 21 were based on the technology specific default (proxy) ACR values and 24 were unit-specific offer caps (23.8 percent).

- **2016/2017 Capacity Performance Transition Incremental Auction.** All 709 generation resources

73 There are 27 Locational Deliverability Areas (LDAs) identified to recognize locational constraints as defined in "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region", Schedule 10.1. PJM determines, in advance of each BRA, whether the defined LDAs will be modeled in the given Delivery Year using the rules defined in OATT Attachment DD (Reliability Pricing Model) § 5.10(a)(ii).

74 See PJM. OATT Attachment DD § 6.5.

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

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

which submitted offers in the 2016/2017 CP Transition Incremental Auction were subject to an offer cap of $165.27 per MW-day, which is 50 percent of the Net Cost of New Entry (CONE) used in the 2016/2017 RPM Base Residual Auction.

- **2017/2018 RPM Base Residual Auction.** Of the 1,202 generation resources which submitted offers, unit-specific offer caps were calculated for 131 generation resources (10.9 percent). The MMU calculated offer caps for 531 generation resources (44.2 percent), of which 400 were based on the technology specific default (proxy) ACR values.
- **2017/2018 Capacity Performance Transition Incremental Auction.** All 785 generation resources which submitted offers in the 2017/2018 CP Transition Incremental Auction were subject to an offer cap of $210.83 per MW-day, which is 60 percent of the Net Cost of New Entry (CONE) used in the 2017/2018 RPM Base Residual Auction.
- **2017/2018 RPM First Incremental Auction.** Of the 118 generation resources that submitted offers, the MMU calculated offer caps for 53 generation resources (44.9 percent), of which 36 were based on the technology specific default (proxy) ACR values and 17 were unit-specific offer caps (14.4 percent).
- **2018/2019 RPM Base Residual Auction.** Of the 473 generation resources that submitted Base Capacity offers, the MMU calculated offer caps for 219 generation resources (46.3 percent), of which 166 (35.1 percent) were based on the technology specific default (proxy) ACR values and 53 were unit-specific offer caps (11.2 percent). Of the 992 generation resources that submitted Capacity Performance offers, the MMU calculated unit specific offer caps for 35 generation resources (3.5 percent).

Market Performance

- The 2015/2016 RPM Third Incremental Auction, the 2016/2017 RPM Second Incremental Auction, 2018/2019 RPM Base Residual Auction, 2016/2017 Capacity Performance Transition Incremental Auction, 2017/2018 Capacity Performance Transition Incremental Auction, and 2017/2018 RPM First Incremental Auction were conducted in 2015. The weighted average capacity price for the 2016/2017 Delivery Year is $122.70 per MW-day, including all RPM Auctions for the 2016/2017 Delivery Year held through 2015. The weighted average capacity price for the 2017/2018 Delivery Year is $142.83, including all RPM Auctions for the 2017/2018 Delivery Year held through 2015. The weighted average capacity price for the 2018/2019 Delivery Year is $179.60, including all RPM Auctions for the 2018/2019 Delivery Year held through 2015.RPM net excess increased 383.6 MW from 5,472.3 MW on June 1, 2014, to 5,855.9 MW on June 1, 2015.
- For the 2015/2016 Delivery Year, RPM annual charges to load are $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 2015 was 6.9 percent, a decrease from 9.4 percent for 2014.[77]
- **Generator Performance Factors.** The PJM aggregate equivalent availability factor for 2015 was 83.7 percent, an increase from 82.2 percent for 2014.
- **Outages Deemed Outside Management Control (OMC).** In 2015, 4.2 percent of forced outages were classified as OMC outages, a decrease from 7.7 percent in 2014. In 2015, 0.6 percent of OMC outages were due to lack of fuel, compared to 0.5 percent in 2014.

Section 5 Recommendations[78]

The MMU recognizes that PJM has implemented 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. The MMU's recommendations are based on the existing capacity market rules. The status is reported as adopted if

77 The generator performance analysis includes all PJM capacity resources for which there are data in the PJM generator availability data systems (GADS) database. This set of capacity resources may include generators in addition to those in the set of generators committed as capacity resources in RPM. Data is for the twelve months ending December 31, as downloaded from the PJM GADS database on January 27, 2016. EFORd data presented in state of the market reports may be revised based on data submitted after the publication of the reports as generation owners may submit corrections at any time with permission from PJM GADS administrators.

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

the recommendation was included in FERC's order approving PJM's Capacity Performance filing.[79]

- 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.[80] [81] (Priority: High. First reported 2013. Status: Not adopted. Pending before FERC.)

- 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: Partially 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.[82,83] 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 modifications to existing resources not be treated as new resources for purposes of market power related offer caps or MOPR offer floors. (Priority: Low. First reported 2012. 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.[84] (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 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 definition of demand side resources be modified in order to

79 *PJM Interconnection, L.L.C.*, 151 FERC ¶ 61,208 (June 9, 2015).

80 See also Comments of the Independent Market Monitor for PJM. Docket No. ER14-503-000 (December 20, 2013).

81 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).

82 See *PJM Interconnection, L.L.C.*, Docket No. ER12-513-000 (December 1, 2011) ("Triennial Review").

83 See the *2012 State of the Market Report for PJM*, Volume II, Section 6, Net Revenue.

84 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).

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 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 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 2012. 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.[85] (Priority: Medium. First reported 2013. Status: Adopted.)

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 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 2015.

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 Order No. 745, which provided for payment of demand-side resources at full LMP.[86] 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."[87] On January 25, 2016, the Supreme Court voted 6-2 to reverse the decision of the lower court.[88] The result is that FERC retains jurisdiction over demand-side programs.
- **Demand Response Activity.** Demand response includes the economic program and the emergency program. The economic program includes the

85 See OATT Attachment DD § 10(e). 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).

86 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).

87 *Id.*

88 FERC v. Electric Power Supply Association, Slip Op. No. 14-840.

response to energy prices in the energy market. The emergency program is the capacity market program which includes both capacity payments and associated energy revenues when the capacity is called on to respond. The emergency program accounted for 98.4 percent of all revenue received by demand response providers, the economic program for 1.0 percent and synchronized reserve for 0.6 percent. In 2015, total emergency revenue increased by $136.4 million, or 20.2 percent, from $675.7 million in 2014 to $812.2 in 2015. Capacity market revenue increased by $178.9 million, or 28.3 percent, from $632.8 million in 2014 to $811.7 million 2015.[89] Emergency energy revenue decreased by $42.5 million, from $43.0 million in 2014 to $0.5 million in 2015. Economic program revenue decreased by $9.5 million, from $17.8 million in 2014 to $8.3 million in 2015, a 53.2 percent decrease.[90] Synchronized reserve revenue increased by $43.3 thousand, a 0.6 percent increase. Total demand response revenue in 2015 increased by 18.2 percent from $675.7 million 2014 to $825.6 million in 2015. Not all DR activities in 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 although emergency demand response can and does set LMP. 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 single system price determined under the net benefits test for that month.[91]

- **Demand Response Market Concentration.** The ownership of economic demand response was highly concentrated in 2014 and 2015. The HHI for economic demand response reductions increased from 7713 in 2014 to 7862 in 2015. The ownership of emergency demand response was moderately concentrated in 2015. The HHI for emergency demand response registrations was 1760 for the 2014/2015 Delivery Year and 1497 for the 2015/2016 Delivery Year. 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 it is 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 as is the case for generation resources.

Section 6 Recommendations

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 December 31, 2015.

- 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.)

- The MMU recommends that there be only one demand response product, with an obligation to respond when called for all hours of the year, and that the demand response be on the demand side of the capacity market. (Priority: High. First reported 2011. Status: Partially Adopted.[92])

- The MMU recommends that the option to specify a minimum dispatch price under the Emergency and Pre-Emergency Program Full option be eliminated and that participating resources receive the hourly real-time LMP less any generation component of their retail rate. (Priority: Medium. First reported 2010. Status: Not adopted.)

89 The total credits and MWh numbers for demand resources were calculated as of February 27, 2015 and may change as a result of continued PJM billing updates.

90 Economic credits are synonymous with revenue received for reductions under the economic load response program.

91 PJM: "Manual 28: Operating Agreement Accounting," Revision 64 (April 11, 2014), p 70.

92 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.

- The MMU recommends that the emergency load response program be classified as an economic program, responding to economic price signals and not an emergency program responding only after an emergency is called and not triggering the definition of a PJM emergency. (Priority: High. First reported 2012. Status: Not adopted.)
- The MMU recommends that the Emergency Program Energy Only option be eliminated because the opportunity to receive the appropriate energy market incentive is already provided in the Economic Program. (Priority: Low. First reported 2010. Status: Not adopted.)
- The MMU recommends that a daily energy market must offer requirement apply to demand resources, comparable to the rule applicable to generation capacity resources.[93] (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that 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: Partially adopted.)
- The MMU recommends that demand resources be required to provide their nodal location, comparable to generation resources. (Priority: High. First reported 2011. Status: Not adopted.)
- The MMU recommends that PJM require nodal dispatch of demand resources with no advance notice required or, if nodal location is not required, subzonal dispatch of demand resources with no advance notice required. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM eliminate the measurement of compliance across zones within a compliance aggregation area (CAA). 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. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends capping the baseline for measuring compliance under GLD, for the limited summer product, at the customers' PLC. (Priority: High. First reported 2010. Status: Adopted.)
- The MMU recommends capping the baseline for measuring capacity compliance under winter compliance at the customers' PLC, similar to GLD, to avoid double counting. (Priority: High. First reported 2010. Status: Partially adopted.)
- The MMU recommends that measurement and verification methods for demand resources be modified to reflect compliance more accurately. (Priority: Medium. First reported 2009. Status: Not adopted.)
- The MMU recommends that compliance rules be revised to include submittal of all necessary hourly load data, and that negative values be included when calculating event compliance across hours and registrations. (Priority: Medium. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM adopt the ISO-NE five-minute metering requirements in order to ensure that dispatchers have the necessary information for reliability and that market payments to demand resources be calculated based on interval meter data at the site of the demand reductions.[94] (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that demand response event compliance be calculated for each hour and the penalty structure reflect hourly compliance for the base and capacity performance products. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that demand resources whose load drop method is designated as "Other" explicitly record the method of load drop. (Priority: Low. First reported 2013. Status: Adopted, Q2, 2014.)
- The MMU recommends that 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.)

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

94 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 shutdown cost be defined as the cost to curtail load for a given period that does not vary with the measured reduction or, for behind the meter generators, be the start cost defined in Manual 15 for generators. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that the Net Benefits Test be eliminated and that demand response resources be paid LMP less any generation component of the applicable retail rate. (Priority: Low. New recommendation. Status: Not adopted.)
- 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 because load has been reduced or eliminated, such as in the case of bankrupt and/or out of service facilities. (Priority: Medium. First reported Q2, 2015. Status: Not adopted.)

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 in the same year in which demand for capacity changes. 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.

In the energy market, if there is to be a demand side program, demand resources should be paid the value of energy, which is LMP less any generation component of the applicable retail rate. There is no reason to have the net benefits test. The necessity for the net benefits test is an illustration of the illogical approach to demand side compensation embodied in paying full LMP to demand resources. The benefit of demand side resources is not that they suppress market prices, but that customers can choose not to consume at the current price of power, that individual customers benefit from their choices and that the choices of all customers are reflected in market prices. If customers face the market price, customers should have the ability to not purchase power and the market impact of that choice does not require a test for appropriateness.

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. This 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 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 be subject to robust measurement and verification techniques to ensure that transitional DR programs incent the desired behavior. The methods used in PJM programs today are not adequate to determine and quantify deliberate actions taken to reduce consumption.

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. Both subzonal and multi-zone compliance should be eliminated because they are inconsistent with an efficient nodal 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, reductions should be calculated hourly for dispatched DR. The current rules use the average reduction for the duration of an event. The average reduction across multiple hours does not provide an accurate metric for each hour of the event and is inconsistent with the measurement of generation resources. Measuring compliance hourly would provide accurate information to the PJM system. Under the new CP rules, the performance of demand response during Performance Assessment Hours will be measured on an hourly basis. Overall demand response compliance is still measured by performance across the entire event.[95]

In order to be a substitute for generation, any demand resource and its Curtailment Service Provider (CSP), 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 should 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 proposed 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 the Supreme Court decision in EPSA as it does not depend on whether FERC has jurisdiction over the demand side. This approach will allow FERC to more fully realize its overriding policy objective to create competitive and efficient wholesale energy markets. The decision of the Supreme Court addressed jurisdictional issues and did not address the merits of FERC's approach. The Supreme Court's decision has removed the uncertainty surrounding the jurisdictional issues and created the opportunity for FERC to revisit its approach to demand side.

95 PJM "Manual 18: Capacity Market," Revision 29 (October 16, 2015), p 148.

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 2015 than in 2014. Net revenues from the energy market for all plant types were affected by the lower prices. Capacity prices for calendar year 2015 were higher than in 2014 in the western zones and helped some of the new entrant gas units fully recover levelized total costs.
- In 2015, average energy market net revenues decreased by 23 percent for a new CT, 27 percent for a new CC, 53 percent for a new CP, 59 percent for a new DS, 38 percent for a new nuclear plant, 30 percent for a new wind installation, and 31 percent for a new solar installation. The comparison to 2014 reflects, in part, the very high net revenues in January 2014.
- Capacity revenues for calendar year 2015 increased over 2014 in the western zones and decreased in the eastern zones. Capacity revenue accounted for 49 percent of total net revenues for a new CT, 38 percent for a new CC, 49 percent for a new CP, 81 percent for a new DS, and 6 percent for a new nuclear plant.
- In 2015, a new CT would have received sufficient net revenue to cover levelized total costs in six of the 20 zones and more than 90 percent of levelized total costs in an additional six zones.
- In 2015, a new CC would have received sufficient net revenue to cover levelized total costs in nine of the 20 zones and more than 90 percent of levelized total costs in an additional four zones.
- In 2015, a new CP would not have received sufficient net revenue to cover levelized total costs in any zone.
- In 2015, a new nuclear plant would not have received sufficient net revenue to cover levelized total costs in any zone.
- In 2015, net revenues covered more than 82 percent of the annual levelized total costs of a new entrant wind installation and 175 percent of the annual levelized total costs of a new entrant solar installation. Production tax credits and renewable energy credits accounted for 47 percent of the total net revenue of a wind installation and 78 percent of the total net revenue of a solar installation.
- In 2015, a substantial portion of units did not achieve full recovery of avoidable costs through net revenue from energy markets alone, illustrating the critical role of the PJM Capacity Market in providing incentives for continued operation and investment. In 2015, RPM capacity revenues were sufficient to cover the shortfall between energy revenues and avoidable costs for the majority of units and technology types in PJM, with the exception of some coal and oil or gas steam units.
- The actual net revenue results show that 28 units with 11,908 MW of capacity in PJM are at risk of retirement in addition to the units that are currently planning to retire. Of the 28 units, 23 are coal units and account for 99 percent of the capacity at risk.

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.[96] The rule established a compliance deadline of April 16, 2015.

  In a related EPA rule also issued on December 16, 2011, 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.[97] On December 15, 2015, the D.C. Circuit Court remanded the matter to EPA while keeping the rule effective, noting that the "EPA has represented that it is on track to issue a final finding … by April 15, 2016."[98]

- **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.[99]

  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).[100] [101]

  In the same decision, the U.S. Supreme Court remanded "particularized as-applied challenge[s]" to the EPA's 2014 emissions budgets.[102] 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.[103] The court directed the EPA to reconsider the 2015 emissions budgets for these states based on the actual amount of reduced emissions that states in upwind states needed to attain in order to bring each downwind state into attainment.[104] Under the invalidated approach, the EPA calculated how much pollution each upwind state could eliminate if all of its sources applied pollution control at particular cost thresholds.[105] A new approach likely will significantly reduce the emission budgets (lower emissions levels will be allowed) for the indicated states. The court did not vacate the currently assigned budgets which remain effective until replaced.[106]

  On November 21, 2014, the EPA issued a rule tolling by three years CSAPR's original deadlines. The rule means that 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.[107]

- **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

96 *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).

97 Michigan et al. v. EPA, Slip Op. No. 14-46.

98 White Stallion Energy Center, LLC v EPA, Slip Op. No. 12-1100 (D.C. Cir. 2015) (per curiam).

99 CAA § 110(a)(2)(D)(i)(I).

100 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).

101 See EME Homer City Generation, L.P. v EPA et al., No. 11-1302.

102 134 S. Ct. at 1609.

103 EME Homer City Generation , L.P. v EPA et al., Slip Op. No. 11-1302 (July 28, 2015).

104 *Id.* at 11–12.

105 *Id.* at 11.

106 Emissions Budget Decision at 24–25.

107 *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).

in emergency demand response programs.[108] As a result, the national emissions standards uniformly apply to all RICE.[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 the 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 (the Clean Power Plan).[112] The rule requires that individual state plans be submitted by September 6, 2016. However, on February 9, 2016, the U.S. Supreme Court issued a stay on the rule that will prevent its taking effect until judicial review is completed.[113]
- **Cooling Water Intakes.** The EPA has promulgated a rule implementing Section 316(b) of the Clean Water Act (CWA), which requires that cooling water intake structures reflect the best technology available for minimizing adverse environmental impacts.[114] The rule is implemented as National Pollutant Discharge Elimination System (NPDES) permits are issued, with exceptions in certain cases for permits expiring prior to July 14, 2018.
- **Waste Disposal.** On December 19, 2014, EPA issued its Coal Combustion Residuals rule (CCRR), effective October 19, 2015. The CCRR likely will raise the costs of disposal of CCRs to meet the EPA criteria.

108 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).

109 *Id.*

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* (August 3, 2015), also known as the "Clean Power Plan."

113 North Dakota v. EPA, et al., Order 15A793.

114 See EPA, *National Pollutant Discharge Elimination System—Final Regulations to Establish Requirements for Cooling Water Intake Structures at Existing Facilities and Amend Requirements at Phase I Facilities*, EPA-HQ-OW-2008-0667, 79 Fed. Reg. 48300 (Aug. 15, 2014).

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.[115] 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.[116]
- **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").[117] 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 $7.50 per ton. The clearing price is equivalent to a price of $8.27 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 December 31, 2015, 76.7 percent of coal steam MW had some type of FGD (flue-gas

115 N.J.A.C. § 7:27–19.

116 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).

117 35 Ill. Admin. Code §§ 225.233 (Multi-Pollutant Standard (MPS)), 224.295 (Combined Pollutant Standard: Emissions Standards for NO_X and SO_2 (CPS)).

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 December 31, 2015, Delaware, Illinois, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, and Washington D.C. had renewable portfolio standards. Virginia and Indiana have enacted voluntary renewable portfolio standards. 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.[118] West Virginia had a voluntary standard, but the state Legislature repealed the West Virginia 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 the REC is sold as part of a transaction that also includes a wholesale sale of electric energy in a bundled transaction.[119]

Renewable energy credits (RECs), federal investment tax credits 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 for all PJM states. 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 emissions credits are included in energy offers. PJM markets also provide a flexible mechanism that incorporates renewable resources and the impacts of 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 and prescriptive environmental dispatch rules would, in contrast, pose a threat to economic dispatch and create very difficult market power monitoring and mitigation issues.

118 See Ohio Senate Bill 310.

119 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.").

Overview: Section 9, "Interchange Transactions"

Interchange Transaction Activity

- **Aggregate Imports and Exports in the Real-Time Energy Market.** In 2015, PJM was a net exporter of energy in the Real-Time Energy Market in September, and a net importer in the remaining 11 months.[120] In 2015, the real-time net interchange of 15,717.4 GWh was higher than net interchange of 1,137.8 GWh in 2014.
- **Aggregate Imports and Exports in the Day-Ahead Energy Market.** In 2015, PJM was a net exporter of energy in the Day-Ahead Energy Market in February, August, September, October, November and December, and a net importer in the remaining six months. In 2015, the total day-ahead net interchange of 1,603.1 GWh was higher than net interchange of -14,305.5 GWh in 2014. The large difference in the day-ahead net interchange totals was a result of the reduction in up to congestion transaction volumes.[121]
- **Aggregate Imports and Exports in the Day-Ahead and the Real-Time Energy Market.** In 2015, gross imports in the Day-Ahead Energy Market were 81.7 percent of gross imports in the Real-Time Energy Market (109.5 percent in 2014). In 2015, gross exports in the Day-Ahead Energy Market were 114.5 percent of the gross exports in the Real-Time Energy Market (143.2 percent in 2014).
- **Interface Imports and Exports in the Real-Time Energy Market.** In 2015, there were net scheduled exports at eight of PJM's 20 interfaces in the Real-Time Energy Market.
- **Interface Pricing Point Imports and Exports in the Real-Time Energy Market.** In 2015, there were net scheduled exports at 10 of PJM's 18 interface pricing points eligible for real-time transactions in the Real-Time Energy Market.[122]
- **Interface Imports and Exports in the Day-Ahead Energy Market.** In 2015, there were net scheduled exports at eight of PJM's 20 interfaces in the Day-Ahead Energy Market.
- **Interface Pricing Point Imports and Exports in the Day-Ahead Energy Market.** In 2015, there were net scheduled exports at 11 of PJM's 19 interface pricing points eligible for day-ahead transactions in the Day-Ahead Energy Market.
- **Up to Congestion Interface Pricing Point Imports and Exports in the Day-Ahead Energy Market.** In 2015, up to congestion transactions were net exports at five of PJM's 19 interface pricing points eligible for day-ahead transactions in the Day-Ahead Market.
- **Inadvertent Interchange.** In 2015, net scheduled interchange was 15,717 GWh and net actual interchange was 15,368 GWh, a difference of 349 GWh. In 2014, the difference was 82 GWh. This difference is inadvertent interchange.
- **Loop Flows.** In 2015, the Wisconsin Energy Corporation (WEC) interface had the largest loop flows of any interface with -846 GWh of net scheduled interchange and 9,985 GWh of net actual interchange, a difference of 10,831 GWh. (Table 9-18.) In 2015, the SouthEXP interface pricing point had the largest loop flows of any interface pricing point with -718 GWh of net scheduled interchange and -10,960 GWh of net actual interchange, a difference of 10,242 GWh.

Interactions with Bordering Areas

PJM Interface Pricing with Organized Markets

- **PJM and MISO Interface Prices.** In 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 55.4 percent of the hours.
- **PJM and New York ISO Interface Prices.** In 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 58.2 percent of the hours.
- **Neptune Underwater Transmission Line to Long Island, New York.** In 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 58.2 percent of the hours.

120 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.

121 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. 18 CFR § 385.213

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

- **Linden Variable Frequency Transformer (VFT) Facility.** In 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 53.0 percent of the hours.
- **Hudson DC Line.** In 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 42.1 percent of the hours.

Interchange Transaction Issues

- **PJM Transmission Loading Relief Procedures (TLRs).** PJM issued 22 TLRs of level 3a or higher in 2015, compared to eight such TLRs issued in 2014.
- **Up to congestion.** On August 29, 2014, FERC issued an Order which created an obligation for up to congestion transactions to pay any uplift determined to be appropriate in the Commission review, effective September 8, 2014.[123] The average number of up to congestion bids decreased by 42.8 percent and the average cleared volume of up to congestion bids decreased by 61.1 percent in 2015, compared to 2014, but there was an increase in up to congestion volume in December 2015, coincident with the expiration of the fifteen month resettlement period for the proceeding related to uplift charges for UTC transactions.[124]
- **45 Minute Schedule Duration Rule.** Effective May 19, 2014, PJM removed the 45 minute scheduling duration rule in response to FERC Order No. 764.[125] [126] 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.[127]

Section 9 Recommendations

- The MMU recommends that PJM eliminate the IMO interface pricing point, and assign the transactions that originate or sink in the IESO balancing authority to the MISO interface pricing point. (Priority: Medium. First reported 2013. 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. 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 1800 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 used to meet load in the most economic manner. (Priority: Medium. First reported Q3 2014. Status: Adopted partially, Q1 2015.)
- The MMU recommends that PJM explore an interchange optimization solution with its neighboring balancing authorities that would 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 uses supply curves and treats seams between balancing authorities as constraints, similar to other constraints within an LMP market. (Priority: Medium. First reported 2014. 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 by concealing the true source

123 148 FERC ¶ 61,144 (2014).*Order Instituting Section 206 Proceeding and Establishing Procedures.*
124 16 U.S.C. § 824e.
125 *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).
126 *See* Letter Order, Docket No. ER14-381-000 (June 30, 2014).
127 *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>.

or sink of the transaction. (Priority: Medium. First reported 2013. Status: Not adopted.)

- The MMU recommends that PJM implement a validation method for submitted transactions that would require market participants to submit transactions on market paths that reflect the expected actual 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 requests that, in order to permit a complete analysis of loop flow, FERC and NERC ensure that the identified data are made available to market monitors as well as other industry entities determined appropriate by FERC. (Priority: Medium. First reported 2003. Status: Not adopted.)
- 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 eliminate the NIPSCO, Southeast and Southwest 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 PJMSettlement Inc. immediately request a credit evaluation from all companies that engaged in up to congestion transactions between September 8, 2014, and December 31, 2015. If PJM has the authority, PJM should ensure that the potential exposure to uplift for that period be included as a contingency in the companies' calculations for credit levels and/or collateral requirements. If PJM does not have the authority to take such steps, PJM should request guidance from FERC. (Priority: High. New recommendation. Status: Not adopted.)
- The MMU recommends that the emergency interchange cap be replaced with a market based solution. (Priority: Low. New recommendation. 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 competitive generator offers results in an efficient dispatch and efficient prices. The goal of designing interface transaction rules should be to match the outcome that would exist in an LMP market.

Overview: Section 10, "Ancillary Services"

Primary Reserve

PJM's primary reserves are made up of resources, both synchronized and non-synchronized, that can provide energy within ten minutes. Primary reserve is PJM's implementation of the NERC 15-minute contingency reserve requirement.[128]

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 available to start 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 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 Zone in 2015 was 2,210.3 MW. The actual demand for primary reserve in the MAD Subzone in 2015 was 1,713.3 MW.

Tier 1 Synchronized Reserve

Synchronized reserve is energy or demand reduction synchronized to the grid and capable of increasing output or decreasing load within ten minutes. Synchronized reserve is of two distinct types, tier 1 and tier 2.

Tier 1 synchronized reserve is part of primary reserve and is 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. There is no formal market for tier 1 synchronized reserve.

- **Supply.** No offers are made for tier 1 synchronized reserve. The market solution estimates tier 1 synchronized reserve as available 10-minute ramp from the energy dispatch. In 2015, there was an average hourly supply of 1,363.9 MW of tier 1 for the RTO Synchronized Reserve Zone, and an average hourly supply of 1,159.6 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. The requirement can be met with tier 1 or tier 2 synchronized reserves.
- **Tier 1 Synchronized Reserve Event Response.** Tier 1 synchronized reserve is paid when a synchronized reserve event occurs and it responds. When a synchronized reserve event is called, all tier 1 response is paid the average of five-minute LMPs during the event, rather than hourly integrated LMP, plus $50/MW. This is the Synchronized Energy Premium Price. The synchronized reserve event response credits for tier 1 response are independent of the tier 2 synchronized reserve market clearing price and independent of the non-synchronized reserve market clearing price.

  Of tier 1 synchronized reserve estimated at market clearing, 65.7 percent actually responded during the seven distinct synchronized reserve events longer than ten minutes in 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 offer 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 and the appropriate payment for responding to an event is the five-minute LMP plus $50 per MWh. 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 $10,406,363 to tier 1 resources in 2014, and $34,135,671 in 2015.

128 See PJM. "Manual 10: Pre-Scheduling Operations," Revision. 33 (December 22, 2015), p. 24.

Tier 2 Synchronized Reserve Market

Tier 2 synchronized reserve is part of primary reserve 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 met with tier 1 synchronized reserve, PJM conducts a market to satisfy the balance of 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 2015, the supply of offered and eligible synchronized reserve was 8,549 MW in the RTO Zone of which 3,114 MW (including DSR) was available to the MAD Subzone. This 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 the RTO Reserve Zone and 1,450 MW for the Mid-Atlantic Dominion Reserve Subzone. The requirement can be met with tier 1 or tier 2 synchronized reserves.
- **Market Concentration.** In 2015, the weighted average HHI for cleared tier 2 synchronized reserve in the Mid-Atlantic Dominion Subzone was 5436 which is classified as highly concentrated. The MMU calculates that 55.7 percent of hours would have failed a three pivotal supplier test in the Mid-Atlantic Dominion Subzone.

  In 2015, the weighted average HHI for cleared tier 2 synchronized reserve in the RTO Synchronized Reserve Zone was 4617 which is classified as highly concentrated. The MMU calculates that 40.2 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 2015.

Market Conduct

- **Offers.** There is a must offer requirement for tier 2 synchronized reserve. All non-emergency generation capacity resources are required to submit a daily offer for tier 2 synchronized reserve. 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 for tier 2 synchronized reserve for all cleared hours in the Mid-Atlantic Dominion (MAD) Subzone was $10.12 per MW in 2015, a decrease of $5.38, 34.7 percent from 2014.

  The weighted average price for tier 2 synchronized reserve for all cleared hours in the RTO Synchronized Reserve Zone was $11.88 per MW in 2015, a decrease of $1.06, 8.2 percent from 2014.

Non-Synchronized Reserve Market

Non-synchronized reserve is part of primary reserve and includes 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. There is no formal market for non-synchronized reserve.

Market Structure

- **Supply.** In 2015, the supply of eligible non-synchronized reserve was 2,550.1 MW in the RTO Zone and 1,860.8 MW in MAD Subzone.[129]
- **Demand.** Demand for non-synchronized reserve is the remaining primary reserve requirement after tier 1 synchronized reserve is estimated and tier 2 synchronized reserve is scheduled. In the RTO Zone, the market cleared an hourly average of 345.1 MW of non-synchronized reserve in 2015. In the MAD Subzone, the market cleared an hourly average of 390.3 MW of non-synchronized reserve.

129 See PJM. "Manual 11; Energy & Ancillary Services Markets," Revision 79 (December 17, 2015), p. 81. "Because Synchronized Reserve may be utilized to meet the Primary Reserve requirement, there is no explicit requirement for non-synchronized reserves."

- **Market Concentration.** In 2015, the weighted average HHI for cleared non-synchronized reserve in the Mid-Atlantic Dominion Subzone was 4133 which is classified as highly concentrated. In the RTO Zone the weighted average HHI was 4533 which is also highly concentrated. The MMU calculates that 95.1 percent of hours would have failed a three pivotal supplier test in the Mid-Atlantic Dominion Subzone and 68.0 hours would have failed a three pivotal supplier test in the RTO Zone.

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.** 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 $1.15 per MW in 2015 and in 87.9 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 $1.03 and in 87.6 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.[130] The DASR Market has no performance obligations.

Market Structure

- **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 2015, the average available hourly DASR was 36,396.0 MW.
- **Demand.** The DASR requirement in 2015 was 5.93 percent of peak load forecast, down from 6.27 percent in 2014. The average DASR MW purchased was 6,245.0 MW per hour 2015.
- **Concentration.** In 2015, the DASR Market would have failed a three pivotal supplier test in 4.1 percent of hours.

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. In 2015 a daily average of 37.9 percent of units offered above $0. In 2015 a daily average of 11.6 percent of units offered above $5.
- **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 for all cleared hours in 2015 was $2.99 per MW, an increase from $0.63 per MW in 2014.

Regulation Market

The PJM Regulation Market is a 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 in actual MW into effective MW.

Market Structure

- **Supply.** In 2015, the average hourly eligible supply of regulation was 1,157.8 actual MW (889.9 effective MW). This is a decrease of 122.5 actual MW (27.5 effective MW) from the same period of 2014, when the average hourly eligible supply of regulation was 1,280.3 actual MW (917.4 effective MW).

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

- **Demand.** The average hourly regulation demand was 640.9 actual MW (663.7 effective MW) in 2015. This is a decrease of 19.8 actual MW (0 effective MW) in the average hourly regulation demand of 660.7 actual MW (663.7 effective MW) from the same period of 2014.
- **Supply and Demand.** The ratio of the average hourly eligible supply of regulation to average hourly regulation demand required was 1.81. This is a 6.70 percent decrease from the same period of 2014 when the ratio was 1.94.
- **Market Concentration.** In 2015, the weighted average (HHI) was 1358 which is classified as moderately concentrated. In 2015, the three pivotal supplier test was failed in 97.8 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 and may 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.[131] In 2015, there were 291 resources following the RegA signal and 57 resources following the RegD signal.

Market Performance

- **Price and Cost.** The weighted average clearing price for regulation was $31.92 per effective MW of regulation in 2015, a decrease of $12.55 per MW, or 28.2 percent, from the same period of 2014. The cost of regulation in 2015 was $38.36 per effective MW of regulation, a decrease of $15.46 per MW, or 28.7 percent, from the same period of 2014. The decreases in regulation price and regulation cost resulted primarily from high energy prices in 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 the same price per effective MW.
- **Marginal Benefit Factor Function.** The marginal benefit factor (MBF) measures the substitutability of RegD resources for RegA resources. The marginal benefit factor function is incorrectly applied in the market clearing and incorrectly describes the operational relationship between RegA and RegD.
- **Interim changes to the MBF function.** On December 14, 2015, PJM changed the MBF curve. The modification to the marginal benefit curve did not correct the identified issues with the optimization engine.

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 (automatic load rejection or ALR).[132]

In 2015, total black start charges were $53.6 million with $48.4 million in revenue requirement charges and $5.2 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 ALR option or for black start testing. Black start zonal charges in 2015 ranged from $0.04 per MW-day in the PPL Zone (total charges were $118,541) to $3.81 per MW-day in the BGE Zone (total charges were $9,277,796).

Reactive

Reactive service, reactive supply and voltage control are 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).

131 See the *2015 State of the Market Report for PJM*, Volume II, Appendix F "Ancillary Services Markets."

132 OATT Schedule 1 § 1.3BB.

In 2015, total reactive service charges were $289.0 million, a 6.1 percent decrease from $307.7 million in 2014. Revenue requirement charges decreased from $281.2 million to $278.4 million and operating reserve charges fell from $26.5 million to $10.7 million. Total charges in 2015 ranged from $2,488 in the RECO Zone to $38.5 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.

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 2012. Status: Not adopted.)
- The MMU recommends a number of market design changes to improve the performance of the Regulation Market, including use of a single clearing price based on actual LMP, modifications to the LOC calculation methodology, a software change to save some data elements necessary for verifying market outcomes, and further documentation of the implementation of the market design through SPREGO. (Priority: Medium. First reported 2010. Status: Partially adopted in 2012.)
- The MMU recommends that the lost opportunity cost in the ancillary services markets be calculated using the schedule on which the unit was scheduled to run in the energy market. (Priority: High. First reported 2010. Status: Partially Adopted.)
- The MMU recommends that the single clearing price for synchronized reserves be determined based on the actual LMP and not the forecast LMP. (Priority: Low. First reported 2010. Status: 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. The MMU also recommends that documentation of the Tier 1 synchronized reserve deselection process be published. (Priority: High. First reported Q3, 2014. Status: Adopted July 2014.)
- The MMU recommends that the tier 2 synchronized reserve must offer requirement be enforced. The MMU recommends that PJM define a set of acceptable reasons why a unit can be made unavailable daily or hourly and require operators to select a reason in eMkt whenever making a unit unavailable. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM be explicit about why tier 1 biasing is used in the Tier 2 Synchronized Reserve Market. The MMU recommends that PJM define explicit rules for the use of tier 1 biasing during any phase of the market solution and 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: Partially adopted, 2014.)
- The MMU recommends that the three pivotal supplier test and market power mitigation 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 market operations adds additional DASR MW. (Priority: Medium. First reported Q2, 2015. 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. The market design has failed to correctly incorporate the marginal benefit factor in optimization, pricing and settlement. The market design uses 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 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 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. However, compliance with calls to respond to actual synchronized reserve events has been an issue. The must offer requirement for tier 2 synchronzed reserve has not been enforced.

The rule that requires payment of the tier 2 synchronized reserve price to tier 1 synchronized reserve resources when the non-synchronized reserve price is greater than zero, is inefficient and results in a substantial 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. Tier 1 resources are paid for their response if they do respond. 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. If tier 1 resources wish to be paid as tier 2 resources, that option is available. Application of this rule added $10.4 million to the cost of primary reserve in 2014 and $34.1 million to the cost of primary reserve in 2015.

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 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, although there is concern about offers above the competitive level affecting prices.

Overview: Section 11, "Congestion and Marginal Losses"

Congestion Cost

- **Total Congestion.** Total congestion costs decreased by $546.9 million or 28.3 percent, from $1,932.2 million in 2014 to $1,385.3 million in 2015.
- **Day-Ahead Congestion.** Day-ahead congestion costs decreased by $599.1 million or 26.9 percent, from $2,231.3 million in 2014 to $1,632.1 million in 2015.
- **Balancing Congestion.** Balancing congestion costs increased by $52.2 million or 17.5 percent, from -$299.1 million in 2014 to -$246.9 million in 2015.
- **Real-Time Congestion.** Real-time congestion costs decreased by $668.2 million or 30.7 percent, from $2,173.0 million in 2014 to $1,504.9 million in 2015.
- **Monthly Congestion.** In 2015, 31.0 percent ($429.8 million) of total congestion cost was incurred in February and 14.6 percent ($201.9 million) of total congestion cost was incurred in the months of January and March. Monthly total congestion costs in 2015 ranged from $58.4 million in August 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 Bagley – Graceton Line, the Conastone – Northwest Line and the Cherry Valley Flowgate.

- **Congestion Frequency.** Congestion frequency continued to be significantly higher in the Day-Ahead Energy Market than in the Real-Time Energy Market in 2015. The number of congestion event hours in the Day-Ahead Energy Market was about six times higher than the number of congestion event hours in the Real-Time Energy Market.

  Day-ahead congestion frequency decreased by 49.2 percent from 363,463 congestion event hours 2014 to 184,713 congestion event hours in 2015. The day-ahead congestion event hours decreased significantly after September 8, 2014. The reduction was the result of the reduction in up to congestion (UTC) activity which was a result of FERC's UTC uplift refund notice, retroactive to September 8, 2014.

  Real-time congestion frequency decreased by 1.0 percent from 28,802 congestion event hours in 2014 to 28,524 congestion event hours in 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 Conastone – Northwest Line was the largest contributor to congestion costs in 2015. With $108.8 million in total congestion costs, it accounted for 7.9 percent of the total PJM congestion costs in 2015.

- **Zonal Congestion.** ComEd had the largest total congestion costs among all control zones in 2015. ComEd had $311.3 million in total congestion costs, comprised of -$688.9 million in total load congestion payments, -$1,029.4 million in total generation congestion credits and -$29.2 million in explicit congestion costs. The Cherry Valley Flowgate, the Oak Grove - Galesburg Flowgate, the Braidwood - East Frankfort Line, the Bunsonville - Eugene Flowgate and the Rising Flowgate contributed $150.4 million, or 48.3 percent of the total ComEd control zone congestion costs.

- **Ownership.** In 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 2015, financial entities received $133.1 million in congestion credits, a decrease of $93.6 million or 41.3 percent compared to the 2014. In 2015, physical entities paid $1,518.3 million in congestion charges, a decrease of $640.6 million or 29.7 percent compared to 2014. UTCs are in the explicit congestion cost category and comprise most of that category. The total explicit cost is equal to day-ahead explicit cost plus balancing explicit cost. In 2015, the total explicit cost is -$127.3 million and 122.4 percent of the total explicit cost is comprised of congestion cost by UTCs, which is -$155.9 million.

Marginal Loss Cost

- **Total Marginal Loss Costs.** Total marginal loss costs decreased by $497.4 million or 33.9 percent, from $1,466.1 million in 2014 to $968.7 million in 2015. Total marginal loss costs were higher in 2014 as a result of high load and outages caused by cold weather in January 2014. The loss MWh in PJM decreased 5.3 percent, from 17,150.0 GWh in 2014 to 16,241.3 GWh in 2015. The loss component of LMP remained constant, $0.02 in 2014 and $0.02 in 2015.

- **Monthly Total Marginal Loss Costs.** Monthly total marginal loss costs in 2015 ranged from $44.6 million in December to $220.3 million in February.

- **Day-Ahead Marginal Loss Costs.** Day-ahead marginal loss costs decreased by $558.8 million or 35.6 percent, from $1,571.4 million in 2014 to $1,012.6 million in 2015.

- **Balancing Marginal Loss Costs.** Balancing marginal loss costs increased by $61.4 million or 58.3 percent, from -$105.3 million in 2014 to -$43.9 million in 2015.

- **Total Marginal Loss Surplus.** The total marginal loss surplus decreased in 2015 by $145.8 million or 30.2 percent, from $482.1 million in 2014, to $336.3 million in 2015.

Energy Cost

- **Total Energy Costs.** Total energy costs increased by $350.3 million or 35.8 percent, from -$977.7 million in 2014 to -$627.4 million in 2015.
- **Day-Ahead Energy Costs.** Day-ahead energy costs increased by $585.8 million or 43.6 percent, from -$1,343.7 million in 2014 to -$757.9 million in 2015.
- **Balancing Energy Costs.** Balancing energy costs decreased by $242.4 million or 65.5 percent, from $370.2 million in 2014 to $127.8 million in 2015.
- **Monthly Total Energy Costs.** Monthly total energy costs in 2015 ranged from -$141.5 million in February to -$28.9 million in December.

Section 11 Conclusion

Congestion, as defined, is the total congestion payments by load in excess of the total congestion credits received by generation. The level and distribution of 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.

The current ARR/FTR design does not serve as an efficient way to ensure that load receives all the congestion revenues or has the ability to receive the auction revenues associated with all the potential congestion revenues. Total ARR and self scheduled FTR revenue offset only 59.8 percent of total congestion costs including congestion in the Day-Ahead Energy Market and the balancing energy market for the 2014 to 2015 planning period. For the first seven months of the 2015 to 2016 planning period ARRs and self scheduled FTRs offset 85.8 percent of total congestion costs.

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 first seven months of the 2015 to 2016 planning period (June through December), total ARR and FTR revenues offset 88.7 percent of the congestion costs.

Overview: Section 12, "Planning"

Planned Generation and Retirements

- **Planned Generation.** As of December 31, 2015, 85,323.1 MW of capacity were in generation request queues for construction through 2024, compared to an average installed capacity of 187,744.2 MW as of December 31, 2015. Of the capacity in queues, 6,246.5 MW, or 7.3 percent, are uprates and the rest are new generation. Wind projects account for 15,698.8 MW of nameplate capacity or 18.4 percent of the capacity in the queues. Combined-cycle projects account for 56,827.9 MW of capacity or 66.6 percent of the capacity in the queues.
- **Generation Retirements.** As shown in Table 12-6, 27,689.0 MW have been, or are planned to be, retired between 2011 and 2020. Of that, 3,912.3 MW are planned to retire after 2015. In 2015, 9,859.7 MW were retired, of which 7,661.8 MW were coal units. The coal unit retirements were a result of low gas prices and the EPA's Mercury and Air Toxics Standards (MATS) for some units.
- **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 2,007.0 MW of coal fired steam capacity are currently in the queue, 60,717.7 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.[133] 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

133 See PJM, OATT Parts IV & VI.

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, 2,275 projects, representing 327,280.0 MW, have completed the queue process since its inception. Of those, 605 projects, 41,021.9 MW, went into service. Of the projects that entered the queue process, 87.5 percent of the MW withdrew prior to completion. Such projects may create barriers to entry for projects that would otherwise be completed by taking up queue positions, increasing interconnection costs and creating uncertainty.
- Feasibility, impact and facilities studies may be delayed for reasons including disputes with developers, circuit and network issues and retooling as a result of projects being withdrawn. The Earlier Queue Submittal Task Force (EQSTF) was established in August 2015 to address delays.[134]
- As defined in the tariff, a transmission owner (TO) is an "entity that owns, leases or otherwise has a possessory interest in facilities used for the transmission of electric energy in interstate commerce under the tariff."[135] 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 and when the transmission owner evaluates the interconnection requirements of new generation which is part of the same company as the transmission owner. There is also a potential conflict of interest when the transmission owner evaluates the interconnection requirements of a merchant transmission developer which is a competitor of 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 and operational performance under a range of anticipated system conditions, and the elimination of potential planning criteria violations in this area. On July 30, 2015, the PJM Board of Managers accepted PJM's recommendation to assign the project to LS Power, a merchant developer, PSEG, and PHI with a total cost estimate between \$263M and \$283M.[136] [137]
- On October 25, 2012, Schedule 12 of the tariff and Schedule 6 of the OA were changed to address FERC Order No. 1000 reforms to the cost allocation requirements for local and regional transmission planning projects that were formerly defined in Order No. 890. The new approach was applied for the first time to the 2013 RTEP. Since then, some developers have raised concern with the cost allocations using the new solution based dfax method.

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 may have substantial impacts on energy and capacity markets. There is currently only one backbone project under development, 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 outage requests according to rules in PJM's Manual 3 to decide if the outage is on time, late, or past its deadline and whether or not they will allow the outage.[138]

134 See Earlier Queue Submittal Task Force at <http://www.pjm.com/committees-and-groups/task-forces/eqstf.aspx>

135 See PJM, OATT, Part I, § 1 "Definitions"

136 See "Artificial Island Recommendations," presented at the TEAC meeting on April 28, 2015 at <http://www.pjm.com/~/media/committees-groups/committees/teac/20150428-ai/20150428-artificial-island-recommendations.ashx>

137 See letter from Terry Boston concerning the Artificial Island Project at <http://www.pjm.com/~/media/documents/reports/board-statement-on-artificial-island-project.ashx>

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

- There were 19,593 transmission outage requests submitted for 2015. Of the requested outages, 79.2 percent were planned for five days or shorter and 4.9 percent were planned for longer than 30 days. Of the requested outages, 49.1 percent were late according to the rules in PJM's Manual 3.
- There were 19,614 transmission outage requests submitted for 2014. Of the requested outages, 79.8 percent were planned for five days or shorter and 5.4 percent were planned for longer than 30 days. Of the requested outages, 48.7 percent were late according to the rules in PJM's Manual 3.

Section 12 Recommendations

The MMU recommends improvements to the planning process.

- The MMU recommends that PJM continue to incorporate the principle that the goal of transmission planning should be the incorporation of transmission investment decisions into market driven processes as much as possible. (Priority: Low. First reported 2001. Status: Not adopted.)
- 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 rules be implemented to require that project cost caps on new transmission projects be part of the evaluation of competing projects. (Priority: Low. New recommendation. Status: Not adopted.)
- The MMU recommends that barriers to entry be addressed in a timely manner in order to help ensure that the capacity market will result in the entry of new capacity to meet the needs of PJM market participants and reflect the uncertainty and resultant risks in the cost of new entry used to establish the capacity market demand curve in RPM. (Priority: Low. First reported 2012. 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.[139] (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: Partially 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 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

139 See "Comments of the Independent Market Monitor for PJM," Docket No. ER12-1177-000, <http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Comments_ER12-1177-000_20120312.pdf>.

providers in the RTEP. (Priority: Medium. First reported 2014. Status: Not adopted.)

- 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. First reported Q2, 2015. Status: Not adopted.)
- The MMU recommends consideration of changing the minimum distribution factor in the allocation from .01 to .00 and adding a threshold minimum impact on the load on the line. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that PJM reevaluate all transmission outage tickets as on time or late 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.)
- The MMU recommends that PJM draft a clear definition of the congestion analysis required for transmission outage requests to include in Manual 3 after appropriate review. (Priority: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM modify the rules to reduce or eliminate the approval of late outage requests submitted or rescheduled after the FTR auction bidding opening date. (Priority: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM not permit transmission owners to divide long duration outages into smaller segments to avoid complying with the requirements for long duration outages. (Priority: Low. New recommendation. Status: Not adopted.)

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 FERC 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 a 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 RTEP should build upon FERC 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 the RTEP process and be made available to all providers on equal terms.

There are currently no market incentives for transmission owners to submit and complete transmission outages in a timely and efficient manner. Requiring transmission owners to pay does not create an effective incentive when those payments are passed through to transmission customers. 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"

Auction Revenue Rights

Market Structure

- **ARR Allocations.** PJM's actions to address prior low levels of FTR 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 2015 to 2016 planning period, PJM allocated a total of 26,845.4 MW of residual ARRs, up from 22,737.4 MW in the first seven months of the 2014 to 2015 planning period, with a total target allocation of $7.5 million for the 2015 to 2016 planning period, down from $9.0 million for the first seven months of the 2014 to 2015 planning period. Total Residual ARR allocations for the 2013 to 2014 planning period were 15,417.5 MW for $4.7 million. This large increase in residual ARR allocations over the 2013 to 2014 planning period was primarily a result of PJM's significant reductions in Annual ARR Stage 1B allocations. The outages were only assumed in order to reduce the initial allocation. As a result, there were more available ARRs during the year which were distributed as residual ARRs.

- **ARR Reassignment for Retail Load Switching.** There were 53,343 MW of ARRs associated with $503,400 of revenue that were reassigned in the 2014 to 2015 planning period. There were 43,089 MW of ARRs associated with $504,600 of revenue that were reassigned for the first seven months of the 2015 to 2016 planning period.

Market Performance

- **Revenue Adequacy.** For the 2015 to 2016 planning period, the ARR target allocations, which are based on the nodal price differences from the Annual FTR Auction, were $928.8 million, while PJM collected $962.0 million from the combined Long Term, Annual and Monthly Balance of Planning Period FTR Auctions, making ARRs revenue adequate. For the 2014 to 2015 planning period, the ARR target allocations were $735.3 million while PJM collected $767.9 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. For the 2015 to 2016 planning period ARR dollars per MW increased 15.6 percent relative to the 2013 to 2014 planning period.

- **ARRs as an Offset to Congestion.** ARRs did not serve as an effective way to return congestion revenues to load. Total ARR and self scheduled FTR revenue offset only 59.8 percent of total congestion costs including congestion in the Day-Ahead Energy Market and the balancing energy market for the 2014 to 2015 planning period. In the first seven months of the 2015 to 2016 planning period, total ARR and self scheduled FTR revenues offset 85.8 percent of total congestion costs.

Financial Transmission Rights

Market Structure

- **Supply.** The principal binding constraints limiting the supply of FTRs in the 2016 to 2019 Long Term FTR Auction include the Kenney – Stockton line in DPL and the Glenview – Kleeman line in DEOK. The principal binding constraints limiting the supply of FTRs in the Annual FTR Auction for the 2015 to 2016 planning period include the Bush – Lafayette flowgate in MISO and the Oakgrove – Galesburg flowgate in MISO.

  Market participants can sell FTRs. In the 2016 to 2019 Long Term FTR Auction, total participant FTR sell offers were 327,980 MW, up from 240,748 in the 2015 to 2018 Long Term FTR Auction. In the 2015 to 2016 Annual FTR Auction, total participant sell offers were 378,744 MW, up from 271,368 MW in the 2014 to 2015 Annual FTR Auction. In the Monthly Balance of Planning Period FTR Auctions for the 2015 to 2016 planning period, total participant FTR sell offers were 3,495,474 MW, up from 2,424,369 MW for the same period during the 2014 to 2015 planning period.

- **Demand.** In the 2016 to 2019 Long Term FTR Auction, total FTR buy bids were 2,459,946 MW, down 21.3 percent from 3,124,613 MW the previous planning period. There were 2,461,662 MW of buy and self-scheduled bids in the 2015 to 2016 Annual FTR Auction, down 24.7 percent from 3,270,311 MW the previous planning period. The total FTR buy bids from the Monthly Balance of Planning Period FTR Auctions for the 2015 to 2016 planning period decreased 11.5 percent from 17,863,834 MW for the same time period of the prior planning period, to 15,813,526 MW.

- **Patterns of Ownership.** For the 2016 to 2019 Long Term FTR Auction, financial entities purchased 70.1 percent of prevailing flow FTRs and 78.5 percent of counter flow FTRs. For the 2015 to 2016 Annual FTR Auction, financial participants purchased 56.3 percent of all prevailing flow FTRs and 75.0 percent of all counter flow FTRs. For the Monthly Balance of Planning Period Auctions, financial entities purchased 74.9 percent of prevailing flow and 76.8 percent of counter flow FTRs for January through December of 2015. Financial entities owned 65.9 percent of all prevailing and counter flow FTRs, including 60.6 percent of all prevailing flow FTRs and 79.6 percent of all counter flow FTRs during the period from January through December 2015.

Market Behavior

- **FTR Forfeitures.** Total forfeitures for the 2015 to 2016 planning period were $0.2 million for Increment Offers, Decrement Bids and UTC Transactions.

- **Credit Issues.** There were three collateral defaults and seven payment defaults for 2015. Two collateral defaults totaled $710,300 and seven payment defaults totaled $1,726,641 for Intergrid Mideast Group, LLC. There was one other collateral default for the first nine months of 2015 for $35,000, which was promptly cured. There were no additional defaults in the last quarter of 2015.

  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 has liquidated all of Intergrid's FTR positions in accordance with Section 7.3.9 of the Operating Agreement.[140] 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 is $279,414. PJM has notified its Members that the Intergrid default will not result in any default allocation assessments in

140 *See* PJM OATT. Liquidation of Financial Transmission Rights in the Event of Member Default. § 7.3.9.

accordance with Section 15.2.2 of the Operating Agreement.[141]

Market Performance

- **Volume.** The 2016 to 2019 Long Term FTR Auction cleared 277,397 MW (11.3 percent) of demand of FTR buy bids, down 0.2 percent from 277,865 MW (8.9 percent) in the 2015 to 2018 Long Term FTR Auction. The Long Term FTR Auction also cleared 61,210 MW (18.7 percent) of FTR sell offers, compared to 34,629 (14.4 percent), a 76.8 percent increase.

  In the Annual FTR Auction for the 2015 to 2016 planning period 378,328 MW (15.4 percent) of buy and self-schedule bids cleared, up 3.4 percent from 365,843 MW (10.4 percent) for the previous planning period. In the 2015 to 2016 planning period Monthly Balance of Planning Period FTR Auctions 1,466,985 MW (9.3 percent) of FTR buy bids and 803,463 MW (23.0 percent) of FTR sell offers cleared.

- **Price.** The weighted-average buy-bid FTR price in the 2016 to 2019 Long Term FTR Auction was $0.05 per MW, up from $0.04 per MW for the 2015 to 2018 planning period. The weighted-average buy-bid FTR price in the Annual FTR Auction for the 2015 to 2016 planning period 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 2015 to 2016 planning period was $0.25, up from $0.16 per MW for the same period in the 2014 to 2015 planning period.

- **Revenue.** The 2016 to 2019 Long Term FTR Auction generated $23.2 million of net revenue for all FTRs, up from $9.0 million for the 2015 to 2018 Long Term FTR Auction. The 2015 to 2016 Annual FTR Auction generated $936.3 million in net revenue, up from $748.6 million for the 2014 to 2015 Annual FTR Auction. The Monthly Balance of Planning Period FTR Auctions generated $25.8 million in net revenue for all FTRs for the 2015 to 2016 planning period, up from $12.5 million for the same time period in the 2014 to 2015 planning period.

- **Revenue Adequacy.** FTRs were paid at 100 percent of the target allocation level for the 2015 to 2016 planning period. This high level of revenue adequacy was primarily a result of actions taken by PJM to reduce the level of available ARRs and FTRs. 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.

- **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 $453.5 million in profits for physical entities, of which $325.9 million was from self-scheduled FTRs, and $182.3 million for financial entities.

Section 13 Recommendations

- The MMU recommends that the ARR/FTR design be modified to ensure that all congestion revenues are returned to load. (Priority: High. New recommendation. Status: Not adopted.)
- The MMU recommends that all FTR auction revenue be distributed to ARR holders. (Priority: High. New recommendation. Status: Not adopted.)
- The MMU recommends that historical generation to load paths be eliminated as a basis for allocating ARRs. (Priority: High. New recommendation. Status: Not adopted.)
- The MMU recommends that counter flow FTRs be eliminated. (Priority: High. New recommendation. Status: Not adopted.)
- The MMU recommends that FTR auction revenues not be used to buy counter flow FTRs with the purpose of improving FTR payout ratios.[142] (Priority: High. New recommendation. Status: Not adopted.)
- The MMU recommends that PJM report correct monthly payout ratios to reduce understatement of payout ratios on a monthly basis. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM eliminate portfolio netting to eliminate cross subsidies among FTR

141 *See* PJM OATT. Default Allocation Assessment § 15.2.2.

142 See PJM. "Manual 6: Financial Transmission Rights" Revision 16 (June 1, 2014), p. 56.

marketplace participants. (Priority: High. First reported 2012. Status: Not adopted. Pending before FERC.)

- 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 2012. 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 the basis for the Stage 1A assignments be reviewed and made explicit, that the role of out of date generation to load paths be reviewed and that the building of the transmission capability required to provide all defined Stage 1A allocations be reviewed. (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 examine the mechanism by which self scheduled FTRs are allocated when load switching among LSEs occurs throughout the planning period. (Priority: Low. First reported 2011. Status: Not adopted.)

Section 13 Conclusion

The annual ARR allocation should be designed to return congestion revenues to firm transmission service customers, without requiring contract path physical transmission rights that are difficult or impossible to define and enforce in LMP markets. The fixed charges paid for firm transmission services result in the transmission system which provides physically firm transmission service which results in load paying congestion revenues.

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 fact 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 congestion revenues 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, which equals total congestion revenues.

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.

As a result of the creation of ARRs and other changes to the design, the current ARR/FTR design does not serve as an efficient way to ensure that load receives all the congestion revenues or has the ability to receive the auction revenues associated with all the potential congestion revenues. Total ARR and self scheduled FTR revenue offset only 59.8 percent of total congestion costs including congestion in the Day-Ahead Energy Market and the balancing energy market for the 2014 to 2015 planning period.

For these reasons, load should never be required to subsidize payments to FTR holders, regardless of the reason. Such subsidies have been suggested repeatedly.[143] 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 and that congestion is defined, in an accounting sense, to equal the sum of 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 and result in profits to FTR holders.

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 even when defined correctly. Load does have those rights based on load's payment for the transmission system and load's payment of total congestion.

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 balancing congestion which is the other part of total congestion. 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 in recent years, 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 markets. Such differences are not an indication that FTR holders are under paid.

The difference between the congestion payout using total congestion and the congestion payout using only day-ahead congestion illustrates the issue. For 2015, total day-ahead congestion was $1,632.1 million while total day-ahead plus balancing congestion was $1,385.3 million, compared to target allocations of $1,231.3 million in the same time period.

PJM used a more conservative approach to modeling the transmission capability for the 2014 to 2015 planning period. PJM simply assumed higher outage levels and included additional constraints, both of which reduced system capability in the FTR auction model. The result was a significant reduction in Stage 1B and Stage 2 ARR allocations, 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.

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. In the 2014 to 2015 and 2015 to 2016 planning periods, due to reduced ARR allocations, FTR volume decreased relative to the 2013 to 2014 planning period. The reduction in ARR allocations and resulting FTR volume caused, by definition, an improvement in revenue adequacy, and also resulted in an increase in the prices of FTRs. Increased FTR prices resulted in increased ARR target allocations, because ARR target allocations are based on the Annual FTR Auction nodal prices.

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.

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

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. The origin and basis for the requirement to assign Stage 1A ARRs needs further investigation. The issues associated with over allocation appear to be based on the use of out of date generation to load ARR paths and on whether PJM has appropriately built transmission to meet the requirement.

The MMU recommends that the basis for the Stage 1A assignments be reviewed and made explicit, that the role of out of date generation to load paths be reviewed and that the building of the transmission capability required to provide all defined Stage 1A allocations be reviewed. The implementation of the MMU's recommendation to return all congestion revenues to load would also significantly affect this issue.

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.

For the 2014 to 2015 and 2015 to 2016 planning periods FTRs have been revenue adequate. This is not because the underlying problems have been fixed. Revenue adequacy has been accomplished by limiting the amount of available ARRs and FTRs by arbitrarily decreasing the ARR allocations for Stage 1B and Stage 2 which also results in a redistribution of ARRs based on differences in allocations between Stage 1A and Stage 1B ARRs.

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.

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:** 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 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 State of the Market Report for PJM*, the MMU includes 27 recommendations that were new in 2015, ten of which are evaluated as high priority. Seventeen of the 27 new recommendations for 2015 are reported for the first time in this annual state of the market report.

New Recommendation from Section 3, Energy Market

- The MMU recommends, in order to ensure effective market power mitigation when the TPS test is failed, that markup be constant across price and cost offers, that there be at least one cost-based offer using the same fuel as the available price-based

1 OATT Attachment M § IV.D.
2 *Id.*
3 *Id.*
4 *Id.*
5 OATT Attachment M § VI.A.
6 18 CFR § 35.28(g)(3)(ii)(A); see also OATT Attachment M § IV.D.

offer. (Priority: High. New recommendation. Status: Not adopted.)

- The MMU recommends that in order to ensure effective market power mitigation when the TPS test is failed, the operating parameters in the cost-based offer and the price-based parameter limited schedule (PLS) offer be at least as flexible as the operating parameters in the available non-PLS price-based offer, and that the price-MW pairs in the price based PLS offer be exactly equal to the price based non PLS offer. (Priority: High. New recommendation. Status: Not adopted.)
- The MMU recommends that under the Capacity Performance construct, PJM recognize the difference between operational parameters that indicate to PJM dispatchers what a unit is capable of during the operating day and the parameters that are used for capacity performance assessment as well as uplift payments. The parameters which determine non-performance charges and the amount of uplift payments to those generators should reflect the flexibility goals of the capacity performance construct. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that capacity performance resources and base capacity resources (during the June through September period) be held to the OEM operating parameters of the capacity market CONE reference resource for performance assessment and energy uplift payments. (Priority: Medium. New recommendation. Status: Not adopted.)
- 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. (Priority: Medium. First reported Q2, 2015. Status: Not adopted.)
- The MMU recommends that PJM explicitly state its policy on the use of transmission penalty factors including the level of the penalty factors, the triggers for the use of the penalty factors, the appropriate line ratings to trigger the use of penalty factors, and when the transmission penalty factors will be used to set the shadow price. (Priority: Medium. New recommendation Status: Not adopted.)

New Recommendations from Section 4, Energy Uplift

- The MMU recommends that PJM not use price setting logic to artificially override the nodal prices that are based on fundamental LMP logic in order to reduce uplift. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that units scheduled in the Day-Ahead Energy Market and not committed in real time should be compensated for LOC based on their real-time desired and achievable output, not their scheduled day-ahead output. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that only flexible fast start units (startup plus notification times of 30 minutes or less) and short minimum run times (one hour or less) be eligible by default for the LOC compensation to units scheduled in the Day-Ahead Energy Market and not committed in real time. Other units should be eligible for LOC compensation only if PJM explicitly cancels their day-ahead commitment. (Priority: Medium. First reported 2015. Status: Not adopted.)

New Recommendations from Section 6, Demand Response

- The MMU recommends that PJM require nodal dispatch of demand resources with no advance notice required or, if nodal location is not required, subzonal dispatch of demand resources with no advance notice required. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM eliminate the measurement of compliance across zones within a compliance aggregation area (CAA). 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. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that the Net Benefits Test be eliminated and that demand response resources be paid LMP less any generation component of the applicable retail rate. (Priority: Low. New recommendation. Status: Not adopted.)

- 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 because load has been reduced or eliminated, such as in the case of bankrupt and/or out of service facilities. (Priority: Medium. First reported Q2, 2015. Status: Not adopted.)

New Recommendations from Section 9, Interchange Transactions

- The MMU recommends that PJMSettlement Inc. immediately request a credit evaluation from all companies that engaged in up to congestion transactions between September 8, 2014, and December 31, 2015. If PJM has the authority, PJM should ensure that the potential exposure to uplift for that period be included as a contingency in the companies' calculations for credit levels and/or collateral requirements. If PJM does not have the authority to take such steps, PJM should request guidance from FERC. (Priority: High. New recommendation. Status: Not adopted.)
- The MMU recommends that the emergency interchange cap be replaced with a market based solution. (Priority: Low. New recommendation. Status: Not adopted.)

New Recommendations from Section 10, Ancillary Services

- The MMU recommends that a reason code be attached to every hour in which PJM market operations adds additional DASR MW. (Priority: Medium. First reported Q2, 2015. Status: not adopted.)

New Recommendations from Section 12, Planning

- The MMU recommends that rules be implemented to require that project cost caps on new transmission projects be part of the evaluation of competing projects. (Priority: Low. New recommendation. Status: Not adopted.)
- 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. First reported Q2, 2015. Status: Not adopted.)
- The MMU recommends consideration of changing the minimum distribution factor in the allocation from .01 to .00 and adding a threshold minimum impact on the load on the line. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that PJM draft a clear definition of the congestion analysis required for transmission outage requests to include in Manual 3 after appropriate review. (Priority: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM modify the rules to reduce or eliminate the approval of late outage requests submitted or rescheduled after the FTR auction bidding opening date. (Priority: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM not permit transmission owners to divide long duration outages into smaller segments to avoid complying with the requirements for long duration outages. (Priority: Low. New recommendation. Status: Not adopted.)

New Recommendations from Section 13, Financial Transmission Rights

- The MMU recommends that the ARR/FTR design be modified to ensure that all congestion revenues are returned to load. (Priority: High. New recommendation. Status: Not adopted.)
- The MMU recommends that all FTR auction revenue be distributed to ARR holders. (Priority: High. New recommendation. Status: Not adopted.)
- The MMU recommends that historical generation to load paths be eliminated as a basis for allocating ARRs. (Priority: High. New recommendation. Status: Not adopted.)
- The MMU recommends that counter flow FTRs be eliminated. (Priority: High. New recommendation. Status: Not adopted.)
- The MMU recommends that FTR auction revenues not be used to buy counter flow FTRs with the

purpose of improving FTR payout ratios.[7] (Priority: High. New recommendation. Status: Not adopted.)

History of MMU Recommendations

The MMU began making recommendations to PJM in the 1999 State of the Market Report. Since that time, the MMU has made approximately 200 recommendations in the State of the Market Reports. In 2014, the MMU began including a priority and status with each recommendation. In this *2015 State of the Market Report for PJM*, the MMU has reviewed all past recommendations, assigned priority and determined their current status.

MMU recommendations are given the status of "Adopted," "Partially Adopted," or "Not Adopted." Some early recommendations are no longer reported and may have evolved into newer recommendations. These are categorized as "Replaced by Newer Recommendation."

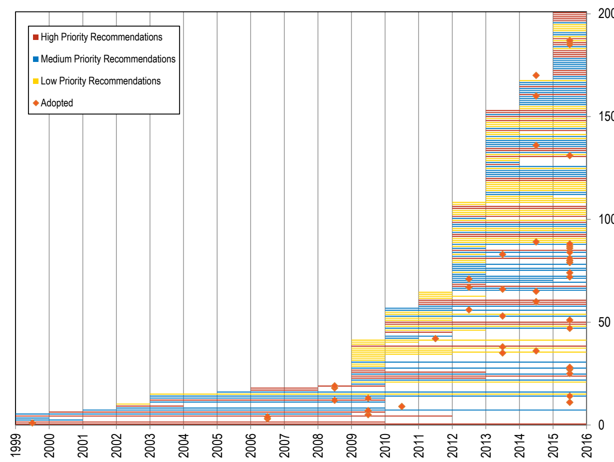
Table 2-1 shows the status of all recommendations reported by the MMU from 1999 through 2015. Over that time, 24 percent of all MMU recommendations have been adopted and 60 percent are not adopted. Of the 56 high priority recommendations, 20 (36 percent) have been adopted.

Table 2-1 Status of MMU reported recommendations: 1999 through 2015

Status	Priority High	Priority Medium	Priority Low	Total	Percent of Total
Adopted	20	13	16	49	24.4%
Partially Adopted	6	10	8	24	11.9%
Not Adopted	20	39	44	103	51.2%
Not Adopted (Pending before FERC)	3	1	0	4	2.0%
Not Adopted (Stakeholder Process)	6	7	1	14	7.0%
Not Adopted (Total)	29	47	45	121	60.2%
Replaced by Newer Recommendation	1	5	1	7	3.5%
Total	56	75	70	201	100%

As shown in Figure 2-1, the MMU continues to make recommendations, and progress continues on recommendation adoption. In the figure, each line represents a recommendation, starting on the date it was first reported, and ending on the most recent instance of the recommendation. The orange markers indicate the date of adoption of a recommendation.

Figure 2-1 History of recommendation creation and closure: 1999 through 2015



7 See PJM. "Manual 6: Financial Transmission Rights" Revision 16 (June 1, 2014), p. 56.

Complete List of Current MMU Recommendations

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

Section 3, Energy Market

- The MMU recommends that PJM retain the $1,000 per MWh offer cap in the PJM energy market except when cost-based offers exceed $1,000 per MWh, and other existing rules that limit incentives to exercise market power. (Priority: High. First reported 1999. Status: Partially adopted, 1999.)
- The MMU recommends that the rules governing the application of the TPS test be clarified and documented. (Priority: High. First reported 2010. Status: Not adopted.)
- The MMU recommends, in order to ensure effective market power mitigation when the TPS test is failed, that markup be constant across price and cost offers, that there be at least one cost-based offer using the same fuel as the available price-based offer. (Priority: High. New recommendation. Status: Not adopted.)
- The MMU recommends that in order to ensure effective market power mitigation when the TPS test is failed, the operating parameters in the cost-based offer and the price-based parameter limited schedule (PLS) offer be at least as flexible as the operating parameters in the available non-PLS price-based offer, and that the price-MW pairs in the price based PLS offer be exactly equal to the price based non PLS offer. (Priority: High. New recommendation. Status: Not adopted.)
- 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 under the Capacity Performance construct, PJM recognize the difference between operational parameters that indicate to PJM dispatchers what a unit is capable of during the operating day and the parameters that are used for capacity performance assessment as well as uplift payments. The parameters which determine non-performance charges and the amount of uplift payments to those generators should reflect the flexibility goals of the capacity performance construct. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that capacity performance resources and base capacity resources (during the June through September period) be held to the OEM operating parameters of the capacity market CONE reference resource for performance assessment and energy uplift payments. (Priority: Medium. New recommendation. Status: Not adopted.)
- 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. (Priority: Medium. First reported Q2, 2015. Status: Not 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 rather than indicating its availability to supply energy on an emergency basis. (Priority: Low. First reported 2009. Status: Not Adopted.)
- The MMU recommends that PJM explain how LMPs are calculated when demand response is marginal. The LMPs in excess of $1,800 per MWh on January 7, 2014, were potentially a result of the way in which PJM modeled zonal (not nodal) demand response as a marginal resource. (Priority: Low. First reported Q1, 2014. Status: Not Adopted.)
- The MMU recommends that PJM explicitly state its policy on the use of transmission penalty factors including the level of the penalty factors, the triggers for the use of the penalty factors, the appropriate line ratings to trigger the use of penalty factors, and when the transmission penalty factors will be used to set the shadow price. (Priority: Medium. New recommendation 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: Partially 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 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.)
- 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] There is currently no PJM documentation in the tariff or manuals explaining how hubs are created and how their definitions are 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 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: Partially adopted.)
- The MMU recommends that PJM continue to enhance its posting of market data to promote market efficiency. (Priority: Medium. First reported 2005. Status: Partially Adopted.)
- The MMU recommends the elimination of FMU and AU adders. 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.)

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 interface constraints to artificially override the nodal prices that are based on fundamental LMP logic in order to: accommodate rather than resolve the inadequacies of the demand side resource capacity product; address the inability of the power flow model to incorporate the need for reactive power; accommodate rather than resolve the flaws in PJM's approach to scarcity pricing; or for any other reason. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM not use price setting logic to artificially override the nodal prices that are based on fundamental LMP logic in order to reduce uplift. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that PJM initiate an analysis of the reasons why some combustion turbines and diesels scheduled in the Day-Ahead Energy Market are not called in real time when they are economic. (Priority: Medium. First Reported 2012. Status: Not adopted.)
- 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

8 PJM. OATT Section: 6A.1.3 Maximum Emergency, (February 25, 2014), p. 1740, 1795.

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.

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

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 2014.)

- 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. Stakeholder process.)
- 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 2009. 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 seven modifications to the energy lost opportunity cost calculations:
  - The MMU recommends that the lost opportunity cost in the energy market be calculated using the schedule on which the unit was scheduled to run in the energy market. (Priority: High. First reported 2012. Status: Adopted 2015.)
  - 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: Adopted 2015.)
  - 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: Adopted 2015.)
  - The MMU recommends calculating LOC based on 24 hour daily periods or multi-hour segments of hours for 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 units scheduled in the Day-Ahead Energy Market and not committed in real time should be compensated for LOC based on their real-time desired and achievable output, not their scheduled day-ahead output. (Priority: Medium. First reported 2015. Status: Not adopted.)
  - The MMU recommends that units scheduled in the Day-Ahead Energy Market and not committed in real time be compensated for LOC incurred within an hour. (Priority: Medium. First reported 2013. Status: Not adopted.)
  - The MMU recommends that only flexible fast start units (startup plus notification times of 30 minutes or less) and short minimum run times (one hour or less) be eligible by default for the LOC compensation to units scheduled in the Day-Ahead Energy Market and not committed in real time. Other units should be eligible for LOC compensation only if PJM explicitly cancels their day-ahead commitment. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that up to congestion transactions be required to pay energy uplift charges. (Priority: High. First reported 2011. 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. Stakeholder process.)
- 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 solely to real-time RTO load. (Priority: Low. First reported 2013. Status: Not adopted. Stakeholder process.)
- 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 Q2, 2012. Status: Not adopted. Stakeholder process.)

Section 5, Capacity[11]

The MMU recognizes that PJM has implemented 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. The MMU's 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 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: Partially 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 modifications to existing resources not be treated as new resources for purposes of market power related offer caps or MOPR offer floors. (Priority: Low. First reported 2012. Status: Not adopted.)

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).

15 See PJM Interconnection, L.L.C., Docket No. ER12-513-000 (December 1, 2011) ("Triennial Review").

16 See the *2012 State of the Market Report for PJM*, Volume II, Section 6, Net Revenue.

- 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 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 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 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 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 2012. 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: Adopted.)

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 See OATT Attachment DD § 10(e). 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 that PJM has incorporated some of these recommendations in the Capacity Performance filing. The status of each recommendation reflects the status at December 31, 2015.

- 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.)
- The MMU recommends that there be only one demand response product, with an obligation to respond when called for all hours of the year, and that the demand response be on the demand side of the capacity market. (Priority: High. First reported 2011. Status: Partially Adopted.[19])
- The MMU recommends that the option to specify a minimum dispatch price under the Emergency and Pre-Emergency Program Full option be eliminated and that participating resources receive the hourly real-time LMP less any generation component of their retail rate. (Priority: Medium. First reported 2010. Status: Not adopted.)
- The MMU recommends that the emergency load response program be classified as an economic program, responding to economic price signals and not an emergency program responding only after an emergency is called and not triggering the definition of a PJM emergency. (Priority: High. First reported 2012. Status: Not adopted.)
- The MMU recommends that the Emergency Program Energy Only option be eliminated because the opportunity to receive the appropriate energy market incentive is already provided in the Economic Program. (Priority: Low. First reported 2010. Status: Not adopted.)
- The MMU recommends that 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.)
- The MMU recommends that 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: Partially adopted.)
- The MMU recommends that demand resources be required to provide their nodal location, comparable to generation resources. (Priority: High. First reported 2011. Status: Not adopted.)
- The MMU recommends that PJM require nodal dispatch of demand resources with no advance notice required or, if nodal location is not required, subzonal dispatch of demand resources with no advance notice required. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM eliminate the measurement of compliance across zones within a compliance aggregation area (CAA). 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. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends capping the baseline for measuring compliance under GLD, for the limited summer product, at the customers' PLC. (Priority: High. First reported 2010. Status: Adopted.)
- The MMU recommends capping the baseline for measuring capacity compliance under winter compliance at the customers' PLC, similar to GLD, to avoid double counting. (Priority: High. First reported 2010. Status: Partially adopted.)
- The MMU recommends that measurement and verification methods for demand resources be modified to reflect compliance more accurately. (Priority: Medium. First reported 2009. Status: Not adopted.)
- 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

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.

and registrations. (Priority: Medium. First reported 2012. Status: Not adopted.)

- The MMU recommends that PJM adopt the ISO-NE five-minute metering requirements in order to ensure that dispatchers have the necessary information for reliability and that market payments to demand resources be calculated based on interval meter data at the site of the demand reductions.[21] (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that demand response event compliance be calculated for each hour and the penalty structure reflect hourly compliance for the base and capacity performance products. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that demand resources whose load drop method is designated as "Other" explicitly record the method of load drop. (Priority: Low. First reported 2013. Status: Adopted, Q2, 2014.)
- The MMU recommends that 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 that shutdown cost be defined as the cost to curtail load for a given period that does not vary with the measured reduction or, for behind the meter generators, be the start cost defined in Manual 15 for generators. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that the Net Benefits Test be eliminated and that demand response resources be paid LMP less any generation component of the applicable retail rate. (Priority: Low. New recommendation. Status: Not adopted.)
- 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 because load has been reduced or eliminated, such as in the case of bankrupt and/or out of service facilities. (Priority: Medium. First reported Q2, 2015. Status: Not adopted.)

21 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.

Section 7, Net Revenue

There are no recommendations in this section.

Section 8, Environmental

There are no recommendations in this section.

Section 9, Interchange Transactions

- The MMU recommends that PJM eliminate the IMO interface pricing point, and assign the transactions that originate or sink in the IESO balancing authority to the MISO interface pricing point. (Priority: Medium. First reported 2013. 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. 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 1800 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 used to meet load in the most economic manner. (Priority: Medium. First reported Q3 2014. Status: Adopted partially, Q1 2015.)
- The MMU recommends that PJM explore an interchange optimization solution with its neighboring balancing authorities that would 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 uses supply curves and treats seams between balancing authorities as constraints, similar to other constraints within an LMP market.

(Priority: Medium. First reported 2014. 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 by concealing the true source or sink of the transaction. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM implement a validation method for submitted transactions that would require market participants to submit transactions on market paths that reflect the expected actual 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 requests that, in order to permit a complete analysis of loop flow, FERC and NERC ensure that the identified data are made available to market monitors as well as other industry entities determined appropriate by FERC. (Priority: Medium. First reported 2003. Status: Not adopted.)
- 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 eliminate the NIPSCO, Southeast and Southwest 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 PJMSettlement Inc. immediately request a credit evaluation from all companies that engaged in up to congestion transactions between September 8, 2014, and December 31, 2015. If PJM has the authority, PJM should ensure that the potential exposure to uplift for that period be included as a contingency in the companies' calculations for credit levels and/or collateral requirements. If PJM does not have the authority to take such steps, PJM should request guidance from FERC. (Priority: High. New recommendation. Status: Not adopted.)
- The MMU recommends that the emergency interchange cap be replaced with a market based solution. (Priority: Low. New recommendation. 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 2012. Status: Not adopted.)
- The MMU recommends a number of market design changes to improve the performance of the Regulation Market, including use of a single clearing price based on actual LMP, modifications to the LOC calculation methodology, a software change to save some data elements necessary for verifying market outcomes, and further documentation of the implementation of the market design through SPREGO. (Priority: Medium. First reported 2010. Status: Partially adopted in 2012.)

- The MMU recommends that the lost opportunity cost in the ancillary services markets be calculated using the schedule on which the unit was scheduled to run in the energy market. (Priority: High. First reported 2010. Status: Partially Adopted.)
- The MMU recommends that the single clearing price for synchronized reserves be determined based on the actual LMP and not the forecast LMP. (Priority: Low. First reported 2010. Status: 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. The MMU also recommends that documentation of the Tier 1 synchronized reserve deselection process be published. (Priority: High. First reported Q3, 2014. Status: Adopted July 2014.)
- The MMU recommends that the tier 2 synchronized reserve must offer requirement be enforced. The MMU recommends that PJM define a set of acceptable reasons why a unit can be made unavailable daily or hourly and require operators to select a reason in eMkt whenever making a unit unavailable. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM be explicit about why tier 1 biasing is used in the Tier 2 Synchronized Reserve Market. The MMU recommends that PJM define explicit rules for the use of tier 1 biasing during any phase of the market solution and 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: Partially adopted, 2014.)
- The MMU recommends that the three pivotal supplier test and market power mitigation 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 market operations adds additional DASR MW. (Priority: Medium. First reported Q2, 2015. Status: not adopted.)

Section 11, Congestion and Marginal Losses

There are no recommendations in this section.

Section 12, Planning

- The MMU recommends that PJM continue to incorporate the principle that the goal of transmission planning should be the incorporation of transmission investment decisions into market driven processes as much as possible. (Priority: Low. First reported 2001. Status: Not adopted.)
- 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 rules be implemented to require that project cost caps on new transmission projects be part of the evaluation of competing projects. (Priority: Low. New recommendation. Status: Not adopted.)
- The MMU recommends that barriers to entry be addressed in a timely manner in order to help ensure that the capacity market will result in the entry of new capacity to meet the needs of PJM market participants and reflect the uncertainty

and resultant risks in the cost of new entry used to establish the capacity market demand curve in RPM. (Priority: Low. First reported 2012. 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.[22] (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: Partially 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 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 RTEP. (Priority: Medium. First reported 2014. Status: Not adopted.)
- 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. First reported Q2, 2015. Status: Not adopted.)
- The MMU recommends consideration of changing the minimum distribution factor in the allocation from .01 to .00 and adding a threshold minimum impact on the load on the line. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that PJM reevaluate all transmission outage tickets as on time or late 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.)
- The MMU recommends that PJM draft a clear definition of the congestion analysis required for transmission outage requests to include in Manual 3 after appropriate review. (Priority: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM modify the rules to reduce or eliminate the approval of late outage requests submitted or rescheduled after the FTR auction bidding opening date. (Priority: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM not permit transmission owners to divide long duration outages into smaller segments to avoid complying with the requirements for long duration outages. (Priority: Low. New recommendation. Status: Not adopted.)

Section 13, FTRs and ARRs

- The MMU recommends that the ARR/FTR design be modified to ensure that all congestion revenues are returned to load. (Priority: High. New recommendation. Status: Not adopted.)
- The MMU recommends that all FTR auction revenue be distributed to ARR holders. (Priority: High. New recommendation. Status: Not adopted.)

22 See "Comments of the Independent Market Monitor for PJM," Docket No. ER12-1177-000, <http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Comments_ER12-1177-000_20120312.pdf>.

- The MMU recommends that historical generation to load paths be eliminated as a basis for allocating ARRs. (Priority: High. New recommendation. Status: Not adopted.)
- The MMU recommends that counter flow FTRs be eliminated. (Priority: High. New recommendation. Status: Not adopted.)
- The MMU recommends that FTR auction revenues not be used to buy counter flow FTRs with the purpose of improving FTR payout ratios.[23] (Priority: High. New recommendation. Status: Not adopted.)
- The MMU recommends that PJM report correct monthly payout ratios to reduce understatement of payout ratios on a monthly basis. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM eliminate portfolio netting to eliminate cross subsidies among FTR marketplace participants. (Priority: High. First reported 2012. Status: Not adopted. Pending before FERC.)
- 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 2012. 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 the basis for the Stage 1A assignments be reviewed and made explicit, that the role of out of date generation to load paths be reviewed and that the building of the transmission capability required to provide all defined Stage 1A allocations be reviewed. (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 examine the mechanism by which self scheduled FTRs are allocated when load switching among LSEs occurs throughout the planning period. (Priority: Low. First reported 2011. Status: Not adopted.)

23 See PJM. "Manual 6: Financial Transmission Rights" Revision 16 (June 1, 2014), p. 56.

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 2015, including market size, concentration, residual supply index, and price.[1] The MMU concludes that the PJM energy market results were competitive in 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 2015 was moderately concentrated. Average HHI was 1096 with a minimum of 879 and a maximum of 1468 in 2015. The fact that the average HHI was in the moderately concentrated range does not mean that the aggregate market was competitive in all hours. The PJM Energy Market intermediate and peaking segments of supply were highly concentrated.
- 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 identified local market power and resulted in offer capping to force competitive offers, correcting for structural issues created by local transmission constraints. There are, however, identified issues with the application of market power mitigation to resources whose owners fail the TPS test that need to be addressed.
- 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 both routinely and during periods of high demand is consistent with 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 general, 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 identifies 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.

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

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

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

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 primarily 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, however, identified issues with the application of market power mitigation to resources whose owners fail the TPS test that can result in the exercise of local market power. These issues need to be addressed. There are issues related to the definition of gas costs includable in energy offers that need to be addressed. There are currently no market power mitigation rules in place that limit the ability to exercise market power when aggregate market conditions are tight. If market-based offer caps are raised, or if generators are allowed to modify offers hourly, market design must reflect appropriate incentives for competitive behavior and 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 increased by 4,490 MW, or 2.8 percent, in the summer months of 2015 from an average maximum of 160,190 in the summer of 2014 to 164,680 MW in the summer of 2015 of 160,190 MW to 164,680 MW. In 2015, 3,041.2 MW of new capacity were added to PJM. This new generation was more than offset by the deactivation of 9,897.2 MW.

  PJM average real-time generation in 2015 decreased by 2.5 percent from 2014, from 90,894 MW to 88,628 MW.

  PJM average day-ahead supply in 2015, including INCs and up to congestion transactions, decreased by 21.7 percent from 2014, from 146,672 MW to 114,889 MW, primarily as a result of decreases in UTC volumes.

- **Market Concentration.** The PJM energy market was moderately concentrated overall with moderate concentration in the baseload segment, but high concentration in the intermediate and peaking segments.

- **Generation Fuel Mix.** During 2015, coal units provided 36.6 percent, nuclear units 35.5 percent and gas units 23.4 percent of total generation. Compared to 2014, generation from coal units decreased 17.8 percent, generation from gas units increased 27.7 percent and generation from nuclear units increased 0.5 percent.

- **Marginal Resources.** In the PJM Real-Time Energy Market, in 2015, coal units were 51.74 percent of marginal resources and natural gas units were 35.52 percent of marginal resources. In 2014, coal units were 52.90 percent and natural gas units were 35.81 percent of the marginal resources.

  In the PJM Day-Ahead Energy Market, in 2015, up to congestion transactions were 76.1 percent of marginal resources, INCs were 5.1 percent of marginal resources, DECs were 8.9 percent of marginal resources, and generation resources were 9.6 percent of marginal resources. In 2014, up to congestion transactions were 91.0 percent of marginal resources, INCs were 2.3 percent of marginal resources, DECs were 3.3 percent of marginal resources, and generation resources were 3.3 percent of marginal resources.

- **Demand.** Demand includes physical load and exports and virtual transactions. The PJM system peak load during 2015 was 143,697 MW in the HE 1700 on July 28, 2015, which was 2,023 MW, or 1.4 percent, higher than the PJM peak load for 2014, which was 141,673 MW in the HE 1700 on June 17, 2014.

  PJM average real-time load in 2015 decreased by 0.6 percent from 2014, from 89,099 MW to 88,594 MW. PJM average day-ahead demand in 2015, including DECs and up to congestion transactions, decreased by 21.5 percent from 2014, from 142,644 MW to 111,644 MW.

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.

- **Supply and Demand: Scarcity.** There were no shortage pricing events in 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 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 0.5 percent in 2014 to 0.4 percent in 2015.

  In 2015, 15 control zones experienced congestion resulting from one or more constraints binding for 100 or more hours. The analysis of the application of the TPS test to local markets demonstrates that it is working successfully to identify 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. There are, however, identified issues with the application of market power mitigation to resources whose owners fail the TPS test that can result in the exercise of local market power. These issues need to be addressed.

- **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 remained at 0.4 percent in 2014 and 2015. In the Real-Time Energy Market, for units committed for reliability reasons, offer-capped unit hours increased from 0.3 percent in 2014 to 0.4 percent in 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, when using unadjusted cost offers, in 2015, 85.9 percent of marginal units had average dollar markups less than zero and had an average markup index less than zero. Using adjusted cost offers, in 2015, 47.1 percent of marginal units had average dollar markups less than zero and average markup index less than or equal to zero. Some marginal units did have substantial markups. Using unadjusted cost offers, 0.17 percent of offers had offer prices greater than $400 per MWh with average dollar markup of $56.87 per MWh.

  In the PJM Day-Ahead Energy Market, when using unadjusted cost offers, in 2015, 3.2 percent of marginal generating units had an average markup index less than or equal to zero. Using adjusted cost offers, in the 2015, 3.2 percent of marginal units had an average markup index less than or equal to zero.

- **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. There were no units eligible for an FMU or AU adder in 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 but there was an increase in up to congestion volume in December 2015, coincident with the expiration of the fifteen month resettlement period for the proceeding related to uplift charges for UTC transactions.[4] [5]

- **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. 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 2015, 56.1 percent were offered as available for economic dispatch, 23.8 percent were offered as

4 148 FERC ¶ 61,144 (2014).
5 16 U.S.C. § 824e.

self scheduled, and 20.1 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 changes in supply and demand, generation fuel mix, the cost of fuel, emission related expenses, markup and local price differences caused by congestion. PJM also may administratively set prices with the creation of a closed loop interface related to demand side resources or reactive power or the application of price setting logic.

  PJM Real-Time Energy Market prices decreased in 2015 compared to 2014. The load-weighted average real-time LMP was 31.9 percent lower in 2015 than in 2014, $36.16 per MWh versus $53.14 per MWh.

  PJM Day-Ahead Energy Market prices decreased in 2015 compared to 2014. The load-weighted average day-ahead LMP was 31.5 percent lower in 2015 than in 2014, $36.73 per MWh versus $53.62 per MWh.

- **Components of LMP.** In the PJM Real-Time Energy Market, for 2015, 43.2 percent of the load-weighted LMP was the result of coal costs, 27.2 percent was the result of gas costs and 2.32 percent was the result of the cost of emission allowances.

  In the PJM Day-Ahead Energy Market for 2015, 29.6 percent of the load-weighted LMP was the result of the cost of coal, 22.5 percent was the result of DECs, 14.3 percent was the result of the cost of gas, 11.6 percent was the result of INCs, and 4.3 percent was the result of up to congestion transactions.

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

  In the PJM Real-Time Energy Market in 2015, the adjusted markup component of LMP was $1.75 per MWh or 4.8 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 PJM Day-Ahead Energy Market, marginal INCs, DECs and UTCs have zero markups. In 2015, the adjusted markup component of LMP resulting from generation resources was $0.78 per MWh or 2.1 percent of the PJM day-ahead load-weighted average LMP. The month of February had the highest adjusted markup component, $2.81 per MWh or 3.6 percent of the day-ahead load-weighted average LMP. In 2015, the highest hourly adjusted markup was $710.63.

  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 is consistent with economic withholding.

- **Price Convergence.** Hourly and daily price differences between the Day-Ahead and Real-Time Energy Markets fluctuate continuously and substantially from positive to negative. The difference between the average day-ahead and real-time prices was -$0.93 per MWh in 2014 and -$0.73 per MWh in 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 2015.

Recommendations

- The MMU recommends that PJM retain the $1,000 per MWh offer cap in the PJM energy market except when cost-based offers exceed $1,000 per MWh, and other existing rules that limit incentives to exercise market power. (Priority: High. First reported 1999. Status: Partially adopted, 1999.)

- The MMU recommends that the rules governing the application of the TPS test be clarified and documented. (Priority: High. First reported 2010. Status: Not adopted.)

- The MMU recommends, in order to ensure effective market power mitigation when the TPS test is failed, that markup be constant across price and cost offers, that there be at least one cost-based offer using the same fuel as the available price-based offer. (Priority: High. New recommendation. Status: Not adopted.)

- The MMU recommends that in order to ensure effective market power mitigation when the TPS test is failed, the operating parameters in the cost-based offer and the price-based parameter limited schedule (PLS) offer be at least as flexible as the operating parameters in the available non-PLS price-based offer, and that the price-MW pairs in the price based PLS offer be exactly equal to the price based non PLS offer. (Priority: High. New recommendation. Status: Not adopted.)
- 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 under the Capacity Performance construct, PJM recognize the difference between operational parameters that indicate to PJM dispatchers what a unit is capable of during the operating day and the parameters that are used for capacity performance assessment as well as uplift payments. The parameters which determine non-performance charges and the amount of uplift payments to those generators should reflect the flexibility goals of the capacity performance construct. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that capacity performance resources and base capacity resources (during the June through September period) be held to the OEM operating parameters of the capacity market CONE reference resource for performance assessment and energy uplift payments. (Priority: Medium. New recommendation. Status: Not adopted.)
- 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. (Priority: Medium. First reported Q2, 2015. Status: Not 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 rather than indicating its availability to supply energy on an emergency basis. (Priority: Low. First reported 2009. Status: Not Adopted.)
- The MMU recommends that PJM explain how LMPs are calculated when demand response is marginal. The LMPs in excess of $1,800 per MWh on January 7, 2014, were potentially a result of the way in which PJM modeled zonal (not nodal) demand response as a marginal resource. (Priority: Low. First reported Q1, 2014. Status: Not Adopted.)
- The MMU recommends that PJM explicitly state its policy on the use of transmission penalty factors including the level of the penalty factors, the triggers for the use of the penalty factors, the appropriate line ratings to trigger the use of penalty factors, and when the transmission penalty factors will be used to set the shadow price. (Priority: Medium. New recommendation 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: Partially 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.[6] (Priority: Medium. First reported 2012. 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

6 PJM. OATT Section: 6A.1.3 Maximum Emergency, (February 25, 2014), p. 1740, 1795.

be made transparent. (Priority: Low. First reported 2013. Status: Not adopted.)

- 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.[7] There is currently no PJM documentation in the tariff or manuals explaining how hubs are created and how their definitions are changed.[8] (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 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: Partially adopted.)
- The MMU recommends that PJM continue to enhance its posting of market data to promote market efficiency. (Priority: Medium. First reported 2005. Status: Partially Adopted.)
- The MMU recommends the elimination of FMU and AU adders. 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.)

7 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.

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

Conclusion

The MMU analyzed key elements of PJM energy market structure, participant conduct and market performance in 2015, including aggregate supply and demand, concentration ratios, three pivotal supplier test results, offer capping, participation in demand response programs, loads and prices.

Average PJM real-time generation increased by 4,490 MW, or 2.8 percent, in the summer of 2015 compared to the summer of 2014, and peak load increased by 2,023 MW. Market concentration levels remained moderate although there is high concentration in the intermediate and peaking segments of the supply curve 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 the 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 aggregate market power does exist during high demand hours.

Prices are a key outcome of markets. Prices vary across hours, days and years for multiple reasons. Price is an indicator of the level of competition in a market although individual prices are not always easy to interpret. In a competitive market, prices are directly related to the marginal cost of the most expensive unit required to serve load in each hour. The pattern of prices within days and across months and years illustrates how prices are directly related to supply and demand conditions and thus also illustrates the potential significance of the impact of the price elasticity of demand on prices. Energy market results in 2015 generally reflected supply-demand fundamentals, although the behavior of some participants during high demand periods is consistent with economic withholding. Economic withholding is the ability to increase markups substantially in tight market conditions. There are additional issues in the energy market including the uncertainties about the pricing and availability of natural gas, the way that generation owners incorporate natural gas costs in offers, and 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.[9] This is a flexible, targeted real-time measure of market structure which replaced the offer capping of all units required to relieve a constraint. A generation owner or group of generation owners is pivotal for 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 for most hours to exempt owners when the local market structure is competitive and to require offer capping of owners when the local market structure is noncompetitive.

However, there are some issues with the application of mitigation in the Day-Ahead Energy Market and the Real-Time Energy Market when market sellers fail the TPS test. There is no tariff or manual language that defines in detail the application of the TPS test and offer capping in the Day-Ahead Energy Market and the Real-Time Energy Market. In both the Day-Ahead and Real-Time Energy Markets, generators have the ability to avoid mitigation by using varying markups in their price-based offers, offering different operating parameters in their price-based and cost-based offers, and using different fuels in their price-based and cost-based offers. These issues can be resolved by simple rule changes requiring that markup be constant across price and cost offers, that there be at least one cost-based offer using the same fuel as the available price-based offer, that the price-MW pairs in the price based PLS offer be exactly equal to the price based non PLS offer, and requiring cost- based and price-based PLS offers to be at least as flexible as price-based non-PLS offers.

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

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.

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 based on measured reserve levels and transparent 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 net 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. There are also significant issues with PJM's scarcity pricing rules, including the absence of a clear trigger based on measured reserve levels (the current triggers are based on estimated reserves) and the lack of adequate locational scarcity pricing options.

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 2014 or 2015. 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 is consistent with economic withholding. Given the structure of the energy market which can permit the exercise of aggregate market power at times of high demand, the tighter market conditions 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 2015.

Market Structure

Market Concentration

Analysis of supply curve segments of the PJM energy market in 2015 indicates moderate concentration in the base load segment, but high concentration in the intermediate and peaking segments.[10] High concentration levels, particularly in the peaking segment, increase the probability that a generation owner will be pivotal in the aggregate market 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 2015 although there are issues with the application of market power mitigation for resources whose owners fail the TPS test.

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).

The HHI may not accurately capture market power issues in situations where, for example, there is moderate concentration in all on line resources but there is a high level of concentration in resources needed to meet increases in load. The HHIs for supply curve segments is an indication of such issues. An aggregate pivotal supplier test is required to accurately measure the ability of incremental resources to exercise market power when load is high, for example.

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.[11]

PJM HHI Results

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

Table 3-2 PJM hourly energy market HHI: 2014 and 2015[12]

	Hourly Market HHI (2014)	Hourly Market HHI (2015)
Average	1153	1096
Minimum	930	879
Maximum	1468	1468
Highest market share (One hour)	29%	31%
Average of the highest hourly market share	21%	21%
# Hours	8,760	8,760
# 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 2014 and 2015. The PJM energy market was moderately concentrated overall with moderate concentration in the baseload segment, but high concentration in the intermediate and peaking segments.

10 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.

11 77 FERC ¶ 61,263, pp. 64-70 (1996), *"Inquiry Concerning the Commission's Merger Policy under the Federal Power Act: Policy Statement."*

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

Table 3-3 PJM hourly energy market HHI (By supply segment): 2014 and 2015

	2014			2015		
	Minimum	Average	Maximum	Minimum	Average	Maximum
Base	1031	1182	1484	988	1132	1487
Intermediate	795	1919	7307	603	1863	6375
Peak	643	5959	10000	716	5728	10000

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

Figure 3-1 Fuel source distribution in unit segments: 2015[13]

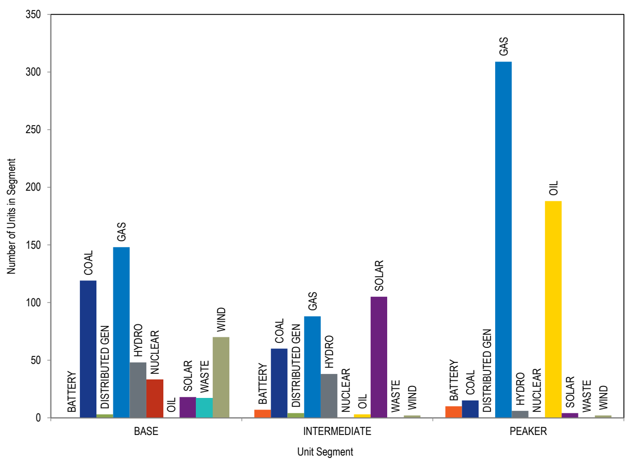
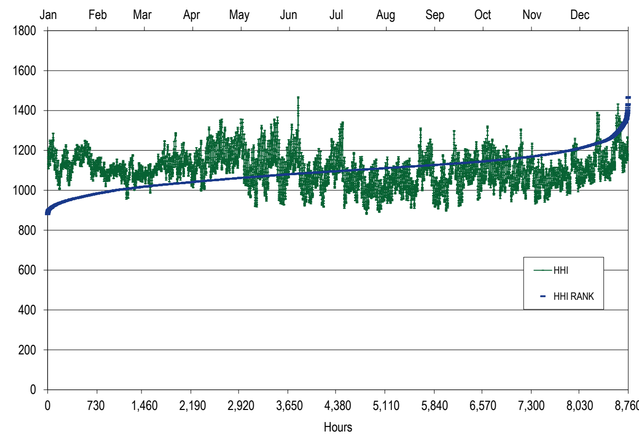


Figure 3-2 presents the hourly HHI values in chronological order and an HHI duration curve for 2015.

Figure 3-2 PJM hourly energy market HHI: 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 2015, the offers of one company contributed 19.0 percent of the real-time, load-weighted PJM system LMP and that the offers of the top four companies contributed 55.2 percent of the real-time, load-weighted, average PJM system LMP. During 2014, the offers of one company contributed 17.1 percent of the real time, load-weighted PJM system LMP and offers of the top four companies contributed 56.6 percent of the real-time, load-weighted, average PJM system LMP.

Table 3-4 Marginal unit contribution to PJM real-time, load-weighted LMP (By parent company): 2014 and 2015

2014		2015	
Company	Percent of Price	Company	Percent of Price
1	17.1%	1	19.0%
2	17.1%	2	15.6%
3	12.6%	3	10.9%
4	9.8%	4	9.8%
5	7.9%	5	8.7%
6	5.8%	6	8.4%
7	5.6%	7	4.4%
8	4.8%	8	4.0%
9	3.1%	9	2.6%
Other (62 companies)	16.3%	Other (62 companies)	16.7%

13 The units classified as Distributed Gen are buses within Electric Distribution Companies (EDCs) that are modeled as generation buses to accurately reflect net energy injections from distribution level load buses. The modeling change was the outcome of the Net Energy Metering Task Force stakeholder group in July, 2012.

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

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 the parent company that offers the marginal resource into the Day-Ahead Energy Market. The results show that in 2015, the offers of one company contributed 12.5 percent of the day-ahead, load-weighted PJM system LMP and that the offers of the top four companies contributed 39.3 percent of the day-ahead, load-weighted, average PJM system LMP. In 2014, the offers of one company contributed 10.0 percent of the day-ahead, load-weighted PJM system LMP and offers of the top four companies contributed 32.9 percent of the day-ahead, load-weighted, average PJM system LMP.

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

2014		2015	
Company	Percent of Price	Company	Percent of Price
1	10.0%	1	12.5%
2	9.0%	2	11.3%
3	7.5%	3	9.7%
4	6.3%	4	5.9%
5	5.7%	5	5.2%
6	5.3%	6	5.1%
7	4.8%	7	4.0%
8	3.9%	8	3.7%
9	2.8%	9	3.6%
Other (154 companies)	44.8%	Other (155 companies)	39.0%

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 2015, coal units were 51.74 percent and natural gas units were 35.52 percent of marginal resources. In 2014, coal units were 52.90 percent and natural gas units were 35.81 percent of the total marginal resources. In 2015, 75.26 percent of the wind marginal units had negative offer prices, 20.93 percent had zero offer prices and 3.81 percent had positive offer prices.

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]

Table 3-6 Type of fuel used (By real-time marginal units): 2011 through 2015

	Year				
Type/Fuel	2011	2012	2013	2014	2015
Coal	68.73%	58.84%	56.94%	52.90%	51.74%
Gas	25.84%	30.35%	34.72%	35.81%	35.52%
Oil	2.24%	6.00%	3.27%	7.44%	8.99%
Wind	2.36%	4.19%	4.76%	3.29%	3.27%
Other	0.00%	0.47%	0.20%	0.43%	0.39%
Municipal Waste	0.62%	0.13%	0.07%	0.05%	0.06%
Uranium	0.01%	0.02%	0.02%	0.04%	0.03%
Emergency DR	0.00%	0.00%	0.02%	0.04%	0.00%
Interface	0.20%	0.00%	0.00%	0.00%	0.00%

Table 3-7 shows the type and fuel type where relevant, of marginal resources in the Day-Ahead Energy Market. In 2015, up to congestion transactions were 76.14 percent of marginal resources. Up to congestion transactions were 91.05 percent of marginal resources in 2014.

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

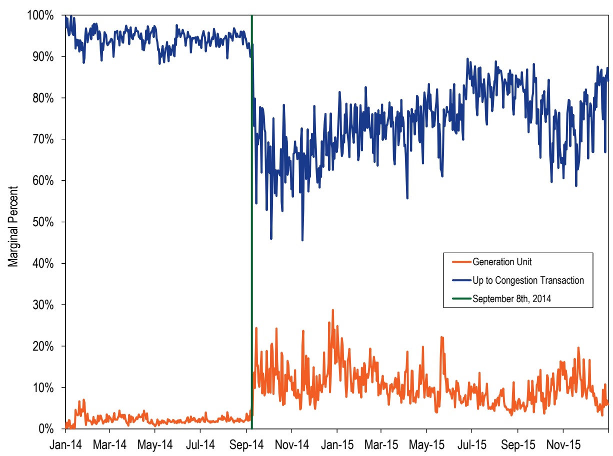
16 Prior to April 1, 2015, for the generation units that are capable of using multiple fuel types, PJM did not require the participants to disclose the fuel type associated with their offer schedule. For these units, the cleared offer schedules on a given day were compared to the cost associated with each fuel to determine the fuel type most likely to have been the basis for the cleared schedule.

Table 3-7 Day-ahead marginal resources by type/fuel: 2011 through 2015

Type/Fuel	2011	2012	2013	2014	2015
Up to Congestion Transaction	73.40%	88.40%	96.44%	91.05%	76.14%
DEC	12.38%	4.30%	1.27%	3.28%	8.87%
Coal	4.66%	2.31%	0.78%	2.03%	5.50%
INC	7.54%	3.81%	1.05%	2.28%	5.08%
Gas	1.54%	1.04%	0.36%	1.16%	3.31%
Oil	0.00%	0.00%	0.00%	0.05%	0.56%
Dispatchable Transaction	0.17%	0.07%	0.05%	0.08%	0.26%
Wind	0.07%	0.03%	0.04%	0.05%	0.12%
Nuclear	0.00%	0.00%	0.00%	0.00%	0.11%
Price Sensitive Demand	0.23%	0.04%	0.01%	0.01%	0.02%
Other	0.00%	0.00%	0.00%	0.00%	0.01%
Total	100.00%	100.00%	100.00%	100.00%	100.00%

Figure 3-3 shows, for the Day-Ahead Market in 2014 and 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 and 2015

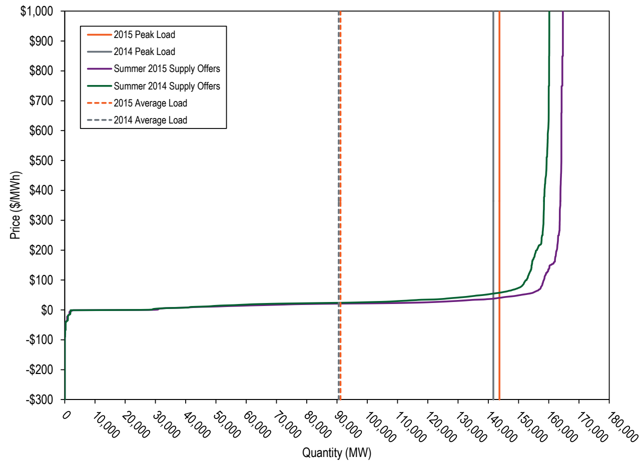


Supply

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 the summer of 2014 and 2015. Total average PJM aggregate real-time generation supply increased by 4,490 MW, or 2.8 percent, in the summer of 2015 from an average maximum of 160,190 MW in the summer of 2014 to 164,680 MW in the summer of 2015.

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



Energy Production by Fuel Source

Table 3-8 shows PJM generation by fuel source in GWh for 2014 and 2015. In 2015, generation from coal units decreased 17.8 percent and generation from natural gas units increased 28.4 percent compared to 2014.[18]

17 See 18 CFR § 385.213 (2014).

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.

Table 3-8 PJM generation (By fuel source (GWh)): 2014 and 2015[19 20]

	2014		2015		Change in
	GWh	Percent	GWh	Percent	Output
Coal	349,961.9	43.3%	287,634.7	36.6%	(17.8%)
Standard Coal	346,053.6	42.8%	284,414.0	36.2%	(17.8%)
Waste Coal	3,908.3	0.5%	3,220.7	0.4%	(17.6%)
Nuclear	277,635.6	34.4%	279,106.5	35.5%	0.5%
Gas	144,140.0	17.8%	184,083.2	23.4%	27.7%
Natural Gas	140,463.4	17.4%	180,307.8	22.9%	28.4%
Landfill Gas	2,369.0	0.3%	2,404.2	0.3%	1.5%
Biomass Gas	1,307.6	0.2%	1,371.2	0.2%	4.9%
Hydroelectric	14,394.3	1.8%	13,066.6	1.7%	(9.2%)
Pumped Storage	7,138.7	0.9%	5,946.1	0.8%	(16.7%)
Run of River	7,255.5	0.9%	7,120.5	0.9%	(1.9%)
Wind	15,540.5	1.9%	16,609.7	2.1%	6.9%
Waste	4,833.3	0.6%	4,729.7	0.6%	(2.1%)
Solid Waste	4,251.4	0.5%	4,175.4	0.5%	(1.8%)
Miscellaneous	581.8	0.1%	554.3	0.1%	(4.7%)
Oil	1,073.2	0.1%	917.6	0.1%	(14.5%)
Heavy Oil	464.3	0.1%	610.9	0.1%	31.6%
Light Oil	511.8	0.1%	247.8	0.0%	(51.6%)
Diesel	75.3	0.0%	56.9	0.0%	(24.4%)
Kerosene	21.7	0.0%	1.8	0.0%	(91.6%)
Jet Oil	0.0	0.0%	0.0	0.0%	NA
Solar, Net Energy Metering	400.9	0.0%	542.7	0.0%	35.4%
Battery	6.5	0.0%	7.6	0.0%	17.5%
Total	807,986.2	100.0%	786,698.2	100.0%	(2.6%)

Table 3-9 Monthly PJM generation (By fuel source (GWh)): 2015

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Coal	32,666.4	33,315.4	25,902.0	18,265.1	21,619.0	24,258.9	27,534.0	26,910.5	24,461.1	18,003.1	17,816.0	16,883.2	287,634.7
Standard Coal	32,309.5	32,992.8	25,589.6	18,068.7	21,363.2	24,000.4	27,330.1	26,618.6	24,193.8	17,830.3	17,533.9	16,583.0	284,414.0
Waste Coal	356.8	322.6	312.4	196.4	255.8	258.5	203.8	291.9	267.3	172.8	282.1	300.1	3,220.7
Nuclear	25,881.8	21,994.5	22,290.8	20,346.7	22,641.7	23,823.5	24,119.1	24,889.5	23,390.5	22,736.5	21,790.8	25,201.0	279,106.5
Gas	13,911.6	13,267.0	14,462.9	12,115.7	14,289.8	16,629.6	20,057.0	18,852.0	16,618.1	13,769.3	14,458.8	15,651.5	184,083.2
Natural Gas	13,567.7	12,957.9	14,155.0	11,840.9	13,978.2	16,281.6	19,690.6	18,495.6	16,304.3	13,509.3	14,176.6	15,350.0	180,307.8
Landfill Gas	213.5	188.1	208.4	200.0	212.1	196.1	208.0	201.6	187.9	194.6	193.7	200.1	2,404.2
Biomass Gas	130.4	121.0	99.5	74.7	99.5	151.9	158.3	154.8	125.9	65.4	88.5	101.4	1,371.2
Hydroelectric	953.9	763.3	1,152.3	1,379.6	1,025.2	1,310.5	1,624.2	1,105.5	758.8	754.7	1,023.2	1,215.4	13,066.6
Pumped Storage	398.8	388.7	344.7	331.4	504.2	729.1	842.9	823.6	546.7	292.4	337.3	406.3	5,946.1
Run of River	555.1	374.6	807.6	1,048.2	521.0	581.4	781.3	281.9	212.0	462.4	685.9	809.1	7,120.5
Wind	1,664.4	1,511.1	1,701.2	1,642.0	1,209.1	955.2	639.4	623.9	846.5	1,756.2	2,023.3	2,037.4	16,609.7
Waste	400.9	324.0	357.1	378.6	384.8	407.5	412.9	430.7	383.9	392.8	426.5	429.9	4,729.7
Solid Waste	347.8	279.7	308.0	335.4	347.2	370.7	369.8	380.9	332.1	350.0	371.4	382.3	4,175.4
Miscellaneous	53.1	44.3	49.1	43.2	37.5	36.8	43.2	49.8	51.8	42.8	55.1	47.6	554.3
Oil	81.0	408.6	13.1	5.3	43.8	45.7	158.0	69.9	26.7	11.9	39.5	35.2	938.6
Heavy Oil	64.3	315.0	0.0	0.0	0.0	29.3	143.3	57.6	0.0	0.0	0.0	1.4	610.9
Light Oil	13.7	58.8	10.3	5.2	40.0	12.6	11.9	8.6	18.9	6.9	33.8	27.2	247.8
Diesel	2.9	33.4	2.5	0.2	3.8	3.8	1.8	1.6	4.8	1.0	0.6	0.6	56.9
Kerosene	0.1	1.4	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.8
Jet Oil	0.0	0.0	0.0	0.0	0.0	0.0	1.0	2.0	3.0	4.0	5.0	6.0	21.0
Solar, Net Energy Metering	23.3	32.1	38.7	53.1	61.9	53.0	61.2	63.1	50.4	45.9	34.4	25.6	542.7
Battery	0.4	0.4	0.5	0.4	0.5	0.6	0.6	0.5	0.8	0.8	1.1	1.1	7.6
Total	75,583.7	71,616.3	65,918.5	54,186.4	61,275.7	67,484.5	74,606.4	72,945.6	66,536.7	57,471.3	57,613.8	61,480.5	786,719.2

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.

20 Net Energy Metering is combined with Solar due to data confidentiality reasons.

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 increased by 4,490 MW, or 2.8 percent, in the summer months of 2015 from an average maximum of 160,190 MW in the summer months of 2014 to 164,680 MW in the summer months of 2015.[21]

In 2015, 3,041.2 MW of new capacity were added to PJM. This new generation was more than offset by the deactivation of and 9,897.2 MW of generation retired (108 units).

PJM average real-time generation in 2015 decreased by 2.5 percent from 2014, from 90,894 MW to 88,628 MW.[22]

PJM average real-time supply including imports decreased by 2.0 percent in 2015 from 2014, from 96,295 MW to 94,329 MW.

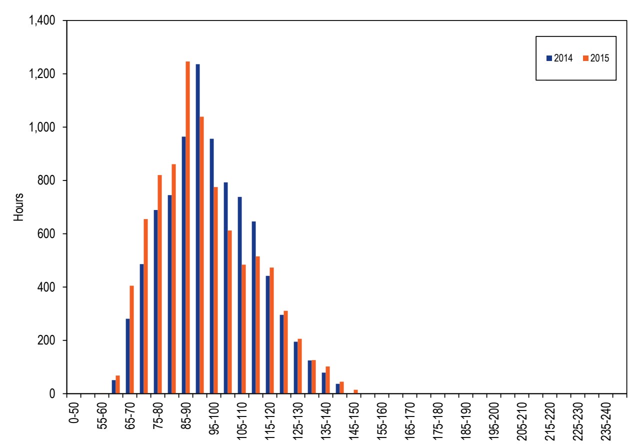
In the PJM Real-Time Energy Market, there are three types of supply offers:

- **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.
- **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 2014 and 2015.

Figure 3-5 Distribution of PJM real-time generation plus imports: 2014 and 2015[23]



21 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.

22 Generation data are the net MWh injections and withdrawals MWh at every generation bus in PJM.

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

PJM Real-Time, Average Supply

Table 3-10 presents summary real-time supply statistics for each year for the 16-year period from 2000 through 2015.[24]

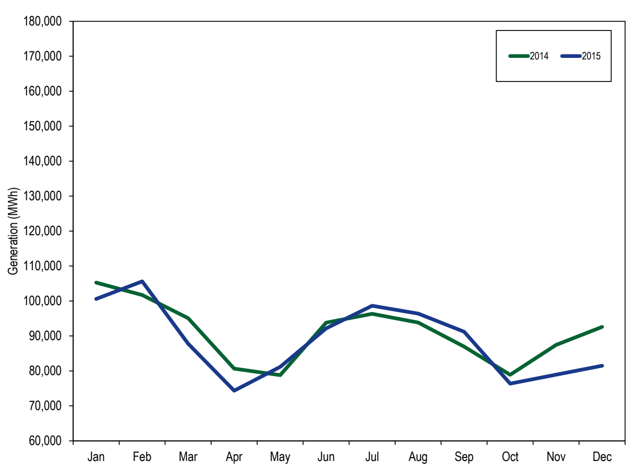
Table 3-10 PJM real-time average hourly generation and real-time average hourly generation plus average hourly imports: 2000 through 2015

	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	30,301	4,980	33,256	5,456	NA	NA	NA	NA
2001	29,553	4,937	32,552	5,285	(2.5%)	(0.9%)	(2.1%)	(3.1%)
2002	34,928	7,535	38,535	7,751	18.2%	52.6%	18.4%	46.7%
2003	36,628	6,165	40,205	6,162	4.9%	(18.2%)	4.3%	(20.5%)
2004	51,068	13,790	55,781	14,652	39.4%	123.7%	38.7%	137.8%
2005	81,127	15,452	86,353	15,981	58.9%	12.0%	54.8%	9.1%
2006	82,780	13,709	86,978	14,402	2.0%	(11.3%)	0.7%	(9.9%)
2007	85,860	14,018	90,351	14,763	3.7%	2.3%	3.9%	2.5%
2008	83,476	13,787	88,899	14,256	(2.8%)	(1.7%)	(1.6%)	(3.4%)
2009	78,026	13,647	83,058	14,140	(6.5%)	(1.0%)	(6.6%)	(0.8%)
2010	82,585	15,556	87,386	16,227	5.8%	14.0%	5.2%	14.8%
2011	85,775	15,932	90,511	16,759	3.9%	2.4%	3.6%	3.3%
2012	88,708	15,701	94,083	16,505	3.4%	(1.4%)	3.9%	(1.5%)
2013	89,769	15,012	94,833	15,878	1.2%	(4.4%)	0.8%	(3.8%)
2014	90,894	15,151	96,295	16,199	1.3%	0.9%	1.5%	2.0%
2015	88,628	16,118	94,329	17,312	(2.5%)	6.4%	(2.0%)	6.9%

PJM Real-Time, Monthly Average Generation

Figure 3-6 compares the real-time, monthly average hourly generation in 2014 and 2015.

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



Day-Ahead Supply

PJM average day-ahead supply in 2015, including INCs and up to congestion transactions, decreased by 21.7 percent from 2014, from 146,672 MW to 114,889 MW.

PJM average day-ahead supply in 2015, including INCs, up to congestion transactions, and imports, decreased by 21.3 percent from 2014, from 148,906 MW to 117,146 MW. The reduction in PJM day-ahead supply was a result of a 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.[25]

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-

24 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.

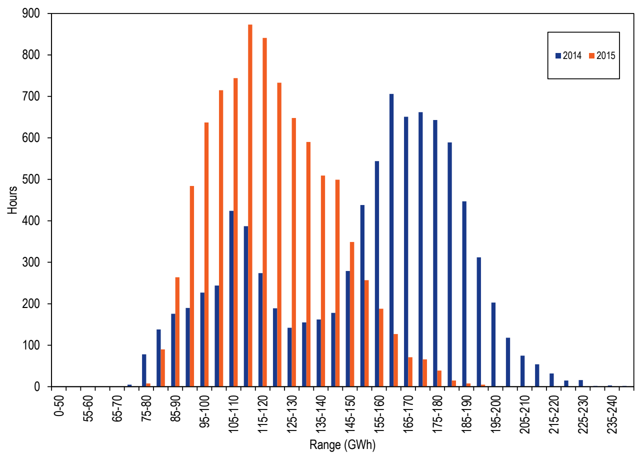
25 148 FERC ¶ 61,144 (2014).

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 2014 and 2015. The shift in the results was a result of the decrease in in UTCs beginning in September 2014.

Figure 3-7 Distribution of PJM day-ahead supply plus imports: 2014 and 2015[26]



PJM Day-Ahead, Average Supply

Table 3-11 presents summary day-ahead supply statistics for each year of the 16-year period from 2000 through 2015.[27]

Table 3-11 PJM day-ahead average hourly supply and day-ahead average hourly supply plus average hourly imports: 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	27,135	4,858	27,589	4,895	NA	NA	NA	NA
2001	26,762	4,595	27,497	4,664	(1.4%)	(5.4%)	(0.3%)	(4.7%)
2002	31,434	10,007	31,982	10,015	17.5%	117.8%	16.3%	114.7%
2003	40,642	8,292	41,183	8,287	29.3%	(17.1%)	28.8%	(17.3%)
2004	62,755	17,141	63,654	17,362	54.4%	106.7%	54.6%	109.5%
2005	94,438	17,204	96,449	17,462	50.5%	0.4%	51.5%	0.6%
2006	100,056	16,543	102,164	16,559	5.9%	(3.8%)	5.9%	(5.2%)
2007	108,707	16,549	111,023	16,729	8.6%	0.0%	8.7%	1.0%
2008	105,485	15,994	107,885	16,136	(3.0%)	(3.4%)	(2.8%)	(3.5%)
2009	97,388	16,364	100,022	16,397	(7.7%)	2.3%	(7.3%)	1.6%
2010	107,307	21,655	110,026	21,837	10.2%	32.3%	10.0%	33.2%
2011	117,130	20,977	119,501	21,259	9.2%	(3.1%)	8.6%	(2.6%)
2012	134,479	17,905	136,903	18,080	14.8%	(14.6%)	14.6%	(15.0%)
2013	148,323	18,783	150,595	18,978	10.3%	4.9%	10.0%	5.0%
2014	146,672	33,145	148,906	33,346	(1.1%)	76.5%	(1.1%)	75.7%
2015	114,889	19,164	117,146	19,405	(21.7%)	(42.2%)	(21.3%)	(41.8%)

26 Each range on the horizontal axis excludes the start value and includes the end value.
27 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 2014 and 2015. The reduction in PJM day-ahead supply was a result of a 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.[28]

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

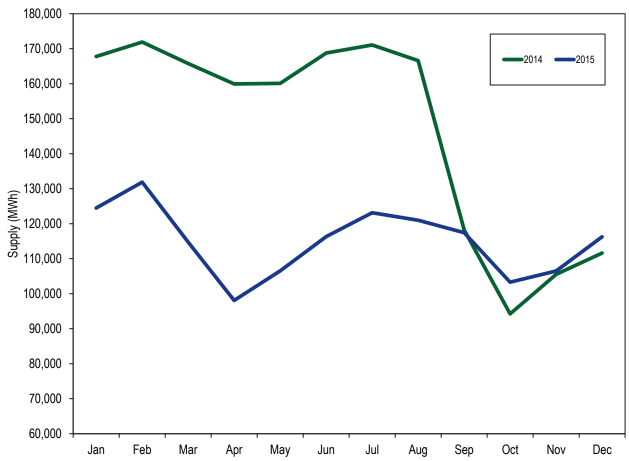


Table 3-12 presents summary statistics for 2014 and 2015, for day-ahead and real-time supply. The last two columns of Table 3-12 are the day-ahead supply minus the real-time supply. The first of these columns is the total day-ahead supply less the total real-time supply and the second of these columns is the total physical day-ahead generation less the total physical real-time generation. In 2015, up-to congestion transactions were 16.4 percent of the total day-ahead supply compared to 33.2 percent in 2014.

Figure 3-9 shows the average hourly cleared volumes of day-ahead supply and real-time supply for 2015. The day-ahead supply consists of day-ahead generation, imports, cleared increments and up to congestion transactions. The real-time generation includes generation and imports.

Real-Time and Day-Ahead Supply

Table 3-12 Day-ahead and real-time supply (MWh): 2014 and 2015

		Day Ahead					Real Time		Day Ahead Less Real Time	
		Generation	Cleared INC	Up-to Congestion	Imports	Total Supply	Generation	Total Supply	Total Supply	Total Generation
Average	2014	93,687	3,492	49,492	2,235	148,906	90,895	96,295	52,611	2,793
	2015	90,959	4,675	19,255	2,257	117,146	88,628	94,329	22,817	2,331
Median	2014	92,635	3,382	61,234	2,233	158,207	89,449	94,703	63,505	3,186
	2015	88,874	4,599	18,435	2,215	114,964	85,989	91,318	23,647	2,885
Standard Deviation	2014	15,992	917	26,785	446	33,346	15,150	16,198	17,148	842
	2015	17,341	791	5,230	503	19,405	16,118	17,312	2,093	1,223
Peak Average	2014	103,462	4,002	49,854	2,411	159,729	99,634	105,731	53,998	3,828
	2015	100,528	4,765	20,779	2,416	128,487	96,809	103,211	25,275	3,718
Peak Median	2014	102,051	3,995	61,834	2,386	171,568	98,610	104,536	67,032	3,441
	2015	97,480	4,714	19,777	2,428	126,042	93,304	99,485	26,558	4,176
Peak Standard Deviation	2014	13,014	830	26,086	407	32,171	12,742	13,578	18,593	272
	2015	14,481	715	5,336	504	16,480	14,438	15,379	1,102	43
Off-Peak Average	2014	85,167	3,048	49,176	2,081	139,473	83,277	88,071	51,402	1,890
	2015	82,242	4,594	17,867	2,112	106,815	81,176	86,238	20,578	1,067
Off-Peak Median	2014	83,792	2,959	60,803	2,035	151,999	81,614	86,212	65,787	2,178
	2015	79,108	4,485	17,186	2,059	103,524	78,333	82,832	20,692	775
Off-Peak Standard Deviation	2014	13,235	742	27,377	421	31,435	12,785	13,607	17,828	449
	2015	14,976	847	4,722	455	15,757	13,787	14,832	925	1,189

28 148 FERC ¶ 61,144 (2014).

Figure 3-9 Day-ahead and real-time supply (Average hourly volumes): 2015

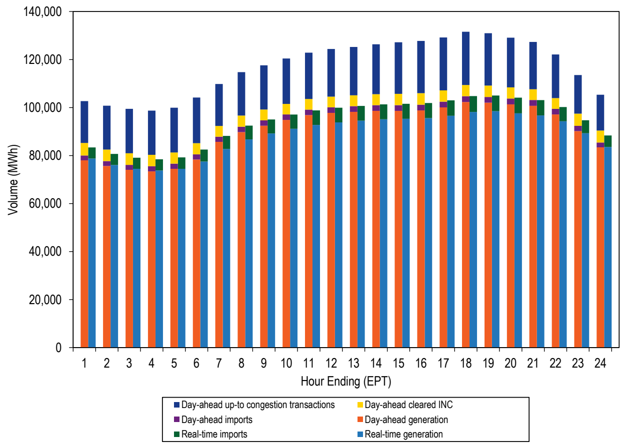


Figure 3-10 shows the difference between the day-ahead and real-time average daily supply in 2014 through 2015.

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

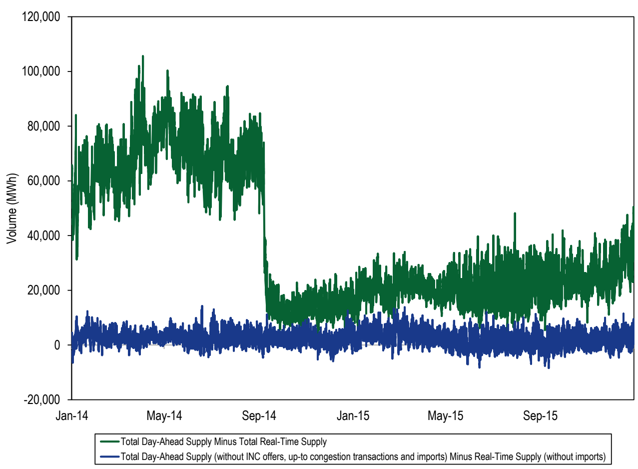
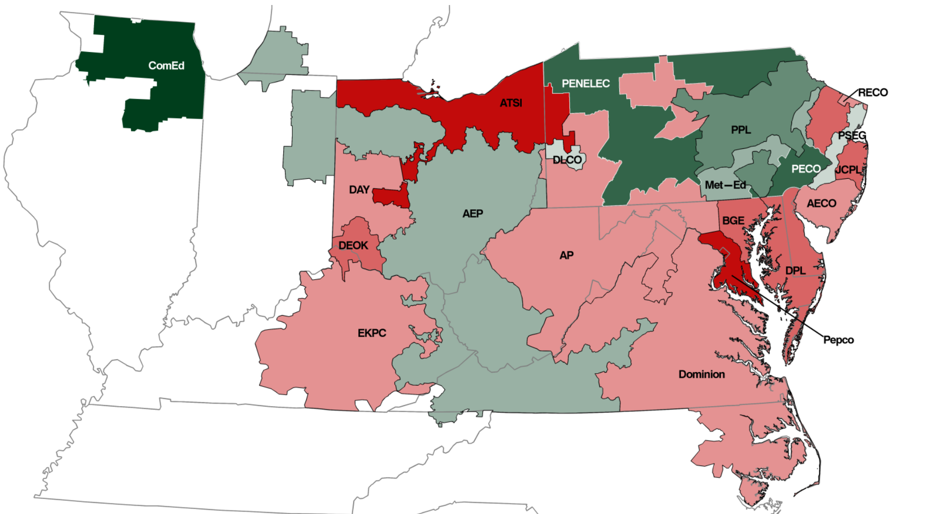


Figure 3-11 shows the difference between the PJM real-time generation and real-time load by zone in 2015. Table 3-13 shows the difference between the PJM real-time generation and real-time load by zone in 2014 and 2015. Figure 3-11 is color coded on a scale on which red shades represent zones that have 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: 2015[29]



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	(3,608)	ComEd	21,540	DPL	(8,462)	PENELEC	17,357
AEP	10,612	DAY	(2,977)	EKPC	(2,652)	Pepco	(16,285)
AP	(3,635)	DEOK	(6,684)	JCPL	(7,600)	PPL	9,548
ATSI	(14,301)	DLCO	1,802	Met-Ed	5,405	PSEG	2,189
BGE	(8,009)	Dominion	(6,885)	PECO	14,138	RECO	(1,193)

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

	Zonal Generation and Load (GWh)					
	2014			2015		
Zone	Generation	Load	Net	Generation	Load	Net
AECO	3,296.0	10,252.7	(6,956.6)	6,208.5	10,436.1	(4,227.6)
AEP	148,249.6	128,957.3	19,292.3	134,241.8	126,850.3	7,391.5
AP	46,089.7	48,355.4	(2,265.7)	44,431.4	48,207.0	(3,775.5)
ATSI	53,453.7	67,730.8	(14,277.1)	48,684.8	66,651.7	(17,966.9)
BGE	21,368.7	31,967.1	(10,598.4)	22,244.0	32,072.4	(9,828.5)
ComEd	126,274.9	97,683.0	28,591.9	125,658.7	95,365.1	30,293.6
DAY	14,342.8	17,011.2	(2,668.4)	13,661.1	16,884.0	(3,223.0)
DEOK	19,823.2	27,019.7	(7,196.5)	17,115.3	26,843.3	(9,727.9)
DLCO	17,735.1	14,411.1	3,324.0	16,604.9	14,167.8	2,437.1
Dominion	82,444.7	95,306.3	(12,861.6)	88,335.4	95,891.2	(7,555.8)
DPL	7,514.5	18,379.3	(10,864.7)	7,479.8	18,578.0	(11,098.2)
EKPC	10,384.4	12,803.0	(2,418.6)	8,603.7	12,180.9	(3,577.2)
JCPL	12,976.5	22,758.7	(9,782.2)	14,415.1	23,172.8	(8,757.7)
Met-Ed	21,625.3	15,082.6	6,542.7	22,081.5	15,208.6	6,872.9
PECO	60,038.1	39,803.7	20,234.4	60,404.2	40,307.4	20,096.8
PENELEC	44,805.9	17,274.8	27,531.1	37,224.2	17,105.7	20,118.5
Pepco	11,775.6	30,446.7	(18,671.1)	8,868.6	30,398.5	(21,529.9)
PPL	49,135.5	40,885.7	8,249.8	52,504.7	40,586.7	11,918.0
PSEG	44,896.7	42,883.6	2,013.1	47,617.7	43,664.3	3,953.4
RECO	0.0	1,492.7	(1,492.7)	0.0	1,521.2	(1,521.2)

Demand

Demand includes physical load and exports and virtual transactions.

Peak Demand

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

The PJM system real-time peak load for 2015 was 143,697 MW in the HE 17 on July 28, 2015, which was 2,023 MW, or 1.4 percent, higher than the peak load for 2014, which was 141,673 MW in the HE 17 on June 17, 2014.

Table 3-14 shows the peak loads for 1999 through 2015.

29 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>.

Table 3-14 Actual PJM footprint peak loads: 1999 to 2015[30]

	Date	Hour Ending (EPT)	PJM Load (MW)	Annual Change (MW)	Annual Change (%)
1999	Fri, July 30	17	120,227	NA	NA
2000	Wed, August 09	17	114,036	(6,191)	(5.1%)
2001	Wed, August 08	17	128,535	14,499	12.7%
2002	Thu, August 01	17	130,159	1,625	1.3%
2003	Thu, August 21	17	126,259	(3,900)	(3.0%)
2004	Wed, June 09	17	120,218	(6,041)	(4.8%)
2005	Tue, July 26	16	133,761	13,543	11.3%
2006	Wed, August 02	17	144,644	10,883	8.1%
2007	Wed, August 08	16	139,428	(5,216)	(3.6%)
2008	Mon, June 09	17	130,100	(9,328)	(6.7%)
2009	Mon, August 10	17	126,798	(3,302)	(2.5%)
2010	Tue, July 06	17	136,460	9,662	7.6%
2011	Thu, July 21	17	158,016	21,556	15.8%
2012	Tue, July 17	17	154,344	(3,672)	(2.3%)
2013	Thu, July 18	17	157,508	3,165	2.1%
2014	Tue, June 17	17	141,673	(15,835)	(10.1%)
2015	Tue, July 28	17	143,697	2,023	1.4%

Figure 3-12 shows the peak loads for 1999 through 2015.

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

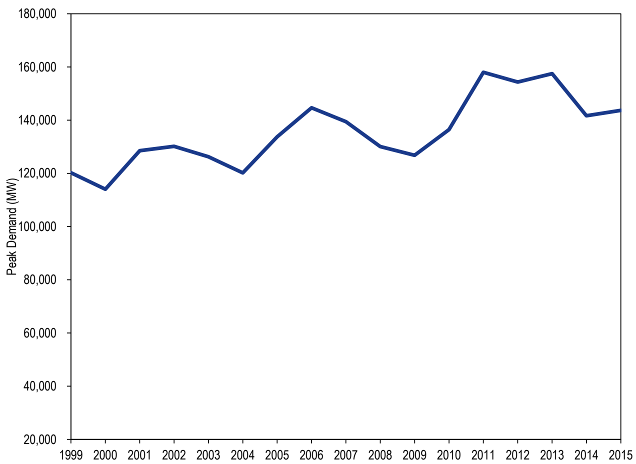
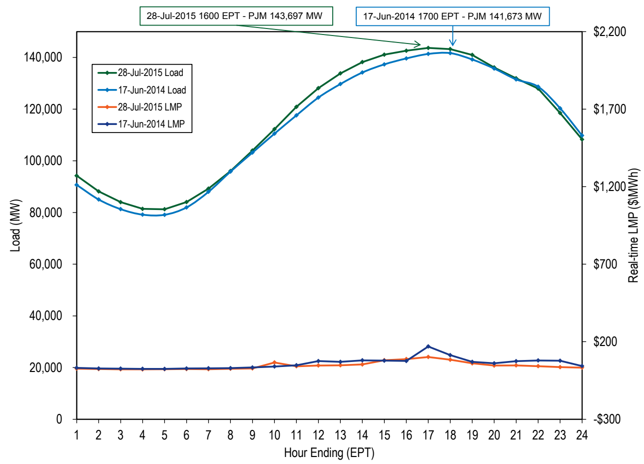


Figure 3-13 compares the peak load days during 2014 and 2015. The average hourly real-time LMP peaked at $101.40 on July 28, 2015 and peaked at $169.33 on June 17, 2014.

Figure 3-13 PJM peak-load comparison: Tuesday, July 28, 2015 and Tuesday, June 17, 2014



Real-Time Demand

PJM average real-time load in 2015 decreased by 0.6 percent from 2014, from 89,099 MW to 88,594 MW.[31]

PJM average real-time demand in 2015 decreased 1.9 percent from 2014, from 94,471 MW to 92,665 MW.

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

- **Load.** The actual MWh level of energy used by load within PJM.
- **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

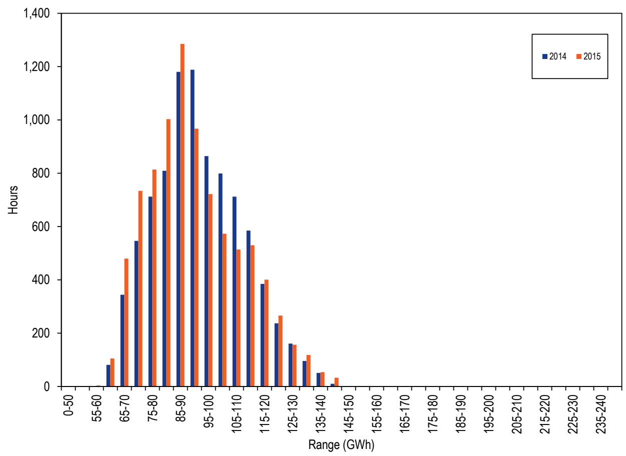
Figure 3-14 shows the hourly distribution of PJM real-time load plus exports for 2014 and 2015.[32]

30 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>.

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

32 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>.

Figure 3-14 Distribution of PJM real-time accounting load plus exports: 2014 and 2015[33]



PJM Real-Time, Average Load

Table 3-15 presents summary real-time demand statistics for the 18-year period 1998 to 2015. Before June 1, 2007, transmission losses were included in accounting load. After June 1, 2007, transmission losses were excluded from accounting load and losses were addressed through marginal loss pricing.[34]

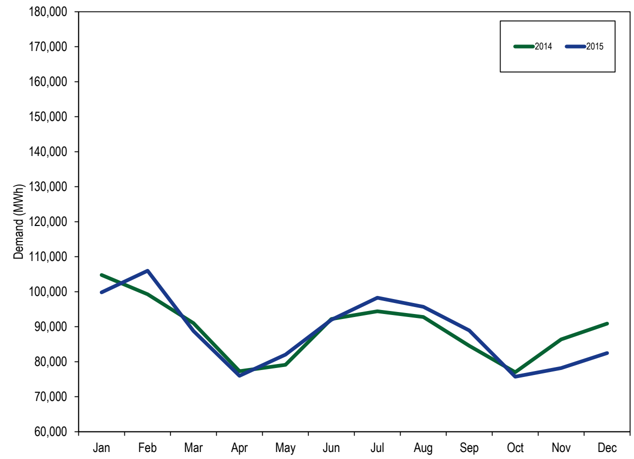
Table 3-15 PJM real-time average hourly load and real-time average hourly load plus average hourly exports: 1998 through 2015[35]

	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	28,578	5,511	28,578	5,511	NA	NA	NA	NA
1999	29,641	5,955	29,641	5,955	3.7%	8.1%	3.7%	8.1%
2000	30,113	5,529	31,341	5,728	1.6%	(7.2%)	5.7%	(3.8%)
2001	30,297	5,873	32,165	5,564	0.6%	6.2%	2.6%	(2.9%)
2002	35,776	7,976	37,676	8,145	18.1%	35.8%	17.1%	46.4%
2003	37,395	6,834	39,380	6,716	4.5%	(14.3%)	4.5%	(17.5%)
2004	49,963	13,004	54,953	14,947	33.6%	90.3%	39.5%	122.6%
2005	78,150	16,296	85,301	16,546	56.4%	25.3%	55.2%	10.7%
2006	79,471	14,534	85,696	15,133	1.7%	(10.8%)	0.5%	(8.5%)
2007	81,681	14,618	87,897	15,199	2.8%	0.6%	2.6%	0.4%
2008	79,515	13,758	86,306	14,322	(2.7%)	(5.9%)	(1.8%)	(5.8%)
2009	76,034	13,260	81,227	13,792	(4.4%)	(3.6%)	(5.9%)	(3.7%)
2010	79,611	15,504	85,518	15,904	4.7%	16.9%	5.3%	15.3%
2011	82,541	16,156	88,466	16,313	3.7%	4.2%	3.4%	2.6%
2012	87,011	16,212	92,135	16,052	5.4%	0.3%	4.1%	(1.6%)
2013	88,332	15,489	92,879	15,418	1.5%	(4.5%)	0.8%	(3.9%)
2014	89,099	15,763	94,471	15,677	0.9%	1.8%	1.7%	1.7%
2015	88,594	16,663	92,665	16,784	(0.6%)	5.7%	(1.9%)	7.1%

PJM Real-Time, Monthly Average Load

Figure 3-15 compares the real-time, monthly average hourly loads in 2014 and 2015.

Figure 3-15 PJM real-time monthly average hourly load: 2014 and 2015



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

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

35 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 load is significantly affected by temperature. Figure 3-16 and Table 3-16 compare the PJM monthly heating and cooling degree days in 2014 and 2015.[36] Heating degree days decreased 1.9 percent and cooling degree days increased 19.7 percent from 2014 to 2015.

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

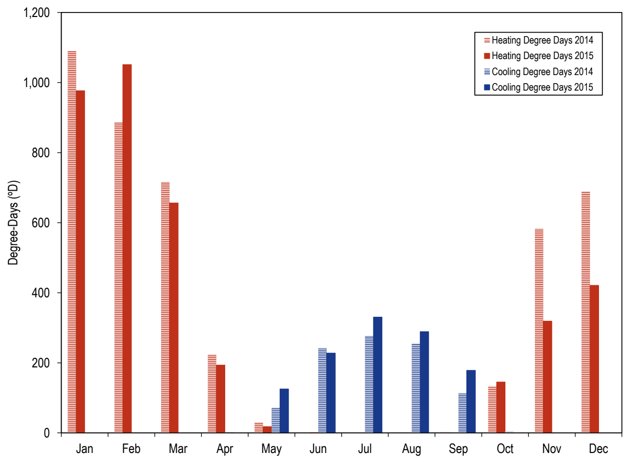


Table 3-16 PJM heating and cooling degree days: 2014 and 2015

	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	228	0.0%	(5.8%)
Jul	0	277	0	330	0.0%	19.2%
Aug	0	256	0	289	0.0%	12.9%
Sep	3	113	0	179	(100.0%)	57.7%
Oct	133	4	145	0	8.9%	0.0%
Nov	583	0	319	0	(45.3%)	0.0%
Dec	690	0	421	0	(39.0%)	0.0%
Total	4,358	966	3,781	1,151	(1.9%)	19.7%

Day-Ahead Demand

PJM average day-ahead demand in 2015, including DECs and up to congestion transactions, decreased by 21.5 percent from 2014, from 142,251 MW to 111,644 MW.

PJM average day-ahead demand in 2015, including DECs, up to congestion transactions, and exports, decreased by 21.3 percent from 2014, from 146,120 MW to 115,007 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.[37]

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

- **Fixed-Demand Bid.** Bid to purchase a defined MWh level of energy, regardless of LMP.
- **Price-Sensitive Bid.** Bid to purchase a defined MWh level of energy only up to a specified LMP, above which the load bid is zero.
  - **Decrement Bid (DEC).** Financial bid to purchase a defined MWh level of energy up to a specified LMP, above which the bid is zero. A DEC can be submitted by any market participant.
  - **Up to Congestion Transaction (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

36 A heating degree day is defined as the number of degrees that a day's average temperature is below 65 degrees F (the temperature below which buildings need to be heated). A cooling degree day is the number of degrees that a day's average temperature is above 65 degrees F (the temperature when people will start to use air conditioning to cool buildings). 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.

37 148 FERC ¶ 61,144 (2014).

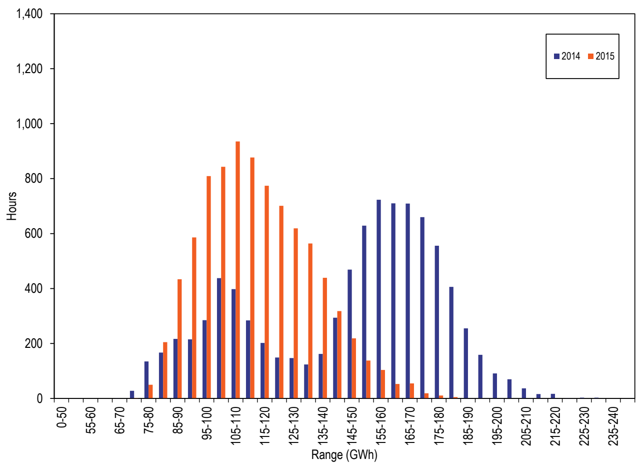
Energy Market and the PJM Real-Time Energy Market, so an export energy transaction approved in the Day-Ahead Energy Market will not physically flow in real time unless it is also submitted through the Real-Time Energy Market scheduling process.

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 2014 and 2015. The shift in day-ahead demand was the result of a reduction in UTC activity.

Figure 3-17 Distribution of PJM day-ahead demand plus exports: 2014 and 2015[38]



PJM Day-Ahead, Average Demand

Table 3-17 presents summary day-ahead demand statistics for each year of the 16-year period 2000 to 2015.[39]

Table 3-17 PJM day-ahead average demand and day-ahead average hourly demand plus average hourly exports: 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	33,039	6,852	33,411	6,757	NA	NA	NA	NA
2001	33,370	6,562	33,757	6,431	1.0%	(4.2%)	1.0%	(4.8%)
2002	42,305	10,161	42,413	10,208	26.8%	54.9%	25.6%	58.7%
2003	44,674	7,841	44,807	7,811	5.6%	(22.8%)	5.6%	(23.5%)
2004	62,101	16,654	63,455	17,730	39.0%	112.4%	41.6%	127.0%
2005	93,534	17,643	96,447	17,952	50.6%	5.9%	52.0%	1.3%
2006	98,527	16,723	101,592	17,197	5.3%	(5.2%)	5.3%	(4.2%)
2007	105,503	16,686	108,932	17,030	7.1%	(0.2%)	7.2%	(1.0%)
2008	101,903	15,871	105,368	16,119	(3.4%)	(4.9%)	(3.3%)	(5.3%)
2009	94,941	15,869	98,094	15,999	(6.8%)	(0.0%)	(6.9%)	(0.7%)
2010	103,937	21,358	108,069	21,640	9.5%	34.6%	10.2%	35.3%
2011	113,866	20,708	117,681	20,929	9.6%	(3.0%)	8.9%	(3.3%)
2012	131,612	17,421	134,947	17,527	15.6%	(15.9%)	14.7%	(16.3%)
2013	144,858	18,489	148,132	18,570	10.1%	6.1%	9.8%	5.9%
2014	142,251	32,664	146,120	32,671	(1.8%)	76.7%	(1.4%)	75.9%
2015	111,644	18,715	115,007	18,867	(21.5%)	(42.7%)	(21.3%)	(42.3%)

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

39 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 Demand

Figure 3-18 compares the day-ahead, monthly average hourly demand, including decrement bids and up to congestion transactions, in 2014 and 2015. The reduction in PJM day-ahead demand was a result of a decrease 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.[40]

Figure 3-18 PJM day-ahead monthly average hourly demand: 2014 and 2015

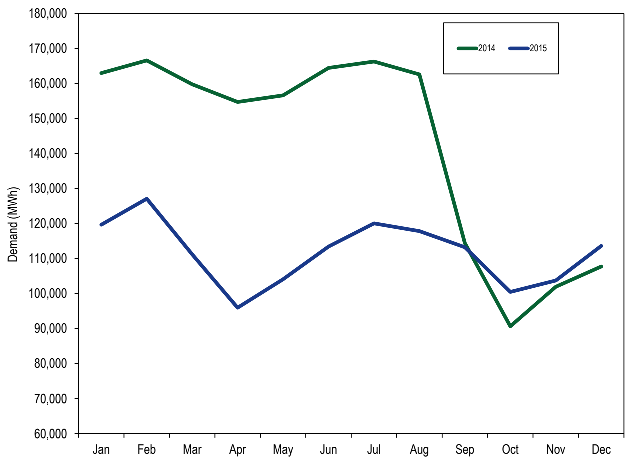


Table 3-18 presents summary statistics for 2014 and 2015 day-ahead and real-time demand. The last two columns of Table 3-18 are the day-ahead demand minus the real-time demand. The first such column is the total day-ahead demand less the total real-time demand and the second such column is the total physical day-ahead load (fixed demand plus price sensitive demand) less the physical real-time load.

Figure 3-19 shows the average hourly cleared volumes of day-ahead demand and real-time demand for 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.

Real-Time and Day-Ahead Demand

Table 3-18 Cleared day-ahead and real-time demand (MWh): 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	85,004	1,212	6,592	49,443	3,869	146,120	89,093	94,465	51,654	37,439
	2015	85,171	3,167	4,051	19,255	3,363	115,007	88,594	92,665	22,342	66,252
Median	2014	83,546	1,203	6,354	61,205	3,770	155,243	87,436	92,950	62,293	25,143
	2015	82,980	3,214	3,821	18,435	3,213	112,811	85,997	89,783	23,028	62,969
Standard Deviation	2014	14,908	167	1,490	26,804	926	32,671	15,758	15,672	16,999	(1,242)
	2015	15,726	553	1,311	5,230	926	18,867	16,663	16,784	2,083	14,580
Peak Average	2014	94,326	1,283	7,408	49,835	3,865	156,718	98,451	103,651	53,067	45,385
	2015	94,077	3,438	4,428	20,779	3,327	126,049	97,416	101,318	24,731	72,684
Peak Median	2014	92,878	1,277	7,259	61,833	3,783	168,393	97,036	102,457	65,935	31,101
	2015	90,912	3,481	4,213	19,777	3,138	123,781	94,086	97,727	26,054	68,032
Peak Standard Deviation	2014	12,179	161	1,414	26,095	932	31,555	13,159	13,123	18,432	(5,273)
	2015	13,302	512	1,241	5,336	969	16,062	14,529	14,908	1,153	13,376
Off-Peak Average	2014	76,890	1,149	5,883	49,102	3,872	136,896	80,948	86,470	50,425	30,522
	2015	77,057	2,921	3,706	17,867	3,396	104,947	80,574	84,798	20,149	60,425
Off-Peak Median	2014	75,237	1,142	5,658	60,731	3,762	149,205	79,055	84,726	64,478	14,576
	2015	74,197	2,924	3,445	17,186	3,283	101,821	77,587	81,544	20,277	57,310
Off-Peak Standard Deviation	2014	12,047	147	1,152	27,404	922	30,776	13,083	13,121	17,655	(4,572)
	2015	13,166	466	1,277	4,722	883	15,263	14,253	14,346	917	13,335

40 148 FERC ¶ 61,144 (2014).

Figure 3-19 Day-ahead and real-time demand (Average hourly volumes): 2015

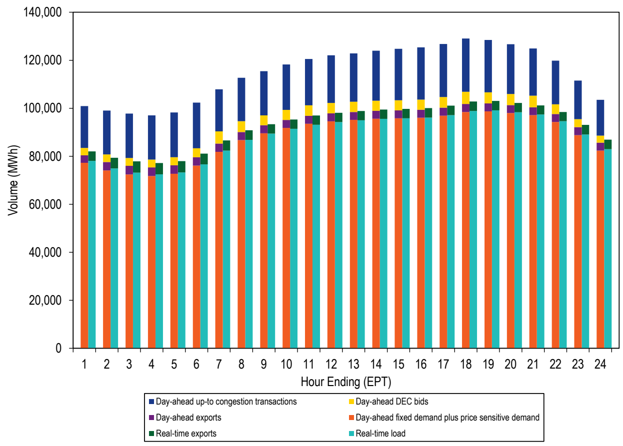
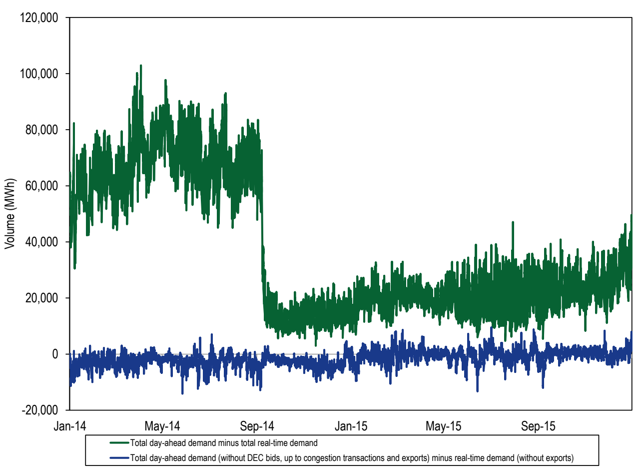


Figure 3-20 shows the difference between the day-ahead and real-time average daily demand in 2014 and 2015. The substantial decrease in UTC MW in September 2014, which resulted in a corresponding decrease in day-ahead demand, was a result of a FERC order setting September 8, 2014, as the effective date for any uplift charges assigned to UTCs.[41]

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



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.

The analysis of the application of the three pivotal supplier test demonstrates that it is working for most hours to exempt owners when the local market structure is competitive and to offer cap owners when the local market structure is noncompetitive. However, there are some issues with the application of mitigation in the Day-Ahead Energy Market and the Real-Time Energy Market when market sellers fail the TPS test. There is no tariff or manual language that defines in detail the application of the TPS test and offer capping in the Day-Ahead Energy Market and the Real-Time Energy Market.

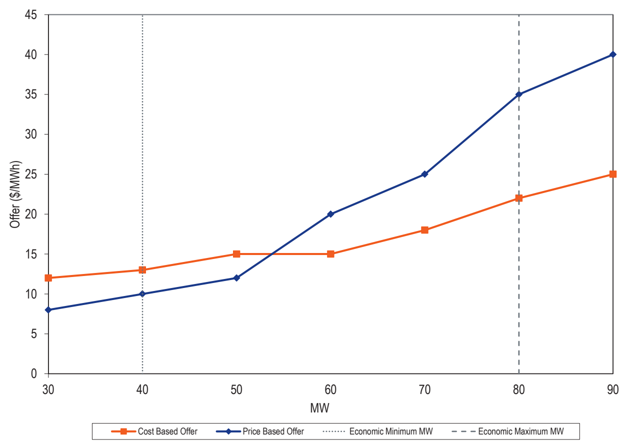
In both the Day-Ahead and Real-Time Energy Markets, generators have the ability to avoid mitigation by using varying markups in their price-based offers, offering different operating parameters in their price-based and cost-based offers, and using different fuels in their price-based and cost-based offers. These issues can be resolved by simple rule changes.

When an owner fails the TPS test, the units offered by the owner that are committed to provide relief are committed on the cheaper of cost or price-based offers. With the ability to submit offer curves with varying markups at different output levels in the price-based offer, units can avoid mitigation by using a low markup at low output levels and a high markup at higher output levels. Figure 3-21 shows an example of offers from a unit that has a negative markup at the economic minimum MW level and a positive markup at the economic maximum MW level. The result would be that a unit that failed the

41 148 FERC ¶ 61,144 (2014).

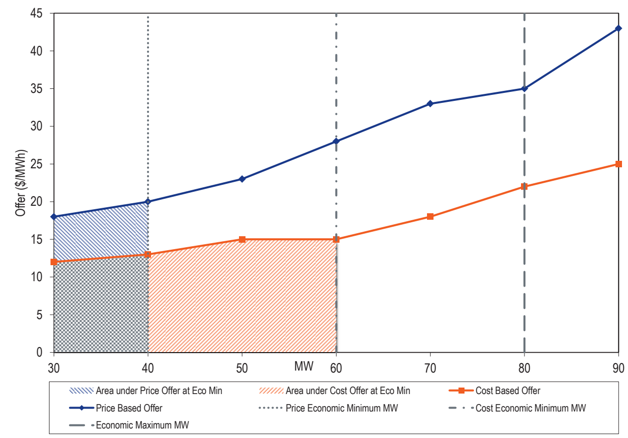
TPS test would be committed on its price-based offer even though the price-based offer is higher than cost at higher output levels and includes positive markups, inconsistent with the explicit goal of local market power mitigation.

Figure 3-21 Offers with varying markups at different MW output levels



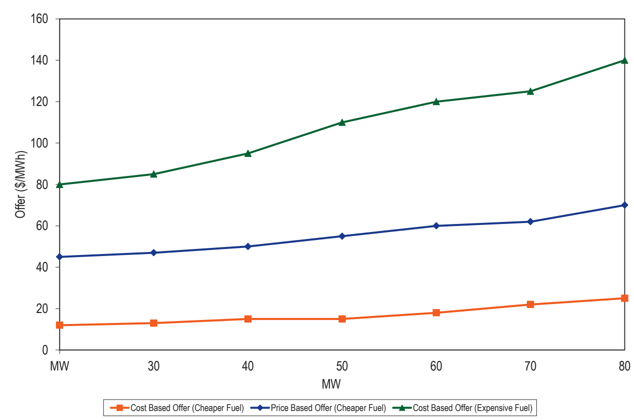
Offering a different economic minimum MW level, different minimum run times, different start up and notification times on the cost-based and price-based offers can also be used to avoid mitigation. For example, a unit may offer its price-based offer with a negative markup, but have a longer minimum run time (MRT) on the price-based offer. For example, a unit may offer a lower economic minimum MW level on the price-based offer than the cost-based offer. Such a unit may appear to be cheaper to commit on the price-based offer even with a positive markup because the total cost of commitment (calculated as a product of MW and the offer in dollars per MWh plus the startup and no-load cost) can be lower on price-based offer at the lower economic minimum level compared to cost-based offer at a higher economic minimum level. Figure 3-22 shows an example of offers from a unit that has a positive markup and a price based offer with a lower economic minimum MW than the cost based offer. The cost of commitment (area under the curve) for this unit is lower on the price based offer than on the cost based offer. However, the price based offer includes a positive markup and could result in setting the market price at a non-competitive level even after the resource owner fails the TPS test.

Figure 3-22 Offers with a positive markup but different economic minimum MW



In case of dual fuel units, if the price-based offer uses a cheaper fuel and the cost-based offer uses a more expensive fuel, the price-based offer will appear to be lower cost even when it includes a markup. Figure 3-23 shows an example of offers by a dual fuel unit, where the active cost-based offer uses a more expensive fuel and the price-based offer uses a cheaper fuel and includes a markup.

Figure 3-23 Dual fuel unit offers



These issues can be solved by simple rule changes.[42] The MMU recommends that markup of price based offers over cost based offers be constant across the offer curve, that there be at least one cost based offer using the same fuel as the available price based offer, and that operating

42 The MMU proposed these offer rule changes as part of a broader reform to address generator offer flexibility and associated impact on market power mitigation rules in the Generator Offer Flexibility Senior Task Force (GOFSTF).

parameters on parameter limited schedules (PLS) be at least as flexible as price based non PLS offers.

Levels of offer capping have historically been low in PJM, as shown in Table 3-19. The offer capping percentages shown in Table 3-19 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 3-19 Offer-capping statistics – energy only: 2011 to 2015

	Real Time		Day Ahead	
Year	Unit Hours Capped	MW Capped	Unit Hours Capped	MW Capped
2011	0.6%	0.2%	0.0%	0.0%
2012	0.8%	0.4%	0.1%	0.1%
2013	0.4%	0.2%	0.1%	0.0%
2014	0.5%	0.2%	0.2%	0.1%
2015	0.4%	0.2%	0.2%	0.1%

Table 3-20 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 black start service and reactive support reasons increased 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 2014 and 2015 because higher LMPs (in the first three months) resulted in the increased economic dispatch of black start and reactive service resources. As of April 2015, the Automatic Load Rejection (ALR) units that were committed for black start previously no longer provide black start service, and are not included in the offer capping statistics for black start. PJM also created closed loop interfaces to, in some cases, model reactive constraints. The result was higher LMPs, which increased economic dispatch, which contributed to the reduction in units offer capped for reactive support. In instances where units are now committed for the modeled closed loop interface constraints, they are considered offer capped for providing constraint relief. They are included in the offer capping percentages in Table 3-19.

Table 3-20 Offer-capping statistics for energy and reliability: 2011 through 2015

	Real Time		Day Ahead	
Year	Unit Hours Capped	MW Capped	Unit Hours Capped	MW Capped
2011	0.7%	0.2%	0.0%	0.0%
2012	1.7%	1.0%	0.9%	0.5%
2013	2.9%	2.4%	3.2%	2.1%
2014	0.8%	0.5%	0.6%	0.4%
2015	0.7%	0.8%	0.6%	0.7%

Table 3-21 shows the offer capping percentages for units committed to provide black start service and reactive support. The data in Table 3-21 is the difference between the offer cap percentages shown in Table 3-20 and Table 3-19.

Table 3-21 Offer-capping statistics for reliability: 2011 through 2015

	Real Time		Day Ahead	
Year	Unit Hours Capped	MW Capped	Unit Hours Capped	MW Capped
2011	0.1%	0.0%	0.0%	0.0%
2012	0.9%	0.6%	0.8%	0.4%
2013	2.5%	2.2%	3.1%	2.1%
2014	0.3%	0.3%	0.4%	0.3%
2015	0.4%	0.6%	0.4%	0.6%

Table 3-22 presents data on the frequency with which units were offer capped in 2014 and 2015, for failing the TPS test to provide energy for constraint relief in the Real-Time Energy Market. Table 3-22 shows that seven units were offer capped for 90 percent or more of their run hours in 2015 compared to one in 2014.

Table 3-22 Real-time offer-capped unit statistics: 2014 through 2015

		Offer-Capped Hours					
Run Hours Offer-Capped, Percent Greater Than Or Equal To:	Year	Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	2015	2	0	0	0	1	4
	2014	1	0	0	0	0	0
80% and < 90%	2015	0	1	1	0	0	6
	2014	2	0	0	3	0	0
75% and < 80%	2015	0	0	0	0	0	3
	2014	1	0	0	0	1	0
70% and < 75%	2015	0	0	0	0	0	4
	2014	0	0	0	0	0	0
60% and < 70%	2015	0	0	0	1	0	9
	2014	0	0	0	1	7	5
50% and < 60%	2015	0	0	0	0	1	9
	2014	0	0	0	0	3	6
25% and < 50%	2015	0	0	0	0	1	26
	2014	0	3	1	1	10	45
10% and < 25%	2015	0	0	5	2	5	34
	2014	0	1	4	1	8	56

TPS Test Statistics

In 2015, the AECO, AEP, AP, ATSI, BGE, ComEd, DEOK, DLCO, Dominion, DPL, MetEd, PECO, PENELEC, PPL, and PSEG control zones experienced congestion resulting from one or more constraints binding for 100 or more hours or resulting from an interface constraint. The DAY, EKPC, JCPL, Pepco, and RECO control zones did not have constraints binding for 100 or more hours in 2015. Table 3-23 shows that BGE, ComEd, PPL and PSEG were the control zones that experienced congestion resulting from one or more constraints binding for 100 or more hours or resulting from an interface constraint that was binding for one or more hours in every year in 2009 through 2015.

Table 3-23 Numbers of hours when control zones experienced congestion resulting from one or more constraints binding for 100 or more hours or from an interface constraint: 2009 through 2015

	2009	2010	2011	2012	2013	2014	2015
AECO	149	172	234	NA	208	NA	394
AEP	1,045	1,192	2,253	NA	2,611	2,710	1,274
AP	1,877	4,765	1,924	206	NA	170	167
ATSI	157	NA	NA	208	270	489	242
BGE	152	470	1,041	2,970	1,760	6,255	9,601
ComEd	1,212	2,080	1,134	4,554	5,143	4,119	5,878
DEOK	NA	NA	NA	109	NA	NA	112
DLCO	156	475	206	209	NA	223	617
Dominion	468	905	1,506	1,020	944	NA	1,172
DPL	NA	122	NA	1,542	639	3,071	2,066
Met-Ed	NA	180	162	NA	NA	NA	222
PECO	247	NA	788	386	732	1,953	895
PENELEC	103	284	NA	NA	176	4,281	1,683
Pepco	149	1	NA	143	245	41	NA
PPL	176	118	40	350	452	148	266
PSEG	303	549	1,107	913	3,021	4,688	2,665

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 2015.[43] The three pivotal supplier (TPS) test is applied every time the system solution indicates that out of merit resources are needed to relieve a transmission constraint. Only uncommitted resources, which would be started to relieve the transmission constraint, are subject to offer capping. Already committed units that can provide incremental relief cannot be offer capped. The results of the TPS test are shown for tests that could have resulted in offer capping and tests that resulted in offer capping.

Overall, the results confirm that the three pivotal supplier test results in offer capping when the local market is structurally noncompetitive and does not result in offer capping when that is not the case. Local markets are noncompetitive when the number of suppliers is relatively small.

Table 3-24 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 3-24 Three pivotal supplier test details for interface constraints: 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	249	274	7	0	7
AP South	Peak	341	423	11	2	10
	Off Peak	276	438	11	1	10
Bedington - Black Oak	Peak	174	233	14	2	12
	Off Peak	172	218	12	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 3-25 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.

43 See the *MMU Technical Reference for PJM Markets*, at "Three Pivotal Supplier Test" for a more detailed explanation of the three pivotal supplier test. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>

Table 3-25 Summary of three pivotal supplier tests applied for interface constraints: 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	110	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	1,595	59	4%	30	2%	51%
	Off Peak	984	33	3%	13	1%	39%
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%

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.[44] 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 in 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.

Currently, there are no specific rules in the PJM tariff or manuals that specify the limits on price based PLS offers. The intent of the price based PLS offer is to prevent the exercise of market power during high demand conditions by units offering inflexible operating parameters to extract uplift payments. However, a generator can use a price based PLS offer but include a higher markup than the price based non-PLS schedule. The result would that it is more expensive to commit a unit on the price based PLS, thus permitting the exercise of market power using the PLS offer. This defeats the purpose of having the price based PLS offers.

The MMU recommends that in order to ensure rigorous market power mitigation when the TPS test is failed, the operating parameters in the cost-based offer and the price-based parameter limited schedule (PLS) offer be at least as flexible as the operating parameters in the available non-PLS price-based offer, and that the price-MW pairs in the price based PLS offer be exactly equal to the price based non PLS offer.

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

Parameter Limited Schedules under Capacity Performance

Beginning in delivery year 2016-2017, resources that have Capacity Performance (CP) commitments are required to submit, in their parameter limited schedules (cost-based offers and price-based PLS offers), unit specific parameters that reflect the physical capability of the technology type of the resource. In its order on Capacity Performance, the Commission determined that resources should be able to reflect actual constraints based on not just the resource physical constraints, but also other constraints, such as contractual limits that are not based on the physical characteristics of the generator.[45] The Commission found that it is unjust and unreasonable to not provide uplift payments to resources with parameters based on non-physical constraints.[46] The Commission directed PJM to submit tariff language to establish a process through which resources that operate outside the defined unit-specific parameter limits can justify such operation and therefore remain eligible for make-whole payments.[47]

A primary goal of the Capacity Performance market design is to assign performance risk to generation owners and to ensure that capacity prices reflect underlying supply and demand conditions, including the cost of taking on performance risk. The Order's determination on parameters is not consistent with that goal. By permitting generation owners to establish unit parameters based on non-physical limits, the June 9th Order has weakened the incentives for units to be flexible and has weakened the assignment of performance risk to generation owners. Contractual limits, unlike generating unit operational limits, are a function of the interests and incentives of the parties to the contracts. If a generation owner expects to be compensated through uplift payments for running for 24 hours regardless of whether the energy is economic or needed, that generation owner has no incentive to pay more to purchase the flexible gas service that would permit the unit to be flexible in response to dispatch.

The fact that a contract may be just and reasonable because it was an arm's length contract entered into by two willing parties does not mean that is the only possible arrangement between the two parties or that it is consistent with an efficient market outcome. The actual contractual terms are a function of the incentives and interests of the parties. The fact that a just and reasonable contract exists between a generation owner and a gas supplier does not mean that it is appropriate or efficient to impose the resultant costs on electric customers or that it incorporates an efficient allocation of performance risk between the generation owner and other market participants.

The approach to parameters defined in the June 9th Order would increase energy market uplift payments substantially. Uplift costs are unpredictable, opaque and unhedgeable. Electric customers are not in a position to determine the terms of the contracts that resources enter into. Customers rely on the market rules to create incentives that protect them by assigning operational risk to generators, who are in the best position to efficiently manage those risks.

The MMU recommends that the revised rules recognize the difference between operational parameters that indicate to PJM dispatchers what a unit is capable of during the operating day and the parameters that are reflected in uplift payments. The parameters provided to PJM dispatchers each day should reflect what units are physically capable of. That is an operational necessity. However, the parameters which determine the amount of uplift payments to those generators should reflect the flexibility goals of the capacity performance construct.

The MMU recommends that resources be held to the OEM operating parameters of the capacity market CONE reference resource for performance assessment and energy uplift payments. This solution creates the incentives for flexibility and preserves, to the extent possible, the incentives to follow PJM's dispatch instructions during tight conditions. The proposed operating parameters should be based on the physical capability of the Reference Resource used in the Cost of New Entry, currently two GE Frame 7FA turbines with dual fuel capability. All resources that are less flexible than the Reference Resource are expected to be scheduled and running during tight conditions anyway, while the flexible CTs that are used as peaking plants would still have the incentive to follow LMP and dispatch instructions. CCs would also have the capability to be as flexible as the reference resource. These units

45 *PJM Interconnection, L.L.C. et al.*, 151 FERC ¶ 61,208 at P 437 (June 9th Order).
46 *Id* at P 439.
47 *Id* at P 440.

will be exempt from non-performance charges and made whole as long as they perform in accordance with their parameters. This ensures that all the peaking units that are needed by PJM for flexible operation do not self schedule at their maximum output, and follow PJM dispatch instructions during tight conditions. If any of the less flexible resources need to be dispatched down by PJM for reliability reasons, they would be exempt from non-performance charges.

Such an approach is consistent with the Commission's no excuses policy for non-performance because the flexibility target is set based on the optimal OEM-defined capability for the marginal resource that is expected to meet peak demand, which is consistent with the level of performance that customers are paying for in the capacity market. Any resource that is less flexible is not excused for non-performance and any resource that meets the flexibility target is performing according to the commitments made in the capacity market.

The June 9th Order pointed out that the way to ensure that a resource's parameters are exposed to market consequences is to not allow any parameter limitations as an excuse for non-performance. The same logic should apply to energy market uplift rules. A resource's parameters should be exposed to market consequences and the resource should not be made whole if it is operating less flexibly than the reference resource. Paying energy market uplift on the basis of parameters consistent with the flexibility goals of the capacity performance construct would ensure that performance incentives are consistent across the capacity and energy markets and ensure that performance risk is appropriately assigned to generation owners.

Markup Index

The markup index is a summary measure of participant offer behavior or conduct for individual marginal units. The markup index for each marginal unit is calculated as (Price – Cost)/Price.[48] The markup index is normalized and can vary from -1.00 when the offer price is less than short run marginal cost, to 1.00 when the offer price is higher than short run marginal cost. The markup index does not measure the impact of unit markup on total LMP.

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

Real-Time Markup

Table 3-26 shows the average markup index of marginal units in the Real-Time Energy Market, by offer price category using unadjusted cost offers. Table 3-27 shows the average markup index of marginal units in the Real-Time Energy Market, by offer price category using adjusted cost offers. The markup is negative if the cost-based offer of the marginal unit exceeds its price-based offer at its operating point. In 2015, 85.9 percent of marginal units had average dollar markups less than zero, when using unadjusted offers. In 2015, 47.1 percent of marginal units had average dollar markups less than zero, when using adjusted offers. The data show that some marginal units did have substantial markups. Using unadjusted cost offers, 0.17 percent of offers had offer prices greater than $400 per MWh with average dollar markup of $56.87 per MWh. Using the unadjusted cost offers, the highest markup in 2015 was $792.21 while the highest markup in 2014 was $922.26.

Table 3-26 Average, real-time marginal unit markup index (By offer price category unadjusted): 2014 and 2015

	2014			2015		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $25	(0.1 0)	($2.43)	16.9%	(0.04)	($2.45)	47.1%
$25 to $50	(0.02)	($1.04)	58.8%	(0.02)	($1.32)	38.9%
$50 to $75	0.06	$2.52	6.7%	0.08	$4.39	2.8%
$75 to $100	0.12	$9.46	1.9%	0.13	$10.46	1.1%
$100 to $125	0.04	$4.29	3.4%	0.11	$11.48	1.2%
$125 to $150	0.11	$13.69	1.0%	0.03	$3.33	3.1%
>= $150	0.05	$13.25	11.3%	0.05	$12.54	5.8%

Table 3-27 Average, real-time marginal unit markup index (By offer price category adjusted): 2014 and 2015

	2014			2015		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $25	(0.06)	($1.46)	16.9%	(0.00)	($1.45)	47.1%
$25 to $50	0.03	$0.40	58.8%	0.03	$0.31	38.9%
$50 to $75	0.07	$3.20	6.7%	0.10	$5.44	2.8%
$75 to $100	0.13	$10.08	1.9%	0.14	$10.93	1.1%
$100 to $125	0.04	$4.43	3.4%	0.11	$11.75	1.2%
$125 to $150	0.11	$13.84	1.0%	0.03	$3.40	3.1%
>= $150	0.05	$13.35	11.3%	0.05	$12.75	5.8%

Day-Ahead Markup

Table 3-28 shows the average markup index of marginal units in the Day-Ahead Energy Market, by offer price category using unadjusted offers. In 2015, 3.2 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 2014 did have substantial markups. The average markup index decreased significantly, for example, from 0.16 in 2014, to 0.02 in 2015 in the offer price category from $100 to $125.

Table 3-28 Average day-ahead marginal unit markup index (By offer price category, unadjusted): 2014 and 2015

	2014			2015		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $25	(0.08)	($2.31)	16.5%	0.08	$0.29	43.9%
$25 to $50	(0.02)	($0.90)	70.5%	0.06	$1.42	45.3%
$50 to $75	0.05	$2.17	7.5%	0.15	$8.77	2.4%
$75 to $100	0.09	$6.63	1.1%	0.05	$3.69	1.0%
$100 to $125	0.16	$17.04	0.8%	0.02	($0.25)	0.8%
$125 to $150	0.02	($2.02)	0.7%	(0.00)	($0.68)	3.2%
>= $150	0.04	$8.53	2.7%	0.02	$3.58	3.1%

Table 3-29 shows the average markup index of marginal units in the Day-Ahead Energy Market, by offer price category using adjusted offers. In 2015, 2.1 percent of marginal units had average dollar markups less than zero and an average markup index less than or equal to 0.00. The average markup index decreased significantly, for example, from 0.15 in 2014, to 0.00 in 2015 in the offer price category from $100 to $125.

Table 3-29 Average day-ahead marginal unit markup index (By offer price category, adjusted): 2014 and 2015

	2014			2015		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $25	(0.02)	($0.76)	16.5%	0.10	$0.86	43.9%
$25 to $50	0.04	$1.17	70.5%	0.09	$2.55	45.3%
$50 to $75	0.07	$3.78	7.5%	0.17	$9.79	2.4%
$75 to $100	0.09	$7.15	1.1%	0.05	$3.93	1.0%
$100 to $125	0.16	$17.26	0.8%	0.02	$0.22	0.8%
$125 to $150	0.02	($1.86)	0.7%	0.00	($0.60)	3.2%
>= $150	0.08	$17.63	2.7%	0.02	$3.63	3.1%

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.[49] 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 PJM Capacity Market). That function became unnecessary with the introduction of the RPM capacity market design in 2007, and changes to the scarcity pricing rules in 2012. 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.

For those reasons, the MMU recommended the elimination of FMU and AU adders.[50] 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 generating units to qualify for FMU adders when units have 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.

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 eligible for 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 eligible for 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 eligible for 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 an 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 an 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.[51]

49 110 FERC ¶ 61,053 (2005).

50 See the *"FMU Problem Statement and Issue Charge."* <http://www.monitoringanalytics.com/reports/Presentations/2013/IMM_MIC_FMU_Problem_Statement_and_Issue_Charge_20130306.pdf >

51 PJM. OA, Schedule 1 § 6.4.2.

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.[52] 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 an 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.[53] 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).

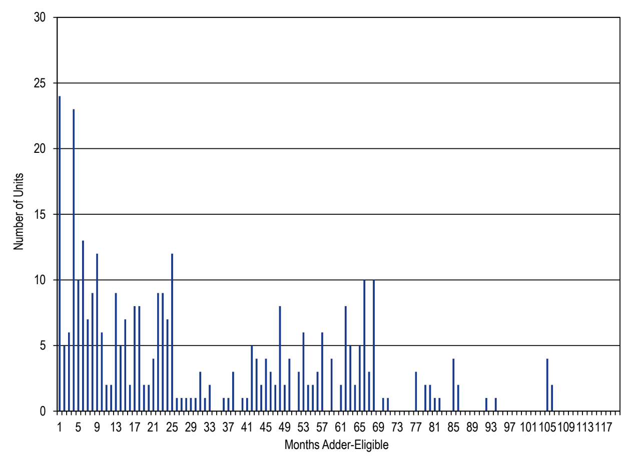
Table 3-30 shows the number of units that were eligible for an FMU or AU adder (Tier 1, Tier 2 or Tier 3) by the number of months they were eligible in 2014 and 2015.[54] In 2015, no units qualified as an FMU or AU.

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

	FMU & AU Count	
Months Adder-Eligible	2014	2015
1	23	0
2	6	0
3	0	0
4	4	0
5	4	0
6	15	0
7	2	0
8	5	0
9	8	0
10	5	0
11	39	0
12	0	0
Total	111	0

Figure 3-24 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 December 31, 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 120 possible months, and 70 of the 351 units (19.9 percent) qualified for an adder in more than half of the possible months.

Figure 3-24 Frequently mitigated units and associated units total months eligible: February, 2006 through December, 2015



52 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.

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

54 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.

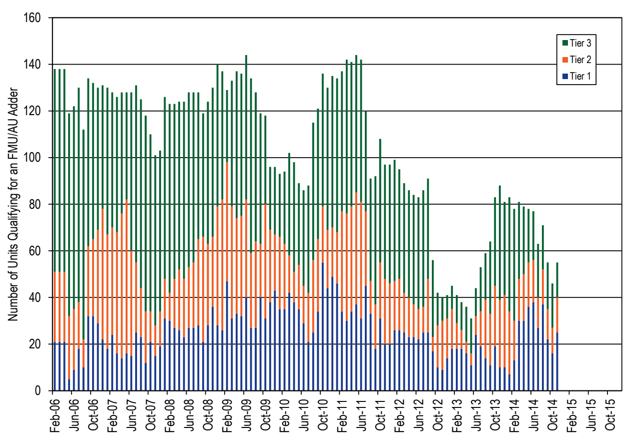
Table 3-31 shows, by month, the number of FMUs and AUs in 2014 and 2015. For example, in November 2014, there were 25 FMUs and AUs in Tier 1, 15 FMUs and AUs in Tier 2, and 15 FMUs and AUs in Tier 3. In 2015, no units qualified as an FMU or AU.[55]

Table 3-31 Number of frequently mitigated units and associated units (By month): 2014 and 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	0	0	0	0
February	13	17	48	78	0	0	0	0
March	30	18	33	81	0	0	0	0
April	30	20	29	79	0	0	0	0
May	36	19	23	78	0	0	0	0
June	38	18	21	77	0	0	0	0
July	27	13	23	63	0	0	0	0
August	37	15	19	71	0	0	0	0
September	22	13	20	55	0	0	0	0
October	16	11	19	46	0	0	0	0
November	25	15	15	55	0	0	0	0
December	0	0	0	0	0	0	0	0

Figure 3-25 shows the total number of FMUs and AUs that qualified for an adder since the inception of the business rule in February 2006.

Figure 3-25 Frequently mitigated units and associated units (By month): February, 2006 through December, 2015



Virtual Offers and Bids

There is a substantial volume of virtual offers and bids in the PJM Day-Ahead Energy 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 431 buses, eligible for up to congestion transaction bidding.[56] Financial Transaction Rights (FTRs) bids may be submitted at any bus on a list of selected buses that change every planning period, 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 3-26 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.

55 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. There was no impact on the day-ahead market outcomes resulting from the incorrect FMU status. A total of four five-minute intervals in the real-time market were affected. There was no impact on the monthly PJM system-wide load-weighted real-time LMP.

56 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 3-26 PJM day-ahead aggregate supply curves: 2015 example day

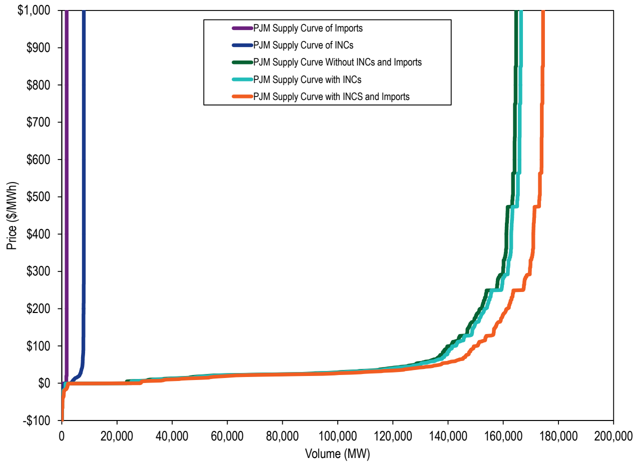


Table 3-32 shows the hourly average number of cleared and submitted increment and decrements by month for 2014 and 2015. The hourly average submitted and cleared increment MW increased by 35.9 and 33.8 percent, from 5,279 MW and 3,494 MW in 2014 to 7,175 MW and 4,675 MW in 2015. The hourly average submitted and cleared decrement MW decreased by 25.8 and 38.6 percent, from 9,278 MW and 6,596 MW in 2014 to 6,879 MW and 4,051 MW in 2015.

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

		Increment Offers				Decrement Bids			
Year		Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume	Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume
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	Jun	4,592	7,043	143	697	4,196	6,696	89	410
2015	Jul	4,101	6,534	128	745	3,335	5,830	86	448
2015	Aug	4,457	6,956	135	749	3,433	5,506	74	398
2015	Sep	4,527	6,772	148	733	4,391	7,030	112	437
2015	Oct	4,631	7,112	199	846	3,990	6,757	112	462
2015	Nov	5,022	7,822	223	1,008	3,671	6,435	109	482
2015	Dec	5,102	7,775	189	1,010	4,028	6,869	129	486
2015	Annual	4,675	7,175	156	729	4,051	6,879	95	444

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.[57] Table 3-33 shows the average hourly number of up to congestion transactions and the average hourly MW for 2014 and 2015. In 2015, the average hourly up to congestion submitted MW decreased 49.9 percent and cleared MW decreased 61.1 percent, compared to 2014, as a result of the decreases after September 8, 2014. Section 206(b) of the Federal Power Act states that "...the Commission may order refunds of any amounts paid, for the period subsequent to the refund effective date through a date fifteen months after such refund effective date..."[58] An increase in up to congestion volume was observed in December 2015, coincident with the expiration of the fifteen month resettlement period in this proceeding. In December 2015, the hourly average up to congestion submitted MW increased 14.1 percent and cleared MW increased 29.9 percent, compared to November 2015.

Table 3-33 Hourly average of cleared and submitted up to congestion bids by month: 2014 and 2015

Up to Congestion					
Year		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	18,382	72,906	978	2,909
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	Jul	18,883	88,543	952	3,502
2015	Aug	18,490	102,084	1,126	4,291
2015	Sep	20,779	108,730	1,451	4,909
2015	Oct	20,183	100,673	1,493	4,736
2015	Nov	20,880	86,857	1,468	4,067
2015	Dec	27,124	99,083	1,933	4,841
2015	Annual	19,255	83,422	1,147	3,611

Table 3-34 shows the average hourly number of import and export transactions and the average hourly MW for 2014 and 2015. In 2015, the average hourly submitted MW increased by 3.2 percent, cleared import transaction MW decreased by 0.2 percent, and the average hourly submitted and cleared export transaction MW decreased 17.3 and 16.3 percent, compared to 2014.

57 148 FERC ¶ 61,144 (2014).
58 16 U.S.C. § 824e.

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

		Imports				Exports			
Year		Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume	Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume
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	Jul	2,319	2,445	16	18	2,961	2,983	14	14
2015	Aug	2,410	2,549	14	16	3,209	3,239	15	15
2015	Sep	1,854	2,015	11	14	3,873	3,913	18	18
2015	Oct	1,419	1,485	8	9	2,190	2,197	11	11
2015	Nov	1,840	1,988	15	17	2,715	2,734	15	15
2015	Dec	1,998	2,137	18	20	2,475	2,483	13	13
2015	Annual	2,217	2,348	15	17	3,131	3,160	16	17

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 2014 and 2015.

Table 3-35 Type of day-ahead marginal units: 2014 and 2015

	2014						2015					
	Generation	Dispatchable Transaction	Up to Congestion Transaction	Decrement Bid	Increment Offer	Price Sensitive Demand	Generation	Dispatchable Transaction	Up to Congestion Transaction	Decrement Bid	Increment Offer	Price Sensitive Demand
Jan	2.7%	0.1%	94.5%	1.4%	1.2%	0.0%	14.2%	0.5%	71.9%	6.9%	6.3%	0.1%
Feb	2.0%	0.3%	94.8%	1.9%	1.1%	0.0%	13.1%	0.4%	73.1%	7.6%	5.6%	0.1%
Mar	2.5%	0.2%	94.7%	1.5%	1.0%	0.0%	10.0%	0.7%	73.3%	10.6%	5.3%	0.0%
Apr	2.3%	0.0%	95.1%	1.4%	1.2%	0.0%	10.4%	0.3%	73.2%	10.8%	5.3%	0.0%
May	1.6%	0.0%	92.0%	4.0%	2.4%	0.0%	10.2%	0.1%	75.2%	9.2%	5.3%	0.0%
Jun	2.0%	0.0%	94.6%	2.0%	1.4%	0.0%	8.0%	0.1%	78.2%	9.5%	4.1%	0.0%
Jul	2.1%	0.0%	93.9%	2.1%	1.9%	0.0%	7.2%	0.1%	81.1%	7.8%	3.8%	0.0%
Aug	2.2%	0.0%	94.8%	1.5%	1.6%	0.0%	6.0%	0.1%	83.4%	7.1%	3.3%	0.0%
Sep	6.9%	0.1%	84.1%	5.5%	3.5%	0.0%	7.2%	0.2%	80.0%	7.5%	5.1%	0.0%
Oct	12.2%	0.1%	64.0%	14.5%	9.2%	0.0%	9.8%	0.1%	72.4%	11.2%	6.6%	0.0%
Nov	10.1%	0.2%	64.9%	14.6%	10.1%	0.0%	11.8%	0.1%	72.0%	10.7%	5.3%	0.0%
Dec	12.6%	0.2%	67.2%	12.4%	7.6%	0.0%	7.3%	0.1%	79.8%	8.0%	4.8%	0.0%
Total	3.3%	0.1%	91.0%	3.3%	2.3%	0.0%	9.6%	0.3%	76.1%	8.9%	5.1%	0.0%

Figure 3-27 shows the monthly volume of bid and cleared INC, DEC and up to congestion bids by month for the period from January 2005 through September 2015.

Figure 3-27 Monthly bid and cleared INCs, DECs, and UTCs (MW): January 2005 through December 2015

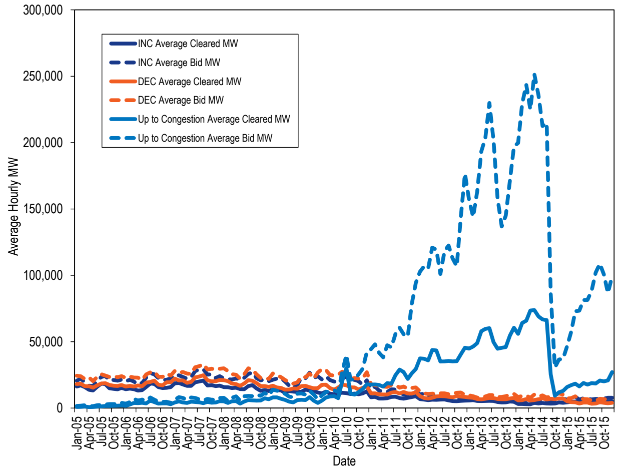
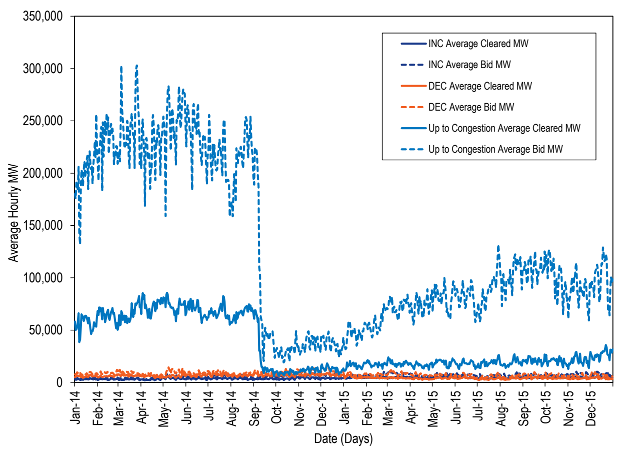


Figure 3-28 shows the daily volume of bid and cleared INC, DEC and up to congestion bids for the period from January 2014 through December 2015.

Figure 3-28 Daily bid and cleared INCs, DECs, and UTCs (MW): January 2014 through December 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 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): 2014 and 2015

	2014		2015	
Category	Total Virtual Bids MW	Percent	Total Virtual Bids MW	Percent
Financial	45,631,883	35.8%	54,941,962	44.6%
Physical	81,887,800	64.2%	68,165,222	55.4%
Total	127,519,683	100.0%	123,107,185	100.0%

Table 3-37 shows, for 2014 and 2015, the total up to congestion transactions by whether the parent organization is financial or physical.

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

	2014		2015	
Category	Total Up to Congestion MW	Percent	Total Up to Congestion MW	Percent
Financial	407,879,549	94.0%	134,555,951	79.8%
Physical	25,839,452	6.0%	34,117,122	20.2%
Total	433,719,001	100.0%	168,673,073	100.0%

Table 3-38 shows for 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): 2014 and 2015

	2014		2015	
Category	Total Import and Export MW	Percent	Total Import and Export MW	Percent
Financial	18,874,396	35.3%	19,015,698	38.6%
Physical	34,598,073	64.7%	30,214,300	61.4%
Total	53,472,469	100.0%	49,229,998	100.0%

Table 3-39 shows increment offers and decrement bids bid by top ten locations for 2014 and 2015.

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

2014					2015				
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	14,144,703	15,893,094	30,037,797	WESTERN HUB	HUB	19,527,215	21,691,683	41,218,898
MISO	INTERFACE	398,020	7,059,365	7,457,385	SOUTHIMP	INTERFACE	7,136,144	0	7,136,144
PPL	ZONE	267,547	6,406,394	6,673,941	N ILLINOIS HUB	HUB	905,858	2,733,941	3,639,799
SOUTHIMP	INTERFACE	5,941,022	0	5,941,022	IMO	INTERFACE	3,530,900	70,753	3,601,653
PECO	ZONE	353,741	5,389,431	5,743,172	NYIS	INTERFACE	1,895,475	400,046	2,295,521
AEP-DAYTON HUB	HUB	2,299,031	2,368,105	4,667,135	BGE	ZONE	223,721	1,750,290	1,974,011
IMO	INTERFACE	4,236,242	174,918	4,411,159	MISO	INTERFACE	414,835	1,216,550	1,631,385
N ILLINOIS HUB	HUB	1,044,461	2,696,413	3,740,873	BAGLEY 34 KV 230-1LD	LOAD	403,792	912,882	1,316,673
BGE	ZONE	25,650	2,999,433	3,025,084	AEP-DAYTON HUB	HUB	651,596	649,136	1,300,732
NYIS	INTERFACE	1,081,753	488,366	1,570,119	DOMINION HUB	HUB	365,184	811,772	1,176,956
Top ten total		29,792,169	43,475,518	73,267,687			35,054,718	30,237,052	65,291,770
PJM total		46,227,055	81,206,816	127,433,871			62,848,910	60,258,275	123,107,185
Top ten total as percent of PJM total		64.4%	53.5%	57.5%			55.8%	50.2%	53.0%

Table 3-40 shows up to congestion transactions by import bids for the top ten locations for 2014 and 2015.[59]

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

2014 Imports				
Source	Source Type	Sink	Sink Type	MW
HUDSONTP	INTERFACE	LEONIA 230 T-2	AGGREGATE	979,669
SOUTHEAST	INTERFACE	EDANVILL T1	AGGREGATE	759,991
MISO	INTERFACE	COOK	EHVAGG	666,261
OVEC	INTERFACE	BIG SANDY CT1	AGGREGATE	603,745
NORTHWEST	INTERFACE	N ILLINOIS HUB	HUB	571,373
MISO	INTERFACE	AEP-DAYTON HUB	HUB	462,719
NEPTUNE	INTERFACE	SOUTHRIV 230	AGGREGATE	436,574
SOUTHEAST	INTERFACE	CLOVER	EHVAGG	428,397
OVEC	INTERFACE	AEP-DAYTON HUB	HUB	402,375
HUDSONTP	INTERFACE	LEONIA 230 T-1	AGGREGATE	383,260
Top ten total				5,694,366
PJM total				29,282,620
Top ten total as percent of PJM total				19.4%
2015 Imports				
Source	Source Type	Sink	Sink Type	MW
SOUTHIMP	INTERFACE	NAGELAEP	EHVAGG	1,480,928
NORTHWEST	INTERFACE	N ILLINOIS HUB	HUB	445,796
SOUTHEAST	INTERFACE	CLOVER	EHVAGG	413,115
NORTHWEST	INTERFACE	COMED	ZONE	412,351
SOUTHEAST	INTERFACE	HALIFXDP TX1	AGGREGATE	364,808
OVEC	INTERFACE	AEP-DAYTON HUB	HUB	356,720
SOUTHIMP	INTERFACE	WOLF HILLS 1-5	AGGREGATE	342,579
SOUTHEAST	INTERFACE	DOM	ZONE	277,721
OVEC	INTERFACE	MALISZEWSKI	EHVAGG	258,387
MISO	INTERFACE	21 KINCA ATR24304	AGGREGATE	244,650
Top ten total				4,597,055
PJM total				19,561,806
Top ten total as percent of PJM total				23.5%

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

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

2014 Exports				
Source	Source Type	Sink	Sink Type	MW
JEFFERSON	EHVAGG	OVEC	INTERFACE	2,073,052
TANNERS CRK 4	AGGREGATE	SOUTHWEST	INTERFACE	1,782,780
TANNERS CRK 4	AGGREGATE	OVEC	INTERFACE	809,364
21 KINCA ATR24304	AGGREGATE	SOUTHWEST	INTERFACE	693,816
ROCKPORT	EHVAGG	SOUTHWEST	INTERFACE	607,054
JEFFERSON	EHVAGG	SOUTHWEST	INTERFACE	606,723
ROCKPORT	EHVAGG	OVEC	INTERFACE	564,629
EAST BEND 2	AGGREGATE	SOUTHWEST	INTERFACE	427,156
UNIV PARK 1-6	AGGREGATE	NIPSCO	INTERFACE	426,011
BECKJORD 6	AGGREGATE	OVEC	INTERFACE	418,718
Top ten total				8,409,302
PJM total				30,285,649
Top ten total as percent of PJM total				27.8%
2015 Exports				
Source	Source Type	Sink	Sink Type	MW
SULLIVAN-AEP	EHVAGG	OVEC	INTERFACE	460,314
FOWLER 34.5 KV FWLR1AWF	AGGREGATE	SOUTHWEST	INTERFACE	378,483
21 KINCA ATR24304	AGGREGATE	SOUTHWEST	INTERFACE	367,085
FOWLER RIDGE II WF	AGGREGATE	SOUTHWEST	INTERFACE	360,994
ROCKPORT	EHVAGG	SOUTHWEST	INTERFACE	303,419
COMED	ZONE	NIPSCO	INTERFACE	274,034
21 KINCA ATR24304	AGGREGATE	NIPSCO	INTERFACE	270,867
SULLIVAN-AEP	EHVAGG	SOUTHWEST	INTERFACE	222,668
21 KINCA ATR24404	AGGREGATE	SOUTHWEST	INTERFACE	217,732
SULLIVAN-AEP	EHVAGG	MISO	INTERFACE	167,996
Top ten total				3,023,589
PJM total				9,849,007
Top ten total as percent of PJM total				30.7%

59 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 2014 and 2015.

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

Source	Source Type	Sink	Sink Type	MW
2014				
Wheels				
NORTHWEST	INTERFACE	MISO	INTERFACE	775,527
OVEC	INTERFACE	SOUTHEXP	INTERFACE	344,298
MISO	INTERFACE	NORTHWEST	INTERFACE	334,888
SOUTHWEST	INTERFACE	SOUTHEXP	INTERFACE	255,763
MISO	INTERFACE	NIPSCO	INTERFACE	128,693
OVEC	INTERFACE	SOUTHWEST	INTERFACE	120,854
MISO	INTERFACE	SOUTHEXP	INTERFACE	97,877
NYIS	INTERFACE	IMO	INTERFACE	97,249
IMO	INTERFACE	NYIS	INTERFACE	91,942
NORTHWEST	INTERFACE	NIPSCO	INTERFACE	89,794
Top ten total				2,336,885
PJM total				2,984,112
Top ten total as percent of PJM total				78.3%
2015				
Wheels				
Source	Source Type	Sink	Sink Type	MW
MISO	INTERFACE	NORTHWEST	INTERFACE	361,210
NORTHWEST	INTERFACE	MISO	INTERFACE	232,735
MISO	INTERFACE	NIPSCO	INTERFACE	221,536
NYIS	INTERFACE	IMO	INTERFACE	129,966
IMO	INTERFACE	NYIS	INTERFACE	113,455
SOUTHWEST	INTERFACE	SOUTHEXP	INTERFACE	47,741
SOUTHWEST	INTERFACE	IMO	INTERFACE	33,166
NIPSCO	INTERFACE	IMO	INTERFACE	29,379
SOUTHEAST	INTERFACE	SOUTHEXP	INTERFACE	21,292
MISO	INTERFACE	SOUTHWEST	INTERFACE	20,984
Top ten total				1,211,465
PJM total				1,453,602
Top ten total as percent of PJM total				83.3%

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 8.2 percent of the PJM total internal up to congestion transactions in 2015.

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

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

Source	Source Type	Sink	Sink Type	MW
2014				
Internal				
MOUNTAINEER	EHVAGG	GAVIN	EHVAGG	6,627,189
DAY	ZONE	BUCKEYE - DPL	AGGREGATE	5,207,776
MOUNTAINEER	EHVAGG	FLATLICK	EHVAGG	4,297,331
ATSI GEN HUB	HUB	ATSI	ZONE	4,114,584
VERNON BK 4	AGGREGATE	AEC - JC	AGGREGATE	3,733,527
FE GEN	AGGREGATE	ATSI	ZONE	3,357,260
JEFFERSON	EHVAGG	COOK	EHVAGG	2,548,989
DUMONT	EHVAGG	COOK	EHVAGG	2,466,575
WESTERN HUB	HUB	AEP-DAYTON HUB	HUB	2,147,264
TANNERS CRK 4	AGGREGATE	STUART DIESEL	AGGREGATE	1,813,835
Top ten total				36,314,330
PJM total				371,166,620
Top ten total as percent of PJM total				9.8%
2015				
Internal				
Source	Source Type	Sink	Sink Type	MW
BERGEN 2CC	AGGREGATE	LEONIA 230 T-1	AGGREGATE	2,362,692
ROCKPORT	EHVAGG	JEFFERSON	EHVAGG	1,763,337
BYRON 1	AGGREGATE	ROCKFORD	AGGREGATE	1,465,725
BERGEN 2CC	AGGREGATE	LEONIA 230 T-2	AGGREGATE	1,017,317
JEFFERSON	EHVAGG	COOK	EHVAGG	958,975
MARYSVILLE	EHVAGG	MALISZEWSKI	EHVAGG	892,606
BLACKOAK	EHVAGG	BEDINGTON	EHVAGG	718,298
PSEG	ZONE	WESTERN HUB	HUB	711,099
WHIPPANY BK 7	AGGREGATE	TRAYNOR	AGGREGATE	686,989
21 KINCA ATR24304	AGGREGATE	DUMONT - OLIVE	AGGREGATE	673,830
Top ten total				11,250,868
PJM total				137,808,658
Top ten total as percent of PJM total				8.2%

Table 3-44 shows the number of source-sink pairs that were offered and cleared monthly in January 2013 through December 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 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.[60]

60 See 148 FERC ¶ 61,144 (2014)..

Table 3-44 Number of PJM offered and cleared source and sink pairs: January 2013 through December 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	8,109	10,614	5,690	7,570
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	Jul	3,957	5,225	2,786	4,044
2015	Aug	4,996	6,143	3,702	4,378
2015	Sep	5,775	7,439	4,222	5,462
2015	Oct	6,000	7,414	4,221	5,397
2015	Nov	5,846	7,148	4,494	5,842
2015	Dec	7,097	8,250	5,709	6,610
2015	Annual	4,259	6,152	2,897	3,912

Table 3-45 and Figure 3-29 show total cleared up to congestion transactions by type for 2014 and 2015. Internal up to congestion transactions in 2015 were 81.7 percent of all up to congestion transactions compared to 85.6 percent in 2014.

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

	2014				
	Cleared Up to Congestion Bids				
	Import	Export	Wheel	Internal	Total
Top ten total (MW)	5,694,366	8,409,302	2,336,885	36,314,330	52,754,883
PJM total (MW)	29,282,620	30,285,649	2,984,112	371,166,620	433,719,001
Top ten total as percent of PJM total	19.4%	27.8%	78.3%	9.8%	12.2%
PJM total as percent of all up to congestion transactions	6.8%	7.0%	0.7%	85.6%	100.0%
	2015				
	Cleared Up to Congestion Bids				
	Import	Export	Wheel	Internal	Total
Top ten total (MW)	4,597,055	3,023,589	1,211,465	11,250,868	20,082,977
PJM total (MW)	19,561,806	9,849,007	1,453,602	137,808,658	168,673,073
Top ten total as percent of PJM total	23.5%	30.7%	83.3%	8.2%	11.9%
PJM total as percent of all up to congestion transactions	11.6%	5.8%	0.9%	81.7%	100.0%

Figure 3-29 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 decrease in UTCs in September as a result of a FERC order setting September 8, 2014, as the effective date for any uplift charges subsequently assigned to UTCs and an increase in UTCs in December 2015, coincident with the expiration of the fifteen month resettlement period in this proceeding.[61]

Figure 3-29 PJM monthly cleared up to congestion transactions by type (MW): January 2005 through December 2015

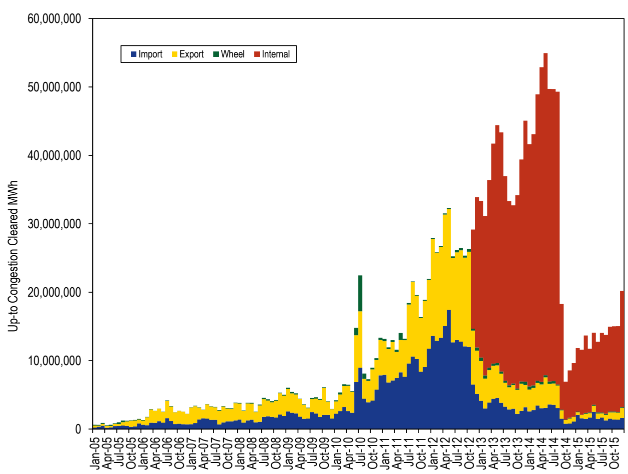
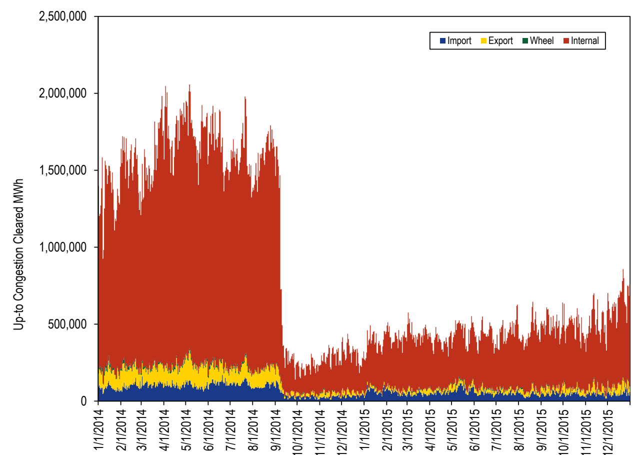


Figure 3-30 shows the daily cleared up to congestion MW by transaction type for the period from January 2014 through December 2015.

Figure 3-30 PJM daily cleared up to congestion transaction by type (MW): January 2014 through December 2015



Generator Offers

Generator offers are categorized as dispatchable (Table 3-46) or self scheduled (Table 3-47).[62] 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 are categorized as emergency MW. The emergency MW are included in both tables.

61 See 148 FERC ¶ 61,144 (2014).

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

Table 3-46 shows the proportion of MW offers by dispatchable units, by unit type and by offer price range, for 2015. For example, 73.0 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, 81.2 percent of all CC MW offers were dispatchable, including the 6.2 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, 46.7 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 2015, 51.7 percent were offered as available for economic dispatch.

Table 3-47 shows the proportion of MW offers by unit type that were self scheduled to generate fixed output and by unit type and price range for self-scheduled and dispatchable units, for 2015. For example, 15.2 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, 18.8 percent of all CC MW offers were either self scheduled to generate at fixed output or self scheduled to generate at economic minimum and dispatchable up to economic maximum, including the 1.7 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 22.5 percent of all offers and self-scheduled and dispatchable units accounted for 19.0 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 2015, 23.8 percent were offered as self scheduled and 20.1 percent were offered as self scheduled and dispatchable.

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

	Dispatchable (Range)							
Unit Type	($200) - $0	$0 - $200	$200 - $400	$400 - $600	$600 - $800	$800 - $1,000	Emergency	Total
CC	0.2%	73.0%	1.1%	0.3%	0.4%	0.0%	6.2%	81.2%
CT	0.1%	75.3%	10.2%	1.4%	1.2%	0.1%	10.9%	99.1%
Diesel	5.6%	27.7%	18.7%	8.2%	0.9%	0.3%	13.7%	75.0%
Fuel Cell	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Nuclear	0.0%	6.6%	0.0%	0.0%	0.0%	0.0%	0.0%	6.7%
Pumped Storage	33.5%	21.7%	0.0%	0.0%	0.0%	0.0%	12.5%	67.7%
Run of River	0.2%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.3%
Solar	6.5%	7.2%	0.0%	0.0%	0.0%	0.0%	2.7%	16.4%
Steam	0.1%	47.2%	1.2%	0.1%	0.1%	0.0%	2.6%	51.3%
Transaction	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Wind	48.7%	11.3%	0.0%	0.0%	0.0%	0.0%	0.6%	60.6%
All Dispatchable Offers	1.6%	46.7%	2.6%	0.4%	0.3%	0.0%	4.4%	56.1%

Table 3-47 Distribution of MW for self scheduled offer prices: 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	1.4%	0.5%	0.2%	15.2%	0.1%	0.0%	0.1%	0.0%	1.2%	18.8%
CT	0.4%	0.1%	0.0%	0.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.9%
Diesel	23.1%	1.0%	0.4%	0.3%	0.1%	0.0%	0.0%	0.0%	0.1%	25.0%
Fuel Cell	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%
Nuclear	91.9%	1.1%	0.0%	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%	93.3%
Pumped Storage	16.1%	8.4%	3.4%	0.0%	0.0%	0.0%	0.0%	0.0%	4.4%	32.3%
Run of River	60.1%	9.9%	2.7%	19.8%	0.0%	0.0%	0.0%	3.5%	3.7%	99.7%
Solar	61.7%	21.6%	0.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	83.6%
Steam	5.4%	1.5%	0.2%	39.6%	0.2%	0.0%	0.0%	0.0%	1.8%	48.7%
Transaction	74.9%	25.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%
Wind	4.1%	2.9%	25.8%	2.8%	0.0%	0.0%	0.0%	0.0%	4.0%	39.4%
All Self-Scheduled Offers	22.5%	1.3%	0.6%	18.2%	0.1%	0.0%	0.0%	0.1%	1.1%	43.9%

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.[63]

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 short run marginal cost. Thus the results do not reflect a counterfactual market outcome based on the assumption that all units made all offers at short run 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 short run marginal cost and actual dispatch. It is possible that the unit-specific markup, based on a redispatch analysis, would be lower than the markup component of price if the reference point were an inframarginal unit with a lower price and a higher cost than the actual marginal unit. If the actual marginal unit has short run 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 3-26.

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

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

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 short run marginal costs, and market behavior reflected that fact.[64]

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 Markup component of the overall PJM real-time, load-weighted, average LMP by primary fuel type and unit type: 2014 and 2015[65]

		2014		2015	
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	$0.32	$1.75	($1.26)	$0.37
Gas	CC	$0.83	$0.83	$1.29	$1.29
Gas	CT	$0.27	$0.27	($0.13)	($0.13)
Gas	Diesel	$0.09	$0.09	$0.02	$0.02
Gas	Steam	($0.01)	($0.01)	$0.02	$0.02
Municipal Waste	Steam	$0.15	$0.15	($0.01)	($0.01)
Oil	CC	$0.09	$0.09	$0.05	$0.05
Oil	CT	$0.09	$0.09	$0.03	$0.03
Oil	Diesel	$0.00	$0.00	$0.00	$0.00
Oil	Steam	$0.03	$0.03	$0.12	$0.12
Other	Steam	($0.00)	($0.00)	($0.05)	($0.05)
Uranium	Steam	$0.01	$0.01	$0.00	$0.00
Wind	Wind	$0.03	$0.03	$0.03	$0.03
Total		$1.88	$3.32	$0.12	$1.75

Table 3-48 shows the mark-up component of the load-weighted LMP by fuel type and unit type using unadjusted and adjusted offers. The adjusted markup component of LMP decreased from $3.22 in 2014 to $1.75 in 2015. The adjusted markup contribution of coal units in 2015 was $0.37. Although the price of natural gas was substantially lower in 2015 than in 2014, the adjusted mark-up component of all gas-fired units in 2015 was $1.20, an increase of $0.03 from 2014. Coal units accounted for 87.8 percent of the decrease in the markup component of LMP in 2015. The markup component of wind units was $0.03. If a price-based offer is negative, but less negative than a cost-based offer, the markup is positive. In 2015, among the wind units that were marginal, 3.81 percent had positive offer prices.

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 2015, when using unadjusted cost offers, $0.12 per MWh of the PJM real-time load-weighted average LMP was attributable to markup. Using adjusted cost-offers, $1.75 per MWh of the PJM real-time load-weighted average LMP was attributable to markup. In 2015, the peak markup component was highest in February, $7.46 per MWh using unadjusted cost offers and $9.24 per MWh using adjusted cost offers. This corresponds to 13.78 percent and 17.08 percent of the real time load-weighted average LMP in February.[66]

64 See PJM. "Manual 15: Cost Development Guidelines," Revision 26 (November 5, 2014).

65 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.

66 In the *2015 Quarterly State of the Market Report for PJM: January through March*; January through June; and January through September, the peak markup component was incorrectly reported as $4.79 per MWh using unadjusted cost offers and $6.64 using adjusted cost offers.

Table 3-49 Monthly markup components of real-time load-weighted LMP (Unadjusted): 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)	($2.62)	($0.15)
Feb	$3.02	$0.88	$5.08	$4.62	$1.72	$7.46
Mar	$7.11	$3.24	$11.17	$1.84	$1.82	$1.86
Apr	($0.43)	($2.16)	$1.07	($0.42)	($0.69)	($0.18)
May	$1.74	($1.27)	$4.62	($1.85)	($3.59)	($0.01)
Jun	$2.43	($0.08)	$4.60	($0.43)	($1.20)	$0.21
Jul	($0.15)	($1.22)	$0.77	($0.46)	($1.29)	$0.21
Aug	($1.08)	($1.91)	($0.29)	($0.90)	($0.96)	($0.83)
Sep	$1.51	($0.13)	$3.01	($0.55)	($0.64)	($0.47)
Oct	$2.04	($0.74)	$4.34	($0.13)	($0.35)	$0.08
Nov	$0.17	($1.12)	$1.70	$0.57	($0.42)	$1.62
Dec	($0.19)	($1.59)	$1.13	$0.38	($0.22)	$0.95
Total	$1.88	($0.06)	$3.71	$0.12	($0.72)	$0.92

Table 3-50 Monthly markup components of real-time load-weighted LMP (Adjusted): 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	($0.61)	$1.90
Feb	$3.94	$1.97	$5.84	$6.44	$3.57	$9.24
Mar	$8.21	$4.59	$12.02	$3.71	$3.69	$3.74
Apr	$0.86	($0.45)	$2.00	$1.22	$0.72	$1.65
May	$2.87	$0.09	$5.54	($0.45)	($2.41)	$1.64
Jun	$3.69	$1.46	$5.62	$1.18	$0.06	$2.10
Jul	$1.48	$0.35	$2.44	$1.17	$0.16	$1.97
Aug	$0.50	($0.29)	$1.25	$0.65	$0.43	$0.86
Sep	$3.18	$1.65	$4.59	$0.86	$0.71	$1.00
Oct	$3.71	$1.06	$5.90	$1.43	$0.91	$1.91
Nov	$1.93	$0.80	$3.25	$2.06	$0.80	$3.39
Dec	$1.65	$0.27	$2.97	$1.79	$0.84	$2.68
Total	$3.32	$1.54	$5.00	$1.75	$0.75	$2.70

Hourly Markup Component of Real-Time Prices

Figure 3-31 shows the markup contribution to the hourly load-weighted LMP using unadjusted cost offers for 2015 and 2014. Figure 3-32 shows the markup contribution to the hourly load-weighted LMP using adjusted cost offers for 2015 and 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 3-31 Markup contribution to real-time hourly load-weighted LMP (Unadjusted): 2014 and 2015

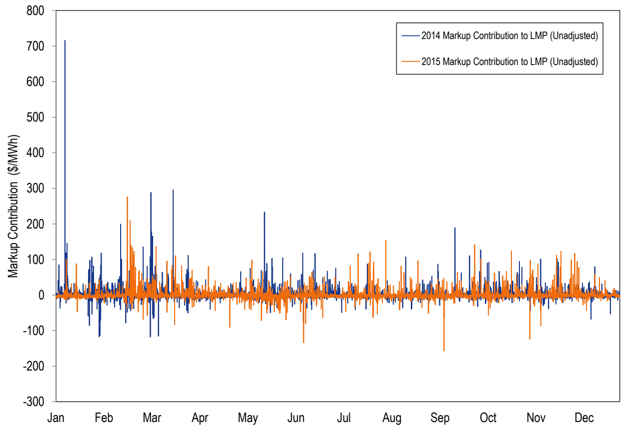
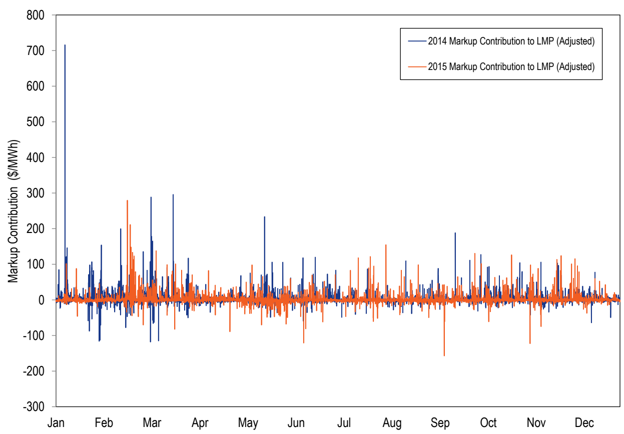


Figure 3-32 Markup contribution to real-time hourly load-weighted LMP (Adjusted): 2014 and 2015



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 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 2015 was in the DPL Zone, -$0.67 per MWh, while the highest was in the BGE Control Zone, $1.64 per MWh. The smallest zonal on peak average markup was in the AECO Control Zone, -$1.32 per MWh, while the highest was in the BGE Control Zone, $1.00 per MWh.

Table 3-51 Average real-time zonal markup component (Unadjusted): 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
AECO	$1.77	($0.26)	$3.71	($0.62)	($1.32)	$0.05
AEP	$1.59	($0.30)	$3.42	$0.04	($0.97)	$1.00
APS	$1.72	($0.05)	$3.43	$0.56	($0.31)	$1.41
ATSI	$1.25	($0.48)	$2.89	$0.03	($0.89)	$0.89
BGE	$3.14	$0.85	$5.30	$1.64	$1.00	$2.26
ComEd	$0.99	($0.62)	$2.48	($0.22)	($1.04)	$0.53
DAY	$1.27	($0.54)	$2.94	$0.10	($0.97)	$1.09
DEOK	$1.27	($0.57)	$3.01	($0.01)	($1.10)	$1.03
DLCO	$1.53	($0.17)	$3.14	($0.15)	($0.98)	$0.63
DPL	$2.23	$0.25	$4.10	($0.67)	($1.11)	($0.25)
Dominion	$3.15	$0.79	$5.39	$0.79	$0.09	$1.46
EKPC	$1.59	($0.09)	$3.26	$0.05	($1.16)	$1.27
JCPL	$1.50	($0.33)	$3.14	($0.60)	($1.24)	($0.02)
Met-Ed	$1.58	($0.12)	$3.14	($0.52)	($1.22)	$0.13
PECO	$1.83	($0.07)	$3.61	($0.61)	($1.26)	($0.00)
PENELEC	$1.96	($0.11)	$3.89	$0.20	($0.77)	$1.11
PPL	$2.02	($0.03)	$3.94	($0.27)	($1.10)	$0.50
PSEG	$2.33	$0.16	$4.31	($0.19)	($1.10)	$0.63
Pepco	$2.94	$0.73	$4.97	$1.19	$0.36	$1.94
RECO	$2.44	$0.14	$4.39	$0.04	($1.28)	$1.17

Table 3-52 Average real-time zonal markup component (Adjusted): 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
AECO	$3.04	$1.10	$4.88	$0.44	($0.32)	$1.16
AEP	$3.09	$1.37	$4.75	$1.78	$0.59	$2.93
APS	$3.19	$1.56	$4.77	$2.32	$1.28	$3.33
ATSI	$2.74	$1.16	$4.23	$1.76	$0.66	$2.79
BGE	$4.90	$2.78	$6.90	$4.13	$3.16	$5.06
ComEd	$2.41	$1.01	$3.71	$1.34	$0.33	$2.27
DAY	$2.81	$1.16	$4.33	$1.90	$0.60	$3.10
DEOK	$2.75	$1.07	$4.34	$1.75	$0.43	$3.00
DLCO	$3.05	$1.47	$4.53	$1.54	$0.53	$2.49
DPL	$3.46	$1.59	$5.24	$0.44	($0.05)	$0.92
Dominion	$4.67	$2.46	$6.77	$2.77	$1.89	$3.62
EKPC	$3.06	$1.55	$4.57	$1.77	$0.42	$3.14
JCPL	$2.74	$1.03	$4.26	$0.47	($0.24)	$1.10
Met-Ed	$2.77	$1.21	$4.21	$0.53	($0.24)	$1.25
PECO	$3.05	$1.29	$4.69	$0.42	($0.26)	$1.05
PENELEC	$3.33	$1.38	$5.15	$1.67	$0.57	$2.69
PPL	$3.23	$1.31	$5.02	$0.79	($0.09)	$1.61
PSEG	$3.60	$1.52	$5.49	$0.95	($0.03)	$1.85
Pepco	$4.56	$2.52	$6.44	$3.39	$2.29	$4.41
RECO	$3.79	$1.55	$5.70	$1.34	($0.05)	$2.52

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): 2014 and 2015

	2014		2015	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $25	$0.46	76.0%	($0.14)	89.9%
$25 to $50	($0.15)	12.5%	($0.01)	9.2%
$50 to $75	$0.17	5.0%	$0.11	0.6%
$75 to $100	$0.17	1.9%	$0.09	0.2%
$100 to $125	$0.09	1.0%	$0.02	0.1%
$125 to $150	$0.15	0.8%	$0.04	0.1%
>= $150	$1.01	2.8%	$0.01	0.0%

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

	2014		2015	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $25	$1.60	76.0%	$1.32	89.9%
$25 to $50	$0.06	12.5%	$0.15	9.2%
$50 to $75	$0.20	5.0%	$0.12	0.6%
$75 to $100	$0.19	1.9%	$0.10	0.2%
$100 to $125	$0.10	1.0%	$0.02	0.1%
$125 to $150	$0.16	0.8%	$0.04	0.1%
>= $150	$1.05	2.8%	$0.01	0.0%

Day-Ahead Markup

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

The markup component of the PJM day-ahead, load-weighted average LMP by primary fuel and unit type is shown in Table 3-55. INC, DEC and up to congestion transactions have zero markups. Up to congestion transactions were 76.1 percent of marginal resources, INCs were 2.3 percent of marginal resources, and DECs were 3.3 percent of marginal resources in 2015. The share of marginal up to congestion transactions decreased significantly beginning on September 8, 2014, as a result of the FERC's UTC uplift refund notice which became effective on September 8, 2014.[67] The adjusted markup of coal units is calculated as the difference between the price offer, and the cost offer excluding the 10 percent adder. Table 3-55 shows the markup component of LMP for marginal generating resources. Generating resources were only 9.6 percent of marginal resources in 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 $0.97 in 2014 to $0.19 in 2015 using adjusted offers. The markup component of LMP for gas-fired CCs increased from -$0.13 in 2014 to $0.75 in 2015 using adjusted offers.

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

		2014		2015	
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	($0.29)	$0.97	($0.32)	$0.19
Gas	CC	($0.13)	($0.13)	$0.75	$0.75
Gas	CT	$0.02	$0.02	$0.07	$0.07
Gas	Diesel	$0.00	$0.00	$0.03	$0.03
Gas	Steam	($0.03)	($0.03)	($0.42)	($0.42)
Municipal Waste	Steam	($0.01)	($0.01)	($0.00)	($0.00)
Oil	CC	$0.02	$0.02	$0.03	$0.03
Oil	CT	$0.03	$0.04	$0.02	$0.02
Oil	Diesel	$0.00	$0.00	$0.00	$0.00
Oil	Steam	$0.02	$0.02	$0.07	$0.07
Other	Steam	$0.00	$0.00	($0.00)	($0.00)
Wind	Wind	$0.02	$0.02	$0.05	$0.05
Total		($0.34)	$0.93	$0.28	$0.78

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 2015, when using adjusted cost-offers, $0.78 per MWh of the PJM day-ahead load-weighted average LMP was attributable to markup. In 2015, the peak markup component was highest in February, $4.51 per MWh using adjusted cost offers. Using adjusted cost-offers, the markup component in 2015 decreased in every month except February, May, June and October from 2014. Using adjusted cost-offers, the markup component decreased from $1.79 to -$0.29 in January.

67 See 18 CFR § 385.213 (2014).

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

	2014			2015		
	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)	($1.98)	($1.27)	($2.66)
Feb	$0.34	$2.07	($1.47)	$1.39	$3.35	($0.62)
Mar	$0.14	($0.27)	$0.53	($0.43)	$0.49	($1.38)
Apr	($0.88)	$0.42	($2.37)	($0.79)	($0.06)	($1.63)
May	($0.99)	$0.07	($2.10)	$0.75	$0.70	$0.80
Jun	$0.03	$1.29	($1.45)	$1.66	$2.32	$0.85
Jul	($0.98)	($0.38)	($1.68)	($0.34)	$0.60	($1.53)
Aug	($0.70)	$0.07	($1.51)	$0.08	$0.90	($0.79)
Sep	($0.37)	$0.79	($1.64)	$0.94	$1.38	$0.44
Oct	($0.48)	$0.52	($1.69)	$2.68	$4.42	$0.77
Nov	($0.47)	$0.86	($1.61)	($0.30)	($0.05)	($0.54)
Dec	($1.02)	($0.36)	($1.72)	$0.07	($0.04)	$0.18
Annual	($0.34)	$0.68	($1.42)	$0.28	$1.07	($0.56)

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

	2014			2015		
	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
Jan	$1.79	$3.41	$0.09	($0.29)	$0.21	($0.76)
Feb	$1.42	$2.84	($0.07)	$2.81	$4.51	$1.06
Mar	$1.31	$0.61	$1.98	$1.01	$1.79	$0.21
Apr	$0.51	$1.34	($0.45)	$0.50	$1.03	($0.11)
May	$0.23	$0.85	($0.41)	$0.75	$0.70	$0.80
Jun	$1.37	$2.30	$0.29	$1.66	$2.32	$0.85
Jul	$0.52	$0.92	$0.05	($0.34)	$0.60	($1.53)
Aug	$0.64	$1.23	$0.01	$0.08	$0.90	($0.79)
Sep	$1.04	$1.94	$0.05	$0.94	$1.38	$0.44
Oct	$0.89	$1.62	($0.01)	$2.68	$4.42	$0.77
Nov	$0.80	$1.75	($0.00)	($0.30)	($0.05)	($0.54)
Dec	$0.41	$0.92	($0.13)	$0.07	($0.04)	$0.18
Annual	$0.93	$1.67	$0.14	$0.78	$1.49	$0.03

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 2014 to 2015. The smallest zonal all hours average markup component using adjusted offers for 2015 was in the Met-Ed Zone, $0.47 per MWh, while the highest was in the AECO Control Zone, $1.15 per MWh. The smallest zonal on peak average markup was in the BGE Control Zone, $0.85 per MWh, while the highest was in the AECO Control Zone, $2.50 per MWh.

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

	2014			2015		
	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
AECO	($0.11)	$0.96	($1.27)	$0.75	$2.18	($0.81)
AEP	($0.40)	$0.64	($1.48)	$0.25	$1.08	($0.62)
AP	($0.40)	$0.68	($1.53)	$0.19	$0.73	($0.39)
ATSI	($0.45)	$0.61	($1.59)	$0.10	$0.87	($0.74)
BGE	($0.30)	$0.77	($1.46)	$0.13	$0.40	($0.17)
ComEd	($0.43)	$0.41	($1.34)	$0.22	$1.12	($0.76)
DAY	($0.43)	$0.59	($1.53)	$0.17	$1.04	($0.78)
DEOK	($0.42)	$0.56	($1.44)	$0.16	$0.94	($0.67)
DLCO	($0.43)	$0.54	($1.48)	($0.02)	$0.66	($0.76)
Dominion	($0.36)	$0.68	($1.46)	$0.34	$0.86	($0.20)
DPL	($0.43)	$0.29	($1.21)	$0.68	$1.95	($0.67)
EKPC	($0.30)	$0.69	($1.28)	$0.29	$1.19	($0.62)
JCPL	($0.16)	$0.87	($1.33)	$0.54	$1.58	($0.66)
Met-Ed	($0.09)	$1.00	($1.28)	$0.04	$0.65	($0.61)
PECO	($0.05)	$1.08	($1.27)	$0.40	$1.43	($0.71)
PENELEC	($0.34)	$0.69	($1.50)	$0.23	$0.91	($0.50)
Pepco	($0.25)	$0.80	($1.45)	$0.56	$1.32	($0.27)
PPL	($0.14)	$0.97	($1.34)	$0.25	$1.11	($0.68)
PSEG	($0.14)	$0.93	($1.33)	$0.56	$1.67	($0.68)
RECO	($0.16)	$0.86	($1.36)	$0.64	$1.63	($0.54)

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

	2014			2015		
	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
AECO	$1.07	$1.87	$0.20	$1.15	$2.50	($0.32)
AEP	$0.90	$1.64	$0.12	$0.80	$1.55	$0.03
AP	$0.87	$1.65	$0.05	$0.73	$1.20	$0.23
ATSI	$0.85	$1.62	$0.03	$0.67	$1.36	($0.09)
BGE	$1.12	$1.91	$0.26	$0.66	$0.85	$0.45
ComEd	$0.86	$1.43	$0.25	$0.75	$1.59	($0.17)
DAY	$0.90	$1.63	$0.11	$0.73	$1.51	($0.12)
DEOK	$0.87	$1.55	$0.16	$0.71	$1.41	($0.03)
DLCO	$0.81	$1.44	$0.12	$0.52	$1.13	($0.14)
Dominion	$0.94	$1.71	$0.12	$0.84	$1.29	$0.38
DPL	$0.74	$1.21	$0.25	$1.10	$2.26	($0.15)
EKPC	$0.95	$1.64	$0.26	$0.87	$1.66	$0.07
JCPL	$1.04	$1.82	$0.16	$0.94	$1.92	($0.16)
Met-Ed	$1.08	$1.92	$0.17	$0.47	$1.00	($0.10)
PECO	$1.11	$1.97	$0.17	$0.80	$1.76	($0.23)
PENELEC	$0.88	$1.64	$0.01	$0.71	$1.30	$0.09
Pepco	$1.10	$1.90	$0.21	$1.08	$1.77	$0.32
PPL	$1.02	$1.87	$0.09	$0.70	$1.48	($0.15)
PSEG	$1.00	$1.81	$0.09	$0.95	$1.98	($0.21)
RECO	$0.96	$1.74	$0.05	$1.03	$1.95	($0.06)

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): 2014 and 2015

	2014		2015	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $25	($2.75)	9.7%	($0.76)	30.3%
$25 to $50	($1.19)	71.3%	$0.21	59.9%
$50 to $75	$1.33	12.4%	$2.91	5.3%
$75 to $100	($0.49)	2.4%	($2.20)	2.3%
$100 to $125	($6.74)	0.8%	$1.16	1.1%
$125 to $150	$5.79	0.6%	$10.37	0.5%
>= $150	$10.52	2.7%	$12.53	0.7%

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

	2014		2015	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $25	($1.17)	9.7%	($0.57)	30.3%
$25 to $50	$0.57	71.3%	$0.93	59.9%
$50 to $75	$2.35	12.4%	$3.45	5.3%
$75 to $100	($0.03)	2.4%	($1.60)	2.3%
$100 to $125	($6.28)	0.8%	$1.81	1.1%
$125 to $150	$6.23	0.6%	$11.02	0.5%
>= $150	$11.42	2.7%	$12.89	0.7%

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, markup and local price differences caused by congestion. PJM also may administratively set prices with the creation of a closed loop interface related to demand side resources or reactive power.

Real-time and day-ahead energy market load-weighted prices were 31.9 percent and 31.5 percent lower in 2015 than in 2014 as a result of lower fuel costs and lower demand in 2015. Coal and natural gas prices decreased in 2015. Comparing fuel prices in 2015 to 2014, the price of Northern Appalachian coal was 21.3 percent lower; the price of Central Appalachian coal was 22.7 percent lower; the price of Powder River Basin coal was 12.6 percent lower; the price of eastern natural gas was 42.6 percent lower; and the price of western natural gas was 49.5 percent lower.

PJM real-time energy market prices decreased in 2015 compared to 2014. The average LMP was 30.7 percent lower in 2015 than in 2014, $33.39 per MWh versus $48.22 per MWh. The load-weighted average LMP was 31.89 percent lower in 2015 than in 2014, $36.16 per MWh versus $53.14 per MWh.

The fuel-cost adjusted, load-weighted, average LMP in 2015 was 15.9 percent higher than the load-weighted, average LMP for 2015. If fuel costs in 2015 had been the same as in 2014, holding everything else constant, the load-weighted LMP would have been higher, $41.91 per MWh instead of the observed $36.16 per MWh.

PJM day-ahead energy market prices decreased in 2015 compared to 2014. The average LMP was 30.6 percent lower in 2015 than in 2014, $34.12 per MWh versus $49.15 per MWh. The day-ahead load-weighted average LMP was 31.5 percent lower in 2015 than in 2014, $36.73 per MWh versus $53.62 per MWh.[68]

Occasionally, in a constrained market, the LMPs at some pricing nodes can exceed the offer price of the highest cleared generator in the supply stack.[69] In the nodal pricing system, the LMP at a pricing node is the total cost of meeting incremental demand at that node. When there are binding transmission constraints, satisfying the marginal increase in demand at a node may require increasing the output of some generators while simultaneously decreasing the output of other generators, such that the transmission constraints are not violated. The total cost of redispatching multiple generators can at times exceed the cost of marginally increasing the output of the most expensive generator offered. Thus occasionally the LMPs at some pricing nodes exceed $1,000 per MWh, the cap on the generators' offer price in the PJM market.[70]

Real-Time LMP

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

68 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."

69 See O'Neill R. P, Mead D. and Malvadkar P. "On Market Clearing Prices Higher than the Highest Bid and Other Almost Paranormal Phenomena." *The Electricity Journal* 2005; 18(2): pp 19-27.

70 The offer cap in PJM was temporarily increased to $1,800 per MWh prior to the winter of 2014/2015. A new cap of $2,000 per MWh, only for offers with costs exceeding $1,000 per MWh, went into effect on December, 14, 2015, 153 FERC ¶ 61,289 (2015).

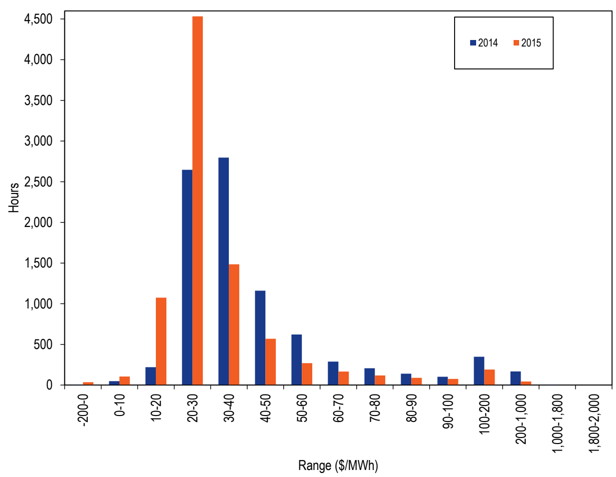
71 See the *MMU Technical Reference for the PJM Markets*, at "Calculating Locational Marginal Price," for detailed definition of Real-Time LMP. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

Real-Time Average LMP

PJM Real-Time Average LMP Duration

Figure 3-33 shows the hourly distribution of PJM real-time average LMP for 2014 and 2015. In 2014, there were five hours in January in which the PJM real-time average LMP was greater than $1,000 and less than $1,800, and one hour in which the real-time LMP was greater than $1,800.

Figure 3-33 Average LMP for the PJM Real-Time Energy Market: 2014 and 2015[72]



PJM Real-Time, Average LMP

Table 3-62 shows the PJM real-time, average LMP for each year of the 18 year period 1998 to 2015.[73]

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

	Real-Time LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$21.72	$16.60	$31.45	NA	NA	NA
1999	$28.32	$17.88	$72.42	30.4%	7.7%	130.3%
2000	$28.14	$19.11	$25.69	(0.6%)	6.9%	(64.5%)
2001	$32.38	$22.98	$45.03	15.1%	20.3%	75.3%
2002	$28.30	$21.08	$22.41	(12.6%)	(8.3%)	(50.2%)
2003	$38.28	$30.79	$24.71	35.2%	46.1%	10.3%
2004	$42.40	$38.30	$21.12	10.8%	24.4%	(14.5%)
2005	$58.08	$47.18	$35.91	37.0%	23.2%	70.0%
2006	$49.27	$41.45	$32.71	(15.2%)	(12.1%)	(8.9%)
2007	$57.58	$49.92	$34.60	16.9%	20.4%	5.8%
2008	$66.40	$55.53	$38.62	15.3%	11.2%	11.6%
2009	$37.08	$32.71	$17.12	(44.1%)	(41.1%)	(55.7%)
2010	$44.83	$36.88	$26.20	20.9%	12.7%	53.1%
2011	$42.84	$35.38	$29.03	(4.4%)	(4.1%)	10.8%
2012	$33.11	$29.53	$20.67	(22.7%)	(16.5%)	(28.8%)
2013	$36.55	$32.25	$20.57	10.4%	9.2%	(0.5%)
2014	$48.22	$34.46	$65.08	31.9%	6.8%	216.4%
2015	$33.39	$26.61	$27.80	(30.7%)	(22.8%)	(57.3%)

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 31.9 percent compared to 2014.

PJM Real-Time, Load-Weighted, Average LMP

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

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

73 The system average LMP is the average of the hourly LMP without any weighting. The only exception is that market-clearing prices (MCPs) are included for January to April 1998. MCP was the single market-clearing price calculated by PJM prior to implementation of LMP.

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

	Real-Time, Load-Weighted, Average LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$24.16	$17.60	$39.29	NA	NA	NA
1999	$34.07	$19.02	$91.49	41.0%	8.1%	132.8%
2000	$30.72	$20.51	$28.38	(9.8%)	7.9%	(69.0%)
2001	$36.65	$25.08	$57.26	19.3%	22.3%	101.8%
2002	$31.60	$23.40	$26.75	(13.8%)	(6.7%)	(53.3%)
2003	$41.23	$34.96	$25.40	30.5%	49.4%	(5.0%)
2004	$44.34	$40.16	$21.25	7.5%	14.9%	(16.3%)
2005	$63.46	$52.93	$38.10	43.1%	31.8%	79.3%
2006	$53.35	$44.40	$37.81	(15.9%)	(16.1%)	(0.7%)
2007	$61.66	$54.66	$36.94	15.6%	23.1%	(2.3%)
2008	$71.13	$59.54	$40.97	15.4%	8.9%	10.9%
2009	$39.05	$34.23	$18.21	(45.1%)	(42.5%)	(55.6%)
2010	$48.35	$39.13	$28.90	23.8%	14.3%	58.7%
2011	$45.94	$36.54	$33.47	(5.0%)	(6.6%)	15.8%
2012	$35.23	$30.43	$23.66	(23.3%)	(16.7%)	(29.3%)
2013	$38.66	$33.25	$23.78	9.7%	9.3%	0.5%
2014	$53.14	$36.20	$76.20	37.4%	8.9%	220.4%
2015	$36.16	$27.66	$31.06	(31.9%)	(23.6%)	(59.2%)

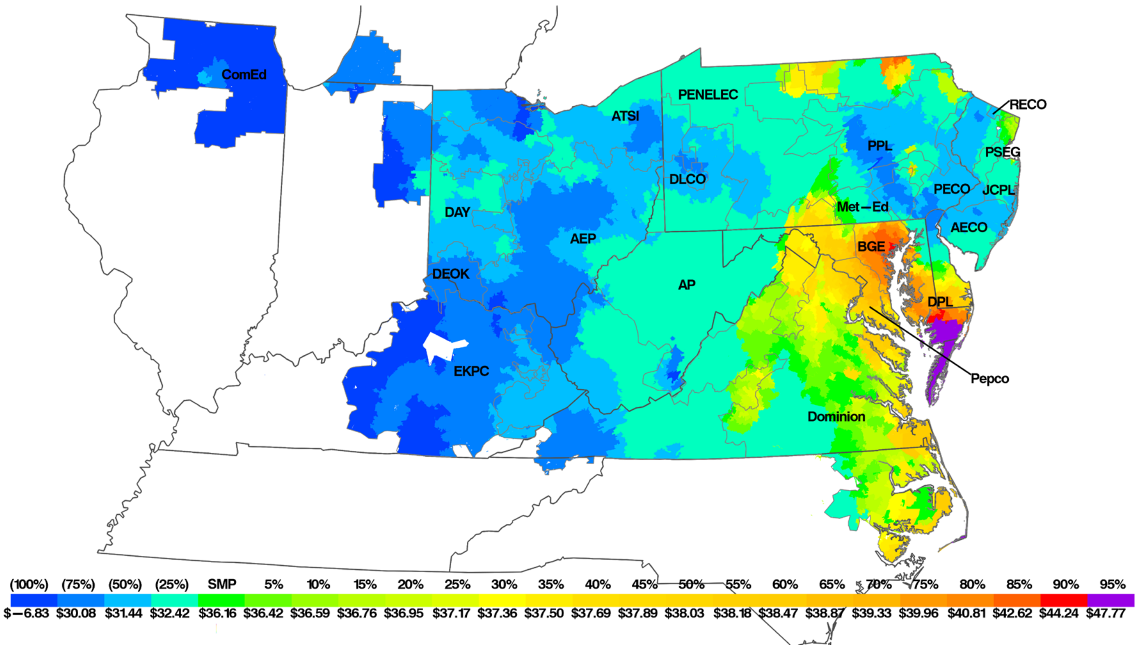
Table 3-64 shows zonal real-time, and real-time, load-weighted, average LMP for 2014 and 2015.

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

	Real-Time Average LMP			Real-Time, Load-Weighted, Average LMP		
Zone	2014 Average	2015 Average	Percent Change	2014 Average	2015 Average	Percent Change
AECO	$51.17	$32.86	(35.8%)	$55.77	$35.85	(35.7%)
AEP	$44.03	$31.76	(27.9%)	$47.81	$33.90	(29.1%)
AP	$47.60	$34.78	(26.9%)	$52.94	$38.04	(28.1%)
ATSI	$45.39	$32.10	(29.3%)	$48.60	$34.00	(30.0%)
BGE	$58.81	$42.84	(27.2%)	$67.78	$47.22	(30.3%)
ComEd	$39.54	$28.21	(28.7%)	$42.04	$29.85	(29.0%)
Day	$43.77	$32.11	(26.6%)	$47.36	$34.20	(27.8%)
DEOK	$41.68	$31.19	(25.2%)	$45.00	$33.28	(26.0%)
DLCO	$41.55	$30.45	(26.7%)	$44.22	$32.21	(27.2%)
Dominion	$54.50	$37.24	(31.7%)	$62.99	$41.42	(34.2%)
DPL	$41.55	$30.45	(26.7%)	$65.03	$42.27	(35.0%)
EKPC	$41.75	$30.10	(27.9%)	$47.88	$32.93	(31.2%)
JCPL	$50.97	$32.36	(36.5%)	$56.07	$35.65	(36.4%)
Met-Ed	$49.60	$32.17	(35.1%)	$56.08	$35.79	(36.2%)
PECO	$50.21	$31.80	(36.7%)	$55.94	$35.11	(37.2%)
PENELEC	$47.63	$33.47	(29.7%)	$51.90	$36.13	(30.4%)
Pepco	$57.34	$39.21	(31.6%)	$65.61	$43.04	(34.4%)
PPL	$49.62	$31.93	(35.6%)	$56.97	$35.95	(36.9%)
PSEG	$53.71	$34.38	(36.0%)	$57.90	$36.97	(36.2%)
RECO	$52.96	$35.02	(33.9%)	$56.79	$37.58	(33.8%)
PJM	$48.22	$33.39	(30.7%)	$53.14	$36.16	(31.9%)

Figure 3-34 is a contour map of the real-time, load-weighted, average LMP in 2015. In the legend, green represents the system marginal price (SMP) and each increment to the right and left of the SMP represents five percent of the pricing nodes above and below the SMP. The LMP for each five percent increment is the highest nodal average LMP for that set of nodes. Each increment to the left of the SMP is the lowest nodal average LMP for that set of nodes.

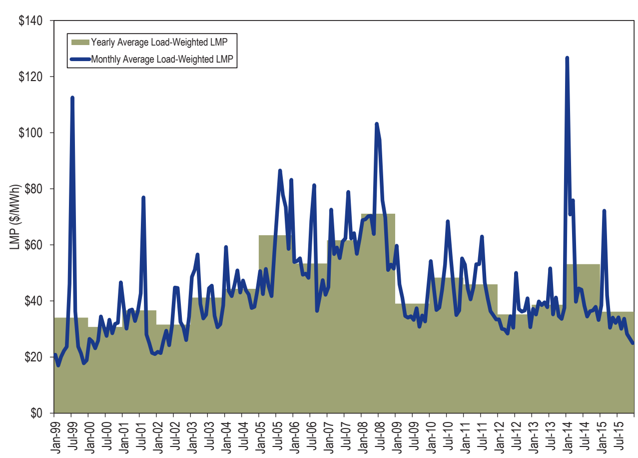
Figure 3-34 PJM real-time, load-weighted, average LMP: 2015



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

Figure 3-35 shows the PJM real-time monthly and annual load-weighted LMP for 1999 through 2015. PJM real-time monthly load-weighted average LMP in December 2015 was $24.95, which is the lowest real-time monthly load-weighted average LMP since May 2002 at $24.19.

Figure 3-35 PJM real-time, monthly and annual, load-weighted, average LMP: 1999 through 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 21.3 percent lower; the price of Central Appalachian coal was 22.7 percent lower; the price of Powder River Basin coal was 12.6 percent lower; the price of eastern natural gas was 42.6 percent lower; and the price of western natural gas was 49.5 percent lower. Figure 3-36 shows monthly average spot fuel prices.[74]

74 Eastern natural gas consists of the average of Texas M3, Transco Zone 6 non-NY, Transco Zone 6 NY and Transco Zone 5 daily fuel price indices. Western natural gas prices are the average of Dominion North Point, Columbia Appalachia and Chicago Citygate daily fuel price indices. Coal prices are the average of daily fuel prices for Central Appalachian coal, Northern Appalachian coal, and Powder River Basin coal. All fuel prices are from Platts.

Figure 3-36 Spot average fuel price comparison with fuel delivery charges: 2012 through 2015 ($/MMBtu)

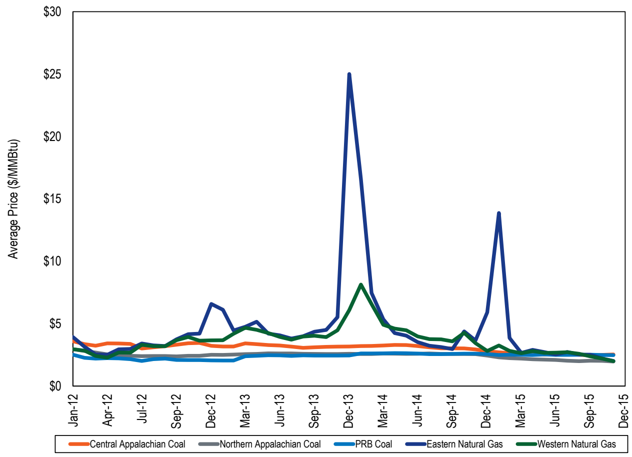


Table 3-65 compares the 2015 PJM real time fuel-cost adjusted, load-weighted, average LMP to the 2015 load-weighted, average LMP. The real time fuel-cost adjusted, load-weighted, average LMP for 2015 was 15.9 percent higher than the real time load-weighted, average LMP for 2015. The real-time, fuel-cost adjusted, load-weighted, average LMP for 2015 was 21.1 percent lower than the real time load-weighted LMP for 2014. If fuel costs in 2015 had been the same as in 2014, holding everything else constant, the real time load-weighted LMP in 2015 would have been higher, $41.91 per MWh instead of the observed $36.16 per MWh.

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

	2015 Load-Weighted LMP	2015 Fuel-Cost-Adjusted, Load-Weighted LMP	Change
Average	$36.16	$41.91	15.9%
	2014 Load-Weighted LMP	2015 Fuel-Cost-Adjusted, Load-Weighted LMP	Change
Average	$53.14	$41.91	(21.1%)
	2014 Load-Weighted LMP	2015 Load-Weighted LMP	Change
Average	$53.14	$36.16	(31.9%)

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 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 2015. Unlike oil and natural gas, there was no substantial change in the price of coal from 2014 to 2015. However, coal units' offer prices were generally lower in 2015 compared to their offers in 2014, particularly the high offer prices during the cold weather days in January and March of 2014.

Table 3-66 Change in PJM real-time annual, fuel-cost adjusted, load-weighted average LMP (Dollars per MWh) by Fuel-type: year over year

Fuel Type	Share of Change in Fuel Cost Adjusted, Load Weighted LMP	Percent
Coal	($1.75)	30.4%
Gas	($3.40)	59.1%
Municipal Waste	($0.00)	0.0%
Oil	($0.58)	10.1%
Other	($0.02)	0.3%
Uranium	$0.00	(0.0%)
Wind	($0.00)	0.0%
Total	($5.75)	100.0%

Components of Real-Time, Load-Weighted LMP

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

Cost offers of marginal units are separated into their component parts. The fuel related component is based on unit specific heat rates and spot fuel prices. Emission costs are calculated using spot prices for NO_x, SO_2 and CO_2 emission credits, emission rates for NO_x, emission rates for SO_2 and emission rates for CO_2. The CO_2 emission costs are applicable to PJM units in the PJM states that participate in RGGI: Delaware and Maryland.[75] The FMU adder is the calculated contribution of the FMU and AU adders to LMP that results when units with FMU or AU adders are marginal.

Since the implementation of scarcity pricing on October 1, 2012, PJM jointly optimizes the commitment and dispatch of energy and ancillary services. In periods of scarcity 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

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

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 will contribute to LMP. In addition, in periods when generators providing energy cannot meet the reserve requirements, PJM can invoke shortage pricing. PJM invoked shortage pricing on January 6 and January 7 of 2014.[76] During the shortage conditions, the LMPs of marginal generators reflect the cost of not meeting the reserve requirements, the scarcity adder, which is defined by the operating reserve demand curve.

LMP may, at times, be set by transmission penalty factors. When a transmission constraint is binding and there are no generation alternatives to resolve the constraint, system operators may allow the transmission limit to be violated. When this occurs, the shadow price of the constraint is set by transmission penalty factors. The shadow price directly affects the LMP. Transmission penalty factors are administratively determined and can be thought of as a form of locational scarcity pricing.

Transmission penalty factors should be stated explicitly and publicly and applied without discretion. Penalty factors should be set high enough so that they do not act to suppress prices based on available generator solutions. But rather than permit the transmission penalty factor to set the shadow price, PJM has been using a procedure called constraint relaxation logic to prevent the penalty factors from setting the shadow price of the constraint. The result is that the transmission penalty factor does not set the shadow price. The details of PJM's logic and practice are not entirely clear. But in 2015, for all transmission constraints for which a penalty factor at or above $2,000 per MWh was used, 41 percent of the constraints' shadow prices were within ten percent of the penalty factor.

The MMU recommends that PJM explicitly state its policy on the use of transmission penalty factors including the level of the penalty factors, the triggers for the use of the penalty factors, the appropriate line ratings to trigger the use of penalty factors, and when the transmission penalty factors will be used to set the shadow price.

The components of LMP are shown in Table 3-67, including markup using unadjusted cost offers.[77] Table 3-67 shows that for 2015, 43.2 percent of the load-weighted LMP was the result of coal costs, 27.2 percent was the result of gas costs and 2.32 percent was the result of the cost of emission allowances. Markup was 0.3 percent of the load-weighted LMP. 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 unexplained 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 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 2015 and 2014.

76 PJM triggered shortage pricing on January 6, 2015, following a RTO-wide voltage reduction action. PJM triggered shortage pricing on January 7, 2014 due to RTO-wide shortage of synchronized reserve.

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

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

	2014		2015		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change Percent
Coal	$17.73	33.4%	$15.62	43.2%	9.8%
Gas	$18.71	35.2%	$9.85	27.2%	(8.0%)
Ten Percent Adder	$3.77	7.1%	$3.02	8.4%	1.3%
VOM	$2.65	5.0%	$2.38	6.6%	1.6%
Oil	$2.80	5.3%	$1.25	3.5%	(1.8%)
Ancillary Service Redispatch Cost	$0.52	1.0%	$1.06	2.9%	2.0%
LPA Rounding Difference	$0.07	0.1%	$0.94	2.6%	2.5%
NA	$1.56	2.9%	$0.89	2.4%	(0.5%)
SO_2 Cost	$0.01	0.0%	$0.35	1.0%	0.9%
NO_x Cost	$0.13	0.2%	$0.29	0.8%	0.6%
Increase Generation Adder	$0.69	1.3%	$0.24	0.7%	(0.6%)
CO_2 Cost	$0.23	0.4%	$0.21	0.6%	0.1%
Other	$0.03	0.1%	$0.15	0.4%	0.4%
Markup	$1.88	3.5%	$0.12	0.3%	(3.2%)
Municipal Waste	$0.02	0.0%	$0.01	0.0%	(0.0%)
Market-to-Market Adder	($0.00)	(0.0%)	$0.01	0.0%	0.0%
FMU Adder	$0.62	1.2%	$0.00	0.0%	(1.2%)
Emergency DR Adder	$1.83	3.4%	$0.00	0.0%	(3.4%)
Scarcity Adder	$0.10	0.2%	$0.00	0.0%	(0.2%)
Constraint Violation Adder	$0.00	0.0%	($0.00)	(0.0%)	(0.0%)
Uranium	($0.01)	(0.0%)	($0.00)	(0.0%)	0.0%
Decrease Generation Adder	($0.17)	(0.3%)	($0.06)	(0.2%)	0.2%
Wind	($0.01)	(0.0%)	($0.07)	(0.2%)	(0.2%)
LPA-SCED Differential	($0.01)	(0.0%)	($0.11)	(0.3%)	(0.3%)
Total	$53.14	100.0%	$36.16	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), load-weighted, average LMP: 2014 and 2015

	2014		2015		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change Percent
Coal	$17.73	33.4%	$15.62	43.2%	9.8%
Gas	$18.71	35.2%	$9.85	27.2%	(8.0%)
VOM	$2.65	5.0%	$2.38	6.6%	1.6%
Markup	$3.32	6.2%	$1.75	4.8%	(1.4%)
Ten Percent Adder	$2.33	4.4%	$1.40	3.9%	(0.5%)
Oil	$2.80	5.3%	$1.25	3.5%	(1.8%)
Ancillary Service Redispatch Cost	$0.52	1.0%	$1.06	2.9%	2.0%
LPA Rounding Difference	$0.07	0.1%	$0.94	2.6%	2.5%
NA	$1.56	2.9%	$0.89	2.4%	(0.5%)
SO_2 Cost	$0.01	0.0%	$0.35	1.0%	0.9%
NO_x Cost	$0.13	0.2%	$0.29	0.8%	0.6%
Increase Generation Adder	$0.69	1.3%	$0.24	0.7%	(0.6%)
CO_2 Cost	$0.23	0.4%	$0.21	0.6%	0.1%
Other	$0.03	0.1%	$0.15	0.4%	0.4%
Municipal Waste	$0.02	0.0%	$0.01	0.0%	(0.0%)
Market-to-Market Adder	($0.00)	(0.0%)	$0.01	0.0%	0.0%
FMU Adder	$0.62	1.2%	$0.00	0.0%	(1.2%)
Emergency DR Adder	$1.83	3.4%	$0.00	0.0%	(3.4%)
Scarcity Adder	$0.10	0.2%	$0.00	0.0%	(0.2%)
Constraint Violation Adder	$0.00	0.0%	($0.00)	(0.0%)	(0.0%)
Uranium	($0.01)	(0.0%)	($0.00)	(0.0%)	0.0%
Decrease Generation Adder	($0.17)	(0.3%)	($0.06)	(0.2%)	0.2%
Wind	($0.01)	(0.0%)	($0.07)	(0.2%)	(0.2%)
LPA-SCED Differential	($0.01)	(0.0%)	($0.11)	(0.3%)	(0.3%)
Total	$53.14	100.0%	$36.16	100.0%	0.0%

Day-Ahead LMP

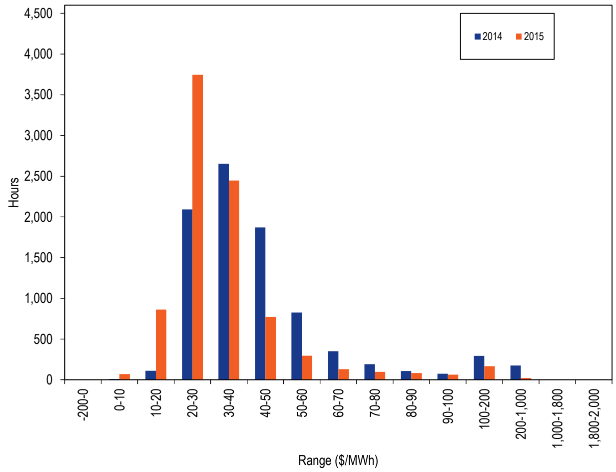
Day-ahead average LMP is the hourly average LMP for the PJM Day-Ahead Energy Market.[78]

Day-Ahead Average LMP

PJM Day-Ahead Average LMP Duration

Figure 3-37 shows the hourly distribution of PJM day-ahead average LMP for 2014 and 2015.

Figure 3-37 Average LMP for the PJM Day-Ahead Energy Market: 2014 and 2015



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

PJM Day-Ahead, Average LMP

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

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

	Day-Ahead LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2001	$32.75	$27.05	$30.42	NA	NA	NA
2002	$28.46	$23.28	$17.68	(13.1%)	(14.0%)	(41.9%)
2003	$38.73	$35.22	$20.84	36.1%	51.3%	17.8%
2004	$41.43	$40.36	$16.60	7.0%	14.6%	(20.4%)
2005	$57.89	$50.08	$30.04	39.7%	24.1%	81.0%
2006	$48.10	$44.21	$23.42	(16.9%)	(11.7%)	(22.0%)
2007	$54.67	$52.34	$23.99	13.7%	18.4%	2.4%
2008	$66.12	$58.93	$30.87	20.9%	12.6%	28.7%
2009	$37.00	$35.16	$13.39	(44.0%)	(40.3%)	(56.6%)
2010	$44.57	$39.97	$18.83	20.5%	13.7%	40.6%
2011	$42.52	$38.13	$20.48	(4.6%)	(4.6%)	8.8%
2012	$32.79	$30.89	$13.27	(22.9%)	(19.0%)	(35.2%)
2013	$37.15	$34.63	$15.46	13.3%	12.1%	16.5%
2014	$49.15	$38.10	$51.88	32.3%	10.0%	235.6%
2015	$34.12	$29.09	$22.59	(30.6%)	(23.7%)	(56.5%)

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 each year of the 15-year period 2001 through 2015.

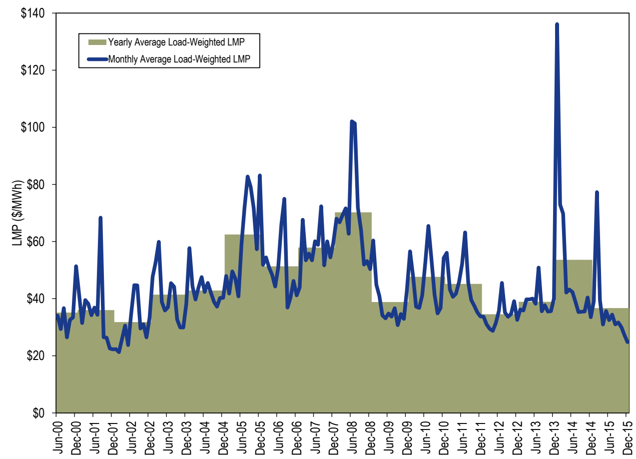
Table 3-70 PJM day-ahead, load-weighted, average LMP (Dollars per MWh): 2001 through 2015

	Day-Ahead, Load-Weighted, Average LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2001	$36.01	$29.02	$37.48	NA	NA	NA
2002	$31.80	$26.00	$20.68	(11.7%)	(10.4%)	(44.8%)
2003	$41.43	$38.29	$21.32	30.3%	47.3%	3.1%
2004	$42.87	$41.96	$16.32	3.5%	9.6%	(23.4%)
2005	$62.50	$54.74	$31.72	45.8%	30.4%	94.3%
2006	$51.33	$46.72	$26.45	(17.9%)	(14.6%)	(16.6%)
2007	$57.88	$55.91	$25.02	12.8%	19.7%	(5.4%)
2008	$70.25	$62.91	$33.14	21.4%	12.5%	32.4%
2009	$38.82	$36.67	$14.03	(44.7%)	(41.7%)	(57.7%)
2010	$47.65	$42.06	$20.59	22.7%	14.7%	46.8%
2011	$45.19	$39.66	$24.05	(5.2%)	(5.7%)	16.8%
2012	$34.55	$31.84	$15.48	(23.5%)	(19.7%)	(35.6%)
2013	$38.93	$35.77	$18.05	12.7%	12.3%	16.6%
2014	$53.62	$39.84	$59.62	37.8%	11.4%	230.4%
2015	$36.73	$30.60	$25.46	(31.5%)	(23.2%)	(57.3%)

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

Figure 3-38 shows the PJM day-ahead, monthly and annual, load-weighted LMP from June 2000 through December 2015.[79] The PJM day-ahead monthly load-weighted average LMP in December 2015 was $24.82, which is the lowest day-ahead monthly load-weighted average since May 2002 at $23.74.

Figure 3-38 Day-ahead, monthly and annual, load-weighted, average LMP: June 2000 through December 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 Energy Market with an offer price that cannot be decomposed. Using identified marginal resource offers and the components of unit offers, it is possible to decompose PJM system LMP using the components of unit offers and sensitivity factors.

Cost offers of marginal units are separated into their component parts. The fuel related component is based

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

on unit specific heat rates and spot fuel prices. Emission costs are calculated using spot prices for NO_X, SO_2 and CO_2 emission credits, emission rates for NO_X, emission rates for SO_2 and emission rates for CO_2. CO_2 emission costs are applicable to PJM units in the PJM states that participate in RGGI: Delaware and Maryland.[80] Day-ahead scheduling reserve (DASR) lost opportunity cost (LOC) and DASR offer adders are the calculated contribution to LMP when redispatch of resources is needed in order to satisfy DASR requirements. The FMU adder is the calculated contribution of the FMU and AU adders to LMP that results when units with FMU or AU adders are marginal.

Table 3-71 shows the components of the PJM day-ahead, annual, load-weighted average LMP. In 2015, 29.6 percent of the load-weighted LMP was the result of coal cost, 14.3 percent of the load-weighted LMP was the result of gas cost, 4.3 percent was the result of the up to congestion transaction cost, 22.5 percent was the result of DEC bid cost and 11.6 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.[81]

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

	2014		2015		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change Percent
Coal	$11.30	21.1%	$10.86	29.6%	8.5%
DEC	$9.20	17.2%	$8.27	22.5%	5.4%
Gas	$10.71	20.0%	$5.25	14.3%	(5.7%)
INC	$8.16	15.2%	$4.27	11.6%	(3.6%)
Ten Percent Cost Adder	$2.45	4.6%	$1.88	5.1%	0.6%
Up to Congestion Transaction	$6.21	11.6%	$1.56	4.3%	(7.3%)
VOM	$1.46	2.7%	$1.40	3.8%	1.1%
Dispatchable Transaction	$2.25	4.2%	$1.05	2.9%	(1.3%)
Oil	$0.78	1.5%	$0.87	2.4%	0.9%
Markup	($0.34)	(0.6%)	$0.28	0.8%	1.4%
DASR LOC Adder	($0.03)	(0.1%)	$0.28	0.7%	0.8%
SO_2	$0.01	0.0%	$0.22	0.6%	0.6%
DASR Offer Adder	$0.05	0.1%	$0.17	0.5%	0.4%
NO_x	$0.08	0.1%	$0.16	0.4%	0.3%
CO_2	$0.15	0.3%	$0.09	0.2%	(0.0%)
Price Sensitive Demand	$0.85	1.6%	$0.04	0.1%	(1.5%)
Municipal Waste	$0.02	0.0%	$0.01	0.0%	(0.0%)
Other	$0.00	0.0%	$0.00	0.0%	0.0%
Constrained Off	$0.00	0.0%	$0.00	0.0%	0.0%
Wind	($0.01)	(0.0%)	($0.04)	(0.1%)	(0.1%)
FMU Adder	$0.33	0.6%	$0.00	0.0%	(0.6%)
NA	($0.01)	(0.0%)	$0.11	0.3%	0.3%
Total	$53.62	100.0%	$36.73	100.0%	0.0%

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.

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

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

	2014		2015		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change Percent
Coal	$11.27	21.0%	$10.86	29.6%	8.5%
DEC	$9.20	17.2%	$8.27	22.5%	5.4%
Gas	$10.71	20.0%	$5.25	14.3%	(5.7%)
INC	$8.16	15.2%	$4.27	11.6%	(3.6%)
Up to Congestion Transaction	$6.21	11.6%	$1.56	4.3%	(7.3%)
VOM	$1.46	2.7%	$1.40	3.8%	1.1%
Ten Percent Cost Adder	$1.21	2.3%	$1.38	3.7%	1.5%
Dispatchable Transaction	$2.25	4.2%	$1.05	2.9%	(1.3%)
Oil	$0.78	1.4%	$0.87	2.4%	0.9%
Markup	$0.93	1.7%	$0.78	2.1%	0.4%
DASR LOC Adder	($0.03)	(0.1%)	$0.28	0.7%	0.8%
SO_2	$0.01	0.0%	$0.22	0.6%	0.6%
DASR Offer Adder	$0.05	0.1%	$0.17	0.5%	0.4%
NO_x	$0.08	0.1%	$0.16	0.4%	0.3%
CO_2	$0.15	0.3%	$0.09	0.2%	(0.0%)
Price Sensitive Demand	$0.85	1.6%	$0.04	0.1%	(1.5%)
Municipal Waste	$0.02	0.0%	$0.01	0.0%	(0.0%)
Other	$0.00	0.0%	$0.00	0.0%	0.0%
Constrained Off	$0.00	0.0%	$0.00	0.0%	0.0%
Wind	($0.01)	(0.0%)	($0.04)	(0.1%)	(0.1%)
FMU Adder	$0.33	0.6%	$0.00	0.0%	(0.6%)
NA	($0.01)	(0.0%)	$0.11	0.3%	0.3%
Total	$53.62	100.0%	$36.73	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, reactions by market participants may 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 regardless of the volume of those transactions. 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.

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 2014 and 2015. In 2015, 51.7 percent of all cleared UTC transactions were net profitable, with 67.4 percent of the source side profitable and 33.8 percent of the sink side profitable.

Table 3-73 Cleared UTC profitability by source and sink point: 2014 and 2015[82]

	Cleared UTCs	Profitable UTCs	UTC Profitable at Source Bus	UTC Profitable at Sink Bus	Profitable UTC	Profitable Source	Profitable Sink
2014	19,876,521	11,029,405	13,427,449	6,713,638	55.5%	67.6%	33.8%
2015	10,052,055	5,198,147	6,771,210	3,394,829	51.7%	67.4%	33.8%

Table 3-74 Day-ahead and real-time average LMP (Dollars per MWh): 2014 and 2015[83]

	2014				2015			
	Day Ahead	Real Time	Difference	Percent of Real Time	Day Ahead	Real Time	Difference	Percent of Real Time
Average	$49.15	$48.22	($0.93)	(1.9%)	$34.12	$33.39	($0.73)	(2.2%)
Median	$38.10	$34.46	($3.64)	(10.6%)	$29.09	$26.61	($2.47)	(9.3%)
Standard deviation	$51.88	$65.08	$13.20	20.3%	$22.59	$27.80	$5.22	18.8%
Peak average	$60.65	$59.12	($1.54)	(2.6%)	$40.97	$39.44	($1.53)	(3.9%)
Peak median	$44.55	$40.50	($4.05)	(10.0%)	$33.69	$29.95	($3.74)	(12.5%)
Peak standard deviation	$64.56	$81.78	$17.22	21.1%	$26.30	$30.23	$3.93	13.0%
Off peak average	$39.12	$38.72	($0.41)	(1.1%)	$28.11	$28.08	($0.03)	(0.1%)
Off peak median	$31.37	$29.39	($1.98)	(6.7%)	$24.51	$23.62	($0.90)	(3.8%)
Off peak standard deviation	$34.48	$43.64	$9.16	21.0%	$16.54	$24.28	$7.74	31.9%

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 3-40).

The analysis of the data from September 1, 2013 through September 31, 2015 period does not support the conclusion that UTCs contribute in any measurable way to price convergence. In addition, the sudden and significant reduction in UTC activity in September of 2014 did not cause a measurable change in price convergence.

Table 3-74 shows that the difference between the average real-time price and the average day-ahead price was -$0.93 per MWh in 2014, and -$0.73 per MWh in 2015. The difference between average peak real-time price and the average peak day-ahead price was -$1.54 per MWh in 2014 and -$1.53 per MWh in 2015.

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 each year of the 15-year period 2001 to 2015.

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

	Day Ahead	Real Time	Difference	Percent of Real Time
2001	$32.75	$32.38	($0.37)	(1.1%)
2002	$28.46	$28.30	($0.16)	(0.6%)
2003	$38.73	$38.28	($0.45)	(1.2%)
2004	$41.43	$42.40	$0.97	2.3%
2005	$57.89	$58.08	$0.18	0.3%
2006	$48.10	$49.27	$1.17	2.4%
2007	$54.67	$57.58	$2.90	5.3%
2008	$66.12	$66.40	$0.28	0.4%
2009	$37.00	$37.08	$0.08	0.2%
2010	$44.57	$44.83	$0.26	0.6%
2011	$42.52	$42.84	$0.32	0.7%
2012	$32.79	$33.11	$0.32	1.0%
2013	$37.15	$36.55	($0.60)	(1.6%)
2014	$49.15	$48.22	($0.93)	(1.9%)
2015	$34.12	$33.39	($0.73)	(2.1%)

82 Calculations exclude PJM administrative charges.
83 The averages used are the annual average of the hourly average PJM prices for day-ahead and real-time.

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

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

	2007		2008		2009		2010		2011	
LMP	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%
($1,000) to ($750)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
($750) to ($500)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
($500) to ($450)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
($450) to ($400)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
($400) to ($350)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
($350) to ($300)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
($300) to ($250)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
($250) to ($200)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
($200) to ($150)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	1	0.01%
($150) to ($100)	0	0.00%	1	0.01%	0	0.00%	0	0.00%	2	0.03%
($100) to ($50)	33	0.38%	88	1.01%	3	0.03%	13	0.15%	49	0.59%
($50) to $0	4,600	52.89%	5,120	59.30%	5,108	58.34%	5,543	63.42%	5,614	64.68%
$0 to $50	3,827	96.58%	3,247	96.27%	3,603	99.47%	3,004	97.72%	2,880	97.56%
$50 to $100	255	99.49%	284	99.50%	41	99.94%	164	99.59%	185	99.67%
$100 to $150	31	99.84%	37	99.92%	5	100.00%	25	99.87%	21	99.91%
$150 to $200	5	99.90%	4	99.97%	0	100.00%	9	99.98%	2	99.93%
$200 to $250	1	99.91%	2	99.99%	0	100.00%	2	100.00%	3	99.97%
$250 to $300	3	99.94%	0	99.99%	0	100.00%	0	100.00%	0	99.97%
$300 to $350	2	99.97%	1	100.00%	0	100.00%	0	100.00%	0	99.97%
$350 to $400	1	99.98%	0	100.00%	0	100.00%	0	100.00%	0	99.97%
$400 to $450	1	99.99%	0	100.00%	0	100.00%	0	100.00%	0	99.97%
$450 to $500	1	100.00%	0	100.00%	0	100.00%	0	100.00%	0	99.97%
$500 to $750	0	100.00%	0	100.00%	0	100.00%	0	100.00%	3	100.00%
$750 to $1,000	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%
$1,000 to $1,250	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%
>= $1,250	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%

Figure 3-39 shows the hourly differences between day-ahead and real-time hourly LMP in of 2015.

Figure 3-39 Real-time hourly LMP minus day-ahead hourly LMP: 2015

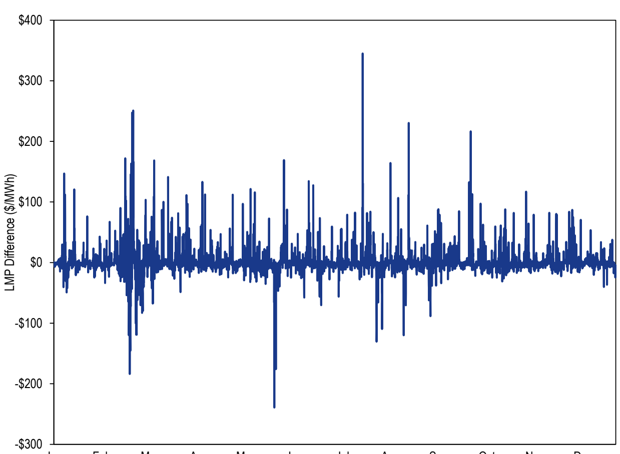


Figure 3-40 shows the monthly average differences between the day-ahead and real-time LMP in 2015.

Figure 3-40 Monthly average of real-time minus day-ahead LMP: January 2014 through December 2015

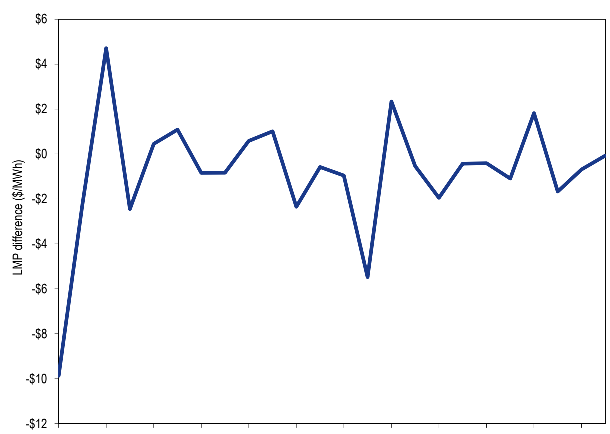
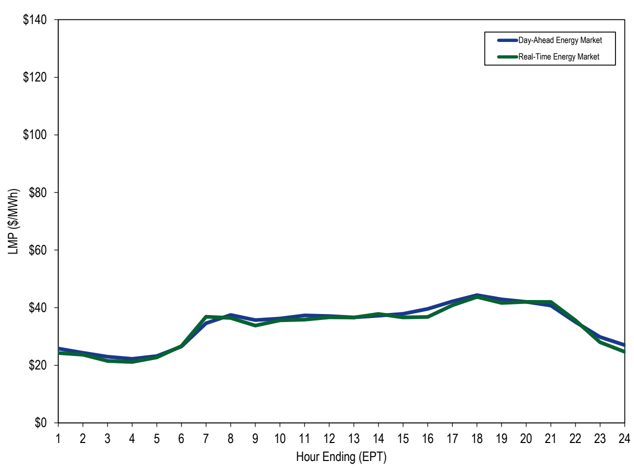


Table 3-76 Frequency distribution by hours of PJM real-time LMP minus day-ahead LMP (Dollars per MWh): 2007 through 2015 *(continued)*

	2012		2013		2014		2015	
LMP	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%
($1,000) to ($750)	0	0.00%	0	0.00%	2	0.02%	0	0.00%
($750) to ($500)	0	0.00%	0	0.00%	3	0.06%	0	0.00%
($500) to ($450)	0	0.00%	0	0.00%	1	0.07%	0	0.00%
($450) to ($400)	0	0.00%	0	0.00%	6	0.14%	0	0.00%
($400) to ($350)	0	0.00%	0	0.00%	5	0.19%	0	0.00%
($350) to ($300)	0	0.00%	0	0.00%	5	0.25%	0	0.00%
($300) to ($250)	0	0.00%	0	0.00%	6	0.32%	0	0.00%
($250) to ($200)	1	0.01%	1	0.01%	14	0.48%	1	0.01%
($200) to ($150)	4	0.06%	3	0.05%	14	0.64%	4	0.06%
($150) to ($100)	6	0.13%	5	0.10%	45	1.15%	17	0.25%
($100) to ($50)	17	0.32%	9	0.21%	91	2.19%	65	0.99%
($50) to $0	5,576	63.80%	5,994	68.63%	5,829	68.73%	6,034	69.87%
$0 to $50	3,061	98.65%	2,659	98.98%	2,525	97.56%	2,467	98.04%
$50 to $100	82	99.58%	64	99.71%	120	98.93%	126	99.47%
$100 to $150	17	99.77%	12	99.85%	39	99.37%	34	99.86%
$150 to $200	12	99.91%	10	99.97%	18	99.58%	7	99.94%
$200 to $250	5	99.97%	1	99.98%	9	99.68%	3	99.98%
$250 to $300	1	99.98%	2	100.00%	8	99.77%	1	99.99%
$300 to $350	2	100.00%	0	100.00%	3	99.81%	1	100.00%
$350 to $400	0	100.00%	0	100.00%	3	99.84%	0	100.00%
$400 to $450	0	100.00%	0	100.00%	2	99.86%	0	100.00%
$450 to $500	0	100.00%	0	100.00%	0	99.86%	0	100.00%
$500 to $750	0	100.00%	0	100.00%	7	99.94%	0	100.00%
$750 to $1,000	0	100.00%	0	100.00%	0	99.94%	0	100.00%
$1,000 to $1,250	0	100.00%	0	100.00%	1	99.95%	0	100.00%
>= $1,250	0	100.00%	0	100.00%	4	100.00%	0	100.00%

Figure 3-41 shows day-ahead and real-time LMP on an average hourly basis for 2015.

Figure 3-41 PJM system hourly average LMP: 2015



Scarcity

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

Table 3-77 Summary of emergency events declared: 2014 and 2015

	Number of days events declared	
Event Type	2014	2015
Cold Weather Alert	25	26
Hot Weather Alert	7	19
Maximum Emergency Generation Alert	6	1
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 2015 compared to 25 days in 2014.[84] The purpose of a cold weather alert is to prepare personnel and facilities for expected extreme cold weather conditions, generally when temperatures are forecast to approach minimums or fall below ten degrees Fahrenheit.

PJM declared hot weather alerts on 19 days in 2015 compared to seven days in 2014.[85] The purpose of a hot weather alert is to prepare personnel and facilities for expected extreme hot and humid weather conditions, generally when temperatures are forecast to exceed 90 degrees Fahrenheit with high humidity.

PJM declared a maximum emergency generation alert on one day in 2015 compared to six days in 2014. The alert was issued for a subzone of the Dominion Zone for local transmission, and was cancelled less than an hour after it was declared. The purpose of a maximum emergency generation alert is to provide an alert at least one day prior to the operating day that system conditions may require use of PJM emergency actions. It is called to alert PJM members that maximum emergency generation may be requested in the operating capacity.[86] This means that if PJM directs members to load maximum emergency generation during the operating day, the resources must be able to increase generation above the maximum economic level of their offer.

PJM did not declare any primary reserve alerts in 2015 compared to two days in 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 2015, compared to two days in 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 2015, compared to one day in 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 warnings and reductions of non-critical plant load in 2015 compared to four days in 2014. The purpose of a voltage reduction warning and reduction of non-critical plant load is to warn members that available synchronized reserves are

84 See PJM. "Manual 13: Emergency Operations," Revision 59 (January 1, 2016), Section 3.3 Cold Weather Alert, p. 46.
85 See PJM. "Manual 13: Emergency Operations," Revision 59 (January 1, 2016), Section 3.4 Hot Weather Alert, p. 50.
86 See PJM. "Manual 13: Emergency Operations," Revision 59 (January 1, 2016), Section 2.3.1 Advance Notice Emergency Procedures: Alerts, p. 17.

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 2015 compared to six days in 2014 in all or parts of the PJM service territory. 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 2015.

PJM declared maximum emergency generation action on one day in 2015 compared to eight days in 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 2015 compared to three days in 2014.

PJM did not declare any voltage reduction actions in the first three months of 2015 compared to one day (January 6) in 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 subzone, 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 21 synchronized reserve events in 2015 compared to 37 in 2014.[87] 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.

87 See *2015 State of the Market Report for PJM*, Section 10: Ancillary Service Markets for details on the spinning events.

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.
Pre-Emergency Load Management Reduction Action	To request load reductions from customers registered in the PJM Demand Response program that need 30, 60, or 120 minute lead time before declaring emergency load management reductions.
Emergency Mandatory Load Management Reduction Action	To request load reductions from customers registered in the PJM Demand Response program that need 30, 60, or 120 minute lead time to provide additional load relief, generally declared simultaneously with NERC Energy Emergency Alert Level 2 (EEA2).
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.
Maximum Emergency Generation Action	To provide real time notice to increase generation above the maximum economic level. It is implemented whenever generation is needed that is greater than the maximum economic level.
Voltage Reduction 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.
Manual Load Dump Warning	To warn members of the critical condition of present operations that may require manually dumping load. Issued when available primary reserve capacity is less than the largest operating generator or the loss of a transmission facility jeopardizes reliable operations after all other possible measures are taken to increase reserve.
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.
Manual Load Dump Action	To provide load relief when all other possible means of supplying internal PJM RTO load have been used to prevent a catastrophe within the PJM RTO or to maintain tie schedules so as not to jeopardize the reliability of the other interconnected regions.

Table 3-79 shows the dates when emergency alerts and warnings were declared and when emergency actions were implemented in 2015.

Table 3-79 PJM declared emergency alerts, warnings and actions, 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
7/20/2015		Mid-Atlantic, Dominion											
7/21/2015		Mid-Atlantic											
7/29/2015		Mid-Atlantic, Dominion	Dominion (Sub-zone)										
7/30/2015		Mid-Atlantic, Dominion											
8/17/2015		Mid-Atlantic											
9/1/2015		Mid-Atlantic											
9/2/2015		Mid-Atlantic											
9/3/2015		Mid-Atlantic											
9/8/2015		Mid-Atlantic											
9/9/2015		Mid-Atlantic											

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.[88] 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 subzone. 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 2015, there were no shortage pricing events triggered in PJM compared to two days in 2014.

NOPR on Shortage Pricing

On September 17, 2015, the Commission issued a Notice of Proposed Rulemaking (NOPR) in which the Commission proposed to address price formation issues in RTOs/ISOs ("price formation NOPR").[89] In particular, the price formation NOPR proposes (i) to require the alignment of settlement and dispatch intervals for energy and operating reserves; and (ii) to require that each RTO/ISO trigger shortage pricing for any dispatch interval during which a shortage of energy or operating reserves occurs. These proposed reforms are intended to ensure that resources have price signals that provide incentives to conform their output to dispatch instructions, and that prices reflect operating needs at each dispatch interval.[90]

Currently in PJM, if the dispatch tools reflect shortage of reserves (primary or synchronized) for a time period shorter than a defined threshold (30 minutes in practice) due to ramp limitations or unit startup delays, it is considered a 'transient shortage,' a shortage event is not declared, and shortage pricing is not implemented. The rationale for having a minimum threshold time for a reserve shortage is to reflect the fact that the level of reserve measurement accuracy does not support a shorter time period. The rationale for including voltage reduction actions and manual load dump actions as triggers for shortage pricing is to reflect the fact that when dispatchers need to take these emergency actions to maintain reliability, the system is short reserves and prices should reflect that condition, even if the data does not show a shortage of reserves.[91]

If PJM were to move to a shortage pricing mechanism that is triggered by transient shortages, there needs to be accurate measurement of real time reserves that can support such a definition. That does not appear to be the case at present in PJM.

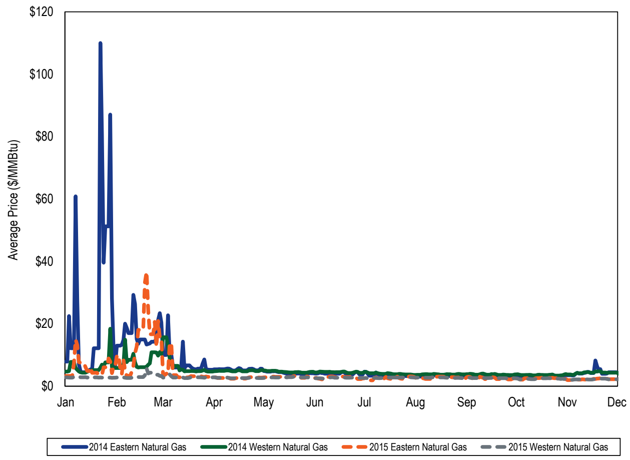
PJM Cold Weather Operations 2015

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 (183,726MW).[92] 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 3-42 shows the average daily price of delivered natural gas for eastern and western parts of PJM service territory in 2014 and 2015.[93]

88 See PJM OATT, 2.2 (d) General, (February 25, 2014), pp. 1815, 1819.
89 152 FERC ¶ 61,218 (September 17, 2015).
90 *Id* at P 5.
91 See, e.g., Scarcity and Shortage Pricing, Offer Mitigation and Offer Caps Workshop, Docket No. AD14-14-000, Transcript 29:21- 30:14 (Oct. 28, 2014)
92 *2015 State of the Market Report for PJM: January through September*, Section 5: Capacity Market, at Installed Capacity.
93 Eastern natural gas consists of the average of Texas Eastern 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 City gate daily fuel price indices.

Figure 3-42 Average daily delivered price for natural gas: 2014 and 2015 ($/MMBtu)



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 restriction notices limiting the availability of non-firm transportation services. 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 or storage service) to deviate from the 24 hour ratable take and which limit the ability of users to have access to unused gas.

Pipeline operators use restrictive and inflexible rules to manage the balance of supply and demand during extreme operating conditions. The independent operations of geographically overlapping pipelines during extreme conditions highlights the potential shortcomings of a gas pipeline network that relies on individual pipelines to manage the balancing of supply and demand. The independent operational restrictions imposed by pipelines and the impact on electric generators during extreme conditions suggests there may be potential benefits to creating an ISO/RTO structure to coordinate the supply of gas across pipelines and with the electric RTOs, or the creation of a gas supply coordination framework under existing electric ISO/RTOs.

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.

In PJM all energy payments to demand response resources are also uplift payments. The energy payments to these resources are not part of the supply and demand balance, they are not paid by LMP revenues and therefore the energy payments to demand response resources have to be paid as out of market uplift. The energy payments to economic DR are funded by real-time load and real-time exports. The energy payments to emergency DR are funded by participants with net energy purchases in the Real-Time Energy Market.

Overview

Energy Uplift Results

- **Energy Uplift Charges.** Total energy uplift charges decreased by $646.3 million, or 67.3 percent, in 2015 compared to 2014, from $960.5 million to $314.2 million.
- **Energy Uplift Charges Categories.** The decrease of $646.3 million in 2015 is comprised of a $12.6 million decrease in day-ahead operating reserve charges, a $587.0 million decrease in balancing operating reserve charges, an $18.8 million decrease in reactive services charges, a $0.1 million decrease in synchronous condensing charges and a $27.7 million decrease in black start services charges.
- **Average Effective Operating Reserve Rates in the Eastern Region.** Day-ahead load paid $0.115 per MWh, real-time load paid $0.050 per MWh, a DEC paid $1.187 per MWh and an INC and any load, generation or interchange transaction deviation paid $1.072 per MWh.
- **Average Effective Operating Reserve Rates in the Western Region.** Day-ahead load paid $0.115 per MWh, real-time load paid $0.042 per MWh, a DEC paid $1.151 per MWh and an INC and any load, generation or interchange transaction deviation paid $1.036 per MWh.
- **Reactive Services Rates.** The DPL, ATSI and Dominion control zones had the three highest local voltage support rates: $0.124, $0.056 and $0.027 per MWh. The reactive transfer interface support rate averaged $0.0019 per MWh.

Characteristics of Credits

- **Types of units.** Combined cycles received 24.0 percent of all day-ahead generator credits and 39.1 percent of all balancing generator credits. Combustion turbines and diesels received 85.6 percent of the lost opportunity cost credits. Coal units received 39.6 percent of all reactive services credits.
- **Concentration of Energy Uplift Credits.** The top 10 units receiving energy uplift credits received 34.2 percent of all credits. The top 10 organizations received 78.0 percent of all credits. Concentration indexes for energy uplift categories classify them as highly concentrated. Day-ahead operating reserves HHI was 5828, balancing operating reserves HHI was 3740, lost opportunity cost HHI was 3788 and reactive services HHI was 9093.
- **Economic and Noneconomic Generation.** In 2015, 88.0 percent of the day-ahead generation eligible for operating reserve credits was economic and 73.2 percent of the real-time generation eligible for operating reserve credits was economic.
- **Day-Ahead Unit Commitment for Reliability.** In 2015, 1.9 percent of the total day-ahead generation MWh was scheduled as must run by PJM, of which 44.0 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.

Geography of Charges and Credits

- In 2015, 88.4 percent of all uplift 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, 3.2 percent by transactions at hubs and aggregates and 8.3 percent by interchange transactions at interfaces.
- Generators in the Eastern Region received 68.2 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.
- Generators in the Western Region received 31.5 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.
- External generators received 0.2 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.

Energy Uplift Issues

- **Lost Opportunity Cost Credits.** In 2015, lost opportunity cost credits decreased by $71.1 million compared to 2014. In 2015, resources in the top three control zones receiving lost opportunity cost credits, AEP, Dominion and ComEd, accounted for 47.1 percent of all lost opportunity cost credits, 41.9 percent of all day-ahead generation from pool-scheduled combustion turbines and diesels, 39.6 percent of all day-ahead generation not committed in real time by PJM from those unit types and 39.0 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 were not economic. These black start units provided black start service under the ALR option, which means that the units had to run in order to provide black start services even if the units were not economic. PJM replaced all ALR units as black start resources as of April 2015. In 2015, the cost of the noneconomic operation of ALR units in the AEP Control Zone was $4.8 million, a decrease of $27.8 million compared to 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 2015, the average rate paid by a DEC in the Eastern Region would have been $0.149 per MWh under the MMU proposal, which is $1.038 per MWh, or 87.4 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 interface constraints to artificially override the nodal prices that are based on fundamental LMP logic in order to: accommodate rather than resolve the inadequacies of the demand side resource capacity product; address the inability of the power flow model to incorporate the need for reactive power; accommodate rather than resolve the flaws in PJM's approach to scarcity pricing; or for any other reason. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM not use price setting logic to artificially override the nodal prices that are based on fundamental LMP logic in order to reduce uplift. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that PJM initiate an analysis of the reasons why some combustion turbines and diesels scheduled in the Day-Ahead Energy Market are not called in real time when they are economic. (Priority: Medium. First Reported 2012. Status: Not adopted.)

- 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 2014.)
- 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. Stakeholder process.)
- 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 2009. 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 seven modifications to the energy lost opportunity cost calculations:
  - The MMU recommends that the lost opportunity cost in the energy market be calculated using the schedule on which the unit was scheduled to run in the energy market. (Priority: High. First reported 2012. Status: Adopted 2015.)
  - 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: Adopted 2015.)
  - 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: Adopted 2015.)
  - The MMU recommends calculating LOC based on 24 hour daily periods or multi-hour segments of hours for 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 units scheduled in the Day-Ahead Energy Market and not committed in real time should be compensated for LOC based on their real-time desired and achievable output, not their scheduled day-ahead output. (Priority: Medium. First reported 2015. Status: Not adopted.)
  - The MMU recommends that units scheduled in the Day-Ahead Energy Market and not committed in real time be compensated for LOC incurred within an hour. (Priority: Medium. First reported 2013. Status: Not adopted.)
  - The MMU recommends that only flexible fast start units (startup plus notification times of 30 minutes or less) and short minimum run times (one hour or less) be eligible by default for the LOC compensation to units scheduled in the Day-Ahead Energy Market and not committed in real time. Other units should be eligible for LOC compensation only if PJM explicitly cancels their day-ahead commitment. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that up to congestion transactions be required to pay energy uplift charges. (Priority: High. First reported 2011. 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. Stakeholder process.)
- 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 solely to real-time RTO load. (Priority: Low. First reported 2013. Status: Not adopted. Stakeholder process.)
- 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 Q2, 2012. 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.

In PJM all energy payments to demand response resources are also uplift payments. The energy payments to these resources are not part of the supply and demand balance, they are not paid by LMP revenues and therefore the energy payments to demand response resources have to be paid as out of market uplift. The energy payments to economic DR are funded by real-time load and real-time exports. The energy payments to emergency DR are funded by participants with net energy purchases in the Real-Time Energy Market.

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.

One part of addressing the level and allocation of uplift payments is to eliminate all day-ahead operating reserve credits. It is illogical and unnecessary to pay units day-ahead operating reserve credits because units do not incur any costs to run and any revenue shortfalls are addressed by balancing operating reserve credits.

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'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. 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. 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.

But it is also important that the reduction of uplift payments not be a goal to be achieved at the expense of the fundamental logic of an LMP system. For example, the use of closed loop interfaces to reduce uplift should be eliminated because it is not consistent with LMP fundamentals and constitutes a form of subjective price setting. The same is true of what PJM terms its price setting logic.

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 Transactions 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	in RTO, Eastern or Western Region
			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	→	Balancing Operating Reserve for Deviations	Deviations	in RTO Region
Real-Time Import Transactions	Balancing Operating Reserve Transaction	→	Balancing Operating Reserve for Deviations	Deviations	in RTO Region
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 $646.3 million or 67.3 percent in 2015 compared to 2014. Table 4-3 shows total energy uplift charges in 2001 through 2015.[2]

Table 4-3 Total energy uplift charges: 2001 through 2015

	Total Energy Uplift Charges (Millions)	Annual Change (Millions)	Annual Percent Change	Energy Uplift as a Percent of Total PJM Billing
2001	$284.0	$67.1	30.9%	8.5%
2002	$273.7	($10.3)	(3.6%)	5.8%
2003	$376.5	$102.8	37.5%	5.4%
2004	$537.6	$161.1	42.8%	6.1%
2005	$712.6	$175.0	32.6%	3.1%
2006	$365.6	($347.0)	(48.7%)	1.7%
2007	$503.3	$137.7	37.7%	1.6%
2008	$474.3	($29.0)	(5.8%)	1.4%
2009	$322.7	($151.5)	(31.9%)	1.2%
2010	$623.2	$300.4	93.1%	1.8%
2011	$603.4	($19.8)	(3.2%)	1.7%
2012	$649.9	$46.5	7.7%	2.2%
2013	$842.8	$192.9	29.7%	2.5%
2014	$960.5	$117.7	14.0%	1.9%
2015	$314.2	($646.3)	(67.3%)	0.9%

Table 4-4 compares energy uplift charges by category for 2014 and 2015. The decrease of $646.3 million in 2015 is comprised of a decrease of $12.6 million in day-ahead operating reserve charges, a decrease of $587.0 million in balancing operating reserve charges, a decrease of $18.8 million in reactive services charges, a decrease of $0.1 million in synchronous condensing charges and a decrease of $27.7 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 energy uplift in 2015 was significantly lower than in 2014.

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

Category	2014 Charges (Millions)	2015 Charges (Millions)	Change (Millions)	Percent Change
Day-Ahead Operating Reserves	$111.3	$98.7	($12.6)	(11.3%)
Balancing Operating Reserves	$786.7	$199.7	($587.0)	(74.6%)
Reactive Services	$29.5	$10.6	($18.8)	(64.0%)
Synchronous Condensing	$0.1	$0.0	($0.1)	(76.1%)
Black Start Services	$32.9	$5.2	($27.7)	(84.3%)
Total	$960.5	$314.2	($646.3)	(67.3%)

The decrease in energy uplift charges in 2015 was primarily a result of decreases from January 2014. Total energy uplift charges decreased by $561.3 million in January 2015, compared to January 2014, while energy uplift charges decreased by $85.0 million in February through December 2015, compared to February through December 2014. Table 4-5 compares monthly energy uplift charges by category for 2014 and 2015.

2 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 January 25, 2016.

Table 4-5 Monthly energy uplift charges: 2014 and 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	$562.4	$3.8	$0.1	$4.0	$606.1	$16.8	$24.5	$1.79	$0.0	$1.7	$44.8
Feb	$9.5	$56.0	$1.0	$0.0	$0.9	$67.4	$31.4	$71.0	$2.4	$0.0	$1.1	$105.9
Mar	$5.7	$59.1	$2.7	$0.0	$2.6	$70.1	$7.0	$24.7	$2.1	$0.0	$1.9	$35.8
Apr	$4.2	$9.7	$5.3	$0.0	$2.8	$22.0	$3.1	$8.5	$1.7	$0.0	$0.1	$13.4
May	$6.4	$21.0	$5.3	$0.0	$1.8	$34.5	$5.7	$15.5	$0.7	$0.0	$0.2	$22.1
Jun	$5.3	$15.8	$4.2	$0.0	$2.1	$27.3	$9.1	$8.9	$0.5	$0.0	$0.0	$18.5
Jul	$6.7	$11.4	$2.9	$0.0	$4.4	$25.4	$5.1	$12.3	$0.1	$0.0	$0.0	$17.5
Aug	$5.8	$9.9	$1.0	$0.0	$4.1	$20.8	$4.5	$9.1	$0.1	$0.0	$0.0	$13.6
Sep	$8.0	$12.5	$1.3	$0.0	$3.9	$25.6	$4.1	$9.0	$0.6	$0.0	$0.0	$13.7
Oct	$9.5	$9.8	$0.8	$0.0	$2.6	$22.8	$3.0	$5.5	$0.4	$0.0	$0.1	$9.0
Nov	$5.6	$10.1	$0.5	$0.0	$1.4	$17.6	$4.3	$6.4	$0.2	$0.0	$0.0	$10.9
Dec	$9.0	$9.0	$0.7	$0.0	$2.2	$20.9	$4.6	$4.3	$0.1	$0.0	$0.0	$8.9
Total	$111.3	$786.7	$29.5	$0.1	$32.9	$960.5	$98.7	$199.7	$10.6	$0.0	$5.2	$314.2
Share	11.6%	81.9%	3.1%	0.0%	3.4%	100.0%	31.4%	63.6%	3.4%	0.0%	1.6%	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 that pay 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.[3,4] Day-ahead operating reserve charges decreased by $12.6 million or 11.3 percent in 2015 compared to 2014. Day-ahead operating reserve charges remain high primarily because of 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 4-6 Day-ahead operating reserve charges: 2014 and 2015

Type	2014 Charges (Millions)	2015 Charges (Millions)	Change (Millions)	2014 Share	2015 Share
Day-Ahead Operating Reserve Charges	$111.3	$98.5	($12.8)	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	$111.3	$98.7	($12.6)	100.0%	100.0%

Table 4-7 shows the composition of the balancing operating reserve charges. Balancing operating reserve charges consist of balancing operating reserve reliability charges (credits to generators), balancing operating reserve deviation charges (credits to generators and import transactions), balancing operating reserve charges for economic load response and balancing local constraint charges. Balancing operating reserve charges decreased by $587.0 million in 2015 compared to 2014. This decrease was a result of lower balancing operating reserve charges in the 2015 winter compared to the 2014 winter. Balancing operating reserve charges decreased by $557.3 million in January, February and March of 2015 compared to January, February and March of 2014.

3 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.

4 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: 2014 and 2015

Type	2014 Charges (Millions)	2015 Charges (Millions)	Change (Millions)	2014 Share	2015 Share
Balancing Operating Reserve Reliability Charges	$447.1	$41.1	($405.9)	56.8%	20.6%
Balancing Operating Reserve Deviation Charges	$337.5	$157.5	($180.0)	42.9%	78.9%
Balancing Operating Reserve Charges for Load Response	$0.2	$0.2	($0.0)	0.0%	0.1%
Balancing Local Constraint Charges	$1.9	$0.9	($1.1)	0.2%	0.4%
Total	$786.7	$199.7	($587.0)	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 2015, 46.1 percent of balancing operating reserve deviation charges were for make whole credits paid to generators and import transactions, a decrease of 7.3 percentage points compared to the share in 2014.

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

Charge Attributable To	2014 Charges (Millions)	2015 Charges (Millions)	Change (Millions)	2014 Share	2015 Share
Make Whole Payments to Generators and Imports	$180.3	$72.6	($107.7)	53.4%	46.1%
Energy Lost Opportunity Cost	$155.8	$84.8	($71.1)	46.2%	53.8%
Canceled Resources	$1.4	$0.2	($1.2)	0.4%	0.1%
Total	$337.5	$157.5	($180.0)	100.0%	100.0%

Table 4-9 shows reactive services, synchronous condensing and black start services charges. Reactive services charges decreased by $18.8 million in 2015 compared to 2014. Black start services charges decreased by $27.7 million in 2015 compared to 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 4-9 Additional energy uplift charges: 2014 and 2015

Type	2014 Charges (Millions)	2015 Charges (Millions)	Change (Millions)	2014 Share	2015 Share
Reactive Services Charges	$29.5	$10.6	($18.8)	47.2%	67.1%
Synchronous Condensing Charges	$0.1	$0.0	($0.1)	0.2%	0.2%
Black Start Services Charges	$32.9	$5.2	($27.7)	52.7%	32.7%
Total	$62.5	$15.8	($46.7)	100.0%	100.0%

Table 4-10 and Table 4-11 show the amount and percent shares of regional balancing charges in 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 2015, regional balancing operating reserve charges decreased by $585.9 million compared to 2014. Balancing operating reserve reliability charges decreased by $405.9 million or 90.8 percent and balancing operating reserve deviation charges decreased by $180.0 million or 53.3 percent.

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

Charge	Allocation	RTO		East		West		Total	
Reliability Charges	Real-Time Load	$429.2	54.7%	$6.7	0.9%	$3.3	0.4%	$439.2	56.0%
	Real-Time Exports	$7.5	1.0%	$0.2	0.0%	$0.1	0.0%	$7.8	1.0%
	Total	$436.7	55.7%	$7.0	0.9%	$3.4	0.4%	$447.1	57.0%
Deviation Charges	Demand	$170.7	21.8%	$12.4	1.6%	$4.8	0.6%	$187.9	23.9%
	Supply	$47.0	6.0%	$3.6	0.5%	$1.0	0.1%	$51.7	6.6%
	Generator	$90.5	11.5%	$5.2	0.7%	$2.3	0.3%	$98.0	12.5%
	Total	$308.3	39.3%	$21.2	2.7%	$8.1	1.0%	$337.5	43.0%
Total Regional Balancing Charges		$745.0	95.0%	$28.2	3.6%	$11.4	1.5%	$784.6	100%

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

Charge	Allocation	RTO		East		West		Total	
Reliability Charges	Real-Time Load	$35.2	17.7%	$4.0	2.0%	$1.1	0.5%	$40.3	20.3%
	Real-Time Exports	$0.7	0.4%	$0.1	0.1%	$0.0	0.0%	$0.9	0.4%
	Total	$35.9	18.1%	$4.2	2.1%	$1.1	0.5%	$41.1	20.7%
Deviation Charges	Demand	$86.8	43.7%	$2.8	1.4%	$1.2	0.6%	$90.8	45.7%
	Supply	$25.6	12.9%	$0.9	0.4%	$0.4	0.2%	$26.9	13.5%
	Generator	$38.3	19.3%	$1.2	0.6%	$0.4	0.2%	$39.9	20.1%
	Total	$150.7	75.9%	$4.8	2.4%	$1.9	1.0%	$157.5	79.3%
Total Regional Balancing Charges		$186.7	94.0%	$9.0	4.5%	$3.0	1.5%	$198.7	100%

Operating Reserve Rates

Under the operating reserves cost allocation rules, PJM calculates nine separate rates, a day-ahead operating reserve rate, a reliability rate for each region, a deviation rate for each region, a lost opportunity cost rate and a canceled resources rate for the entire RTO region. See Table 4-1 for how these charges are allocated.[5]

Figure 4-1 shows the daily day-ahead operating reserve rate for 2014 and 2015. The average rate in 2015 was $0.120 per MWh, $0.014 per MWh lower than the average in 2014. The highest rate in 2015 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 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 2015.

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

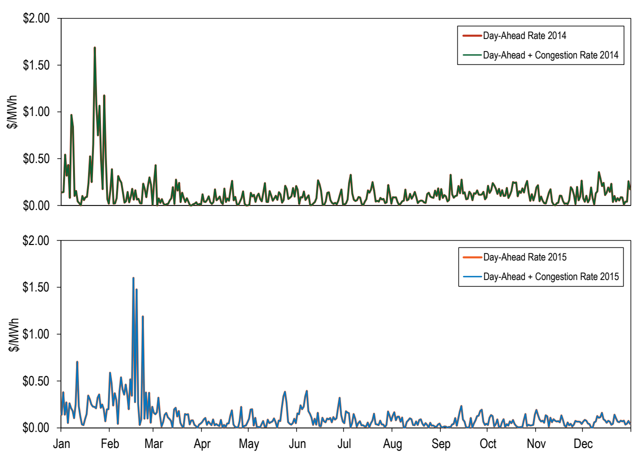


Figure 4-2 shows the RTO and the regional reliability rates for 2014 and 2015. The average daily RTO reliability rate was $0.045 per MWh. The highest RTO reliability rate in 2015 occurred on February 19, when the rate reached $0.772 per MWh, $23.821 per MWh lower than the $24.593 per MWh rate reached in 2014, on January 28.

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

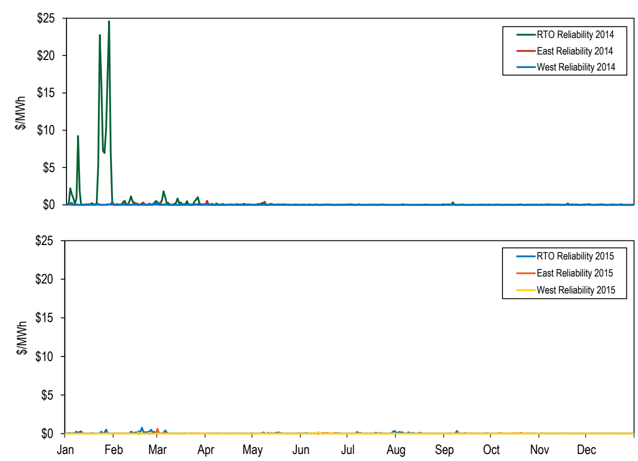


Figure 4-3 shows the RTO and regional deviation rates for 2014 and 2015. The average daily RTO deviation rate was $0.481 per MWh. The highest daily rate in 2015 occurred on February 17, when the RTO deviation rate reached $12.507 per MWh, $7.590 per MWh lower than the $20.097 per MWh rate reached in 2014, on January 25.

5 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 4-3 Daily balancing operating reserve deviation rates ($/MWh): 2014 and 2015

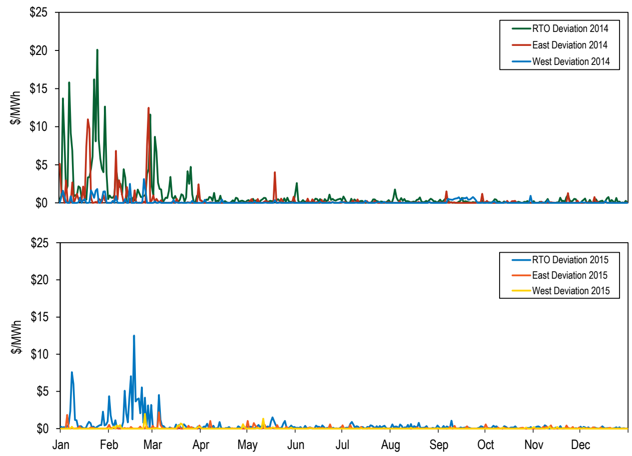


Figure 4-4 shows the daily lost opportunity cost rate and the daily canceled resources rate for 2014 and 2015. The lost opportunity cost rate averaged $0.620 per MWh. The highest lost opportunity cost rate occurred on February 19, when it reached $13.330 per MWh, $19.045 per MWh lower than the $32.375 per MWh rate reached in 2014, January 24.

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

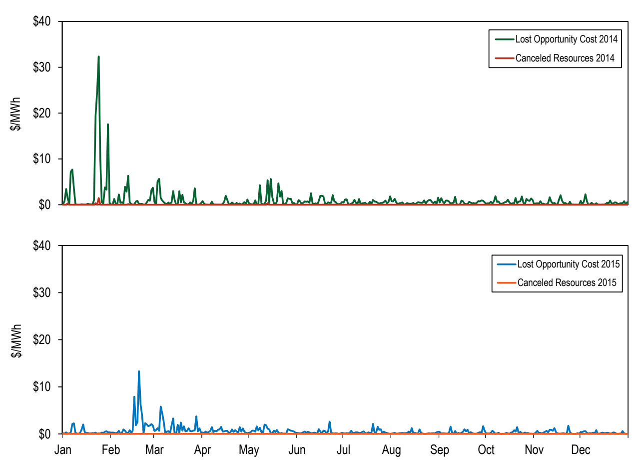


Table 4-12 shows the average rates for each region in each category in 2014 and 2015.

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

Rate	2014 ($/MWh)	2015 ($/MWh)	Difference ($/MWh)	Percent Difference
Day-Ahead	0.134	0.120	(0.014)	(10.7%)
Day-Ahead with Unallocated Congestion	0.134	0.120	(0.014)	(10.7%)
RTO Reliability	0.540	0.045	(0.495)	(91.6%)
East Reliability	0.018	0.011	(0.007)	(40.6%)
West Reliability	0.008	0.003	(0.005)	(66.7%)
RTO Deviation	1.159	0.481	(0.678)	(58.5%)
East Deviation	0.330	0.068	(0.262)	(79.3%)
West Deviation	0.125	0.030	(0.095)	(76.0%)
Lost Opportunity Cost	1.196	0.620	(0.576)	(48.2%)
Canceled Resources	0.011	0.001	(0.009)	(86.4%)

Table 4-13 shows the operating reserve cost of a one MW transaction in 2015. For example, a decrement bid in the Eastern Region (if not offset by other transactions) paid an average rate of $1.187 per MWh with a maximum rate of $17.552 per MWh, a minimum rate of $0.039 per MWh and a standard deviation of $1.941 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): 2015

		Rates Charged ($/MWh)			
Region	Transaction	Maximum	Average	Minimum	Standard Deviation
	INC	17.264	1.072	0.006	1.878
	DEC	17.522	1.187	0.039	1.941
East	DA Load	1.600	0.115	0.000	0.160
	RT Load	0.773	0.050	0.000	0.093
	Deviation	17.264	1.072	0.006	1.878
	INC	17.264	1.036	0.006	1.854
	DEC	17.522	1.151	0.039	1.919
West	DA Load	1.600	0.115	0.000	0.160
	RT Load	0.772	0.042	0.000	0.086
	Deviation	17.264	1.036	0.006	1.854

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. These charges result from uplift payments to units committed by PJM to support reactive/voltage requirements that do not recover their energy offer through LMP payments. These charges are separate from the reactive service revenue requirement charges which are a fixed annual charge based on approved FERC filings. Reactive services charges associated with supporting reactive transfer interfaces above 345 kV are allocated to real-time load across the entire RTO. These charges are allocated daily based on the real-time load ratio share of each network customer.

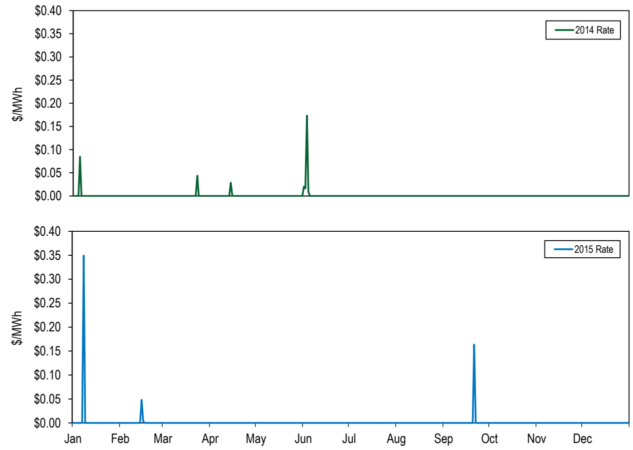
While reactive services rates are not posted by PJM, a local voltage support rate for each control zone can be calculated and a reactive transfer interface support rate can be calculated for the entire RTO. Table 4-14 shows the reactive services rates associated with local voltage support in 2014 and 2015. Table 4-14 shows that in 2015 the DPL Control Zone had the highest rate. Real-time load in the DPL Control Zone paid an average of $0.124 per MWh for reactive services associated with local voltage support, $0.273 or 68.8 percent lower than the average rate paid in 2014.

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

Control Zone	2014 ($/MWh)	2015 ($/MWh)	Difference ($/MWh)	Percent Difference
AECO	0.009	0.000	(0.009)	(99.8%)
AEP	0.006	0.002	(0.004)	(71.3%)
AP	0.005	0.000	(0.005)	(98.8%)
ATSI	0.177	0.056	(0.121)	(68.3%)
BGE	0.001	0.000	(0.001)	(100.0%)
ComEd	0.000	0.000	(0.000)	(79.6%)
DAY	0.001	0.000	(0.001)	(87.8%)
DEOK	0.000	0.000	0.000	NA
DLCO	0.000	0.000	0.000	0.0%
Dominion	0.044	0.027	(0.017)	(39.3%)
DPL	0.397	0.124	(0.273)	(68.8%)
EKPC	0.000	0.000	0.000	0.0%
JCPL	0.001	0.000	(0.001)	(100.0%)
Met-Ed	0.002	0.002	0.000	12.6%
PECO	0.008	0.000	(0.008)	(100.0%)
PENELEC	0.185	0.016	(0.169)	(91.1%)
Pepco	0.001	0.000	(0.000)	(50.9%)
PPL	0.000	0.000	(0.000)	(21.9%)
PSEG	0.008	0.000	(0.008)	(100.0%)
RECO	0.000	0.000	0.000	0.0%

Figure 4-5 shows the daily RTO wide reactive transfer interface rate in 2014 and 2015. The average rate in 2015 was $0.0019 per MWh, 82.8 percent higher than the $0.0010 per MWh average rate in 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 2014 and 2015. Total real-time load and real-time exports were 14,857,282 MWh or 1.8 percent lower in 2015 compared to 2014. Total deviations summed across the demand, supply, and generator categories were 6,449,476 MWh or 5.0 percent higher in 2015 compared to 2014.

Table 4-15 Balancing operating reserve determinants (MWh): 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
2014	RTO	780,507,569	28,586,455	809,094,024	78,151,362	19,990,949	32,114,416	130,256,727
	East	366,534,760	10,893,403	377,428,163	37,923,259	11,159,910	15,122,684	64,205,854
	West	413,972,809	17,693,052	431,665,861	39,345,660	8,426,967	16,991,733	64,764,359
2015	RTO	776,092,885	18,143,858	794,236,742	81,604,825	23,096,560	32,004,819	136,706,204
	East	368,942,881	9,859,610	378,802,491	41,839,924	12,258,045	16,557,937	70,655,907
	West	407,150,004	8,284,248	415,434,252	38,974,508	10,521,360	15,446,881	64,942,749
Difference	RTO	(4,414,684)	(10,442,597)	(14,857,282)	3,453,463	3,105,611	(109,598)	6,449,476
	East	2,408,121	(1,033,793)	1,374,328	3,916,665	1,098,135	1,435,253	6,450,053
	West	(6,822,805)	(9,408,804)	(16,231,609)	(371,152)	2,094,394	(1,544,851)	178,390

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 2015, 24.3 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 75.7 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: 2015

Deviation Category	Transaction	Deviation (MWh) RTO	East	West	Share RTO	East	West
Demand	Bilateral Sales Only	367,885	347,416	20,469	0.3%	0.5%	0.0%
	DECs Only	11,024,474	5,698,789	4,535,292	8.1%	8.1%	7.0%
	Exports Only	4,178,051	2,164,522	2,013,528	3.1%	3.1%	3.1%
	Load Only	56,539,555	27,432,416	29,107,139	41.4%	38.8%	44.8%
	Combination with DECs	6,590,376	4,895,331	1,695,046	4.8%	6.9%	2.6%
	Combination without DECs	2,904,484	1,301,451	1,603,033	2.1%	1.8%	2.5%
Supply	Bilateral Purchases Only	143,923	122,543	21,380	0.1%	0.2%	0.0%
	Imports Only	7,170,390	3,898,355	3,272,035	5.2%	5.5%	5.0%
	INCs Only	12,127,901	6,093,629	5,717,118	8.9%	8.6%	8.8%
	Combination with INCs	3,533,255	2,038,398	1,494,857	2.6%	2.9%	2.3%
	Combination without INCs	121,091	105,121	15,971	0.1%	0.1%	0.0%
Generators		32,004,819	16,557,937	15,446,881	23.4%	23.4%	23.8%
Total		136,706,204	70,655,907	64,942,749	100.0%	100.0%	100.0%

Energy Uplift Credits

Table 4-17 shows the totals for each credit category in 2014 and 2015. During 2015, 63.5 percent of total energy uplift credits were in the balancing operating reserve category, a decrease of 18.4 percentage points from 81.9 in 2014.

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

Category	Type	2014 Credits (Millions)	2015 Credits (Millions)	Change	Percent Change	2014 Share	2015 Share
Day-Ahead	Generators	$111.3	$98.5	($12.8)	(11.5%)	11.6%	31.4%
	Imports	$0.0	$0.0	$0.0	178.8%	0.0%	0.0%
	Load Response	$0.0	$0.2	$0.2	3,298.2%	0.0%	0.1%
Balancing	Canceled Resources	$1.4	$0.2	($1.2)	(85.8%)	0.1%	0.1%
	Generators	$627.2	$113.6	($513.7)	(81.9%)	65.3%	36.1%
	Imports	$0.1	$0.2	$0.0	39.0%	0.0%	0.1%
	Load Response	$0.0	$0.1	$0.1	258.4%	0.0%	0.0%
	Local Constraints Control	$1.9	$0.9	($1.1)	(55.7%)	0.2%	0.3%
	Lost Opportunity Cost	$155.8	$84.8	($71.1)	(45.6%)	16.2%	27.0%
Reactive Services	Day-Ahead	$24.9	$7.7	($17.2)	(69.1%)	2.6%	2.4%
	Local Constraints Control	$0.0	$0.0	($0.0)	(87.3%)	0.0%	0.0%
	Lost Opportunity Cost	$0.2	$0.1	($0.1)	(52.9%)	0.0%	0.0%
	Reactive Services	$3.4	$2.7	($0.7)	(21.3%)	0.4%	0.9%
	Synchronous Condensing	$0.9	$0.2	($0.7)	(81.7%)	0.1%	0.1%
Synchronous Condensing		$0.1	$0.0	($0.1)	(76.1%)	0.0%	0.0%
Black Start Services	Day-Ahead	$27.4	$4.3	($23.1)	(84.2%)	2.9%	1.4%
	Balancing	$5.2	$0.5	($4.7)	(91.0%)	0.5%	0.1%
	Testing	$0.4	$0.4	$0.0	7.1%	0.0%	0.1%
Total		$960.3	$314.2	($646.1)	(67.3%)	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 2014 and 2015. The decrease in energy uplift in 2015 compared to 2014 was due to lower credits paid to combined cycles, combustion turbines and steam turbines (not fired by coal) in the 2015 winter compared to the 2014 winter. Credits to these units decreased $553.2 million or 71.9 percent mainly because these units' offers were affected by high natural gas prices in January 2014. Credits paid to remaining unit types decreased by $93.2 million.

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

Unit Type	2014 Credits (Millions)	2015 Credits (Millions)	Change	Percent Change	2014 Share	2015 Share
Combined Cycle	$399.2	$72.5	($326.6)	(81.8%)	41.6%	23.1%
Combustion Turbine	$256.1	$114.1	($142.0)	(55.4%)	26.7%	36.4%
Diesel	$3.0	$1.9	($1.1)	(36.8%)	0.3%	0.6%
Hydro	$1.7	$1.1	($0.5)	(32.4%)	0.2%	0.4%
Nuclear	$0.3	$0.4	$0.2	62.7%	0.0%	0.1%
Solar	$0.0	$0.0	($0.0)	(100.0%)	0.0%	0.0%
Steam - Coal	$178.1	$89.8	($88.3)	(49.6%)	18.6%	28.6%
Steam - Other	$113.7	$29.1	($84.6)	(74.4%)	11.8%	9.3%
Wind	$8.1	$4.7	($3.4)	(41.9%)	0.8%	1.5%
Total	$960.2	$313.7	($646.4)	(67.3%)	100.0%	100.0%

Table 4-19 shows the distribution of energy uplift credits by category and by unit type in 2015. Combined cycle units received 24.0 percent of the day-ahead generator credits in 2015, 8.9 percentage points lower than the share received in 2014. Combined cycle units received 39.1 percent of the balancing generator credits in 2015, 17.1 percentage points lower than the share received in 2014. Combustion turbines and diesels received 85.6 percent of the lost opportunity cost credits in 2015, 16.7 percentage points higher than the share received in 2014.

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

Unit Type	Day-Ahead Generator	Balancing Generator	Canceled Resources	Local Constraints Control	Lost Opportunity Cost	Reactive Services	Synchronous Condensing	Black Start Services
Combined Cycle	24.0%	39.1%	0.0%	1.7%	2.7%	19.4%	0.0%	1.7%
Combustion Turbine	3.6%	33.0%	24.5%	7.4%	84.8%	6.7%	100.0%	7.1%
Diesel	0.0%	1.0%	0.0%	10.3%	0.8%	0.3%	0.0%	0.0%
Hydro	0.9%	0.1%	75.5%	0.0%	0.0%	0.0%	0.0%	0.0%
Nuclear	0.0%	0.0%	0.0%	0.0%	0.5%	0.0%	0.0%	0.0%
Steam - Coal	63.3%	11.5%	0.0%	80.6%	5.6%	39.6%	0.0%	91.2%
Steam - Others	8.2%	15.2%	0.0%	0.0%	0.1%	34.0%	0.0%	0.0%
Wind	0.0%	0.1%	0.0%	0.0%	5.4%	0.0%	0.0%	0.0%
Total (Millions)	$98.5	$113.6	$0.2	$0.9	$84.8	$10.6	$0.0	$5.2

Table 4-19 also shows the distribution of reactive service credits and black start services credits by unit type. In 2015, coal units received 39.6 percent of all reactive services credits, 29.6 percentage points lower than the share received in 2014. Coal units received 91.2 percent of all black start services credits in 2015 as a result of the ALR units.

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 almost impossible for competition to affect these payments.

Figure 4-6 shows the concentration of energy uplift credits. The top 10 units received 34.2 percent of total energy uplift credits in 2015, compared to 33.7 percent in 2014. In 2015, 246 units received 90 percent of all energy uplift credits, compared to 226 units in 2014.

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

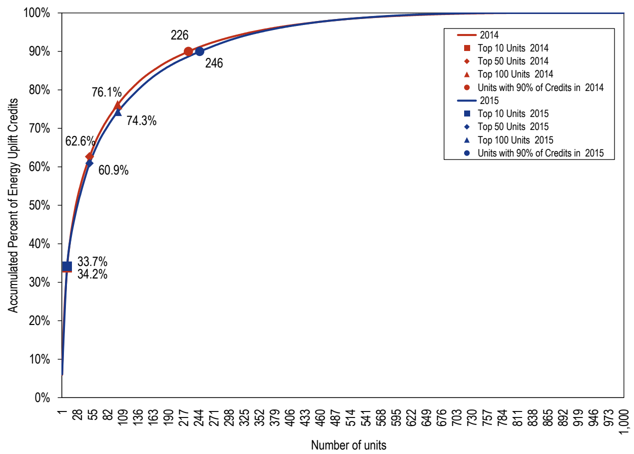


Table 4-20 shows the credits received by the top 10 units and top 10 organizations in each of the energy uplift categories paid to generators.

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

		Top 10 Units		Top 10 Organizations	
Category	Type	Credits (Millions)	Credits Share	Credits (Millions)	Credits Share
Day-Ahead	Generators	$58.8	59.7%	$94.2	95.6%
Balancing	Canceled Resources	$0.2	93.7%	$0.2	100.0%
	Generators	$50.8	44.8%	$91.2	80.3%
	Local Constraints Control	$0.8	88.2%	$0.9	100.0%
	Lost Opportunity Cost	$19.2	22.6%	$64.3	75.8%
Reactive Services		$9.1	85.6%	$10.6	99.9%
Synchronous Condensing		$0.0	94.7%	$0.0	100.0%
Black Start Services		$4.8	93.1%	$5.1	99.5%
Total		$107.2	34.2%	$244.8	78.0%

Table 4-21 shows balancing operating reserve credits received by the top 10 units identified for reliability or for deviations in each region. In 2015, 72.7 percent of all credits paid to these units were allocated to deviations while the remaining 27.3 percent were paid for reliability reasons.

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

	Reliability			Deviations			
	RTO	East	West	RTO	East	West	Total
Credits (Millions)	$13.9	$0.0	$0.0	$36.4	$0.6	$0.0	$50.8
Share	27.3%	0.1%	0.0%	71.5%	1.1%	0.0%	100.0%

In 2015, concentration in all energy uplift credit categories was high.[6,7] 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 5828, for balancing operating reserve credits to generators was 3740, for lost opportunity cost credits was 3788 and for reactive services credits was 9093.

Table 4-22 Daily energy uplift credits HHI: 2015

Category	Type	Average	Minimum	Maximum	Highest Market Share (One day)	Highest Market Share (All days)
Day-Ahead	Generators	5828	1509	10000	100.0%	42.0%
	Imports	10000	10000	10000	100.0%	58.1%
	Load Response	10000	10000	10000	100.0%	99.3%
Balancing	Canceled Resources	9897	5650	10000	100.0%	63.5%
	Generators	3737	913	9979	99.9%	32.1%
	Imports	10000	10000	10000	100.0%	100.0%
	Load Response	9890	7043	10000	100.0%	54.8%
	Lost Opportunity Cost	3786	699	10000	100.0%	15.9%
Reactive Services		9093	2780	10000	100.0%	24.1%
Synchronous Condensing		10000	10000	10000	100.0%	74.7%
Black Start Services		9605	4140	10000	100.0%	89.8%
Total		2569	627	8938	94.5%	21.3%

6 See *2015 State of the Market Report for PJM*, Volume II: Section 3: "Energy Market" at "Market Concentration" for a discussion of concentration ratios and the Herfindahl-Hirschman Index (HHI).
7 Table 4-22 excludes local constraints control categories.

Economic and Noneconomic Generation[8]

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 2015, 35.6 percent of the day-ahead generation was eligible for day-ahead operating reserve credits and 33.8 percent of the real-time generation was eligible for balancing operating reserve credits.[9]

8 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.

9 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 4-23 Day-ahead and real-time generation (GWh): 2015

Energy Market	Total Generation	Generation Eligible for Operating Reserve Credits	Generation Eligible for Operating Reserve Credits Percent
Day-Ahead	803,408	286,030	35.6%
Real-Time	794,089	268,721	33.8%

Table 4-24 shows PJM's economic and noneconomic generation by hour eligible for operating reserve credits. In 2015, 88.0 percent of the day-ahead generation eligible for operating reserve credits was economic and 73.2 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): 2015

Energy Market	Economic Generation	Noneconomic Generation	Economic Generation Percent	Noneconomic Generation Percent
Day-Ahead	251,703	34,327	88.0%	12.0%
Real-Time	196,714	72,007	73.2%	26.8%

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 2015, 5.0 percent of the day-ahead generation eligible for operating reserve credits received credits and 4.8 percent of the real-time generation eligible for operating reserve credits was made whole.

Table 4-25 Day-ahead and real-time generation receiving operating reserve credits (GWh): 2015

Energy Market	Generation Eligible for Operating Reserve Credits	Generation Receiving Operating Reserve Credits	Generation Receiving Operating Reserve Credits Percent
Day-Ahead	286,030	14,169	5.0%
Real-Time	196,714	9,498	4.8%

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 (ALR) 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.[10] 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.[11] 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 2015, 1.9 percent of the total day-ahead generation was scheduled as must run by PJM, 2.1 percentage points lower than 2014.

Table 4-26 Day-ahead generation scheduled as must run by PJM (GWh): 2014 and 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	2,892	4.0%	68,201	1,857	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%	75,490	1,201	1.6%
Aug	73,003	2,778	3.8%	73,934	922	1.2%
Sep	65,066	2,792	4.3%	66,927	616	0.9%
Oct	61,223	2,444	4.0%	58,731	763	1.3%
Nov	64,991	1,859	2.9%	58,517	486	0.8%
Dec	70,853	2,023	2.9%	62,976	551	0.9%
Total	828,682	33,607	4.1%	803,408	15,552	1.9%

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 Day-ahead generation scheduled as must run by PJM by category (GWh): 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	387	1,154	1,857
Apr	4	236	263	634	1,138
May	3	29	459	1,032	1,523
Jun	0	0	670	778	1,447
Jul	0	0	422	779	1,201
Aug	0	1	447	474	922
Sep	0	29	359	227	616
Oct	0	0	417	346	763
Nov	0	0	392	94	486
Dec	0	0	360	192	551
Total	495	605	5,749	8,703	15,552
Share	3.2%	3.9%	37.0%	56.0%	100.0%

Table 4-27 shows the total day-ahead generation scheduled as must run by PJM by category. In 2015, 44.0 percent of the day-ahead generation scheduled as must run by PJM received operating reserve credits, of which, 3.2. percent was generation from units scheduled to provide black start services, 3.9 percent was generation from units scheduled to provide reactive services and 37.0 percent was generation paid normal day-ahead operating reserve credits. The remaining 56.0 percent of the day-ahead generation scheduled as must run by PJM did not need to be made whole.

Total day-ahead operating reserve credits in 2015 were $98.5 million, of which $69.2 million or 70.2 percent was paid to units scheduled as must run by PJM, and not scheduled to provide black start or reactive services.

Geography of Charges and Credits

Table 4-28 shows the geography of charges and credits in 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.

10 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-minutes.ashx>.

11 See PJM. "PJM eMkt Users Guide," Section Managing Unit Data (version July 9, 2015) p. 42, <http://www.pjm.com/~/media/etools/emkt/ts-userguide.ashx>.

Table 4-28 Geography of regional charges and credits: 2015[12]

					Shares			
Location		Charges (Millions)	Credits (Millions)	Balance	Total Charges	Total Credits	Deficit	Surplus
Zones	AECO	$4.2	$3.8	($0.5)	1.4%	1.3%	0.4%	0.0%
	AEP - EKPC	$43.9	$25.7	($18.2)	14.8%	8.6%	15.3%	0.0%
	AP - DLCO	$21.9	$16.0	($5.9)	7.4%	5.4%	5.0%	0.0%
	ATSI	$19.9	$7.6	($12.3)	6.7%	2.5%	10.4%	0.0%
	BGE - Pepco	$23.2	$79.6	$56.4	7.8%	26.8%	0.0%	47.5%
	ComEd - External	$28.8	$17.3	($11.5)	9.7%	5.8%	9.7%	0.0%
	DAY - DEOK	$16.1	$5.1	($11.0)	5.4%	1.7%	9.2%	0.0%
	Dominion	$29.6	$36.9	$7.4	9.9%	12.4%	0.0%	6.2%
	DPL	$7.9	$14.0	$6.1	2.7%	4.7%	0.0%	5.1%
	JCPL	$7.3	$2.3	($5.0)	2.5%	0.8%	4.2%	0.0%
	Met-Ed	$5.5	$1.7	($3.8)	1.9%	0.6%	3.2%	0.0%
	PECO	$13.9	$6.4	($7.5)	4.7%	2.1%	6.3%	0.0%
	PENELEC	$9.1	$11.8	$2.7	3.1%	4.0%	0.0%	2.3%
	PPL	$15.1	$6.8	($8.2)	5.1%	2.3%	6.9%	0.0%
	PSEG	$15.8	$62.1	$46.3	5.3%	20.9%	0.0%	39.0%
	RECO	$0.5	$0.0	($0.5)	0.2%	0.0%	0.4%	0.0%
	All Zones	$262.6	$297.0	$34.4	88.4%	99.9%	71.0%	100.0%
Hubs and Aggregates	AEP - Dayton	$0.6	$0.0	($0.6)	0.2%	0.0%	0.5%	0.0%
	Dominion	$1.0	$0.0	($1.0)	0.3%	0.0%	0.8%	0.0%
	Eastern	$0.4	$0.0	($0.4)	0.1%	0.0%	0.3%	0.0%
	New Jersey	$0.5	$0.0	($0.5)	0.2%	0.0%	0.4%	0.0%
	Ohio	$0.1	$0.0	($0.1)	0.0%	0.0%	0.0%	0.0%
	Western Interface	$0.3	$0.0	($0.3)	0.1%	0.0%	0.2%	0.0%
	Western	$6.7	$0.0	($6.7)	2.3%	0.0%	5.6%	0.0%
	RTEP B0328 Source	$0.0	$0.0	($0.0)	0.0%	0.0%	0.0%	0.0%
	All Hubs and Aggregates	$9.5	$0.0	($9.5)	3.2%	0.0%	8.0%	0.0%
Interfaces	CPLE Imp	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%	0.0%
	Hudson	$0.4	$0.0	($0.4)	0.1%	0.0%	0.3%	0.0%
	IMO	$5.2	$0.0	($5.2)	1.8%	0.0%	4.4%	0.0%
	Linden	$0.5	$0.0	($0.5)	0.2%	0.0%	0.4%	0.0%
	MISO	$3.8	$0.0	($3.8)	1.3%	0.0%	3.2%	0.0%
	Neptune	$0.8	$0.0	($0.8)	0.3%	0.0%	0.7%	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	$5.0	$0.0	($5.0)	1.7%	0.0%	4.2%	0.0%
	OVEC	$1.0	$0.0	($1.0)	0.3%	0.0%	0.9%	0.0%
	South Exp	$2.3	$0.0	($2.3)	0.8%	0.0%	1.9%	0.0%
	South Imp	$5.8	$0.0	($5.8)	1.9%	0.0%	4.8%	0.0%
	All Interfaces	$25.0	$0.2	($24.9)	8.4%	0.1%	21.0%	0.0%
	Total	$297.2	$297.2	$0.0	100.0%	100.0%	100.0%	100.0%

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 1.3 percent of the corresponding credits. The AECO Control Zone received less operating reserve credits than operating reserve charges paid and had 0.4 percent of the deficit. The deficit is the sum of the negative entries in the balance column. Transactions in the PSEG Control Zone paid 5.3 percent of all operating reserve charges allocated regionally, and resources in the PSEG Control Zone were paid 20.9 percent of the corresponding credits. The PSEG Control Zone received more operating reserve credits than operating reserve charges paid and had 39.0 percent of the surplus. The surplus is the sum of the positive entries in the balance column. Table 4-28 also shows that 88.4 percent of all charges were allocated in control zones, 3.2 percent in hubs and aggregates and 8.4 percent in interfaces.

12 Zonal information in each zonal table has been aggregated to ensure that market sensitive data is not revealed. Table 4-28 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 2015, 85.9 percent of all reactive service charges were paid by real-time load in the single zone where the service was provided, 14.0 percent were paid by real-time load in across the entire RTO and 0.2 percent were paid by real-time load in multiple zones. In 2015, the top three zones accounted for 80.9 percent of all the reactive services charges allocated to single zones.

Table 4-29 Geography of reactive services charges: 2015[13]

Location	Charges (Millions)	Share of Charges
Single Zone	$9.1	85.9%
Multiple Zones	$0.0	0.2%
Entire RTO	$1.5	14.0%
Total	$10.6	100.0%

Black start services charges are allocated to zone and non-zone peak transmission use. Resources in one zone accounted for 92.7 percent of all the black start services costs in 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.

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.[14] 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 to as real-time LOC.

In 2015, LOC credits decreased by $71.1 million, 45.6 percent, compared to 2014. The decrease of $71.1 million is comprised of a decrease of $35.4 million in day-ahead LOC and a decrease of $35.7 million in real-time LOC. Table 4-30 shows the monthly composition of LOC credits in 2014 and 2015. In 2015, 18.2 percent of the day-ahead scheduled generation from combustion turbines and diesels was not committed in real time and paid LOC credits, 5.3 percentage points lower than in 2014.

13 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).

14 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 4-30 Monthly lost opportunity cost credits (Millions): 2014 and 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	$44.2	$29.9	$74.1	$4.4	$0.9	$5.2
Feb	$5.9	$5.4	$11.3	$23.0	$3.0	$25.9
Mar	$8.3	$4.1	$12.4	$13.9	$1.5	$15.4
Apr	$1.6	$1.4	$3.0	$5.2	$0.5	$5.7
May	$10.4	$2.5	$12.9	$5.7	$1.8	$7.5
Jun	$7.2	$1.2	$8.4	$4.1	$0.4	$4.5
Jul	$6.2	$0.3	$6.5	$4.5	$0.4	$4.9
Aug	$5.2	$0.1	$5.3	$2.2	$0.4	$2.6
Sep	$5.3	$0.7	$6.0	$3.2	$1.3	$4.5
Oct	$5.5	$1.5	$7.0	$1.8	$0.6	$2.3
Nov	$3.9	$0.7	$4.7	$2.1	$1.6	$3.7
Dec	$4.0	$0.2	$4.2	$2.4	$0.0	$2.5
Total	$107.8	$48.0	$155.8	$72.4	$12.3	$84.8
Share	69.2%	30.8%	100.0%	85.4%	14.6%	100.0%

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 4,106 GWh, 28.1 percent, from 14,628 GWh in the 2014 to 18,734 GWh in 2015, the generation that received LOC credits decreased by 25 GWh or 0.7 percent.

Table 4-31 Day-ahead generation from combustion turbines and diesels (GWh): 2014 and 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	834	346	827	347	244
Feb	763	301	150	1,593	838	499
Mar	976	230	122	1,368	688	505
Apr	438	170	47	1,392	536	408
May	1,206	615	384	1,898	561	369
Jun	1,363	557	356	1,736	445	272
Jul	1,657	532	368	2,651	479	316
Aug	1,791	636	453	1,881	341	208
Sep	1,550	536	396	1,714	291	192
Oct	1,380	571	426	1,375	224	116
Nov	683	284	133	1,258	212	102
Dec	671	340	258	1,041	317	182
Total	14,628	5,605	3,439	18,734	5,279	3,414
Share	100.0%	38.3%	23.5%	100.0%	28.2%	18.2%

In 2015, the top three control zones in which generation received LOC credits, Dominion, AEP and ComEd, accounted for 47.1 percent of all LOC credits, 41.5 percent of all the day-ahead generation from combustion turbines and diesels, 39.6 percent of all day-ahead generation not committed in real time by PJM from those unit types and 38.6 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 2015, $45.0 million or 62.1 percent of all LOC credits were paid to combustion turbines and diesels that did not run for any hour in real time, 6.0 percentage points higher than 2014.

Table 4-32 Lost opportunity cost credits paid to combustion turbines and diesels by scenario (Millions): 2014 and 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	$19.6	$24.5	$44.2	$2.4	$2.0	$4.4
Feb	$3.6	$2.3	$5.9	$15.4	$7.5	$23.0
Mar	$3.6	$4.7	$8.3	$9.1	$4.8	$13.9
Apr	$0.8	$0.8	$1.6	$3.0	$2.2	$5.2
May	$8.2	$2.2	$10.4	$3.1	$2.7	$5.7
Jun	$5.4	$1.8	$7.2	$2.3	$1.8	$4.1
Jul	$3.8	$2.4	$6.2	$2.7	$1.8	$4.5
Aug	$3.7	$1.5	$5.2	$1.3	$0.8	$2.2
Sep	$3.0	$2.2	$5.3	$1.7	$1.5	$3.2
Oct	$3.3	$2.2	$5.5	$1.0	$0.8	$1.8
Nov	$2.9	$1.1	$3.9	$1.2	$0.9	$2.1
Dec	$2.6	$1.4	$4.0	$1.8	$0.6	$2.4
Total	$60.5	$47.3	$107.8	$45.0	$27.4	$72.4
Share	56.2%	43.8%	100.0%	62.1%	37.9%	100.0%

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 2015, 66.4 percent of the scheduled generation not committed by PJM from units receiving LOC credits was economic and the remaining 33.6 percent was noneconomic.

Table 4-33 Day-ahead generation (GWh) from combustion turbines and diesels receiving lost opportunity cost credits by value: 2014 and 2015[15]

	2014			2015		
	Economic Scheduled Generation (GWh)	Noneconomic Scheduled Generation (GWh)	Total (GWh)	Economic Scheduled Generation (GWh)	Noneconomic Scheduled Generation (GWh)	Total (GWh)
Jan	344	356	701	246	102	348
Feb	117	170	288	497	335	832
Mar	116	112	228	543	140	682
Apr	49	130	179	366	168	534
May	333	238	571	281	261	542
Jun	269	234	502	257	144	401
Jul	245	232	477	287	138	425
Aug	268	346	614	165	128	293
Sep	298	225	524	217	74	292
Oct	332	231	563	149	59	208
Nov	82	174	256	121	70	191
Dec	214	116	330	214	75	289
Total	2,667	2,565	5,232	3,343	1,693	5,036
Share	51.0%	49.0%	100.0%	66.4%	33.6%	100.0%

The MMU recommends that PJM initiate an analysis of the reasons why some combustion turbines and diesels scheduled in the Day-Ahead Energy Market are not committed by PJM in real time when they are economic.

15 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.

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 in order to provide black start service 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 2015 decreased by $27.8 million compared to 2014. In 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.[16] 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 $0.51 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 $0.004 per MW of reserved capacity for black start costs related to the noneconomic operation of ALR units.

Closed Loop Interfaces

PJM implemented closed loop interfaces with the stated purpose of improving the incorporation of reactive constraints into energy prices and to allow emergency DR to set price.[17] PJM applies closed loop interfaces so that it can use units needed for reactive support to set the energy price when they would not otherwise set price under the LMP algorithm. PJM also applies closed loop interfaces so that it can use emergency DR resources to set the real-time LMP when DR resources would not otherwise set price under the fundamental LMP logic. Eleven of the 17 (65 percent) closed loop interface definitions were created for the purpose of allowing emergency DR to set price.

Closed loop interfaces are 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 the loop with the rest of PJM. PJM reduces the interface real transfer capability to a level that will artificially make marginal the resource selected by PJM. Table 4-34 shows the closed loop interfaces that PJM has defined.

16 Non-zone peak transmission use is based on interchange transaction MW reservations.

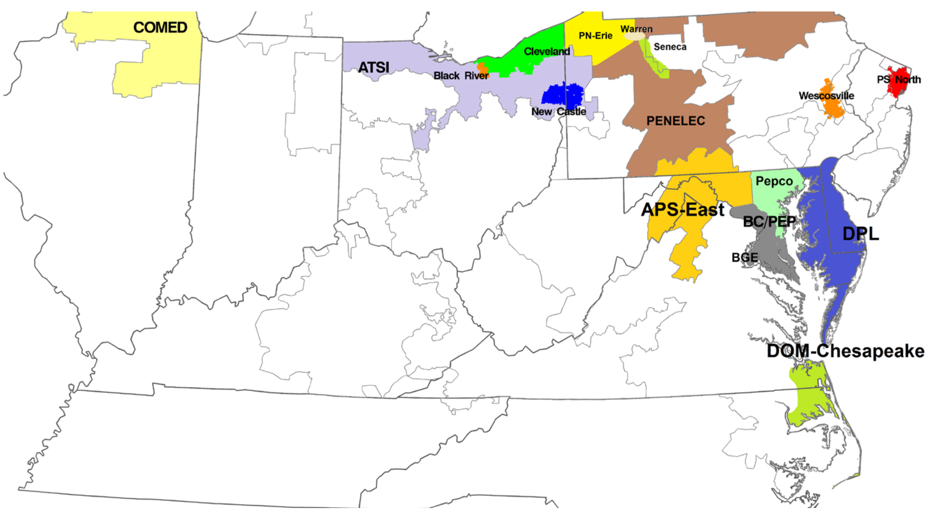
17 See PJM/Alstom. "Approaches to Reduce Energy Uplift and PJM Experiences," presented at the FERC Technical Conference: Increasing Real-Time and Day-Ahead Market Efficiency Through Improved Software in Docket No. AD10-12-006 <http://www.ferc.gov/june-tech-conf/2015/presentations/m2-3.pdf> (June 23, 2015).

Table 4-34 PJM Closed loop interfaces[18,19,20]

Interface	Control Zone(s)	Objective	Effective Date	Limit Calculation
APS-East	AP	Allow emergency DR resources / unit(s) needed for reactive to set real-time LMP	June 19, 2015	Limit equal to actual flow
ATSI	ATSI	Allow emergency DR resources / unit(s) needed for reactive to set real-time LMP	July 17, 2013	Limit equal to actual flow
BC	BGE	Allow emergency DR resources / unit(s) needed for reactive to set real-time LMP	June 19, 2015	Limit equal to actual flow
BC/PEP	BGE and Pepco	Reactive Interface (not an IROL). Used to model import capability into the BGE/ PEPCO/Doubs/Northern Virginia area	NA	PJM Transfer Limit Calculator
Black River	ATSI	Allow emergency DR resources set real-time LMP	September 1, 2014	Limit equal to actual flow
Cleveland	ATSI	Reactive Interface (IROL)	NA	PJM Transfer Limit Calculator
COMED	ComEd	Reactive Interface (IROL)	NA	PJM Transfer Limit Calculator
DOM-Chesapeake	Dominion	Allow emergency DR resources / unit(s) needed for reactive to set real-time LMP	August 14, 2015	Limit equal to actual flow
DPL	DPL	Allow emergency DR resources / unit(s) needed for reactive to set real-time LMP	June 19, 2015	Limit equal to actual flow
New Castle	ATSI	Allow emergency DR resources set real-time LMP	July 1, 2014	Limit equal to actual flow
PENELEC	PENELEC	Allow emergency DR resources / unit(s) needed for reactive to set real-time LMP	April 22, 2015	Limit equal to actual flow
Pepco	Pepco	Allow emergency DR resources / unit(s) needed for reactive to set real-time LMP	June 19, 2015	Limit equal to actual flow
PL-Wescosville	PPL	Allow emergency DR resources / unit(s) needed for reactive to set real-time LMP	July 24, 2014	Limit equal to actual flow
PN-Erie	PENELEC	Allow emergency DR resources set real-time LMP	April 22, 2015	Limit equal to actual flow
PS North	PSEG	Objective not identified. Interface was modeled in 2014/2015 Annual FTR auction	NA	NA
Seneca	PENELEC	Allow unit(s) needed for reactive to set day-ahead and real-time LMP	February 1, 2014	Limit equal to actual flow
Warren	PENELEC	Allow unit(s) needed for reactive to set day-ahead and real-time LMP	September 26, 2014	Limit equal to actual flow

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

Figure 4-7 PJM Closed loop interfaces map



PJM's uses closed loop interfaces to artificially use the strike price of emergency DR to set LMP. This use of closed loop interfaces permits subjective price setting by PJM. PJM has not explained why the economic fundamentals require that DR strike prices set LMP when the resource is not marginal. Although DR should be nodal, DR is not nodal and cannot routinely set price in an LMP model. The MMU has recommended that DR be nodal so that it can set price when appropriate. The current PJM rules permit emergency DR to set a strike price as high as $1,849. There are no incentives for DR to set strike prices at an economically rational level because emergency DR is guaranteed the payment of its strike price whenever called. The MMU has recommended that emergency DR have an offer cap no higher than generation resources, that emergency DR be required to make offers in the Day-Ahead Energy Market like other capacity resources and the emergency DR be paid LMP rather than a guaranteed strike price when called

18 See PJM. "Manual 3: Transmission Operations," Revision 48 (December 1, 2015) at "Section 3.8: Transfer Limits (Reactive/Voltage Transfer Limits)," for a description of reactive interfaces.
19 See closed loop interfaces definitions at <http://www.pjm.com/markets-and-operations/etools/oasis/system-information.aspx>.
20 See the PS North interface definition at <http://www.pjm.com/pub/account/auction-user-info/model-annual/Annual-PJM-interface-definitions-limits.csv>.

on. PJM's use of closed loop interfaces is a result of significant deficiencies in the rules governing DR. PJM's use of closed loop interfaces is also result of significant issues with PJM's scarcity pricing model which is not adequately locational. PJM uses closed loop interfaces and emergency DR strike prices as a substitute for improved scarcity pricing.

In a DC power flow model, such as the one used by PJM for dispatch and pricing, units scheduled for reactive support are only marginal when they are needed to supply energy above their economic minimum. With the use of closed loop interface, these units are forced to be marginal in the model even when not needed for energy, by adjusting the limit of the closed loop interface. This artificially creates 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 forcing these units to be marginal when they are not, raising energy prices and thereby reducing uplift.[21]

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 distortion of the way in which the transmission network is modeled. The use of closed loop interfaces is a distortion of the model.

The MMU recommends that PJM not use closed loop interface constraints to artificially override the nodal prices that are based on fundamental LMP logic in order to: accommodate rather than resolve the inadequacies of the demand side resource capacity product; address the inability of the power flow model to incorporate the need for reactive power; accommodate rather than resolve the flaws in PJM's approach to scarcity pricing; or for any other reason.

Market prices should be a function of market fundamentals and energy market prices should be a function of energy market fundamentals. PJM has not explained why the other consequences of deviating from market fundamentals do not outweigh any benefits of artificially creating constraints in order to let reactive resources set price when they are not in fact marginal. PJM has not explained why the use of closed loop interfaces to permit emergency DR to set price is not simply a crude workaround to a viable solution, consistent with the LMP model, which would be to make DR nodal. The need for closed loop interfaces to let emergency DR set price is primarily a result of the fact that DR is zonal, or subzonal with one day's notice, and therefore cannot be dispatched nodally or set price nodally. The reduction of uplift is a reasonable goal in general, but the reduction of uplift is not a goal that justifies creating distortions in the price setting mechanism.

Price Setting Logic

In November 2014, PJM implemented a software change to its day ahead and real time market solution tools that would enable PJM to reduce energy uplift by artificially selecting the marginal unit for any constraint. The goal is to make marginal any unit committed by PJM to provide reactive services, black start or transmission constraint relief if such unit would otherwise run with an incremental offer greater than the correctly calculated LMP. PJM calls this approach price setting logic.

The application of the price setting logic reduces energy uplift payments by artificially increasing the LMP. The price setting logic is a form of subjective pricing because it varies from fundamental LMP logic based on an administrative decision to reduce energy uplift.

PJM and Alstom presented examples of this approach at the FERC Technical Conference: Increasing Real-Time and Day-Ahead Market Efficiency Through Improved Software.[22] The presentation shows a two bus model connected by one transmission line, three generators (A, B and C) and load at one of the buses. In the solution based on the fundamental LMP logic that PJM has used since the inception of markets, two of the generators are committed (A at 50 MW and B at 50 MW) to serve load (100 MW). The LMP is set at $50 per MWh (the offer of generator A) at both buses. Generator B has to be made whole (paid energy uplift) because the LMP ($50

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

22 See PJM/Alstom. "Approaches to Reduce Energy Uplift and PJM Experiences," presented at the FERC Technical Conference: Increasing Real-Time and Day-Ahead Market Efficiency Through Improved Software in Docket No. AD10-12-006 <http://www.ferc.gov/june-tech-conf/2015/presentations/m2-3.pdf> (June 23, 2015).

per MWh) does not cover the generator's offer ($100 per MWh). Generator B does not set the LMP because its economic minimum is higher than the relief needed to relieve the constraint. This solution is not acceptable for PJM because the most expensive generator would have to be made whole. In order to reduce energy uplift, PJM shows two alternatives. Solution 2: Reduce the economic minimum of generator B to zero MW. Solution 3: Reduce the limit of the transmission line to a level that would make the LMP higher at the bus where the most expensive generator is connected.

In solution 2, generator B is dispatched at 10 MW, despite the fact that this is physically impossible. This allows generator A to increase its output to 80 MW, which makes the transmission constraint binding and causes price separation between the two buses. This is an artificial result, not consistent with actual dispatch, designed to achieve an administrative goal.

In solution 3, the line limit is reduced from 80 MW to 40 MW, despite the fact that this is not the actual limit. As a result, generator A is dispatched to 40 MW (10 MW less than the original solution), the transmission line constraint is binding and congestion occurs. The goal is met and energy uplift is reduced to zero because the LMPs at both buses are increased so that they equal or exceed the generators' offers. Again, this is an artificial result, not consistent with actual dispatch, designed to achieve an administrative goal.

Attempting to reduce uplift at the expense of fundamental LMP logic is not consistent with the objective of clearing the market using a least cost approach. The result of PJM's price setting logic in this example is to increase total production costs.

The MMU recommends that PJM not use price setting logic to artificially override the nodal prices that are based on fundamental LMP logic in order to reduce uplift.

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.[23]

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

Recommendations for Calculation of Credits

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

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

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.[24]

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 until the unit actually operates or does not operate. 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 net revenues in real time.

Units scheduled in the Day-Ahead Energy Market that receive day-ahead operating reserve credits and for which real-time operation results in additional losses, are paid energy uplift in the form of balancing operating reserve or lost opportunity cost credits to ensure that they do not operate at a loss. This determination is not symmetrical because units scheduled in the Day-Ahead Energy Market that receive day-ahead operating reserve credits and for which real-time operation results in reduced losses or not loss do not have a reduction in energy uplift payments.

Units that follow PJM dispatch instructions are made whole through operating reserve credits to ensure that they do not operate at a loss. In order to determine if a unit operated at a loss, it needs to be committed or dispatched. The day-ahead scheduled output is one of PJM's dispatch instructions, but it does not determine if a unit actually operated at a loss. In order to determine if a unit operated at a loss it is necessary to take into account the unit's real-time output and both the day-ahead and balancing energy revenues and ancillary services net revenues.

In order to properly compensate units, the MMU recommended enhancing the day-ahead operating reserve credits calculation 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.[25] These recommendations are superseded by the MMU's recommendation to eliminate day-ahead operating reserve payments.[26] The elimination of day-ahead operating reserve payments also ensures that units are always made whole based on their actual operation and actual revenues.

The MMU calculated the impact of this recommendation in 2014 and 2015. In 2014 and 2015, energy uplift costs associated with units scheduled in the Day-Ahead Energy Market would have had been reduced by $71.6 million or 19.3 percent ($9.2 million paid to units providing reactive support, $6.7 million paid to units providing black start support and $55.7 million paid to units as day-ahead and balancing operating reserves).

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

25 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.

26 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>.

The elimination of the day-ahead operating reserve category would change the allocation of such charges under the current energy uplift rules. If the day-ahead operating reserve category is eliminated but the MMU's uplift allocation recommendations are not implemented, units that clear the Day-Ahead Energy Market will be made whole through balancing operating reserve credits, which under the current rules are allocated to deviations or real-time load plus real-time exports. Therefore, this recommendation should be implemented concurrently with the MMU's allocation recommendations.

Net Regulation Revenues Offset

On October 1, 2008, PJM filed revisions to the Operating Agreement and Tariff with FERC related to the PJM Regulation Market. The filing included four elements: implement the TPS test in the PJM 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 four elements were based on a settlement rather than a rational evaluation of an efficient market design.

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 and inconsistent with the basic PJM uplift logic. Whether a unit is running for PJM at a loss defined by marginal costs cannot be determined if some of the revenues are arbitrarily excluded.

Another issue related to this exclusion is the treatment of pool-scheduled units that elect to self-schedule a portion of their capacity for regulation. A unit can be pool-scheduled for energy, which means PJM may commit or dispatch the unit based on economics, but it can also self-schedule some of its capacity for regulation. When this happens the capacity self-scheduled for regulation is treated as a price-taker, but in the energy market any increase in MW to provide regulation are treated as additional costs, which can result in increased balancing operating reserve credits whenever the real-time LMP is lower than the unit's offer. For example, if a unit raises its economic minimum in order to provide regulation and the additional costs resulting from operating at a higher economic minimum are not covered by the real-time LMP, the unit will be made whole for the additional costs through balancing operating reserve credits.

The MMU recommends reincorporating the use of net regulation revenues as an offset in the calculation of balancing operating reserve credits. In 2014 and 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 $14.2 million, of which $10.3 million or 72.6 percent was due to generators that elected to self-schedule for regulation while noneconomic and receiving balancing operating reserve credits.[27]

Self Scheduled Start

Participants may offer their units as pool-scheduled (economic) or self-scheduled (must run).[28] 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 clear the Day-Ahead Energy Market regardless of their offers and may operate in real time following PJM dispatch instructions. Units offered as self-scheduled follow PJM dispatch instructions when they are offered with a minimum must run output from which the units 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 separately for each hour 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

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

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.

Units offered as self-scheduled for some hours of the day and pool-scheduled for the remaining hours are made whole for startup cost when they should not be. For example, if a unit is offered as self-scheduled for hours 10 through 24 and as pool-scheduled for the balance of the day and PJM selects the unit to start for hour 9, the unit will be made whole for its startup cost if the hourly revenues do not cover the costs. The only hour used in the day-ahead or balancing operating reserve credit calculation is hour 9 because the unit is not eligible for operating reserve credits for hours 10 through 24. The result is that any net revenue from hours 10 through 18 will not be used to offset the unit's startup cost despite the fact that the unit would have started and incurred those costs regardless of PJM dispatch instructions.

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.[29]

- **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 be calculated using the schedule on which the unit was scheduled to run in the energy market.

  This recommendation was adopted on September 1, 2015.[30]

- **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 and overstate LOC credits as a result. 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.

  This recommendation was adopted on September 1, 2015.[31]

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

  The MMU recommends using the entire offer curve and not a single point on the offer curve to calculate energy LOC. This is the only correct way to calculate the lost opportunity cost.

  This recommendation was adopted on September 1, 2015.[32]

- **Segmented Calculation:** Current rules calculate LOC on an hourly basis; each hour is treated as a standalone calculation. This means that units receive an LOC payment during hours in which it is economic for them to run and receive the benefit of not being called on during hours in which it is not

29 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>.

30 152 FERC ¶ 61,165 (2015).

31 *Id.*

32 *Id.*

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 inconsistent with the basic PJM energy uplift logic. If a unit does not run in real time, it loses net revenues if the real-time LMP is greater than the unit's offer but it gains net revenues if the real-time LMP is lower than the unit's offer. The correct lost opportunity costs for units that clear the Day-Ahead Energy Market and are not committed in real time cannot be determined if profitable hours are arbitrarily excluded. In the case of separate hourly calculations, units are overcompensated compared to the net revenues they would have received had they run.

The MMU recommends calculating LOC based on 24 hour daily periods or multi-hour segments of hours for combustion turbines and diesels scheduled in the Day-Ahead Energy Market but not committed in real time.

This recommendation has not been adopted.

These four recommendations 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 forecast 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 2015, for the two categories of lost opportunity cost credits. Energy LOC credits would have been reduced by a net of $21.8 million, or 25.7 percent, if all these changes had been implemented.[33]

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

Table 4-35 Impact on energy market lost opportunity cost credits of rule changes (Millions): 2015

	LOC When Output Reduced in RT	LOC When Scheduled DA Not Called RT	Total
Current Credits	$12.3	$72.3	$84.6
Impact 1: Committed Schedule	$0.4	$5.6	$6.0
Impact 2: Using Offer Curve	($0.3)	$6.9	$6.6
Impact 3: Including No Load Cost	NA	($18.2)	($18.2)
Impact 4: Including Startup Cost	NA	($6.4)	($6.4)
Impact 5: Segmented Calculation	NA	($9.8)	($9.8)
Net Impact	$0.1	($21.9)	($21.8)
Credits After Changes	$12.4	$50.4	$62.9

In addition to these four recommendations, the MMU recommends three additional steps to address issues with the current LOC calculations:

- **Achievable Output:** CTs and diesels are compensated for LOC when scheduled in the Day-Ahead Energy Market and not committed in real time. This LOC calculation uses the day-ahead scheduled output as the achievable output for which units are entitled to receive LOC compensation. Units are paid LOC based on the difference between the real-time energy price (RT LMP) and the unit's offer times the day-ahead scheduled output.

  The actual LOC is a function of the real-time desired and achievable output rather than the day-ahead scheduled output. If a unit is capable of profitably producing more or fewer MWh in real time than the day-ahead scheduled MWh, it is the actual foregone MWh in real time that define actual LOC. Also, if a unit is not capable of producing at the day-ahead scheduled output level in real time it should not be compensated based on an output that cannot be achieved.

  The MMU recommends that units scheduled in the Day-Ahead Energy Market and not committed in real time should be compensated for LOC based on their real-time desired and achievable output, not their scheduled day-ahead output.

- **Intra-Hour Calculations:** CTs and diesels scheduled in the Day-Ahead Energy Market and not committed in real time are compensated for LOC based on their real-time hourly integrated output. In order to compensate a unit for LOC, PJM must determine if the unit was scheduled in the Day-Ahead Energy Market and if the unit was not committed in real time. Units clear the Day-Ahead Energy Market for full hours. That means that if a unit cleared the

Day-Ahead Energy Market in an hour it is expected to produce energy in real time for the entire hour. The determination by PJM of whether a unit is committed or not committed in real time is based on the unit's hourly integrated output. If the hourly integrated output is greater than zero that means the unit was committed during that hour. But in real time a unit may be committed for part of an hour. The calculation of LOC does not reflect the exact time at which the unit was turned on.

The MMU recommends that units scheduled in the Day-Ahead Energy Market and not committed in real time be compensated for LOC incurred within an hour.

- **LOC Unit Type Eligibility:** The current rules compensate only CTs and diesels for LOC when scheduled in the Day-Ahead Energy Market and not committed in real time. The reason for this difference is that other unit types have a commitment obligation when scheduled in the Day-Ahead Energy Market. For example, steam turbines and combined cycle units commitment instructions are their day-ahead schedule. Units of these types that clear the Day-Ahead Energy Market are automatically committed to be on or remain on in real time. These units are eligible for LOC compensation only if PJM explicitly cancels their day-ahead commitment for reliability purposes. CT and diesel commitment instructions occur in real time even if these units were committed in the Day-Ahead Energy Market. CTs and diesels are committed in real time, after PJM dispatch has a more complete knowledge of real-time conditions. The goal is to permit the dispatch of flexible units in real time based on real-time conditions as they evolve. The reason for this special treatment of CTs and diesels is that historically, such units were usually more flexible to commit than other unit types. But that is no longer correct and should not be assumed to be correct.

  The MMU recommends that only flexible fast start units (startup plus notification times of 30 minutes or less) and short minimum run times (one hour or less) be eligible by default for the LOC compensation to units scheduled in the Day-Ahead Energy Market and not committed in real time.

Recommendations for Allocation of Charges

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 recommends that up to congestion transactions be required to pay energy uplift charges.

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.

Up to congestion transactions would have paid an average rate between $0.355 and $0.430 per MWh in 2014 and between $0.294 and $0.299 per MWh in 2015 if the MMU's recommendations regarding energy uplift had been in place.[34,35]

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.[36] Load, interchange transactions, internal bilateral transactions, demand

34 The range of operating reserve rates paid by up to congestion transactions depends on the location of the transactions' source and sink.

35 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 to 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.

36 See PJM. OATT 3.2.3 (o) for a complete description of how generators deviate.

resources, increment offers and decrement bids also incur deviations.

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 For example, a generator with a negative deviation (generation below the desired level) can offset such deviation if a generator at the same bus has a positive deviation (generation above the desired level) if this occurs in the same hour.

Load, interchange transactions, internal bilateral transactions, demand resources, increment offers and decrement bids are also allowed to offset their deviations. These transactions are grouped by demand and supply, and then 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 at the same location at the same hour.[37] Demand transactions such as load, exports, internal bilateral sales and decrement bids may offset. 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 (IBTs) 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.

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

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.[38] 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 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.[39] These units are often run out of merit and receive substantial day-ahead and balancing operating reserve credits.

37 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.

38 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>.

39 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.

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.[40] 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 for the balance through balancing operating reserves. The result is a misallocation of the costs of providing reactive services. Reactive services credits are paid by real-time load in the control zone or zones where the service is provided while balancing operating reserve charges are paid by deviations from day-ahead or real-time load plus exports in the RTO, Eastern or Western Region depending on the allocation process rather than by zone.

In 2015, units providing reactive services were paid $1.1 million in balancing operating reserve credits in order to cover their total energy offer. In 2014, this misallocation was $2.3 million.

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, in addition to real-time load.[41]

Allocation Proposal

The day-ahead operating reserve category elimination and other MMU recommendations require enhancements to the current method of energy uplift allocation.

The current method 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 would shift these costs to the balancing operating reserve category which would 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 related to expected conditions in the real-time market not including reactive or black start services) should be allocated to real-time load, real-time exports and real-time wheels.

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

40 PJM. OATT Attachment K - Appendix § 3.2.3B (f).

41 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>.

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 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

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.

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 $127.6 million or 10.7 percent in 2014 and 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 $55.7 million, the proposed changes to lost opportunity cost calculations would have resulted in a decrease of $57.4 million and the use of net regulation revenues offset would have resulted in a decrease of $14.2 million.[42] Table 4-38 shows that deviations charges would have been reduced by $319.2 million or 64.4 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).

Table 4-38 Current and proposed energy uplift charges by allocation (Millions): 2014 and 2015[43]

Allocation	2014	2015	Total
Current			
Day-Ahead Demand, Day-Ahead Exports and Decrement Bids	$111.3	$98.7	$210.0
Real-Time Load and Real-Time Exports	$447.1	$41.1	$488.2
Deviations	$337.7	$157.7	$495.4
Total	$896.1	$297.5	$1,193.6
Proposal			
Day-Ahead Transactions and Day-Ahead Resources	$47.0	$27.5	$74.5
Real-Time Load and Real-Time Exports	$461.4	$99.7	$561.0
Deviations	$107.0	$69.2	$176.1
Physical Deviations	$203.2	$51.1	$254.4
Total	$818.6	$247.5	$1,066.1
Impact			
Impact ($)	($77.5)	($50.0)	($127.6)
Impact (%)	(8.7%)	(16.8%)	(10.7%)

The MMU calculated the rates that participants would have paid in 2014 and 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 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 8, 2104. The second scenario assumes zero volume of up to congestion transactions in 2014 and 2015. Table 4-39 shows for example

42 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 service charges.
43 These energy uplift charges do not include black start and reactive services charges.

that a decrement bid in the Eastern Region (if not offset by other transactions) would have paid an average rate of $0.215 and $0.149 per MWh in the 2014 and 2015, under the first scenario, $2.189 and $1.038 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 $0.393 and $0.296 per MWh in 2014 and 2015 under the first scenario. Table 4-39 shows the current and proposed averages energy uplift rates for all transactions.

Figure 4-8 shows the net impact of each category on the change in total energy uplift charges from the 2014 level to 2015 level. The outside bars show the total energy uplift charges in 2014 (left side) and total energy uplift charges in 2015 (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 2014 compared to 2015 (a decrease of $12.6 million).

Table 4-39 Current and proposed average energy uplift rate by transaction: 2014 and 2015[44]

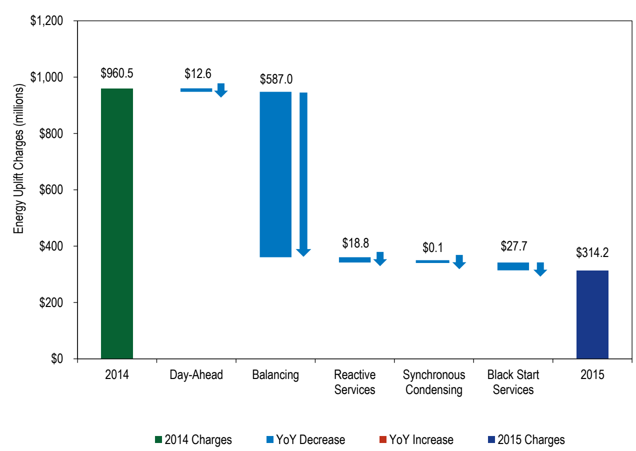
		2014			2015		
	Transaction	Current Rates ($/MWh)	Proposed Rates - 50% UTC ($/MWh)	Proposed Rates - 0% UTC ($/MWh)	Current Rates ($/MWh)	Proposed Rates - 50% UTC ($/MWh)	Proposed Rates - 0% UTC ($/MWh)
East	INC	2.275	0.215	0.681	1.072	0.149	0.383
	DEC	2.404	0.215	0.681	1.187	0.149	0.383
	DA Load	0.129	0.020	0.024	0.115	0.013	0.015
	RT Load	0.450	0.466	0.466	0.050	0.118	0.118
	Deviation	2.275	1.303	1.765	1.072	0.501	0.732
West	INC	2.069	0.177	0.568	1.036	0.147	0.383
	DEC	2.199	0.177	0.568	1.151	0.147	0.383
	DA Load	0.129	0.020	0.024	0.115	0.013	0.015
	RT Load	0.439	0.466	0.466	0.042	0.118	0.118
	Deviation	2.069	1.218	1.604	1.036	0.432	0.666
UTC	East to East	NA	0.430	1.362	NA	0.299	0.765
	West to West	NA	0.355	1.136	NA	0.294	0.766
	East to/from West	NA	0.393	1.249	NA	0.296	0.766

Analysis of Changes in Annual Uplift Charges

Energy uplift charges decreased by $646.3 million (67.3 percent), from $960.5 million in 2014 to $314.2 million in 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.

The year over year change resulted from a decrease of $12.6 million in day-ahead operating reserve charges, a decrease of $587.0 million in balancing operating reserve charges, a decrease of $18.8 million in reactive services charges, a decrease of $0.1 million in synchronous condensing charges and a decrease of $27.7 in black start services charges.

Figure 4-8 Energy uplift charges change from 2014 to 2015 by category



44 The deviation transaction means load, interchange transactions, generators and DR deviations.

Five Year Energy Uplift Charges Analysis

Energy uplift charges decreased by $646.3 million (67.3 percent) in 2015 compared to 2014. A number of changes to factors affecting uplift charges implemented during the period from January 1, 2011, through December 31, 2013, resulted in a change to uplift beginning in January 2014 which were apparent in February 2014, after the polar vortex month of January 2014. From January 2011 through December 2013, energy uplift charges averaged $58.2 million per month, and from February 2014 through December 2015, energy uplift charges averaged $29.0 million, a reduction of $29.3 million per month, or 50 percent. Total energy uplift in January 2014 was $606.1 million. Prior to January 2014, the highest energy uplift in a month had been $131.8 million in December 2010. January 2014 was excluded from this analysis in order to focus on the factors affecting uplift prior to January 2014 and after January 2014.

Since 2011, a number of factors affected energy uplift in PJM:

- **Lower natural gas prices:** Energy uplift charges have been in part a result of the noneconomic commitment of gas fired units in the Eastern Region of PJM. The decline in natural gas prices has reduced the level of the associated uplift.
- **Lower summer peak demand:** Energy uplift charges have been in part a result of charges incurred on peak summer days. In particular, LOC payments to combustion turbines and diesels not called on by PJM during hours in which they cleared the Day-Ahead Energy Market were lower in 2014 and 2015 as a result of lower load, lower fuel costs and lower energy prices.
- **FMU adders:** Some owners of resources committed by PJM to provide reactive or voltage support elected to reduce the FMU adders of their units at the end of December 2013.[45]
- **FMU adders reform:** On October 31, 2014, the Commission approved a change to the rules governing FMU adders.[46] The result was to eliminate FMU adders in 2014 and 2015, which reduced the cost-based offers of units committed by PJM for reactive services, which reduced uplift.
- **Black start and reactive commitment improvement:** At the end of December 2013, PJM began to schedule fewer units in the BGE and Pepco control zones for reactive support. At the same time, PJM restarted modeling the BC/PEPCO reactive transfer interface in the Day-Ahead and Real-Time Energy Markets. The result was to eliminate energy uplift costs attributable to the noneconomic operation of units providing reactive support to the AP South or the Bedington – Black Oak reactive transfer interfaces after December 26, 2013.
- **ALR black start units:** ALR black start units that had been paid uplift were replaced by much lower cost conventional black start units on April 1, 2015.
- **LOC calculation reform:** On September 1, 2015, the Commission approved several changes recommended by the MMU and PJM related to energy LOC calculations which reduced uplift.
- **CT commitment improvement:** In the first half of 2013, PJM implemented a new tool to improve the commitment of combustion turbines (combustion turbine optimizer or CTO). The result was a reduction in the MW of generation from combustion turbines and diesels scheduled in the Day-Ahead Energy Market but not committed in real time.
- **Closed loop interfaces:** In 2013, PJM began to implement closed loop interfaces. By artificially increasing energy prices based on PJM's changes to the transmission model, uplift was reduced.
- **Price setting logic:** In November 2014, PJM implemented what it terms price setting logic that enables PJM operators to artificially modify the outcome of the fundamental LMP logic in order to increase prices and reduce uplift.

45 See the *2014 State of the Market Report for PJM*, Volume II, Section 4, "Energy Uplift," at "Reactive Services Rates."
46 149 FERC ¶ 61,091 (2014).

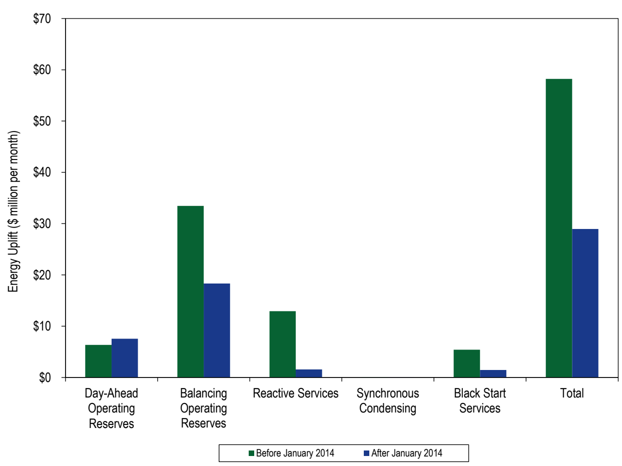
Table 4-40 shows the timeline of these factors.

Table 4-40 Timeline of main factors that reduced energy uplift from 2011 through 2015

Factor / Action	Implementation Month
Black Start / Reactive Commitment Improvement	Sep-12
Closed Loop Interfaces	Jan-13
CT Commitment Improvement	Mar-13
FMU Adders Reduction and Reactive Commitment Improvement	Dec-13
FMU Adders Reform	Oct-14
Price Setting Logic	Nov-14
ALR Units Replacement Completed	May-15
LOC Calculation Reform	Sep-15

Figure 4-9 shows the change in total energy uplift and by energy uplift category from January 2011 through December 2013, to February 2014 through December 2015. The reduction in monthly uplift was comprised of a reduction of $15.1 million per month in balancing operating reserve, a reduction of $11.4 million per month in reactive services, a reduction of $3.9 million per month in black start services and an increase of $1.2 million per month in day-ahead operating reserves.

Figure 4-9 Energy uplift charges from January 2011 through December 2013 and from February 2014 through December 2015 ($million per month)



After January 2014, energy uplift payments to units providing reactive support averaged $1.6 million per month, $11.4 million lower than the average before January 2014. The reduction in energy uplift payments to units providing reactive support resulted from reduced FMU adders and improvement in reactive unit commitment. In addition, the completion of transmission upgrades that had required the use of units for reactive support eliminated the associated energy uplift payments.

After January 2014, energy uplift payments to units providing black start support averaged $1.5 million per month, $3.9 million lower than the average before January 2014. The reduction in energy uplift payments to units providing black start support resulted from the replacement of the ALR black start units.

After January 2014, balancing operating reserves averaged $18.3 million per month, $15.1 million lower than the average before January 2014. Balancing operating reserves are comprised primarily of make whole payments in the balancing market and lost opportunity cost payments.

After January 2014, balancing operating reserve payments (make whole) averaged $11.1 million per month, $9.8 million lower than the average before January 2014. The reduction in balancing operating reserve make whole payments was primarily the result of lower gas prices and the resultant reduction in payments to gas-fired units in the Eastern Region of PJM.

After January 2014, balancing operating reserves (lost opportunity cost) averaged $7.2 million per month, $5.3 million lower than the average before January 2014. The reduction in LOC payments was the result of improvements to the CT commitment process, LOC calculation reform and lower summer peak loads.

After January 2014, day-ahead operating reserves averaged $7.6 million per month, $1.2 million higher than the average before January 2014. The increase in day-ahead operating reserves was the result of payments to coal-fired units that were previously made whole through reactive services credits.

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 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 and the Capacity Performance modifications to RPM, there are several features of the RPM design which still threaten competitive outcomes. These include the definition of DR which permits inferior products to substitute for capacity, the replacement capacity issue, the definition of unit offer parameters and the inclusion of imports which are not substitutes for internal capacity resources.

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.

Overview

RPM Capacity Market

Market Design

The Reliability Pricing Model (RPM) Capacity Market is a forward-looking, annual, locational market, with a must offer requirement for Existing Generation Capacity Resources and mandatory participation by load, with performance incentives, that includes clear market power mitigation rules and that permits the direct participation of demand-side resources.[4]

Under RPM, capacity obligations are annual. Base Residual Auctions (BRA) are held for Delivery Years that are three years in the future. Effective with the 2012/2013 Delivery Year, First, Second and Third Incremental Auctions (IA) are held for each Delivery Year.[5] Prior to the 2012/2013 Delivery Year, the Second Incremental Auction was conducted if PJM determined that an unforced capacity resource shortage exceeded 100 MW of unforced capacity due to a load forecast increase. Effective January 31, 2010, First, Second, 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

4 The terms *PJM Region, RTO Region* and *RTO* are synonymous in the *2015 State of the Market Report for PJM*, Section 5, "Capacity Market," and include all capacity within the PJM footprint.

5 See 126 FERC ¶ 61,275 (2009) at P 86.

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

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]

The 2015/2016 RPM Third Incremental Auction, 2016/2017 RPM Second Incremental Auction, 2018/2019 RPM Base Residual Auction, 2016/2017 Capacity Performance Transition Incremental Auction, 2017/2018 Capacity Performance Transition Incremental Auction, and 2017/2018 RPM First Incremental Auction were conducted in 2015. The Base Residual Auction for the 2018/2019 Delivery Year had been delayed.[8] The Capacity Performance (CP) Transition Incremental Auctions (IAs) were held as part of a five year transition to a single capacity product type in the 2020/2021 Delivery Year. Participation in the CP Transition IAs was voluntary. If a resource cleared a CP Transition IA and had a prior commitment for the relevant Delivery Year, the existing commitment was converted to a CP commitment which is subject to the CP performance requirements and Non-Performance Charges. The Transition IAs were not designed to minimize the cost of purchasing Capacity Performance resources for the two delivery years and were not designed to maximize economic welfare for the two delivery years.[9]

One June 9, 2015, FERC accepted changes to the PJM capacity market rules proposed in PJM's Capacity Performance (CP) filing.[10] For a transition period during the 2018/2019 and 2019/2020 Delivery Years, PJM will procure two product types, Capacity Performance and Base Capacity. PJM also procured Capacity Performance resources in two transition auctions for Delivery Years 2016/2017 and 2017/2018. Effective with the 2020/2021 Delivery Year, PJM will procure a single capacity product, Capacity Performance. CP Resources are expected to be available and capable of providing energy and reserves when needed at any time during the Delivery Year.[11] Effective for the 2018/2019 through the 2019/2020 Delivery Years, a Base Capacity Demand Resource Constraint and a Base Capacity Resource Constraint are established for each modeled LDA. These maximum quantities are set for reliability purpose to limit the quantity procured of the less available products, including Base Capacity Generation Resources, Base Capacity Demand Resources, and Base Capacity Energy Efficiency Resources.

RPM prices are locational and may vary depending on transmission constraints.[12] 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, and the performance incentives have been strengthened significantly under the Capacity Performance modifications to RPM. Under RPM there are explicit market power mitigation rules that define the must offer requirement, that define structural market power based on the marginal cost of capacity, that define offer caps, 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 2015, PJM installed capacity decreased 6,043.2 MW or 3.3 percent, from 183,726 MW on January 1 to 177,682.8 MW on December 31. 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 December 31, 2015, 37.5 percent was coal; 34.0 percent was gas; 18.6 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.

7 See 126 FERC ¶ 61,275 (2009) at P 88.
8 151 FERC ¶ 61,067 (2015).
9 The MMU will publish a detailed report on the operation and design of the transition auctions in 2016.
10 See Docket No. ER15-623-000 (December 12, 2014) and 151 FERC ¶ 61,208 (2015).
11 See PJM. "Manual 18: PJM Capacity Market," Revision 30 (December 17, 2015), p. 7.
12 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.

- **Supply.** Total internal capacity available to offer in the Base Residual Auction for the relevant Delivery Year increased 8,321.5 MW from 196,235.8 MW on June 1, 2014, to 204,557.3 MW on June 1, 2015. This increase was the result of new generation (6,786.1 MW), net generation capacity modifications (cap mods) (-5,118.9 MW), Demand Resource (DR) modifications (5,441.4 MW), Energy Efficiency (EE) modifications (220.1 MW), the EFORd effect due to lower sell offer EFORds (938.4 MW), and lower load management UCAP conversion factor (54.4 MW).
- **Demand.** There was a 902.4 MW decrease in the RPM reliability requirement from 178,086.5 MW on June 1, 2014, to 177,184.1 MW on June 1, 2015. The 902.4 MW decrease in the RTO Reliability Requirement was a result of a 1,718.2 MW decrease in the forecast peak load in UCAP terms holding the Forecast Pool Requirement (FPR) constant at the 2014/2015 level offset by a 815.8 MW increase attributable to the change in FPR. On June 1, 2015, PJM EDCs and their affiliates maintained a large market share of load obligations under RPM, together totaling 65.1 percent, down from 71.1 percent on June 1, 2014.
- **Market Concentration.** In the 2016/2017 RPM Second Incremental Auction, the 2018/2019 RPM Base Residual Auction, and the 2017/2018 RPM First Incremental Auction all participants in the total PJM market as well as the LDA RPM markets failed the three pivotal supplier (TPS) test.[13] The TPS test was not applied in the 2016/2017 Capacity Performance (CP) Transition Incremental Auction and the 2017/2018 CP Transition Incremental Auction. All offers in the Transition Auctions were subject to overall offer caps. Offer caps were applied to all sell offers for resources which were subject to mitigation when the Capacity Market Seller did not pass the test, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, increased the market clearing price.[14,15,16]
- **Imports and Exports.** Of the 5,135.8 MW of imports in the 2018/2019 RPM Base Residual Auction, 4,687.9 MW cleared. Of the cleared imports, 2,509.1 MW (53.5 percent) were from MISO.
- **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

- **2015/2016 RPM Base Residual Auction.** Of the 1,168 generation resources which submitted offers, unit-specific offer caps were calculated for 196 generation resources (16.8 percent). The MMU calculated offer caps for 670 generation resources (57.4 percent), of which 478 were based on the technology specific default (proxy) ACR values.
- **2015/2016 RPM First Incremental Auction.** Of the 131 generation resources which submitted offers, unit-specific offer caps were calculated for 20 generation resources (15.3 percent). The MMU calculated offer caps for 45 generation resources (34.4 percent), of which 25 were based on the technology specific default (proxy) ACR values.
- **2015/2016 RPM Second Incremental Auction.** Of the 80 generation resources which submitted offers, unit-specific offer caps were calculated for 16 generation resources (20.0 percent). The MMU calculated offer caps for 25 generation resources (31.3 percent), of which nine were based on the technology specific default (proxy) ACR values.
- **2015/2016 RPM Third Incremental Auction.** Of the 214 generation resources which submitted offers,

13 There are 27 Locational Deliverability Areas (LDAs) identified to recognize locational constraints as defined in "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region", Schedule 10.1. PJM determines, in advance of each BRA, whether the defined LDAs will be modeled in the given Delivery Year using the rules defined in OATT Attachment DD (Reliability Pricing Model) § 5.10(a)(ii).

14 See PJM. OATT Attachment DD § 6.5.

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

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

unit-specific offer caps were calculated for seven generation resources (3.3 percent). The MMU calculated offer caps for 23 generation resources (10.7 percent), of which 16 were based on the technology specific default (proxy) ACR values.

- **2016/2017 RPM Base Residual Auction.** Of the 1,199 generation resources which submitted offers, unit-specific offer caps were calculated for 152 generation resources (12.7 percent). The MMU calculated offer caps for 638 generation resources (53.2 percent), of which 491 were based on the technology specific default (proxy) ACR values.
- **2016/2017 RPM First Incremental Auction.** Of the 115 generation resources which submitted offers, unit-specific offer caps were calculated for 37 generation resources (32.2 percent). The MMU calculated offer caps for 62 generation resources (53.9 percent), of which 25 were based on the technology specific default (proxy) ACR values.
- **2016/2017 RPM Second Incremental Auction.** Of the 101 generation resources that submitted offers, the MMU calculated offer caps for 45 generation resources (44.6 percent), of which 21 were based on the technology specific default (proxy) ACR values and 24 were unit-specific offer caps (23.8 percent).
- **2016/2017 Capacity Performance Transition Incremental Auction.** All 709 generation resources which submitted offers in the 2016/2017 CP Transition Incremental Auction were subject to an offer cap of $165.27 per MW-day, which is 50 percent of the Net Cost of New Entry (CONE) used in the 2016/2017 RPM Base Residual Auction.
- **2017/2018 RPM Base Residual Auction.** Of the 1,202 generation resources which submitted offers, unit-specific offer caps were calculated for 131 generation resources (10.9 percent). The MMU calculated offer caps for 531 generation resources (44.2 percent), of which 400 were based on the technology specific default (proxy) ACR values.
- **2017/2018 Capacity Performance Transition Incremental Auction.** All 785 generation resources which submitted offers in the 2017/2018 CP Transition Incremental Auction were subject to an offer cap of $210.83 per MW-day, which is 60 percent of the Net Cost of New Entry (CONE) used in the 2017/2018 RPM Base Residual Auction.
- **2017/2018 RPM First Incremental Auction.** Of the 118 generation resources that submitted offers, the MMU calculated offer caps for 53 generation resources (44.9 percent), of which 36 were based on the technology specific default (proxy) ACR values and 17 were unit-specific offer caps (14.4 percent).
- **2018/2019 RPM Base Residual Auction.** Of the 473 generation resources that submitted Base Capacity offers, the MMU calculated offer caps for 219 generation resources (46.3 percent), of which 166 (35.1 percent) were based on the technology specific default (proxy) ACR values and 53 were unit-specific offer caps (11.2 percent). Of the 992 generation resources that submitted Capacity Performance offers, the MMU calculated unit specific offer caps for 35 generation resources (3.5 percent).

Market Performance

- The 2015/2016 RPM Third Incremental Auction, the 2016/2017 RPM Second Incremental Auction, 2018/2019 RPM Base Residual Auction, 2016/2017 Capacity Performance Transition Incremental Auction, 2017/2018 Capacity Performance Transition Incremental Auction, and 2017/2018 RPM First Incremental Auction were conducted in 2015. The weighted average capacity price for the 2016/2017 Delivery Year is $122.70 per MW-day, including all RPM Auctions for the 2016/2017 Delivery Year held through 2015. The weighted average capacity price for the 2017/2018 Delivery Year is $142.83, including all RPM Auctions for the 2017/2018 Delivery Year held through 2015. The weighted average capacity price for the 2018/2019 Delivery Year is $179.60, including all RPM Auctions for the 2018/2019 Delivery Year held through 2015. RPM net excess increased 383.6 MW from 5,472.3 MW on June 1, 2014, to 5,855.9 MW on June 1, 2015.
- For the 2015/2016 Delivery Year, RPM annual charges to load are $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 2015 was 6.9 percent, a decrease from 9.4 percent for 2014.[17]
- **Generator Performance Factors.** The PJM aggregate equivalent availability factor for 2015 was 83.7 percent, an increase from 82.2 percent for 2014.
- **Outages Deemed Outside Management Control (OMC).** In 2015, 4.2 percent of forced outages were classified as OMC outages, a decrease from 7.7 percent in 2014. In 2015, 0.6 percent of OMC outages were due to lack of fuel, compared to 0.5 percent in 2014.

Recommendations[18]

The MMU recognizes that PJM has implemented 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. The MMU's 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.[19]

- 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.[20,21] (Priority: High. First reported 2013. Status: Not adopted. Pending before FERC.)
- 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: Partially 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.[22,23] 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 modifications to existing resources not be treated as new resources for purposes of market power related offer caps or MOPR offer floors. (Priority: Low. First reported 2012. 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

17 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 twelve months ending December 31, as downloaded from the PJM GADS database on January 27, 2016. 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.

18 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.

19 *PJM Interconnection, L.L.C.*, 151 FERC ¶ 61,208 (June 9, 2015).

20 See also Comments of the Independent Market Monitor for PJM. Docket No. ER14-503-000 (December 20, 2013).

21 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).

22 See PJM Interconnection, L.L.C., Docket No. ER12-513-000 (December 1, 2011) ("Triennial Review").

23 See the *2012 State of the Market Report for PJM*, Volume II, Section 6, Net Revenue.

of modeling assumptions.[24] (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 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 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 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 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 2012. 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.[25] (Priority: Medium. First reported 2013. Status: Adopted.)

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,

24 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).

25 See OATT Attachment DD § 10(e). 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).

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 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 2015.

The MMU has identified serious market design issues with RPM and the MMU has made specific recommendations to address those issues.[26,27,28,29,30] In 2014 and 2015, the MMU prepared a number of RPM-related reports and testimony, shown in Table 5-2. The MMU recognizes that the Capacity Performance modifications to the RPM construct have significantly improved the capacity market and addressed many of the issues identified by the MMU. The MMU will publish more detailed reports on the first Capacity Performance BRA for 2018/2019 and on the CP Transition Incremental Auctions which include more specific issues and suggestions for improvements.

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

26 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).

27 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).

28 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).

29 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).

30 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 *(continued)*

Date	Name
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

Table 5-2 RPM related MMU reports, 2014 through 2015 *(continued)*

Date	Name
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
July 31,2015	IMM Answer and Motion for Leave to Answer Request for Rehearing re Capacity Performance Docket Nos. ER15-623-000, -001 and EL15-29-000 http://www.monitoringanalytics.com/reports/Reports/2015/IMM_Answer_and_Motion_for_Leave_to_Answer_Request_for_Rehearing_Docket_No_ER15-623-000_001_EL15-29-000_20150731.pdf
September 11, 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_20150911.pdf
November 4, 2015	IMM Comments re MISO Resources Docket Nos. EL15-70-000, EL15-71-000, EL15-72-000 and EL15-82-000 http://www.monitoringanalytics.com/reports/Reports/2015/IMM_Comments_Docket_Nos_EL15-70-000_EL15-71-000_EL15-72-000_EL15-82-000_20151104.pdf
November 18, 2015	External Capacity: Pseudo Ties http://www.monitoringanalytics.com/reports/Presentations/2015/IMM_PJM_MISO_JCM_External_Capacity_Pseudo_Ties_20151118.pdf
November 30, 2015	IMM Comments re AEP Waiver Request Docket No. ER16-298-000 http://www.monitoringanalytics.com/reports/Reports/2015/IMM_Comments_Docket_No_ER16-298-000_20151130.pdf
December 2, 2015	IMM Answer re AMEA Protest Docket No. ER15-623-000,-008 http://www.monitoringanalytics.com/reports/Reports/2015/IMM_Answer_Docket_No_ER15-623-000_008_201512-2.pdf
December 23, 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/RPM_Material/RPM_Must_Offer_Obligation_20151223.pdf
December 28, 2015	IMM First Supplemental Testimony of Joseph E. Bowring on Behalf of the Independent Market Monitor for PJM re AEP Ohio Case Nos. 14-1693 EL-RDR and 14-1694 EL-AAM http://www.monitoringanalytics.com/reports/Reports/2015/IMM_First_Supplemental_Testimony_AEP_Case_Nos_14-1693_14-1694_20151228.pdf
December 30, 2015	IMM First Supplemental Testimony of Joseph E. Bowring on Behalf of the Independent Market Monitor for PJM re FE Case No. 14-1297 EL-SSO http://www.monitoringanalytics.com/reports/Reports/2015/IMM_First_Supplemental_Testimony_of_Joseph_E_Bowring_14-1297_20151230.pdf
January 13, 2016	IMM Response re Capacity Performance Docket No. ER15-623-000 http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Response_ER15-623-000_20160113.pdf

Installed Capacity

On January 1, 2015, PJM installed capacity was 183,726.0 MW (Table 5-3).[31] Over the next 12 months, new generation, unit deactivations, facility reratings, plus import and export shifts resulted in PJM installed capacity of 177,682.8 MW on December 31, 2015, a decrease of 6,043.2 MW or 3.3 percent from the January 1 level.[32,33] The 6,043.2 MW decrease was the result of deactivations (9,897.2 MW) and derates (195.4 MW) offset by capacity modifications (1,229.2 MW), new or reactivated generation (1,810.0 MW), an increase in imports (987.4 MW), and a decrease in exports (22.8 MW).

At the beginning of the new Delivery Year on June 1, 2015, 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 December 31, 2015.[34] On June 1, 2007, coal comprised 40.7 percent of the installed capacity, reached a maximum of 42.9 percent in 2012, decreased to 37.8 percent on June 1, 2015 and will decrease to 31.4 percent by June 1, 2018. The share of gas increased from 29.1 percent in 2007 to 33.6 percent in 2015, and will increase to 42.2 percent in 2018.

31 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.

32 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.

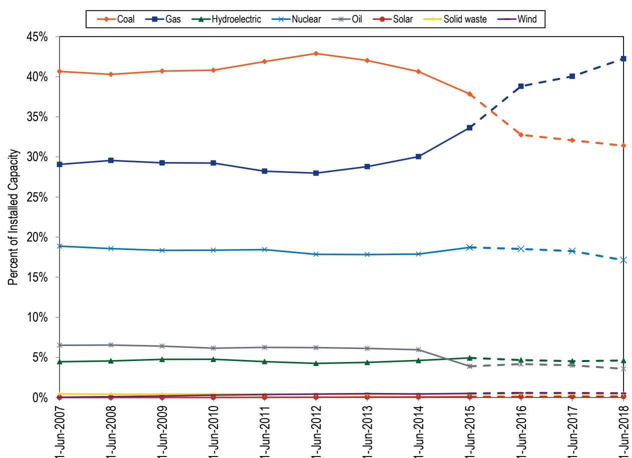
33 Wind resources accounted for 912.9 MW of installed capacity in PJM on September 30, 2015. This value represents approximately 13 percent of wind nameplate capability in PJM. PJM administratively reduces the capabilities of all wind generators to 13 percent of nameplate capacity when determining the 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.

34 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 December 31, 2015

	1-Jan-15		31-May-15		1-Jun-15		31-Dec-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%	66,674.8	37.5%
Gas	59,662.6	32.5%	59,862.3	32.7%	59,460.1	33.6%	60,487.4	34.0%
Hydroelectric	8,765.3	4.8%	8,690.8	4.7%	8,698.8	4.9%	8,787.5	4.9%
Nuclear	32,947.1	17.9%	33,078.4	18.1%	33,071.5	18.7%	33,071.5	18.6%
Oil	7,907.6	4.3%	7,299.7	4.0%	6,853.4	3.9%	6,851.8	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%	769.4	0.4%
Wind	822.7	0.4%	822.7	0.4%	876.2	0.5%	912.4	0.5%
Total	183,726.0	100.0%	182,976.8	100.0%	176,737.4	100.0%	177,682.8	100.0%

Figure 5-1 Percentage of PJM installed capacity (By fuel source): June 1, 2007 through June 1, 2018



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.[35] In 2015, the 2016/2017 RPM Second Incremental Auction, 2018/2019 RPM Base Residual Auction, 2016/2017 Capacity Performance Transition Incremental Auction, 2017/2018 Capacity Performance Transition Incremental Auction, and 2017/2018 RPM First Incremental Auction were conducted.[36]

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).

As shown in Table 5-5, total internal capacity available to offer in the Base Residual Auction for the relevant Delivery Year increased 8,321.5 MW from 196,235.8 MW on June 1, 2014, to 204,557.3 MW on June 1, 2015. This increase was the result of new generation (6,786.1 MW), net generation capacity modifications (cap mods) (-5,118.9 MW), Demand Resource (DR) modifications (5,441.4 MW), Energy Efficiency (EE) modifications (220.1 MW), the EFORd effect due to lower sell offer EFORds (938.4 MW), and higher load management UCAP conversion factor (54.4 MW). The EFORd effect is the measure of the net internal capacity change attributable to EFORd changes and not capacity modifications.

In the 2016/2017, 2017/2018, and 2018/2019 auctions, new generation were 14,685.0 MW; reactivated generation were 1,777.5 MW and net generation cap mods were -13,168.8 MW. DR and Energy Efficiency (EE) modifications totaled -13,003.7 MW through June 1, 2018. A decrease of 2,986.9 MW was due to lower EFORds, and an increase of 666.8 MW was due to a higher Load Management UCAP conversion factor. The integration of the East Kentucky Power Cooperative (EKPC) Zone resources added 2,735.7 MW to total internal capacity. The net effect from June 1, 2015, through June 1, 2018, was a decrease in total internal capacity available to offer in the Base Residual Auction

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

36 151 FERC ¶ 61,067 (2015).

for the relevant Delivery Year of 9,294.5 MW (4.5 percent) from 204,557.3 MW to 195,262.8 MW.

As shown in Table 5-5 and Table 5-13, in the 2015/2016 auction, the 111 additional generation resources offered consisted of 49 new resources (6,221.0 MW), 45 resources that were previously entirely FRR committed (4,803.0 MW), 13 additional resources imported (1,072.2 MW), three resources that were excused and not offered in the 2014/2015 BRA (30.8 MW), and one Duke Energy Ohio and Kentucky (DEOK) integration resource not offered in the 2014/2015 BRA (42.7 MW). The new Generation Capacity Resources consisted of 15 solar resources (13.8 MW), eight CT resources (1,348.4 MW), seven combined cycle resources (4,526.9 MW), six wind resources (104.9 MW), five diesel resources (13.6 MW), five hydroelectric resources (143.6 MW), two fuel cell resources (28.5 MW), and one steam unit (41.3 MW). In addition, there were the following new generation resources that were not offered in to the auction because they were either exported or entirely committed to FRR for the 2015/2016 Delivery Year: two CT resources (283.6 MW). The 95 fewer generation resources offered consisted of 49 additional resources excused from offering (3,761.1 MW), 29 deactivated resources (3,713.2 MW), eight additional resources committed fully to FRR (471.8 MW), three less resources resulting from aggregation of RPM resources, three external resources not offered (866.4 MW), one resource that is no longer a PJM capacity resource (1.2 MW), one Planned Generation Capacity Resource not offered (1.5 MW), and one resource unoffered and unexcused (4.8 MW). In addition, there were the following retirements of resources that were either exported, excused, or committed to an FRR capacity plan in the 2014/2015 BRA: six steam units (918.5 MW).

As shown in Table 5-5 and Table 5-14, in the 2016/2017 auction, the 99 additional generation resources offered consisted of 36 new resources (4,900.8 MW), 29 additional resources imported (3,026.3 MW), 18 East Kentucky Power Cooperative (EKPC) integration resources not offered in the 2015/2016 BRA (2,537.3 MW), nine resources that were excused and not offered in the 2015/2016 BRA (1,033.9 MW), three repowered resources (920.2 MW), two resources that were previously entirely FRR committed (168.3 MW), one reactivated resource (17.6 MW), and one additional resource resulting from the disaggregation of an RPM resource. The 36 new Generation Capacity Resources consisted of 11 diesel resources (36.1 MW), nine solar resources (32.1 MW), eight combined cycle resources (4,597.2 MW), five wind resources (54.3 MW), two CT resources (159.3 MW), and one steam unit (21.8 MW). In addition, there were new generation resources that were not offered in to the auction because they were either exported or entirely committed to FRR for the 2016/2017 Delivery Year: one wind resource (12.8 MW) and one diesel resource (5.3 MW). The 68 fewer generation resources offered consisted of 33 additional resources excused from offering (1,706.0 MW), 28 deactivated resources (1,389.6 MW), three fewer resources resulting from aggregation of RPM resources, two additional resources committed fully to FRR (28.7 MW), and two Planned Generation Capacity Resources not offered (934.8 MW). In addition, there were the following retirements of resources that were either exported, excused, or committed to an FRR capacity plan in the 2015/2016 BRA: 25 steam units (2,207.1 MW) and 13 CT resources (245.0 MW).

As shown in Table 5-5 and Table 5-15, in the 2017/2018 auction the 51 additional generation resources offered consisted of 32 new resources (5,103.3 MW), six repowered resources (941.6 MW), four resources that were excused and not offered in the 2016/2017 BRA (384.6 MW), three additional resources imported (714.1 MW), three resources that were previously entirely FRR committed (164.0 MW), two additional resources resulting from the disaggregation of RPM resources, and one reactivated resource (84.1 MW). The 32 new Generation Capacity Resources consisted of 15 solar resources (27.0 MW), nine diesel resources (122.5 MW), six combined cycle resources (4,825.4 MW), one CT resource (122.7 MW), and one hydro resource (5.7 MW). In addition, there were new generation resources that were not offered in to the auction because they were either exported or entirely committed to FRR for the 2017/2018 Delivery Year: one wind resource (26.0 MW). As shown in Table 5-5 and Table 5-16, in the 2018/2019 auction the 36 additional generation resources offered consisted of 28 new resources (3,447.4 MW), six additional resources imported (483.2 MW), and two resources that were previously entirely FRR committed (2.9 MW). The 28 new Generation Capacity Resources consisted of 11 solar resources (82.8 MW), six wind resources (127.1 MW), four combined cycle resources (2,257.8 MW), four CT resources (912.3 MW), and three diesel resources (67.4 MW).

Table 5-4 Generation capacity changes: 2007/2008 through 2014/2015

	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

Table 5-5 Internal capacity: June 1, 2014 to June 1, 2018[37]

	UCAP (MW)												
	RTO	MAAC	EMAAC	SWMAAC	DPL South	PSEG	PSEG North	Pepco	ATSI	ATSI Cleveland	ComEd	BGE	PPL
Total internal capacity @ 01-Jun-14	196,235.8	76,249.0	36,649.9	14,361.8	1,725.6	8,711.0	4,405.7	6,081.7	10,545.2				
New generation	6,786.1	3,486.9	2,523.3	661.0	297.7	801.0	793.9	661.0	843.8				
Reactivated generation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0				
Generation cap mods	(5,118.9)	(361.0)	7.0	(372.3)	(2.0)	(138.9)	5.5	(372.3)	74.4				
DR mods	5,441.4	(149.6)	606.9	(1,583.0)	(123.8)	(33.9)	(70.7)	(34.8)	2,729.0				
EE mods	220.1	29.4	25.4	(3.0)	(5.0)	5.1	3.5	12.9	78.2				
EFORd effect	938.4	508.9	229.8	156.4	7.0	170.3	87.9	114.4	133.6				
DR and EE effect	54.4	29.5	12.8	6.2	0.9	4.0	2.0	3.4	3.3				
Total internal capacity @ 01-Jun-15	204,557.3	79,793.1	40,055.1	13,227.1	1,900.4	9,518.6	5,227.8	6,466.3	14,407.5	3,484.3			
Integration of existing EKPC resources	2,735.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0			
New generation	5,517.4	2,291.3	606.5	3.6	0.0	30.2	0.0	0.0	767.1	0.0			
Reactivated generation	751.8	751.8	751.8	0.0	0.0	17.6	0.0	0.0	0.0	0.0			
Generation cap mods	(3,373.3)	(2,385.3)	(1,320.6)	(70.4)	(2.8)	(241.3)	(108.7)	0.0	(92.3)	0.0			
DR mods	(10,690.1)	(6,472.2)	(3,268.1)	(1,030.2)	(139.0)	(986.6)	(428.4)	(428.7)	(791.4)	564.7			
EE mods	262.5	145.6	28.7	85.6	0.7	3.2	0.7	50.4	131.0	55.7			
EFORd effect	1,039.0	575.2	160.5	325.3	6.8	(0.6)	(0.6)	146.4	(101.8)	(69.6)			
DR and EE effect	47.8	18.4	7.0	6.8	0.2	2.1	0.8	3.0	5.1	0.0			
Total internal capacity @ 01-Jun-16	200,848.1	74,717.9	37,020.9	12,547.8	1,766.3	8,343.2	4,691.6	6,237.4	14,325.2	4,035.1	26,091.2	3,717.0	10,570.7
Correction in resource modeling	0.0	0.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Adjusted internal capacity @ 01-Jun-16	200,848.1	74,718.7	37,020.9	12,547.8	1,766.3	8,343.2	4,691.6	6,237.4	14,325.2	4,035.1	26,091.2	3,717.0	10,570.7
New generation	5,179.3	3,599.6	1,663.2	856.3	0.0	2.8	0.0	0.0	770.2	0.0	3.4	122.7	959.9
Reactivated generation	1,025.7	1,025.7	84.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Generation cap mods	(7,943.1)	(2,286.3)	(2,190.5)	(57.9)	5.7	(1,135.3)	(509.9)	15.7	(751.7)	(818.0)	85.1	0.0	(49.9)
DR mods	(3,472.4)	(941.6)	(407.6)	(198.9)	(33.0)	(167.9)	(50.2)	(54.4)	(889.9)	(208.7)	497.8	635.1	(171.2)
EE mods	158.9	91.4	26.9	61.5	0.9	4.4	0.1	77.2	(58.4)	(14.6)	583.3	50.9	(1.0)
EFORd effect	(2,167.1)	(987.4)	(267.1)	(329.7)	(19.8)	(122.1)	(62.0)	35.1	(529.7)	(77.2)	33.6	(361.9)	(236.1)
DR and EE effect	(7.1)	(2.5)	(1.4)	(0.4)	(0.2)	(0.4)	(0.2)	(0.3)	(1.3)	(0.4)	(1.0)	(0.1)	(0.3)
Total internal capacity @ 01-Jun-17	193,622.3	75,217.6	35,928.5	12,878.7	1,719.9	6,924.7	4,069.4	6,310.7	12,864.4	2,916.2	27,293.4	4,163.7	11,072.1
Correction in resource modeling	0.0	0.0	0.0	0.0	0.0	0.0	(19.9)	0.0	0.0	0.0	0.0	0.0	0.0
Adjusted internal capacity @ 01-Jun-17	193,622.3	75,217.6	35,928.5	12,878.7	1,719.9	6,924.7	4,049.5	6,310.7	12,864.4	2,916.2	27,293.4	4,163.7	11,072.1
New generation	3,988.3	1,054.8	1,036.1	0.0	50.0	981.2	0.0	0.0	0.0	0.0	245.6	0.0	0.0
Reactivated generation	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
Generation cap mods	(1,852.4)	399.2	(101.3)	(34.9)	(31.2)	(18.3)	(12.8)	0.0	(633.7)	(296.7)	(216.3)	(35.1)	89.5
DR mods	746.6	198.4	67.6	28.7	30.5	(53.7)	(13.4)	23.9	(119.1)	(18.4)	589.6	5.0	69.1
EE mods	(9.3)	(4.9)	(8.2)	3.2	(1.6)	4.7	2.2	(56.6)	(109.4)	(35.5)	136.1	59.8	4.4
EFORd effect	(1,858.8)	(417.7)	(623.1)	(20.4)	12.3	(357.7)	(170.6)	(153.1)	39.2	89.7	(708.1)	131.9	24.6
DR and EE effect	626.1	239.9	85.4	79.7	5.1	19.5	7.9	36.1	44.8	14.3	117.8	43.6	41.4
Total internal capacity @ 01-Jun-18	195,262.8	76,687.3	36,385.0	12,935.0	1,785.0	7,500.4	3,862.8	6,161.0	12,086.2	2,669.6	27,458.1	4,368.9	11,301.1

37 The RTO includes MAAC, EMAAC, SWMAAC, and ATSI. MAAC includes EMAAC, SWMAAC, and PPL. EMAAC includes DPL South, PSEG and PSEG North. PSEG includes PSEG North. SWMAAC includes Pepco and BGE. ATSI includes ATSI Cleveland.

Demand

There was a 902.4 MW decrease in the RPM reliability requirement from 178,086.5 MW on June 1, 2014, to 177,184.1 MW on June 1, 2015. The 902.4 MW decrease in the RTO Reliability Requirement was a result of a 1,718.2 MW decrease in the forecast peak load in UCAP terms holding the FPR constant at the 2014/2015 level offset by a 815.8 MW increase attributable to the change in FPR.

The MMU analyzed market sectors in the PJM Capacity Market to determine how they met their load obligations. The Capacity Market was divided into the following sectors:

- **PJM EDC.** EDCs with a franchise service territory within the PJM footprint. This sector includes traditional utilities, electric cooperatives, municipalities and power agencies.
- **PJM EDC Generating Affiliate.** Affiliate companies of PJM EDCs that own generating resources.
- **PJM EDC Marketing Affiliate.** Affiliate companies of PJM EDCs that sell power and have load obligations in PJM, but do not own generating resources.
- **Non-PJM EDC.** EDCs with franchise service territories outside the PJM footprint.
- **Non-PJM EDC Generating Affiliate.** Affiliate companies of non-PJM EDCs that own generating resources.
- **Non-PJM EDC Marketing Affiliate.** Affiliate companies of non-PJM EDCs that sell power and have load obligations in PJM, but do not own generating resources.
- **Non-EDC Generating Affiliate.** Affiliate companies of non-EDCs that own generating resources.
- **Non-EDC Marketing Affiliate.** Affiliate companies of non-EDCs that sell power and have load obligations in PJM, but do not own generating resources.

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 5-6), 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. The share of capacity market load obligation fulfilled by PJM EDCs and their affiliates, and LSEs not affiliated with any EDC and non PJM EDC affiliates from June 1, 2007 to June 1, 2015 is shown in Figure 5-2. PJM EDCs' and their affiliates' share of load obligation has decreased from 87.6 percent on June 1, 2007, to 65.1 percent on June 1, 2015. The share of load obligation held by LSEs not affiliated with any EDC and non PJM EDC affiliates increased from 12.4 percent on June 1, 2007, to 34.9 percent on June 1, 2015. 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.

Figure 5-2 Capacity market load obligation served: June 1, 2007 through June 1, 2015

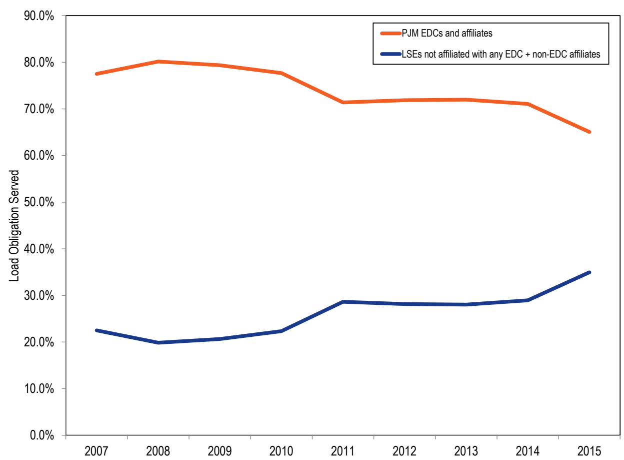


Table 5-6 Capacity market load obligations served: June 1, 2015

	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

Auction Market Structure

As shown in Table 5-7, all participants in the total PJM market as well as the LDA RPM markets failed the three pivotal supplier (TPS) test in the 2015/2016 RPM Base Residual Auction, 2015/2016 RPM First Incremental Auction, 2015/2016 RPM Second Incremental Auction, 2015/2016 RPM Third Incremental Auction, 2016/2017 RPM Base Residual Auction, 2016/2017 RPM First Incremental Auction, 2016/2017 RPM Second Incremental Auction, 2017/2018 RPM Base Residual Auction, 2017/2018 RPM First Incremental Auction, and the 2018/2019 RPM Base Residual Auction.[38] The TPS test was not applied in the 2016/2017 CP Transition Incremental Auction and the 2017/2018 CP Transition Incremental Auction. Offer caps were applied to all sell offers for resources which were subject to mitigation when the capacity market seller did not pass the test, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, increased the market clearing price.[39,40,41] An overall offer cap was applied to all offers in the Transition Auctions.

In applying the market structure test, the relevant supply for the RTO market includes all supply offered at less than or equal to 150 percent of the RTO cost-based clearing price. The relevant supply for the constrained LDA markets includes the incremental supply inside the constrained LDAs which was offered at a price higher than the unconstrained clearing price for the parent LDA market and less than or equal to 150 percent of the cost-based clearing price for the constrained LDA. The relevant demand consists of the MW needed inside the LDA to relieve the constraint.

Table 5-7 presents the results of the TPS test. A generation owner or owners are pivotal if the capacity of the owners' generation facilities is needed to meet the demand for capacity. The results of the TPS are measured by the residual supply index (RSIx). The RSIx is a general measure that can be used with any number of pivotal suppliers. The subscript denotes the number of pivotal suppliers included in the test. If the RSIx is less than or equal to 1.0, the supply owned by the specific generation owner, or owners, is needed to meet market demand and the generation owners are pivotal suppliers with a significant ability to influence market prices. If the RSIx is greater than 1.0, the supply of the specific generation owner or owners is not needed to meet market demand and those generation owners have a reduced ability to unilaterally influence market price.

38 The market definition used for the TPS test includes all offers with costs less than or equal to 1.50 times the clearing price. See *MMU Technical Reference for PJM Markets*, at "Three Pivotal Supplier Test" for additional discussion.

39 See PJM. OATT Attachment DD § 6.5.

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

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

Table 5-7 RSI results: 2015/2016 through 2018/2019 RPM Auctions[42]

RPM Markets	$RSI_{1,1.05}$	RSI_3	Total Participants	Failed RSI_3 Participants
2015/2016 Base Residual Auction				
RTO	0.75	0.57	99	99
MAAC	0.49	0.63	12	12
ATSI	0.01	0.00	3	3
2015/2016 First Incremental Auction				
RTO	0.70	0.61	43	43
MAAC	0.15	0.09	5	5
PSEG	0.00	0.00	1	1
ATSI	0.00	0.00	1	1
2015/2016 Second Incremental Auction				
RTO	0.40	0.21	26	26
MAAC	0.00	0.04	4	4
PSEG	0.00	0.00	0	0
ATSI	0.00	0.00	1	1
2015/2016 Third Incremental Auction				
RTO	0.38	0.28	55	55
MAAC	0.24	0.10	4	4
PSEG	0.00	0.00	0	0
2016/2017 Base Residual Auction				
RTO	0.78	0.59	110	110
MAAC	0.56	0.38	6	6
PSEG	0.00	0.00	1	1
ATSI	0.00	0.00	1	1
2016/2017 First Incremental Auction				
RTO	0.58	0.16	29	29
MAAC	0.26	0.00	3	3
PSEG	0.00	0.00	1	1
ATSI	0.00	0.00	1	1
2016/2017 Second Incremental Auction				
RTO	0.63	0.37	32	32
PSEG North	0.00	0.00	1	1
ATSI	0.00	0.00	1	1
2017/2018 Base Residual Auction				
RTO	0.80	0.61	119	119
PSEG	0.00	0.00	1	1
2017/2018 First Incremental Auction				
RTO	0.47	0.40	38	38
PSEG	0.00	0.00	1	1
2018/2019 Base Residual Auction				
RTO	0.81	0.65	125	125
EMAAC	0.59	0.16	12	12
ComEd	1.11	0.02	4	4

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.[43] 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."[44] 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.[45] Effective for the 2018/2019 through the 2019/2020 Delivery Years, Base Capacity Demand Resource Constraint and a Base Capacity Resource Constraint, replacing the Sub-Annual and Limited Resource Constraints, are established for each modeled LDA.

Locational Deliverability Areas are shown in Figure 5-3, Figure 5-4 and Figure 5-5.

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

43 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.

44 PJM. OATT Attachment DD § 5.10 (a) (ii).

45 146 FERC ¶ 61,052 (2014).

Figure 5-3 Map of PJM Locational Deliverability Areas

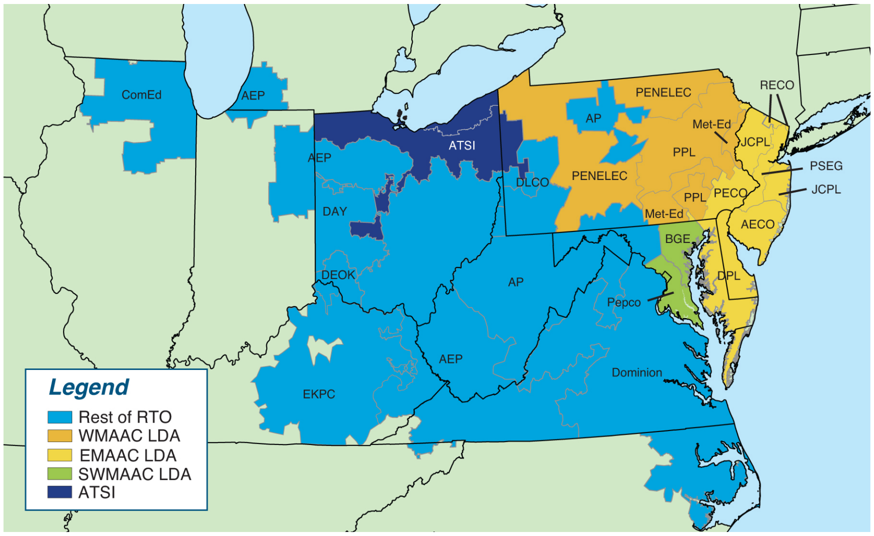


Figure 5-4 Map of PJM RPM EMAAC subzonal LDAs

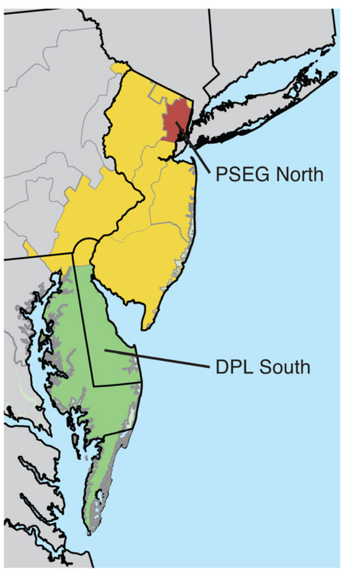
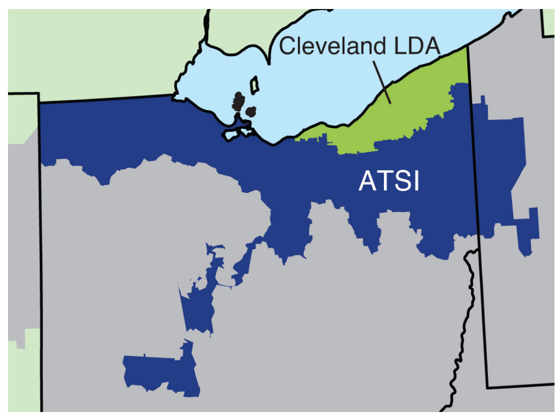


Figure 5-5 Map of PJM RPM ATSI subzonal LDA



Imports and Exports

Units external to the metered boundaries of PJM can qualify as PJM capacity resources if they meet the requirements to be capacity resources. Generators on the PJM system that do not have a commitment to serve PJM loads in the given Delivery Year as a result of RPM Auctions, FRR capacity plans, locational UCAP transactions, and/or are not designated as a replacement resource, are eligible to export their capacity from PJM.[46]

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

46 PJM. OATT Attachment DD § 5.6.6(b).

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.

Effective with the 2017/2018 Delivery Year, Capacity Import Limits (CILs) are established for each of the five external source zones and the overall PJM region to account for the risk that external generation resources may not be able to deliver energy during the relevant Delivery Year due to the curtailment of firm transmission by third parties.[47] Capacity Market Sellers may request an exception to the CIL for an external generation resource by committing that the resource will be pseudo tied prior to the start of the relevant Delivery Year, by demonstrating that it has long-term firm transmission service confirmed on the complete transmission path from the resource to PJM, and by agreeing to be subject to the same RPM must offer requirement as internal PJM generation resources.

Effective June 9, 2015, an external Generation Capacity Resource must obtain an exception to the CILs to be eligible to offer as a Capacity Performance Resource.[48]

As shown in Table 5-8, net exchange increased 353.9 MW from June 1, 2014 to June 1, 2015. Net exchange, which is imports less exports, increased due to an increase in imports of 340.0 MW and a decrease in exports of 13.9 MW.

As shown in Table 5-9, a total of 4,687.9 MW of imports cleared in the 2018/2019 RPM Base Residual Auction. Of these cleared imports, 2,509.1 MW (53.5 percent) were from MISO.

Importing Capacity

Existing External Generation Capacity Resource

Generation external to the PJM region is eligible to be offered into an RPM Auction if it meets specific requirements.[49,50] Firm transmission service from the unit to the border of PJM and generation deliverability into PJM must be demonstrated prior to the start of the delivery year. In order to demonstrate generation deliverability into PJM, external generators must obtain firm point-to-point transmission service on the PJM OASIS from the PJM border into the PJM transmission system or by obtaining network external designated transmission service. In the event that transmission upgrades are required to establish deliverability, those upgrades must be completed by the start of the delivery year. The following are also required: the external generating unit must be in the resource portfolio of a PJM member; twelve months of NERC/GADs unit performance data must be provided to establish an EFORd; the net capability of each unit must be verified through winter and summer testing; a letter of non-recallability must be provided to assure PJM that the energy and capacity from the unit is not recallable to any other balancing authority.

All external generation resources that have an RPM commitment or FRR capacity plan commitment or that are designated as replacement capacity must be offered in the PJM Day-Ahead Energy Market.[51]

To avoid balancing market deviations, any offer accepted in the Day-Ahead Energy Market must be scheduled to physically flow in the Real-Time Energy Market. When submitting the real-time energy market transaction, a valid NERC Tag is required, with the appropriate transmission reservations associated. Additionally, external capacity transactions must designate the transaction as such when submitting the NERC Tag. This designation allows the PJM dispatch operators to identify capacity backed transactions in order to avoid curtailing them out of merit order.

47 147 FERC ¶ 61,060 (2014).
48 151 FERC ¶ 61,208 (2015).
49 See "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Schedule 9 & 10.
50 See PJM. "Manual 18: PJM Capacity Market," Revision 30 (December 17, 2015), pp. 51-52 & p. 74-75.
51 OATT, Schedule 1, Section 1.10.1A.

External capacity backed transactions are evaluated the same way as all other energy transactions and are subject to all scheduling timing requirements and PJM interchange ramp limits. If the offer is not accepted in the Day-Ahead Energy Market, but the unit is requested during the operating day, the PJM dispatch operator will notify the participant. The market participant will then submit a tag to match the request. This tag will also be subject to all scheduling timing requirements and PJM interchange ramp limits.

Planned External Generation Capacity Resource

Planned External Generation Capacity Resources are eligible to be offered into an RPM Auction if they meet specific requirements.[52,53] Planned External Generation Capacity Resources are proposed Generation Capacity Resources, or a proposed increase in the capability of an Existing Generation Capacity Resource, that is located outside the PJM region; participates in the generation interconnection process of a balancing authority external to PJM; is scheduled to be physically and electrically interconnected to the transmission facilities of such balancing authority on or before the first day of the delivery year for which the resource is to be committed to satisfy the reliability requirements of the PJM Region; and is in full commercial operation prior to the first day of the delivery year.[54] An External Generation Capacity Resource becomes an Existing Generation Capacity Resource as of the earlier of the date that interconnection service commences or the resource has cleared an RPM Auction.[55]

Exporting Capacity

Non-firm transmission can be used to export capacity from the PJM region. A Generation Capacity Resource located in the PJM region not committed to service of PJM loads may be removed from PJM Capacity Resource status if the Capacity Market Seller shows that the resource has a financially and physically firm commitment to an external sale of its capacity.[56] The Capacity Market Seller must also identify the megawatt amount, export zone, and time period (in days) of the export.[57]

The MMU evaluates requests submitted by Capacity Market Sellers to export Generation Capacity Resources, makes a determination as to whether the resource meets the applicable criteria to export, and must inform both the Capacity Market Seller and PJM of such determination.[58]

When submitting a real-time market export capacity transaction, a valid NERC Tag is required, with the appropriate transmission reservations associated. Capacity transactions must designate the transaction as capacity when submitting the NERC Tag. This designation allows the PJM dispatch operators to identify capacity backed transactions in order to avoid curtailing them out of merit order. External capacity backed transactions are evaluated the same way as all other energy transactions and are subject to all scheduling timing requirements and PJM interchange ramp limits.

52 See "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Section 1.69A.
53 See PJM. "Manual 18: PJM Capacity Market," Revision 30 (December 17, 2015), pp. 53-54.
54 Prior to January 31, 2011, capacity modifications to existing generation capacity resources were not considered planned generation capacity resources. See 134 FERC ¶ 61,065 (2011).
55 Effective January 31, 2011, the RPM rules related to market power mitigation were changed, including revising the definition for Planned Generation Capacity Resource for purposes of the must-offer requirement and market power mitigation. See 134 FERC ¶ 61,065 (2011).
56 OATT Attachment DD § 6.6(g).
57 *Id.*
58 OATT Attachment M-Appendix § II.C.2.

Table 5-8 PJM capacity summary (MW): June 1, 2007 to June 1, 2018[59,60]

	01-Jun-07	01-Jun-08	01-Jun-09	01-Jun-10	01-Jun-11	01-Jun-12	01-Jun-13	01-Jun-14	01-Jun-15	01-Jun-16	01-Jun-17	01-Jun-18
Installed capacity (ICAP)	163,721.1	164,444.1	166,916.0	168,061.5	172,666.6	181,159.7	197,775.0	210,812.4	217,829.1	216,671.5	208,605.9	210,712.9
Unforced capacity (UCAP)	154,076.7	155,590.2	157,628.7	158,634.2	163,144.3	171,147.8	186,588.0	199,063.2	207,738.6	207,578.0	198,282.6	199,583.9
Cleared capacity	129,409.2	129,597.6	132,231.8	132,190.4	132,221.5	136,143.5	152,743.3	149,974.7	164,561.2	169,159.7	167,003.7	166,836.9
Make-whole	0.0	0.0	0.0	0.0	43.0	222.1	14.0	112.6	2.7	0.0	65.2	38.6
RPM reliability requirement (pre-FRR)	148,277.3	150,934.6	153,480.1	156,636.8	154,251.1	157,488.5	173,549.0	178,086.5	177,184.1	180,332.2	179,545.1	174,896.8
RPM reliability requirement (less FRR)	125,805.0	128,194.6	130,447.8	132,698.8	130,658.7	133,732.4	149,988.7	148,323.1	162,777.4	166,127.5	165,007.1	160,607.4
RPM net excess	5,240.5	5,011.1	8,265.5	7,728.0	10,638.4	5,976.5	6,518.3	5,472.3	5,855.9	7,185.4	6,187.0	6,268.1
Imports	2,809.2	2,460.3	2,505.4	2,750.7	6,420.0	3,831.6	4,348.2	4,055.5	4,395.5	7,941.5	5,854.8	5,603.4
Exports	(3,938.5)	(3,838.1)	(2,194.9)	(3,147.4)	(3,158.4)	(2,637.1)	(2,438.4)	(1,228.1)	(1,214.2)	(1,211.6)	(1,194.5)	(1,282.3)
Net exchange	(1,129.3)	(1,377.8)	310.5	(396.7)	3,261.6	1,194.5	1,909.8	2,827.4	3,181.3	6,729.9	4,660.3	4,321.1
DR cleared	127.6	536.2	892.9	939.0	1,364.9	7,047.2	9,281.9	14,118.4	14,832.8	12,408.1	10,974.8	11,084.4
EE cleared						568.9	679.4	822.1	922.5	1,117.3	1,338.9	1,246.5
ILR	1,636.3	3,608.1	6,481.5	8,236.4	9,032.6							
FRR DR	445.6	452.8	423.6	452.9	452.9	488.1	488.6	518.1	356.8	501.9	556.2	650.2
Short-Term Resource Procurement Target						3,343.3	3,749.7	3,708.1	4,069.4	4,153.2	4,125.2	0.0

Table 5-9 RPM imports: 2007/2008 through 2018/2019 RPM Base Residual Auctions

	UCAP (MW)					
	MISO		Non-MISO		Total Imports	
Base Residual Auction	Offered	Cleared	Offered	Cleared	Offered	Cleared
2007/2008	1,073.0	1,072.9	547.9	547.9	1,620.9	1,620.8
2008/2009	1,149.4	1,109.0	517.6	516.8	1,667.0	1,625.8
2009/2010	1,189.2	1,151.0	518.8	518.1	1,708.0	1,669.1
2010/2011	1,194.2	1,186.6	539.8	539.5	1,734.0	1,726.1
2011/2012	1,862.7	1,198.6	3,560.0	3,557.5	5,422.7	4,756.1
2012/2013	1,415.9	1,298.8	1,036.7	1,036.7	2,452.6	2,335.5
2013/2014	1,895.1	1,895.1	1,358.9	1,358.9	3,254.0	3,254.0
2014/2015	1,067.7	1,067.7	1,948.8	1,948.8	3,016.5	3,016.5
2015/2016	1,538.7	1,538.7	2,396.6	2,396.6	3,935.3	3,935.3
2016/2017	4,723.1	4,723.1	2,770.6	2,759.6	7,493.7	7,482.7
2017/2018	2,624.3	2,624.3	2,320.4	1,901.2	4,944.7	4,525.5
2018/2019	2,879.1	2,509.1	2,256.7	2,178.8	5,135.8	4,687.9

Demand Resources

There are three basic demand products incorporated in the RPM market design:[61]

- **Demand Resources (DR).** Interruptible load resource that is offered into an RPM Auction as capacity and receives the relevant LDA or RTO resource clearing price.
- **Interruptible Load for Reliability (ILR).** Interruptible load resource that is not offered into the RPM Auction, but receives the final zonal ILR price determined after the second incremental auction. The ILR product was eliminated after the 2011/2012 Delivery Year.
- **Energy Efficiency (EE) Resources.** Load resources that are offered into an RPM Auction as capacity and receive the relevant LDA or RTO resource clearing price. The EE resource type was eligible to be offered in RPM Auctions starting with the 2012/2013 Delivery Year and in incremental auctions in the 2011/2012 Delivery Year.[62]

Effective for the 2014/2015 through the 2017/2018 Delivery Year, there are three types of Demand Resource products included in the RPM market design:[63,64]

- **Annual DR.** Demand Resource that is required to be available on any day in the relevant delivery year for an unlimited number of interruptions. Annual DR is required to be capable of maintaining each interruption for only ten hours only during the hours of 10:00 a.m. to 10:00 p.m. EPT for the period May through October and 6:00 a.m. to 9:00 p.m. EPT for the period November through April unless there is an Office of the Interconnection approved maintenance outage during October through April.
- **Extended Summer DR.** Demand Resource that is required to be available on any day from June through October and the following May in the relevant delivery year for an unlimited number of interruptions. Extended Summer DR is required to be capable of maintaining each interruption for

59 Prior to the 2012/2013 Delivery Year, net excess under RPM was calculated as cleared capacity plus make-whole MW less the reliability requirement plus ILR. For 2007/2008 through 2011/2012, certified ILR was used in the calculation, because the certified ILR data are now available. For the 2012/2013 Delivery Year and beyond, net excess under RPM is calculated as cleared capacity plus make-whole MW less the reliability requirement plus the Short-Term Resource Procurement Target. For the 2018/2019 and subsequent Delivery Years, the net excess under RPM is calculated as cleared capacity plus make-whole MW less the reliability requirement.

60 The results for RPM Incremental Auctions are not included in this table.

61 Effective June 1, 2007, the PJM active load management (ALM) program was replaced by the PJM load management (LM) program. Under ALM, providers had received a MW credit which offset their capacity obligation. With the introduction of LM, qualifying load management resources can be offered into RPM Auctions as capacity resources and receive the clearing price.

62 Letter Order in Docket No. ER10-366-000 (January 22, 2010).

63 134 FERC ¶ 61,066 (2011).

64 "Reliability Assurance Agreement among Load-Serving Entities in the PJM Region," Article 1.

only ten hours only during the hours of 10:00 a.m. to 10:00 p.m. EPT.

- **Limited DR.** Demand Resource that is required to be available on weekdays not including NERC holidays during the period of June through September in the relevant delivery year for up to 10 interruptions. Limited DR is required to be capable of maintaining each interruption for only six hours only during the hours of 12:00 p.m. to 8:00 p.m. EPT.

Effective for the 2018/2019 and the 2019/2020 Delivery Years, there are two types of Demand Resource and Energy Efficiency Resource products included in the RPM market design:[65,66]

- **Base Capacity Demand Resource.** Demand Resource that is required to be available on any day from June through September for an unlimited number of interruptions. Base Capacity DR is required to be capable of maintaining each interruption for at least ten hours only during the hours of 10:00 a.m. to 10:00 p.m. EPT.
- **Base Capacity Energy Efficiency Resource.** A project designed to achieve a continuous (during summer peak periods) reduction in electric energy consumption that is not reflected in the peak load forecast for the delivery year for which the Base Capacity Energy Efficiency Resource is proposed, and that is fully implemented at all times during the relevant delivery year, without any requirement of notice, dispatch, or operator intervention. The peak period definition for the Base Capacity Energy Efficiency Resource type includes the period from the hour ending 15:00 EPT and the hour ending 18:00 EPT from June through August, excluding weekends and federal holidays.
- **Capacity Performance Resource**
  - **Annual Demand Resource.** Demand Resource that is required to be available on any day in the relevant delivery year for an unlimited number of interruptions. Annual DR is required to be capable of maintaining each interruption for only ten hours only during the hours of 10:00 a.m. to 10:00 p.m. EPT for the period May through October and 6:00 a.m. to 9:00 p.m. EPT for the period November through April unless there is an Office of the Interconnection approved maintenance outage during October through April.
  - **Annual Energy Efficiency Resource.** A project designed to achieve a continuous (during summer and winter peak periods) reduction in electric energy consumption during peak periods that is not reflected in the peak load forecast for the delivery year for which the Energy Efficiency Resource is proposed, and that is fully implemented at all times during the relevant delivery year, without any requirement of notice, dispatch, or operator intervention. The peak period definition for the Annual Energy Efficiency Resource type includes the period from the hour ending 15:00 EPT and the hour ending 18:00 EPT from June through August, and the period from the hour ending 8:00 EPT and the hour ending 9:00 EPT and the period from the hour ending 19:00 EPT and the hour ending 20:00 EPT from January through February, excluding weekends and federal holidays.

Effective with the 2020/2021 Delivery Year, the Capacity Performance product will be the only capacity product type.

As shown in Table 5-10 and Table 5-12, 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 5-11 shows RPM commitments for DR and EE resources as the result of RPM Auctions prior to adjustments for replacement capacity transactions and certified ILR.

65 151 FERC ¶ 61,208.
66 "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Article 1.

Table 5-10 RPM load management statistics by LDA: June 1, 2014 to June 1, 2018[67,68,69]

	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)	(10.4)	(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	79.0	462.5	149.3	677.4	1,242.9				
DR cleared	12,998.4	5,355.7	2,008.0	1,603.6	105.7	632.3	228.2	664.1	1,841.4	470.8			
EE cleared	1,596.3	355.5	83.6	210.5	2.0	26.1	10.1	84.4	209.7	52.6			
DR net replacements	(955.9)	(400.1)	(125.2)	(37.3)	(5.3)	(14.4)	0.0	(14.2)	(65.1)	0.0			
EE net replacements	(9.2)	(4.1)	(1.7)	0.0	0.0	0.0	0.0	0.0	0.0	0.0			
RPM load management @ 01-Jun-16	13,629.6	5,307.0	1,964.7	1,776.8	102.4	644.0	238.3	734.3	1,986.0	523.4			
DR cleared	11,623.2	4,545.3	1,610.4	1,445.4	86.3	389.6	151.7	639.6	1,049.8	290.3	1,600.8	805.8	811.9
EE cleared	1,611.2	411.9	105.4	234.6	2.0	23.0	6.0	110.0	153.1	35.7	727.7	124.6	41.6
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	13,234.4	4,957.2	1,715.8	1,680.0	88.3	412.6	157.7	749.6	1,202.9	326.0	2,328.5	930.4	853.5
DR cleared	11,084.4	4,286.0	1,674.6	1,183.1	86.8	382.2	132.6	523.1	877.0	267.6	1,876.7	660.0	716.2
EE cleared	1,246.5	258.6	54.3	162.3	0.0	14.1	1.8	66.4	38.8	5.6	744.4	95.9	25.0
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-18	12,330.9	4,544.6	1,728.9	1,345.4	86.8	396.3	134.4	589.5	915.8	273.2	2,621.1	755.9	741.2

Table 5-11 RPM load management cleared capacity and ILR: 2007/2008 through 2018/2019[70,71,72]

	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	12,481.1	12,998.4	1,534.8	1,596.3	0.0	0.0
2017/2018	11,202.1	11,623.2	1,554.4	1,611.2	0.0	0.0
2018/2019	10,229.3	11,084.4	1,150.5	1,246.5	0.0	0.0

67 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

68 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.

69 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.

70 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.

71 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.

72 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 5-12 RPM load management statistics: June 1, 2007 to June 1, 2018[73,74]

	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	14,015.9	14,594.7	(917.8)	(955.9)	(8.8)	(9.2)	13,089.3	13,629.6
01-Jun-17	12,756.5	13,234.4	0.0	0.0	0.0	0.0	12,756.5	13,234.4
01-Jun-18	11,379.8	12,330.9	0.0	0.0	0.0	0.0	11,379.8	12,330.9

Market Conduct

Offer Caps and Offer Floors

Market power mitigation measures were applied to Capacity Resources such that the sell offer was set equal to the defined offer cap when the Capacity Market Seller failed the market structure test for the auction, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, would have increased the market clearing price.[75,76,77]

Avoidable costs are the costs that a generation owner would not incur if the generating unit did not operate for one year, in particular the delivery year.[78] In the calculation of avoidable costs, there is no presumption that the unit would retire as the alternative to operating, although that possibility could be reflected if the owner documented that retirement was the alternative. Avoidable costs may also include annual capital recovery associated with investments required to maintain a unit as a Generation Capacity Resource, termed Avoidable Project Investment Recovery (APIR). Avoidable cost-based offer caps are defined to be net of revenues from all other PJM markets and unit-specific bilateral contracts. Capacity resource owners could provide ACR data by providing their own unit-specific data or by selecting the default ACR values. The specific components of avoidable costs are defined in the PJM Tariff.[79]

The opportunity cost option allows Capacity Market Sellers to input a documented price available in a market external to PJM, subject to export limits. If the relevant RPM market clears above the opportunity cost, the Generation Capacity Resource is sold in the RPM market. If the opportunity cost is greater than the clearing price and the Generation Capacity Resource does not clear in the RPM market, it is available to sell in the external market.

Effective April 12, 2011, the RPM Minimum Offer Price Rule (MOPR) was changed.[80] The changes to the MOPR included updating the calculation of the net Cost of New Entry (CONE) for combined cycle (CC) and combustion turbine (CT) plants which is used as a benchmark value in assessing the competitiveness of a sell offer, increasing the percentage value used in the screen to 90 percent for CC and CT plants, eliminating the net-short requirement as a prerequisite for applying the MOPR, eliminating the impact screen, revising the process for reviewing proposed exceptions to the defined minimum sell offer price, and clarifying which resources are subject to the MOPR along with the duration of mitigation. Subsequent FERC Orders revised the MOPR, including clarification on the duration of mitigation, which resources are subject to MOPR, and the MOPR review process.[81]

Effective May 3, 2013, the RPM Minimum Offer Price Rule (MOPR) was changed again.[82] The changes to the MOPR included establishing Competitive Entry and Self Supply Exemptions while also retaining the unit specific exemption process for those that do not qualify for the Competitive Entry or Self Supply Exemptions; changing the applicability of MOPR to include only combustion turbine, combined cycle, integrated gasification

73 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.

74 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.

75 See OATT Attachment DD § 6.5.

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

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

78 OATT Attachment DD § 6.8 (b).

79 OATT Attachment DD § 6.8 (a).

80 135 FERC ¶ 61,022 (2011).

81 135 FERC ¶ 61,022 (2011), order on reh'g, 137 FERC ¶ 61,145 (2011).

82 143 FERC ¶ 61,090 (2013).

combined cycle (IGCC) technologies while excluding units primarily fueled with landfill gas or cogeneration units which are certified or self-certified as Qualifying Facilities (QFs); changing the applicability to increases in installed capacity of 20.0 MW or more combined for all units at a single point of interconnection to the Transmission System; changing the applicability to include the full capability of repowering of plants based on combustion turbine, combined cycle, IGCC technology; increasing the screen from 90 percent to 100 percent of the applicable net CONE values; and broadening the region subject to MOPR to the entire RTO from constrained LDAs only.

2015/2016 RPM Base Residual Auction

As shown in Table 5-13, 1,168 generation resources submitted offers in the 2015/2016 RPM Base Residual Auction. Unit-specific offer caps were calculated for 196 generation resources (16.8 percent) including 171 generation resources (14.6 percent) with an Avoidable Project Investment Recovery Rate (APIR) component and 17 generation resources (1.5 percent) without an APIR component. The MMU calculated offer caps for 670 generation resources (57.4 percent), of which 478 were based on the technology specific default (proxy) ACR values (40.9 percent). Of the 1,168 generation resources, 32 Planned Generation Capacity Resources had uncapped offers (2.7 percent), 25 generation resources (2.1 percent) had uncapped planned uprates along with default ACR based offer caps calculated for the existing portion, seven generation resources (0.6 percent) had uncapped planned uprates along with price taker status for the existing portion, while the remaining 459 generation resources (39.3 percent) were price takers, of which the offers for 458 generation resources were zero and the offer for one generation resources was set to zero because no data were submitted.

Of the 1,168 generation resources which submitted offers, 171 (14.6 percent) included an APIR component. As shown in Table 5-17, the weighted-average gross ACR for resources with APIR ($401.95 per MW-day) and the weighted-average offer caps, net of net revenues, for resources with APIR ($246.63 per MW-day) were higher than for resources without an APIR component, including resources for which the default ACR value was selected. The APIR component added an average of $238.79 per MW-day to the ACR value of the APIR resources. The default ACR values included an average APIR of $1.48 per MW-day, which is the average APIR ($14.42 per MW-day) for the previously estimated default ACR values in the 2014/2015 BRA escalated using the most recent Handy-Whitman Index value. The highest APIR for a technology ($293.45 per MW-day) was for combustion turbine (CT) units. The maximum APIR effect ($776.46 per MW-day) is the maximum amount by which an offer cap was increased by APIR.

2015/2016 RPM First Incremental Auction

As shown in Table 5-13, 131 generation resources submitted offers in the 2015/2016 RPM First Incremental Auction. Unit-specific offer caps were calculated for 20 generation resources (15.3 percent), including 16 generation resources (12.2 percent) with an Avoidable Project Investment Recovery Rate (APIR). The MMU calculated offer caps for 45 generation resources (34.4 percent), of which 25 (19.1 percent) were based on the technology specific default (proxy) ACR values. Of the 221 generation resources, three Planned Generation Capacity Resources had uncapped offers (2.3 percent), one generation resource had an uncapped planned uprate along with a default ACR based offer cap for the existing portion (0.8 percent), while the remaining 83 generation resources were price takers (63.4 percent). Market power mitigation was applied to the sell offer for one generation resource.

2015/2016 RPM Second Incremental Auction

As shown in Table 5-13, 80 generation resources submitted offers in the 2015/2016 RPM Second Incremental Auction. Unit-specific offer caps were calculated for 16 generation resources (20.0 percent of all generation resources), of which 16 generation resources included an APIR component. The MMU calculated offer caps for 25 generation resources (31.3 percent), of which nine were based on the technology specific default (proxy) ACR values (11.3 percent). Of the 80 generation resources, three Planned Generation Capacity Resources had uncapped offers (3.8 percent), while the remaining 52 generation resources were price takers (65.0 percent). Market power mitigation was applied to the sell offers for three generation resources.

2015/2016 RPM Third Incremental Auction

As shown in Table 5-13, 214 generation resources submitted offers in the 2015/2016 RPM Third Incremental Auction. Unit-specific offer caps were calculated for seven generation resources (3.3 percent of all generation resources), of which seven generation resources included an APIR component. The MMU calculated offer caps for 23 generation resources (10.7 percent), of which 16 were based on the technology specific default (proxy) ACR values (7.5 percent). Of the 214 generation resources, 10 Planned Generation Capacity Resources had uncapped offers (4.7 percent), while the remaining 86 generation resources were price takers (40.2 percent). Market power mitigation was applied to the sell offers for one generation resource.

2016/2017 RPM Base Residual Auction

As shown in Table 5-14, 1,199 generation resources submitted offers in the 2016/2017 RPM Base Residual Auction. Unit-specific offer caps were calculated for 152 generation resources (12.7 percent), including 138 generation resources (11.5 percent) with an Avoidable Project Investment Recovery Rate (APIR) and one generation resource (0.1 percent) without an APIR component. The MMU calculated offer caps for 638 generation resources (53.2 percent), of which 491 (41.0 percent) were based on the technology specific default (proxy) ACR values. Of the 1,199 generation resources, 31 Planned Generation Capacity Resources had uncapped offers (2.6 percent), 15 generation resources had uncapped planned uprates along with default ACR based offer caps calculated for the existing portion (1.3 percent), and 11 generation resources had uncapped planned uprates along with price taker status for the existing portion (0.9 percent), while the remaining 519 generation resources were price takers (43.3 percent). Market power mitigation was applied to the sell offers for 50 generation resources.

Of the 1,199 generation resources which submitted offers, 138 (11.5 percent) included an APIR component. As shown in Table 5-18, the weighted average gross ACR for units with APIR ($352.84 per MW-day) and the weighted-average offer caps, net of net revenues, for units with APIR ($180.23 per MW-day) decreased from the 2015/2016 BRA values of $401.95 per MW-day and $246.63 per MW-day, due primarily to lower weighted average gross ACRs for combined cycle, combustion turbine, oil and gas steam units, and subcritical/supercritical coal units. The APIR component added an average of $191.19 per MW-day to the ACR value of the APIR units compared to $238.79 per MW-day in the 2015/2016 BRA. The highest APIR for a technology ($236.99 per MW-day) was for subcritical/supercritical coal units. The maximum APIR effect ($773.08 per MW-day) is the maximum amount by which an offer cap was increased by APIR.

2016/2017 RPM First Incremental Auction

As shown in Table 5-14, 115 generation resources submitted offers in the 2016/2017 RPM First Incremental Auction. Unit-specific offer caps were calculated for 37 generation resources (32.2 percent of all generation resources), of which 32 generation resources (27.8 percent) included an APIR component. The MMU calculated offer caps for 62 generation resources (53.9 percent), of which 25 were based on the technology specific default (proxy) ACR values (21.7 percent). Of the 115 generation resources, one Planned Generation Capacity Resources had uncapped offers (0.9 percent), while the remaining 52 generation resources were price takers (45.2 percent). Market power mitigation was applied to the sell offers for four generation resources.

2016/2017 RPM Second Incremental Auction

As shown in Table 5-14, 101 generation resources submitted offers in the 2016/2017 RPM Second Incremental Auction. The MMU calculated offer caps for 45 generation resources (44.6 percent), of which 21 were based on the technology specific default (proxy) ACR values and 24 were unit-specific offer caps (23.8 percent of all generation resources), of which 23 offer caps included an APIR component. Of the 101 generation resources, one Planned Generation Capacity Resource had an uncapped offer (1.0 percent), while the remaining 52 generation resources were price takers (51.5 percent).

2016/2017 CP Transition Incremental Auction

All 709 generation resources which submitted offers in the 2016/2017 CP Transition Incremental Auction were subject to an offer cap of $165.27 per MW-day, which is 50 percent of the Net Cost of New Entry (CONE) used in the 2016/2017 RPM Base Residual Auction.

2017/2018 RPM Base Residual Auction

As shown in Table 5-15, 1,202 generation resources submitted offers in the 2017/2018 RPM Base Residual Auction. Unit-specific offer caps were calculated for 131 generation resources (10.9 percent of all generation resources), of which 122 generation resources (10.1 percent) included an APIR component. The MMU calculated offer caps for 531 generation resources (44.2 percent), of which 400 were based on the technology specific default (proxy) ACR values (33.3 percent). Of the 1,202 generation resources, 28 Planned Generation Capacity Resources had uncapped offers (2.3 percent), while the remaining 637 generation resources were price takers (53.0 percent).

Of the 1,202 generation resources which submitted offers, 122 (10.1 percent) included an APIR component. As shown in Table 5-19, the weighted average gross ACR for units with APIR ($413.87 per MW-day) and the weighted-average offer caps, net of net revenues, for units with APIR ($256.02 per MW-day) increased from the 2016/2017 BRA values of $352.84 per MW-day and $180.23 per MW-day, due to higher weighted average gross ACRs for combined cycle, combustion turbine, subcritical/supercritical coal, and other units. The APIR component added an average of $217.84 per MW-day to the ACR value of the APIR units compared to $191.19 per MW-day in the 2016/2017 BRA. The highest APIR for a technology ($281.82 per MW-day) was for subcritical/supercritical coal units. The maximum APIR effect ($863.76 per MW-day) is the maximum amount by which an offer cap was increased by APIR.

2017/2018 CP Transition Incremental Auction

All 785 generation resources which submitted offers in the 2017/2018 CP Transition Incremental Auction were subject to an offer cap of $210.83 per MW-day, which is 60 percent of the Net Cost of New Entry (CONE) used in the 2017/2018 RPM Base Residual Auction.

2017/2018 RPM First Incremental Auction

As shown in Table 5-15, 118 generation resources submitted offers in the 2017/2018 RPM First Incremental Auction. The MMU calculated offer caps for 53 generation resources (44.9 percent), of which 36 were based on the technology specific default (proxy) ACR values, 17 were unit-specific offer caps with an APIR component (14.4 percent of all generation resources), six Planned Generation Capacity Resources had uncapped offers (5.1 percent), and the remaining 57 generation resources were price takers (48.3 percent).

2018/2019 RPM Base Residual Auction

As shown in Table 5-16, 473 generation resources submitted Base Capacity offers in the 2018/2019 RPM Base Residual Auction. The MMU calculated offer caps for 219 generation resources (46.3 percent), of which 166 were based on the technology specific default (proxy) ACR values, 53 were unit-specific offer caps (11.2 percent of all generation resources), of which 45 included an APIR component, eight Planned Generation Capacity Resources had uncapped offers (1.7 percent), and the remaining 246 generation resources were price takers (52.0 percent).

As shown in Table 5-16, 992 generation resources submitted Capacity Performance offers in the 2018/2019 RPM Base Residual Auction. The MMU calculated offer caps for 35 generation resources (3.5 percent), all of which were unit-specific with an APIR component, 15 Planned Generation Capacity Resources had uncapped offers (1.5 percent), and the remaining 54 generation resources were price takers (5.4 percent). All offers were below the offer caps.

Of the 473 generation resources which submitted Base Capacity offers, 45 (9.5 percent) included an APIR component. Of the 992 generation resources which submitted Capacity Performance offers, 35 (3.5 percent) included an APIR component. As shown in Table 5-20, the weighted average gross ACR for units with APIR was $406.58 per MW-day for Base Capacity Resources and $496.37 per MW-day for Capacity Performance Resources. The weighted average offer caps, net of net revenues, for units with APIR was $321.80 per MW-day for Base Capacity Resources and $356.54 per MW-day for Capacity Performance Resources. The APIR component added to the ACR value of the APIR units an average of $281.13 per MW-day for Base Capacity Resources and $344.93 for Capacity Performance Resources. The maximum APIR effect ($1,051.98 per MW-day for Base Capacity Resources and Capacity Performance Resources) is the maximum amount by which an offer cap was increased by APIR. The CPQR component added to the ACR value of the APIR units an average of $0.00 per MW-day for Base Capacity Resources and $10.08 per MW-day for Capacity Performance Resources.

Table 5-13 ACR statistics: 2015/2016 RPM Auctions

	2015/2016 Base Residual Auction		2015/2016 First Incremental Auction		2015/2016 Second Incremental Auction		2015/2016 Third Incremental Auction	
Offer Cap/Mitigation Type	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered
Default ACR	449	38.4%	24	18.3%	9	11.3%	16	7.5%
Unit specific ACR (APIR)	171	14.6%	16	12.2%	16	20.0%	7	3.3%
Unit specific ACR (APIR and CPQR)	NA	NA	NA	NA	NA	NA	NA	NA
Unit specific ACR (non-APIR)	17	1.5%	0	0.0%	0	0.0%	0	0.0%
Unit specific ACR (non-APIR and CPQR)	NA	NA	NA	NA	NA	NA	NA	NA
Opportunity cost input	4	0.3%	4	3.1%	0	0.0%	0	0.0%
Default ACR and opportunity cost	4	0.3%	0	0.0%	0	0.0%	0	0.0%
Net CONE times B	NA	NA	NA	NA	NA	NA	NA	NA
Offer cap of 1.1 times BRA clearing price elected	NA	NA	NA	NA	NA	NA	95	44.4%
Uncapped planned uprate and default ACR	25	2.1%	1	0.8%	0	0.0%	0	0.0%
Uncapped planned uprate and opportunity cost	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Uncapped planned uprate and Net CONE times B	NA	NA	NA	NA	NA	NA	NA	NA
Uncapped planned uprate and price taker	7	0.6%	0	0.0%	0	0.0%	0	0.0%
Uncapped planned uprate and 1.1 times BRA clearing price elected	NA	NA	NA	NA	NA	NA	0	0.0%
Uncapped planned generation resources	32	2.7%	3	2.3%	3	3.8%	10	4.7%
Existing generation resources as price takers	459	39.3%	83	63.4%	52	65.0%	86	40.2%
Total Generation Capacity Resources offered	1,168	100.0%	131	100.0%	80	100.0%	214	100.0%

Table 5-14 ACR statistics: 2016/2017 RPM Auctions

	2016/2017 Base Residual Auction		2016/2017 First Incremental Auction		2016/2017 Second Incremental Auction	
Offer Cap/Mitigation Type	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered
Default ACR	471	39.3%	24	20.9%	17	16.8%
Unit specific ACR (APIR)	138	11.5%	32	27.8%	23	22.8%
Unit specific ACR (APIR and CPQR)	NA	NA	NA	NA	NA	NA
Unit specific ACR (non-APIR)	1	0.1%	4	3.5%	0	0.0%
Unit specific ACR (non-APIR and CPQR)	NA	NA	NA	NA	NA	NA
Opportunity cost input	8	0.7%	1	0.9%	1	1.0%
Default ACR and opportunity cost	5	0.4%	0	0.0%	0	0.0%
Net CONE times B	NA	NA	NA	NA	NA	NA
Offer cap of 1.1 times BRA clearing price elected	NA	NA	NA	NA	NA	NA
Uncapped planned uprate and default ACR	15	1.3%	1	0.9%	4	4.0%
Uncapped planned uprate and opportunity cost	0	0.0%	0	0.0%	0	0.0%
Uncapped planned uprate and Net CONE times B	NA	NA	NA	NA	NA	NA
Uncapped planned uprate and price taker	11	0.9%	0	0.0%	3	3.0%
Uncapped planned uprate and 1.1 times BRA clearing price elected	NA	NA	NA	NA	NA	NA
Uncapped planned generation resources	31	2.6%	1	0.9%	1	1.0%
Existing generation resources as price takers	519	43.3%	52	45.2%	52	51.5%
Total Generation Capacity Resources offered	1,199	100.0%	115	100.0%	101	100.0%

Table 5-15 ACR statistics: 2017/2018 RPM Auctions

	2017/2018 Base Residual Auction		2017/2018 First Incremental Auction	
Offer Cap/Mitigation Type	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered
Default ACR	369	30.7%	36	30.5%
Unit specific ACR (APIR)	122	10.1%	17	14.4%
Unit specific ACR (APIR and CPQR)	NA	NA	NA	NA
Unit specific ACR (non-APIR)	4	0.3%	0	0.0%
Unit specific ACR (non-APIR and CPQR)	NA	NA	NA	NA
Opportunity cost input	5	0.4%	0	0.0%
Default ACR and opportunity cost	0	0.0%	0	0.0%
Net CONE times B	NA	NA	NA	NA
Offer cap of 1.1 times BRA clearing price elected	NA	NA	NA	NA
Uncapped planned uprate and default ACR	31	2.6%	0	0.0%
Uncapped planned uprate and opportunity cost	0	0.0%	0	0.0%
Uncapped planned uprate and Net CONE times B	NA	NA	NA	NA
Uncapped planned uprate and price taker	6	0.5%	2	1.7%
Uncapped planned uprate and 1.1 times BRA clearing price elected	NA	NA	NA	NA
Uncapped planned generation resources	28	2.3%	6	5.1%
Existing generation resources as price takers	637	53.0%	57	48.3%
Total Generation Capacity Resources offered	1,202	100.0%	118	100.0%

Table 5-16 ACR statistics: 2018/2019 RPM Auctions

	2018/2019 Base Residual Auction			
	Base Capacity		Capacity Performance	
Offer Cap/Mitigation Type	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered
Default ACR	164	34.7%	0	0.0%
Unit specific ACR (APIR)	45	9.5%	9	0.9%
Unit specific ACR (APIR and CPQR)	0	0	26	2.6%
Unit specific ACR (non-APIR)	1	0.2%	0	0.0%
Unit specific ACR (non-APIR and CPQR)	0	0	0	0.0%
Opportunity cost input	7	1.5%	0	0.0%
Default ACR and opportunity cost	0	0.0%	0	0.0%
Net CONE times B	NA	NA	881	88.8%
Offer cap of 1.1 times BRA clearing price elected	NA	NA	NA	NA
Uncapped planned uprate and default ACR	2	0.4%	0	0.0%
Uncapped planned uprate and opportunity cost	0	0.0%	0	0.0%
Uncapped planned uprate and Net CONE times B	NA	NA	6	0.6%
Uncapped planned uprate and price taker	0	0.0%	1	0.1%
Uncapped planned uprate and 1.1 times BRA clearing price elected	NA	NA	NA	NA
Uncapped planned generation resources	8	1.7%	15	1.5%
Existing generation resources as price takers	246	52.0%	54	5.4%
Total Generation Capacity Resources offered	473	100.0%	992	100.0%

Table 5-17 APIR statistics: 2015/2016 RPM Base Residual Auction

	Weighted-Average ($ per MW-day UCAP)					
	Combined Cycle	Combustion Turbine	Oil or Gas Steam	Subcritical/ Supercritical Coal	Other	Total
Non-APIR units						
ACR	$50.33	$36.07	$85.46	$232.16	$81.94	$113.51
Net revenues	$160.85	$34.32	$35.86	$248.90	$265.61	$148.07
Offer caps	$5.89	$11.34	$49.70	$26.50	$7.73	$17.86
APIR units						
ACR	$163.25	$334.57	$192.87	$471.60	$41.74	$401.95
Net revenues	$8.33	$17.93	$17.39	$221.10	$57.91	$166.81
Offer caps	$154.94	$316.69	$175.53	$264.18	$8.15	$246.63
APIR	$116.55	$293.45	$87.42	$265.13	$23.35	$238.79
Maximum APIR effect						$776.46

Table 5-18 APIR statistics: 2016/2017 RPM Base Residual Auction

	Weighted-Average ($ per MW-day UCAP)					
	Combined Cycle	Combustion Turbine	Oil or Gas Steam	Subcritical/ Supercritical Coal	Other	Total
Non-APIR units						
ACR	$42.11	$33.46	$78.32	$215.57	$75.69	$102.23
Net revenues	$194.19	$56.23	$42.33	$208.04	$228.59	$150.24
Offer caps	$4.80	$7.64	$36.43	$29.03	$4.63	$16.07
APIR units						
ACR	$52.48	$93.23	$188.80	$432.72	$53.20	$352.84
Net revenues	$72.50	$17.49	$16.68	$222.52	$62.15	$177.14
Offer caps	$13.92	$79.12	$167.29	$213.88	$5.91	$180.23
APIR	$14.45	$57.71	$64.90	$236.99	$23.01	$191.19
Maximum APIR effect						$773.08

Table 5-19 APIR statistics: 2017/2018 RPM Base Residual Auction[83]

	Weighted-Average ($ per MW-day UCAP)					
	Combined Cycle	Combustion Turbine	Oil or Gas Steam	Subcritical/ Supercritical Coal	Other	Total
Non-APIR units						
ACR	$36.92	$31.52	$84.84	$182.60	$47.54	$94.78
Net revenues	$121.99	$51.56	$13.98	$116.61	$158.64	$92.26
Offer caps	$2.17	$9.90	$71.43	$70.61	$8.28	$36.87
APIR units						
ACR	$136.06	$97.45	$180.36	$440.80	$554.65	$413.87
Net revenues	$0.00	$1.84	$42.70	$92.18	$382.31	$137.71
Offer caps	$136.06	$95.61	$137.66	$319.61	$163.77	$256.02
APIR	$95.80	$55.48	$92.23	$281.82	$128.37	$217.84
Maximum APIR effect						$863.76

83 Effective for the 2017/2018 and subsequent Delivery Years, the ACR technology classes of waste coal small and large were eliminated and combined with subcritical and supercritical coal to form the Coal Fired ACR technology class. Waste coal resources were included in the other category in prior versions of this table. For the 2017/2018 BRA, waste coal resources were included in the coal fired category.

Table 5-20 APIR statistics: 2018/2019 RPM Base Residual Auction

	Weighted-Average ($ per MW-day UCAP)	
	Base Capacity	Capacity Performance
Non-APIR units		
ACR	$85.36	$197.45
Net revenues	$117.38	$131.61
Offer caps	$30.74	$65.83
APIR units		
ACR	$406.58	$496.37
Net revenues	$83.43	$139.25
Offer caps	$321.80	$356.54
APIR	$281.13	$344.93
CPQR	$0.00	$10.08
Maximum APIR effect	$1,051.98	$1,051.98

Market Performance

Figure 5-6 shows cleared MW weighted average capacity market prices on a Delivery Year basis for the entire history of the PJM capacity markets. Table 5-21 shows RPM clearing prices for all RPM Auctions held through 2015.

Figure 5-7 shows the RPM cleared MW weighted average prices for each LDA for the current Delivery Year and all results for auctions for future Delivery Years that have been held through 2015. A summary of these weighted average prices is given in Table 5-22.

Table 5-23 shows RPM revenue by resource type for all RPM Auctions held through 2015 with $5.0 billion for new/repower/reactivated generation resources based on the unforced MW cleared and the resource clearing prices. A resource classified as "new/repower/reactivated" is a capacity resource addition since the implementation of RPM and is considered "new/repower/reactivated" for its initial offer and all its subsequent offers in RPM Auctions.

Table 5-24 shows RPM revenue by calendar year for all RPM Auctions held through 2015. In 2015, RPM revenue was $9.0 billion.

Table 5-25 shows the RPM annual charges to load. For the 2015/2016 Delivery Year, RPM annual charges to load are $9.6 billion.

Table 5-21 Capacity prices: 2007/2008 through 2018/2019 RPM Auctions

		RPM Clearing Price ($ per MW-day)							
	Product Type	RTO	MAAC	APS	PPL	EMAAC	SWMAAC	DPL South	PSEG
2007/2008 BRA		$40.80	$40.80	$40.80	$40.80	$197.67	$188.54	$197.67	$197.67
2008/2009 BRA		$111.92	$111.92	$111.92	$111.92	$148.80	$210.11	$148.80	$148.80
2008/2009 Third Incremental Auction		$10.00	$10.00	$10.00	$10.00	$10.00	$223.85	$10.00	$10.00
2009/2010 BRA		$102.04	$191.32	$191.32	$191.32	$191.32	$237.33	$191.32	$191.32
2009/2010 Third Incremental Auction		$40.00	$86.00	$86.00	$86.00	$86.00	$86.00	$86.00	$86.00
2010/2011 BRA		$174.29	$174.29	$174.29	$174.29	$174.29	$174.29	$186.12	$174.29
2010/2011 Third Incremental Auction		$50.00	$50.00	$50.00	$50.00	$50.00	$50.00	$50.00	$50.00
2011/2012 BRA		$110.00	$110.00	$110.00	$110.00	$110.00	$110.00	$110.00	$110.00
2011/2012 First Incremental Auction		$55.00	$55.00	$55.00	$55.00	$55.00	$55.00	$55.00	$55.00
2011/2012 ATSI FRR Integration Auction		$108.89	$108.89	$108.89	$108.89	$108.89	$108.89	$108.89	$108.89
2011/2012 Third Incremental Auction		$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00
2012/2013 BRA		$16.46	$133.37	$16.46	$133.37	$139.73	$133.37	$222.30	$139.73
2012/2013 ATSI FRR Integration Auction		$20.46	$20.46	$20.46	$20.46	$20.46	$20.46	$20.46	$20.46
2012/2013 First Incremental Auction		$16.46	$16.46	$16.46	$16.46	$153.67	$16.46	$153.67	$153.67
2012/2013 Second Incremental Auction		$13.01	$13.01	$13.01	$13.01	$48.91	$13.01	$48.91	$48.91
2012/2013 Third Incremental Auction		$2.51	$2.51	$2.51	$2.51	$2.51	$2.51	$2.51	$2.51
2013/2014 BRA		$27.73	$226.15	$27.73	$226.15	$245.00	$226.15	$245.00	$245.00
2013/2014 First Incremental Auction		$20.00	$20.00	$20.00	$20.00	$178.85	$54.82	$178.85	$178.85
2013/2014 Second Incremental Auction		$7.01	$10.00	$7.01	$10.00	$40.00	$10.00	$40.00	$40.00
2013/2014 Third Incremental Auction		$4.05	$30.00	$4.05	$30.00	$188.44	$30.00	$188.44	$188.44
2014/2015 BRA	Limited	$125.47	$125.47	$125.47	$125.47	$125.47	$125.47	$125.47	$125.47
2014/2015 BRA	Extended Summer	$125.99	$136.50	$125.99	$136.50	$136.50	$136.50	$136.50	$136.50
2014/2015 BRA	Annual	$125.99	$136.50	$125.99	$136.50	$136.50	$136.50	$136.50	$136.50
2014/2015 First Incremental Auction	Limited	$0.03	$5.23	$0.03	$5.23	$5.23	$5.23	$5.23	$5.23
2014/2015 First Incremental Auction	Extended Summer	$5.54	$16.56	$5.54	$16.56	$16.56	$16.56	$16.56	$16.56
2014/2015 First Incremental Auction	Annual	$5.54	$16.56	$5.54	$16.56	$16.56	$16.56	$16.56	$16.56
2014/2015 Second Incremental Auction	Limited	$25.00	$56.94	$25.00	$56.94	$56.94	$56.94	$56.94	$56.94
2014/2015 Second Incremental Auction	Extended Summer	$25.00	$56.94	$25.00	$56.94	$56.94	$56.94	$56.94	$56.94
2014/2015 Second Incremental Auction	Annual	$25.00	$56.94	$25.00	$56.94	$56.94	$56.94	$56.94	$56.94
2014/2015 Third Incremental Auction	Limited	$25.51	$132.20	$25.51	$132.20	$132.20	$132.20	$132.20	$132.20
2014/2015 Third Incremental Auction	Extended Summer	$25.51	$132.20	$25.51	$132.20	$132.20	$132.20	$132.20	$132.20
2014/2015 Third Incremental Auction	Annual	$25.51	$132.20	$25.51	$132.20	$132.20	$132.20	$132.20	$132.20
2015/2016 BRA	Limited	$118.54	$150.00	$118.54	$150.00	$150.00	$150.00	$150.00	$150.00
2015/2016 BRA	Extended Summer	$136.00	$167.46	$136.00	$167.46	$167.46	$167.46	$167.46	$167.46
2015/2016 BRA	Annual	$136.00	$167.46	$136.00	$167.46	$167.46	$167.46	$167.46	$167.46
2015/2016 First Incremental Auction	Limited	$43.00	$111.00	$43.00	$111.00	$111.00	$111.00	$111.00	$122.95
2015/2016 First Incremental Auction	Extended Summer	$43.00	$111.00	$43.00	$111.00	$111.00	$111.00	$111.00	$122.95
2015/2016 First Incremental Auction	Annual	$43.00	$111.00	$43.00	$111.00	$111.00	$111.00	$111.00	$122.95
2015/2016 Second Incremental Auction	Limited	$123.56	$141.12	$123.56	$141.12	$141.12	$141.12	$141.12	$155.02
2015/2016 Second Incremental Auction	Extended Summer	$136.00	$153.56	$136.00	$153.56	$153.56	$153.56	$153.56	$167.46
2015/2016 Second Incremental Auction	Annual	$136.00	$153.56	$136.00	$153.56	$153.56	$153.56	$153.56	$167.46
2015/2016 Third Incremental Auction	Limited	$100.76	$122.33	$100.76	$122.33	$122.33	$122.33	$122.33	$122.56
2015/2016 Third Incremental Auction	Extended Summer	$163.20	$184.77	$163.20	$184.77	$184.77	$184.77	$184.77	$185.00
2015/2016 Third Incremental Auction	Annual	$163.20	$184.77	$163.20	$184.77	$184.77	$184.77	$184.77	$185.00
2016/2017 BRA	Limited	$59.37	$119.13	$59.37	$119.13	$119.13	$119.13	$119.13	$219.00
2016/2017 BRA	Extended Summer	$59.37	$119.13	$59.37	$119.13	$119.13	$119.13	$119.13	$219.00
2016/2017 BRA	Annual	$59.37	$119.13	$59.37	$119.13	$119.13	$119.13	$119.13	$219.00
2016/2017 First Incremental Auction	Limited	$53.93	$89.35	$53.93	$89.35	$89.35	$89.35	$89.35	$214.44
2016/2017 First Incremental Auction	Extended Summer	$60.00	$119.13	$60.00	$119.13	$119.13	$119.13	$119.13	$244.22
2016/2017 First Incremental Auction	Annual	$60.00	$119.13	$60.00	$119.13	$119.13	$119.13	$119.13	$244.22
2016/2017 Second Incremental Auction	Limited	$31.00	$71.00	$31.00	$71.00	$71.00	$71.00	$71.00	$99.01
2016/2017 Second Incremental Auction	Extended Summer	$31.00	$71.00	$31.00	$71.00	$71.00	$71.00	$71.00	$99.01
2016/2017 Second Incremental Auction	Annual	$31.00	$71.00	$31.00	$71.00	$71.00	$71.00	$71.00	$99.01
2016/2017 Capacity Performance Transition Auction	Capacity Performance	$134.00	$134.00	$134.00	$134.00	$134.00	$134.00	$134.00	$134.00
2017/2018 BRA	Limited	$106.02	$106.02	$106.02	$40.00	$106.02	$106.02	$106.02	$201.02
2017/2018 BRA	Extended Summer	$120.00	$120.00	$120.00	$53.98	$120.00	$120.00	$120.00	$215.00
2017/2018 BRA	Annual	$120.00	$120.00	$120.00	$120.00	$120.00	$120.00	$120.00	$215.00
2017/2018 Capacity Performance Transition Auction	Capacity Performance	$151.50	$151.50	$151.50	$151.50	$151.50	$151.50	$151.50	$151.50
2017/2018 First Incremental Auction	Limited	$84.00	$84.00	$84.00	$84.00	$84.00	$84.00	$84.00	$143.08
2017/2018 First Incremental Auction	Extended Summer	$84.00	$84.00	$84.00	$84.00	$84.00	$84.00	$84.00	$143.08
2017/2018 First Incremental Auction	Annual	$84.00	$84.00	$84.00	$84.00	$84.00	$84.00	$84.00	$143.08
2018/2019 BRA	Base Capacity	$149.98	$149.98	$149.98	$75.00	$210.63	$149.98	$210.63	$210.63
2018/2019 BRA	Capacity Performance	$164.77	$164.77	$164.77	$164.77	$225.42	$164.77	$225.42	$225.42

Table 5-21 Capacity prices: 2007/2008 through 2018/2019 RPM Auctions *(continued)*

		RPM Clearing Price ($ per MW-day)			
	Product Type	PSEG North	Pepco	ATSI	ComEd
2007/2008 BRA		$197.67	$188.54		$40.80
2008/2009 BRA		$148.80	$210.11		$111.92
2008/2009 Third Incremental Auction		$10.00	$223.85		$10.00
2009/2010 BRA		$191.32	$237.33		$102.04
2009/2010 Third Incremental Auction		$86.00	$86.00		$40.00
2010/2011 BRA		$174.29	$174.29		$174.29
2010/2011 Third Incremental Auction		$50.00	$50.00		$50.00
2011/2012 BRA		$110.00	$110.00		$110.00
2011/2012 First Incremental Auction		$55.00	$55.00		$55.00
2011/2012 ATSI FRR Integration Auction		$108.89	$108.89	$108.89	$108.89
2011/2012 Third Incremental Auction		$5.00	$5.00	$5.00	$5.00
2012/2013 BRA		$185.00	$133.37		$16.46
2012/2013 ATSI FRR Integration Auction		$20.46	$20.46	$20.46	$20.46
2012/2013 First Incremental Auction		$153.67	$16.46	$16.46	$16.46
2012/2013 Second Incremental Auction		$48.91	$13.01	$13.01	$13.01
2012/2013 Third Incremental Auction		$2.51	$2.51	$2.51	$2.51
2013/2014 BRA		$245.00	$247.14	$27.73	$27.73
2013/2014 First Incremental Auction		$178.85	$54.82	$20.00	$20.00
2013/2014 Second Incremental Auction		$40.00	$10.00	$7.01	$7.01
2013/2014 Third Incremental Auction		$188.44	$30.00	$4.05	$4.05
2014/2015 BRA	Limited	$213.97	$125.47	$125.47	$125.47
2014/2015 BRA	Extended Summer	$225.00	$136.50	$125.99	$125.99
2014/2015 BRA	Annual	$225.00	$136.50	$125.99	$125.99
2014/2015 First Incremental Auction	Limited	$399.62	$5.23	$0.03	$0.03
2014/2015 First Incremental Auction	Extended Summer	$410.95	$16.56	$5.54	$5.54
2014/2015 First Incremental Auction	Annual	$410.95	$16.56	$5.54	$5.54
2014/2015 Second Incremental Auction	Limited	$310.00	$56.94	$25.00	$25.00
2014/2015 Second Incremental Auction	Extended Summer	$310.00	$56.94	$25.00	$25.00
2014/2015 Second Incremental Auction	Annual	$310.00	$56.94	$25.00	$25.00
2014/2015 Third Incremental Auction	Limited	$256.76	$132.20	$25.51	$25.51
2014/2015 Third Incremental Auction	Extended Summer	$256.76	$132.20	$25.51	$25.51
2014/2015 Third Incremental Auction	Annual	$256.76	$132.20	$25.51	$25.51
2015/2016 BRA	Limited	$150.00	$150.00	$304.62	$118.54
2015/2016 BRA	Extended Summer	$167.46	$167.46	$322.08	$136.00
2015/2016 BRA	Annual	$167.46	$167.46	$357.00	$136.00
2015/2016 First Incremental Auction	Limited	$122.95	$111.00	$168.37	$43.00
2015/2016 First Incremental Auction	Extended Summer	$122.95	$111.00	$168.37	$43.00
2015/2016 First Incremental Auction	Annual	$122.95	$111.00	$168.37	$43.00
2015/2016 Second Incremental Auction	Limited	$155.02	$141.12	$204.10	$123.56
2015/2016 Second Incremental Auction	Extended Summer	$167.46	$153.56	$216.54	$136.00
2015/2016 Second Incremental Auction	Annual	$167.46	$153.56	$216.54	$136.00
2015/2016 Third Incremental Auction	Limited	$122.56	$122.33	$100.76	$100.76
2015/2016 Third Incremental Auction	Extended Summer	$185.00	$184.77	$163.20	$163.20
2015/2016 Third Incremental Auction	Annual	$185.00	$184.77	$163.20	$163.20
2016/2017 BRA	Limited	$219.00	$119.13	$94.45	$59.37
2016/2017 BRA	Extended Summer	$219.00	$119.13	$114.23	$59.37
2016/2017 BRA	Annual	$219.00	$119.13	$114.23	$59.37
2016/2017 First Incremental Auction	Limited	$214.44	$89.35	$94.45	$53.93
2016/2017 First Incremental Auction	Extended Summer	$244.22	$119.13	$100.52	$60.00
2016/2017 First Incremental Auction	Annual	$244.22	$119.13	$100.52	$60.00
2016/2017 Second Incremental Auction	Limited	$212.53	$71.00	$101.50	$31.00
2016/2017 Second Incremental Auction	Extended Summer	$212.53	$71.00	$101.50	$31.00
2016/2017 Second Incremental Auction	Annual	$212.53	$71.00	$101.50	$31.00
2016/2017 Capacity Performance Transition Auction	Capacity Performance	$134.00	$134.00	$134.00	$134.00
2017/2018 BRA	Limited	$201.02	$106.02	$106.02	$106.02
2017/2018 BRA	Extended Summer	$215.00	$120.00	$120.00	$120.00
2017/2018 BRA	Annual	$215.00	$120.00	$120.00	$120.00
2017/2018 Capacity Performance Transition Auction	Capacity Performance	$151.50	$151.50	$151.50	$151.50
2017/2018 First Incremental Auction	Limited	$143.08	$84.00	$84.00	$84.00
2017/2018 First Incremental Auction	Extended Summer	$143.08	$84.00	$84.00	$84.00
2017/2018 First Incremental Auction	Annual	$143.08	$84.00	$84.00	$84.00
2018/2019 BRA	Base Capacity	$210.63	$149.98	$149.98	$200.21
2018/2019 BRA	Capacity Performance	$225.42	$164.77	$164.77	$215.00

Table 5-22 Weighted average clearing prices by zone: 2015/2016 through 2018/2019

	Weighted Average Clearing Price ($ per MW-day)			
LDA	2015/2016	2016/2017	2017/2018	2018/2019
RTO				
AEP	$134.00	$116.09	$142.01	$162.73
AP	$134.00	$116.09	$142.01	$162.73
ATSI	$327.79	$122.30	$140.81	$162.28
Cleveland	$327.79	$112.36	$140.05	$163.10
ComEd	$134.00	$116.09	$141.05	$213.25
DAY	$134.00	$116.09	$142.01	$162.73
DEOK	$134.00	$116.09	$142.01	$162.73
DLCO	$134.00	$116.09	$142.01	$162.73
Dominion	$134.00	$116.09	$142.01	$162.73
EKPC	$134.00	$116.09	$142.01	$162.73
MAAC				
EMAAC				
AECO	$166.51	$124.26	$138.50	$221.00
DPL	$166.51	$124.26	$138.50	$221.00
DPL South	$166.80	$120.58	$136.25	$221.72
JCPL	$166.51	$124.26	$138.50	$221.00
PECO	$166.51	$124.26	$138.50	$221.00
PSEG	$166.01	$221.95	$209.69	$223.20
PSEG North	$163.94	$219.01	$214.68	$224.67
RECO	$166.51	$124.26	$138.50	$221.00
SWMAAC				
BGE	$159.24	$121.37	$131.02	$143.54
Pepco	$166.03	$119.88	$135.86	$153.20
WMAAC				
Met-Ed	$164.83	$122.97	$140.70	$163.12
PENELEC	$164.83	$122.97	$140.70	$163.12
PPL	$164.83	$122.97	$136.49	$154.01

Table 5-23 RPM revenue by type: 2007/2008 through 2018/2019[84,85]

				Coal		Gas		Hydroelectric	
	Demand Resources	Energy Efficiency Resources	Imports	Existing	New/repower/ reactivated	Existing	New/repower/ reactivated	Existing	New/repower/ reactivated
2007/2008	$5,537,085	$0	$22,225,980	$1,019,060,206	$0	$1,624,111,360	$3,472,667	$209,490,444	$0
2008/2009	$35,349,116	$0	$60,918,903	$1,835,059,769	$0	$2,112,913,366	$9,751,112	$287,850,403	$0
2009/2010	$65,762,003	$0	$56,517,793	$2,409,315,953	$1,854,781	$2,548,801,710	$30,168,831	$364,742,517	$0
2010/2011	$60,235,796	$0	$106,046,871	$2,648,278,766	$3,168,069	$2,823,632,390	$58,065,964	$442,429,815	$0
2011/2012	$55,795,785	$139,812	$185,421,273	$1,586,775,249	$28,330,047	$1,717,850,463	$98,448,693	$278,529,660	$0
2012/2013	$264,387,897	$11,408,552	$13,260,822	$1,014,858,378	$7,568,127	$1,256,096,304	$76,633,409	$179,117,975	$11,397
2013/2014	$558,715,114	$21,598,174	$31,804,645	$1,741,613,525	$12,950,135	$2,153,560,721	$167,844,235	$308,853,673	$25,708
2014/2015	$681,315,139	$42,308,549	$135,573,409	$1,935,468,356	$57,078,818	$2,172,570,169	$205,555,569	$333,941,614	$6,649,774
2015/2016	$903,496,003	$66,652,986	$260,806,674	$2,902,870,267	$63,682,708	$2,672,530,801	$535,039,154	$389,540,948	$15,478,144
2016/2017	$448,199,933	$68,300,425	$244,076,849	$2,137,183,611	$72,217,195	$2,206,685,188	$666,661,496	$283,474,652	$13,927,638
2017/2018	$500,215,206	$81,758,057	$214,757,642	$2,447,236,561	$62,426,717	$2,537,120,329	$979,308,450	$346,315,522	$15,183,161
2018/2019	$634,336,942	$87,432,139	$262,415,658	$2,620,553,513	$76,339,006	$2,964,180,164	$1,434,073,826	$414,477,423	$15,344,022

84 A resource classified as "new/repower/reactivated" is a capacity resource addition since the implementation of RPM and is considered "new/repower/reactivated" for its initial offer and all its subsequent offers in RPM Auctions.

85 The results for the ATSI Integration Auctions are not included in this table.

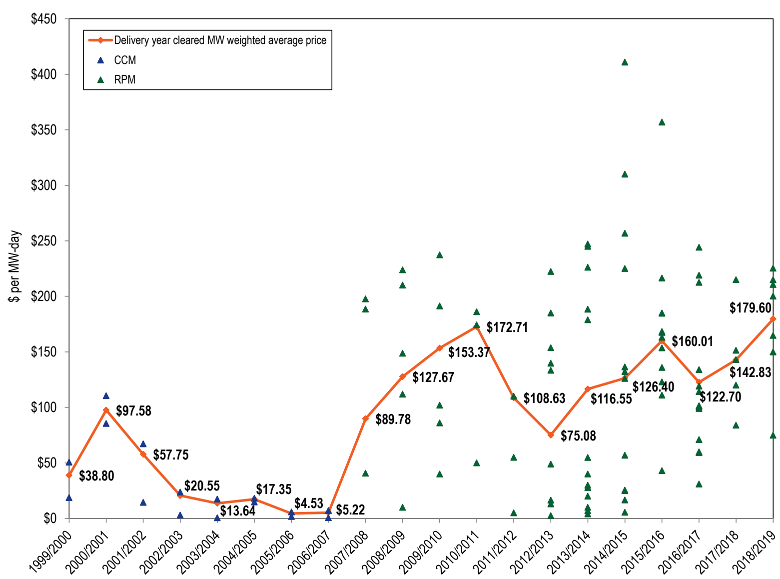
Table 5-23 RPM revenue by type: 2007/2008 through 2018/2019 *(continued)*

Nuclear		Oil		Solar		Solid waste		Wind		
Existing	New/repower/ reactivated	Existing	New/repower/ reactivated	Existing	New/repower/ reactivated	Existing	New/repower/ reactivated	Existing	New/repower/ reactivated	Total revenue
$996,085,233	$0	$340,362,114	$0	$0	$0	$31,512,230	$0	$430,065	$0	$4,252,287,381
$1,322,601,837	$0	$378,756,365	$4,837,523	$0	$0	$35,011,991	$0	$1,180,153	$2,917,048	$6,087,147,586
$1,517,723,628	$0	$450,523,876	$5,676,582	$0	$0	$42,758,762	$523,739	$2,011,156	$6,836,827	$7,503,218,157
$1,799,258,125	$0	$446,000,462	$4,339,539	$0	$0	$40,731,606	$413,503	$1,819,413	$15,232,177	$8,449,652,496
$1,079,386,338	$0	$266,483,502	$967,887	$0	$66,978	$25,636,836	$261,690	$1,072,929	$9,919,881	$5,335,087,023
$762,719,550	$0	$248,611,128	$2,772,987	$0	$1,246,337	$26,840,670	$316,420	$812,644	$5,052,036	$3,871,714,635
$1,346,223,419	$0	$386,561,718	$5,670,399	$0	$3,523,555	$43,943,130	$1,977,705	$1,373,205	$13,538,988	$6,799,778,047
$1,464,950,862	$0	$323,630,668	$4,106,697	$0	$3,836,582	$34,281,137	$1,709,533	$1,524,551	$32,766,219	$7,437,267,646
$1,850,033,226	$0	$401,718,239	$5,947,275	$0	$7,064,983	$35,862,368	$6,179,607	$1,829,269	$42,994,253	$10,161,726,902
$1,483,325,575	$0	$265,462,403	$4,030,823	$0	$6,632,495	$32,520,818	$6,297,639	$1,144,873	$26,093,212	$7,966,234,825
$1,692,199,258	$0	$279,434,857	$3,888,126	$0	$8,393,952	$34,319,981	$8,936,300	$1,298,232	$39,405,929	$9,252,198,278
$1,970,393,801	$0	$342,155,243	$4,047,493	$0	$12,998,289	$37,115,004	$9,521,591	$1,164,910	$52,670,208	$10,939,219,232

Table 5-24 RPM revenue by calendar year: 2007 through 2019[86]

Year	Weighted Average RPM Price ($ per MW-day)	Weighted Average Cleared UCAP (MW)	Effective Days	RPM Revenue
2007	$89.78	129,409.2	214	$2,486,310,108
2008	$111.93	130,223.2	366	$5,334,880,241
2009	$142.74	132,772.0	365	$6,917,391,702
2010	$164.71	134,033.9	365	$8,058,113,907
2011	$135.14	134,105.2	365	$6,615,032,130
2012	$89.01	137,684.7	366	$4,485,656,150
2013	$99.39	154,044.3	365	$5,588,442,225
2014	$122.32	160,668.7	365	$7,173,539,072
2015	$146.10	169,112.0	365	$9,018,343,604
2016	$138.19	176,002.8	366	$8,901,994,574
2017	$134.50	177,921.7	365	$8,734,833,787
2018	$164.39	170,763.0	365	$10,246,047,848
2019	$179.60	166,875.5	151	$4,525,540,011

Figure 5-6 History of PJM capacity prices: 1999/2000 through 2018/2019[87]



86 The results for the ATSI Integration Auctions are not included in this table.

87 The 1999/2000-2006/2007 capacity prices are CCM combined market, weighted average prices. The 2007/2008-2018/2019 capacity prices are RPM weighted average prices. The CCM data points plotted are cleared MW weighted average prices for the daily and monthly markets by Delivery Year. The RPM data points plotted are RPM resource clearing prices. For the 2014/2015 and subsequent Delivery Years, only the prices for Annual Resources or Capacity Performance Resources are plotted.

Figure 5-7 Map of RPM capacity prices: 2015/2016 through 2018/2019

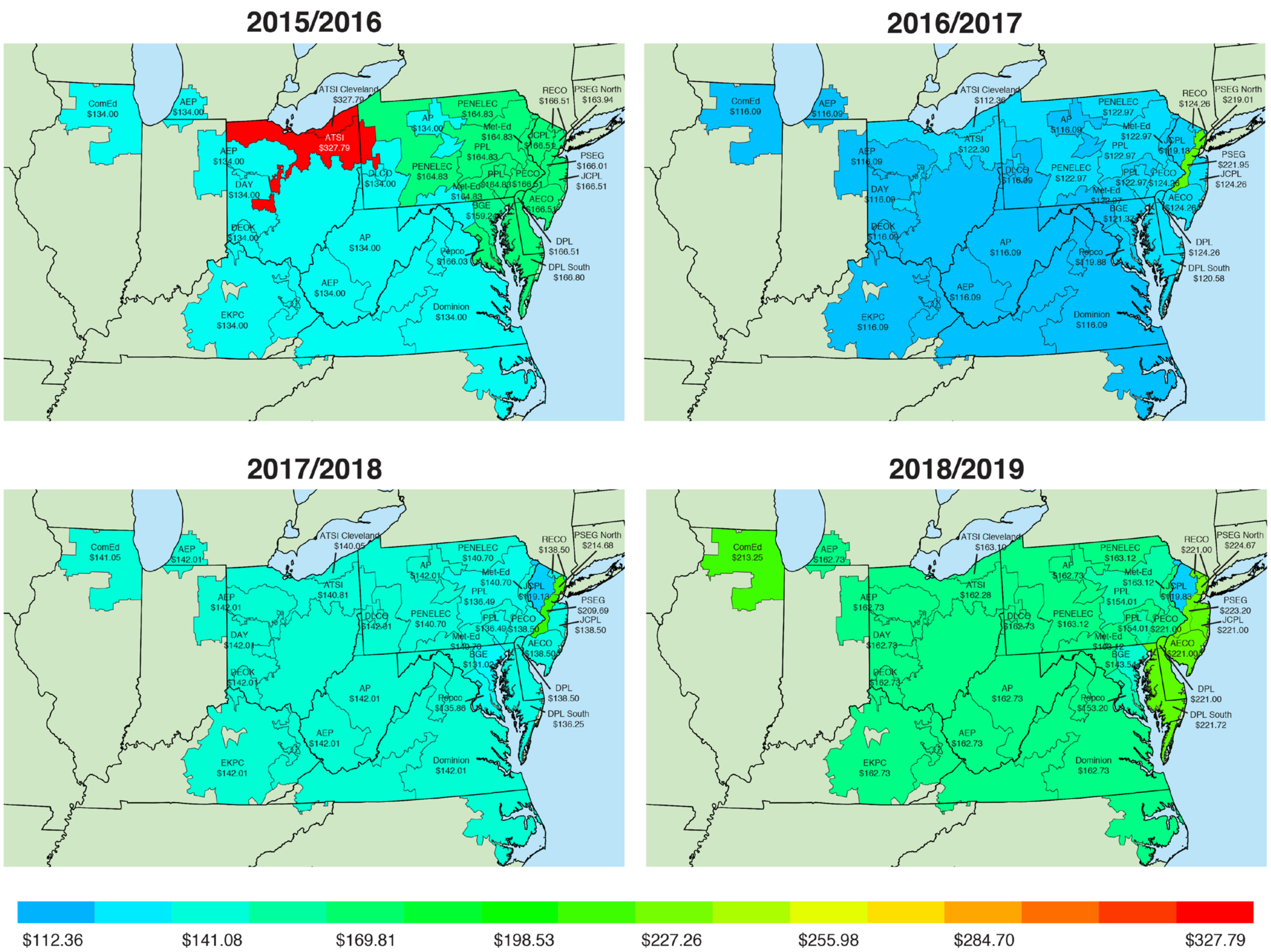


Table 5-25 RPM cost to load: 2015/2016 through 2018/2019 RPM Auctions[88,89,90]

	Net Load Price ($ per MW-day)	UCAP Obligation (MW)	Annual Charges
2015/2016			
Rest of RTO	$135.81	81,984.4	$4,075,305,460
Rest of MAAC	$166.53	53,819.9	$3,280,332,235
PSEG	$166.29	11,398.1	$693,698,017
ATSI	$293.00	14,631.7	$1,569,095,567
Total		161,834.1	$9,618,431,279
2016/2017			
Rest of RTO	$60.13	85,181.9	$1,869,466,854
Rest of MAAC	$120.51	54,674.1	$2,404,986,671
PSEG	$180.48	11,451.4	$754,369,381
ATSI	$91.08	14,631.6	$486,423,274
Total		165,938.9	$5,515,246,180
2017/2018			
Rest of RTO	$149.02	100,253.4	$5,452,838,631
Rest of MAAC	$149.13	46,762.9	$2,545,461,395
PSEG	$205.78	11,480.6	$862,291,793
PPL	$147.33	8,227.7	$442,440,748
Total		166,724.5	$9,303,032,568
2018/2019			
Rest of RTO	$162.44	81,659.7	$4,841,777,199
Rest of MAAC	$215.97	36,256.5	$2,858,052,995
BGE	$156.03	7,948.5	$452,674,129
ComEd	$208.46	25,454.6	$1,936,809,587
Pepco	$154.74	7,315.9	$413,207,985
PPL	$152.74	8,201.7	$457,240,705
Total		166,836.9	$10,959,762,600

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).

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 2015, nuclear units had a capacity factor of 94.5 percent, compared to 94.0 percent in 2014; combined cycle units had a capacity factor of 60.6 percent in 2015, compared to a capacity factor of 55.3 percent in 2014; and steam units, which are primarily coal fired, had a capacity factor of 45.6 percent in 2015, compared to 49.9 percent in 2014.

88 The RPM annual charges are calculated using the rounded, net load prices as posted in the PJM RPM Auction results.

89 There is no separate obligation for DPL South as the DPL South LDA is completely contained within the DPL Zone. There is no separate obligation for PSEG North as the PSEG North LDA is completely contained within the PSEG Zone.

90 Prior to the 2009/2010 Delivery Year, the final UCAP obligation is determined after the clearing of the Second Incremental Auction. For the 2009/2010 through 2011/2012 Delivery Years, the final UCAP obligations are determined after the clearing of the Third Incremental Auction. Effective with the 2012/2013 Delivery Year, the final UCAP obligation is determined after the clearing of the final Incremental Auction. Prior to the 2012/2013 Delivery Year, the Final Zonal Capacity Prices are determined after certification of ILR. Effective with the 2012/2013 Delivery Year, the Final Zonal Capacity Prices are determined after the final Incremental Auction. The 2016/2017, 2017/2018, and 2018/2019 Net Load Prices are not finalized. The 2016/2017, 2017/2018, and 2018/2019 obligation MW are not finalized.

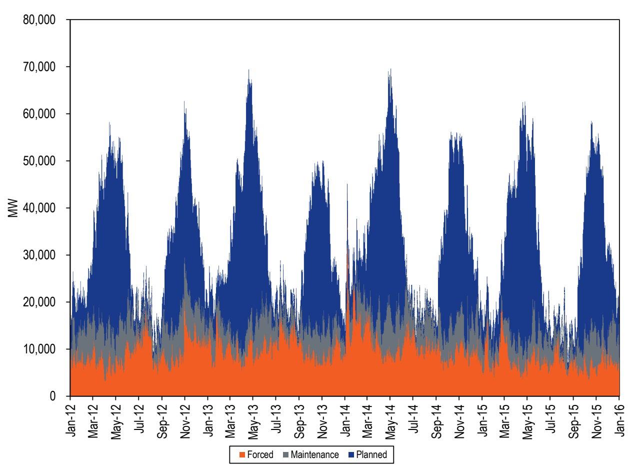
Table 5-26 PJM capacity factor (By unit type (GWh)): 2014 and 2015[91]

	2014		2015		Change in
Unit Type	Generation (GWh)	Capacity Factor	Generation (GWh)	Capacity Factor	2015 from 2014
Battery	6.5	0.7%	7.6	0.5%	(0.3%)
Combined Cycle	126,790.6	55.3%	159,420.8	60.6%	5.4%
Combustion Turbine	9,944.9	3.7%	14,213.8	5.6%	1.9%
Diesel	565.3	14.9%	574.2	15.2%	0.2%
Diesel (Landfill gas)	1,489.0	45.9%	1,508.6	45.6%	(0.3%)
Fuel Cell	222.7	84.7%	227.1	86.4%	1.7%
Nuclear	277,635.6	94.0%	279,106.5	94.5%	0.5%
Pumped Storage Hydro	7,152.9	14.9%	6,038.4	12.8%	(2.1%)
Run of River Hydro	7,241.4	31.1%	7,028.3	29.3%	(1.7%)
Solar	399.8	15.6%	533.0	16.0%	0.5%
Steam	360,995.9	49.9%	301,260.0	45.6%	(4.3%)
Wind	15,540.5	27.8%	16,609.7	28.3%	0.5%
Total	807,985.1	48.8%	786,528.0	48.6%	(0.2%)

Generator Performance Factors

Generator outages fall into three categories: planned, maintenance, and forced. The MW on outage varies throughout the year. For example, the MW on planned outage are generally highest in the spring and fall, as shown in Figure 5-8, 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 Figure 5-12.

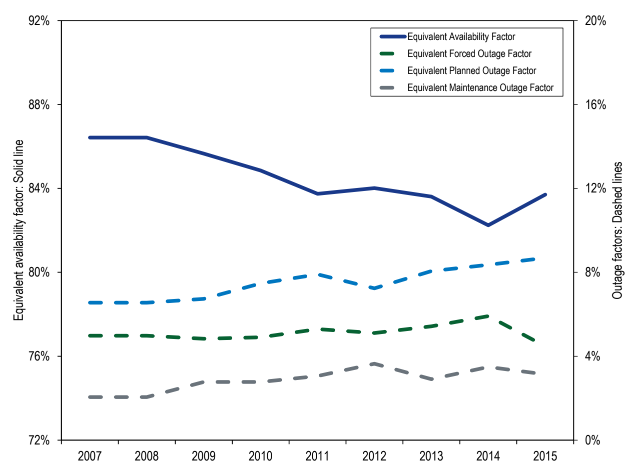
Figure 5-8 PJM outages (MW): 2012 through December 2015



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 2015 was 83.7 percent, an increase from 82.2 percent for 2014. The PJM aggregate EAF, EFOF, EPOF, and EMOF are shown in Figure 5-9. Metrics by unit type are shown in Table 5-27 through Table 5-30.

Figure 5-9 PJM equivalent outage and availability factors: 2007 to 2015



91 The capacity factors in this table are based on nameplate capacity values, and are calculated based on when the units come on line.

Table 5-27 EAF by unit type: 2007 through 2015

	2007	2008	2009	2010	2011	2012	2013	2014	2015
Combined Cycle	90.4%	90.4%	87.9%	86.0%	85.6%	85.5%	86.1%	84.5%	84.9%
Combustion Turbine	91.1%	91.1%	93.2%	93.1%	91.8%	92.4%	89.1%	88.3%	90.2%
Diesel	88.7%	88.7%	91.7%	93.6%	94.8%	93.1%	92.4%	83.5%	89.5%
Hydroelectric	88.8%	88.8%	86.8%	88.8%	84.6%	88.8%	87.9%	85.2%	85.6%
Nuclear	92.3%	92.3%	90.1%	91.8%	90.1%	91.1%	92.2%	91.5%	92.0%
Steam	81.6%	81.6%	81.0%	79.0%	78.3%	77.9%	77.2%	75.4%	77.2%
Total	86.4%	86.4%	85.7%	84.9%	83.7%	84.0%	83.6%	82.2%	83.7%

Table 5-28 EMOF by unit type: 2007 through 2015

	2007	2008	2009	2010	2011	2012	2013	2014	2015
Combined Cycle	1.7%	1.7%	3.1%	3.0%	2.4%	2.7%	2.6%	2.4%	2.2%
Combustion Turbine	2.2%	2.2%	2.3%	2.0%	2.4%	1.7%	1.9%	1.9%	2.5%
Diesel	1.2%	1.2%	1.1%	1.5%	1.8%	2.4%	1.4%	2.3%	2.7%
Hydroelectric	2.1%	2.1%	2.3%	1.9%	1.9%	2.1%	1.9%	3.0%	1.6%
Nuclear	0.8%	0.8%	0.6%	0.5%	1.2%	1.1%	0.7%	0.9%	1.4%
Steam	2.6%	2.6%	3.7%	3.9%	4.2%	5.6%	4.3%	5.5%	4.6%
Total	2.1%	2.1%	2.8%	2.8%	3.1%	3.6%	2.9%	3.5%	3.1%

Table 5-29 EPOF by unit type: 2007 through 2015

	2007	2008	2009	2010	2011	2012	2013	2014	2015
Combined Cycle	5.9%	5.9%	6.3%	8.5%	9.5%	8.3%	8.8%	10.5%	10.9%
Combustion Turbine	4.0%	4.0%	2.8%	3.0%	3.8%	3.2%	4.0%	3.8%	4.4%
Diesel	1.0%	1.0%	0.6%	0.4%	0.1%	0.7%	0.3%	0.4%	0.3%
Hydroelectric	7.8%	7.8%	8.7%	8.6%	11.8%	6.3%	7.8%	9.3%	9.4%
Nuclear	5.1%	5.1%	5.2%	5.4%	6.1%	6.4%	5.9%	5.8%	5.4%
Steam	8.0%	8.0%	8.5%	9.3%	9.2%	8.7%	10.2%	10.3%	10.9%
Total	6.6%	6.6%	6.7%	7.5%	7.9%	7.2%	8.1%	8.4%	8.7%

Table 5-30 EFOF by unit type: 2007 through 2015

	2007	2008	2009	2010	2011	2012	2013	2014	2015
Combined Cycle	2.1%	2.1%	2.7%	2.6%	2.5%	3.5%	2.5%	2.6%	2.1%
Combustion Turbine	2.7%	2.7%	1.6%	1.9%	2.0%	2.8%	5.0%	6.0%	2.8%
Diesel	9.1%	9.1%	6.6%	4.4%	3.3%	3.9%	6.0%	13.9%	7.6%
Hydroelectric	1.3%	1.3%	2.3%	0.7%	1.7%	2.8%	2.3%	2.5%	3.4%
Nuclear	1.8%	1.8%	4.1%	2.3%	2.6%	1.5%	1.1%	1.8%	1.3%
Steam	7.9%	7.9%	6.8%	7.7%	8.3%	7.8%	8.3%	8.8%	7.3%
Total	5.0%	5.0%	4.8%	4.9%	5.3%	5.1%	5.4%	5.9%	4.5%

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 will no longer be used under Capacity Performance market design and 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.[92] The EFORd metric includes all forced outages, regardless of the reason for those outages.

The average PJM EFORd for 2015 was 6.9 percent, a decrease from 9.4 percent for 2014. Figure 5-10 shows the average EFORd since 1999 for all units in PJM.[93]

Figure 5-10 Trends in the PJM equivalent demand forced outage rate (EFORd): 1999 through 2015

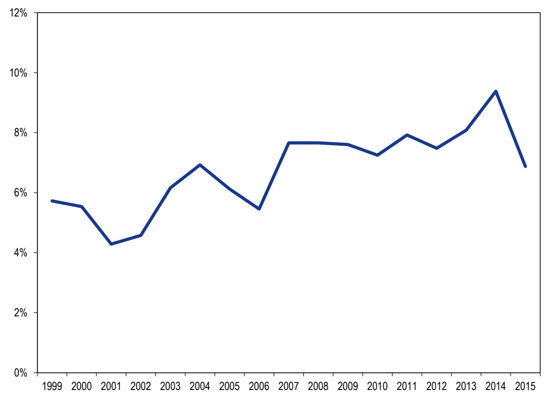


Table 5-31 shows the class average EFORd by unit type.

92 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.

93 The universe of units in PJM changed as the PJM footprint expanded and as units retired from and entered PJM markets. See the 2015 State of the Market Report for PJM, Appendix A: "PJM Geography" for details.

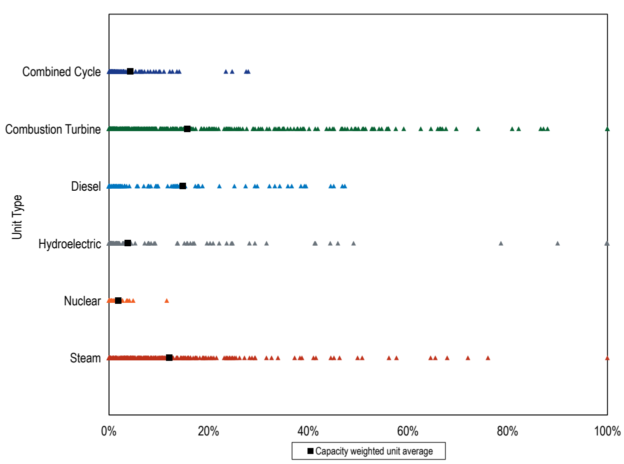
Table 5-31 PJM EFORd data for different unit types: 2007 through 2015

	2007	2008	2009	2010	2011	2012	2013	2014	2015
Combined Cycle	3.7%	3.7%	4.1%	3.8%	3.4%	4.2%	3.2%	4.2%	2.7%
Combustion Turbine	11.1%	11.1%	9.8%	8.9%	8.0%	8.2%	10.7%	15.7%	8.9%
Diesel	10.3%	10.3%	9.3%	6.4%	9.2%	5.1%	6.6%	14.8%	9.0%
Hydroelectric	2.0%	2.0%	3.2%	1.2%	2.9%	4.4%	3.7%	3.8%	4.7%
Nuclear	1.9%	1.9%	4.1%	2.5%	2.8%	1.6%	1.2%	1.9%	1.4%
Steam	10.1%	10.1%	9.3%	9.8%	11.2%	10.6%	11.6%	12.1%	10.0%
Total	7.7%	7.7%	7.6%	7.2%	7.9%	7.5%	8.1%	9.4%	6.9%

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 5-11. Each generating unit is represented by a single point, and the capacity weighted unit average is represented by a solid square. Hydroelectric units had the greatest variance in EFORd, while nuclear units had the lowest variance in EFORd values in 2015.

Figure 5-11 PJM distribution of EFORd data by unit type: 2015



Other Forced Outage Rate Metrics

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. These incentives will change when the Capacity Performance market design is implemented beginning with Delivery Year 2018/2019 but remain essential reasons why the incentive components of Capacity Performance design were necessary.

Currently, there are two additional forced outage rate metrics that play a significant role in PJM markets, XEFORd and EFORp. Under the Capacity Performance modifications to RPM, neither XEFORd nor EFORp will be relevant.

The XEFORd metric is the EFORd metric adjusted to remove outages that have been defined to be outside management control (OMC). Under the Capacity Performance modifications to RPM, all outages will be included in the EFORd metric used to determine the level of unforced capacity for specific units that must be offered in PJM's Capacity Market, including the outages previously designated as OMC. OMC outages will no longer be excluded from the EFORd calculations.

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. Under the Capacity Performance modifications to RPM, EFORp will no longer be used to calculate performance penalties.

Current 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.

The current PJM Capacity Market rules 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 current PJM Capacity Market includes an incentive to classify as many forced outages as possible as OMC. That incentive is removed in the Capacity Performance design.

Outages Deemed Outside Management Control

OMC outages will continue to be excluded from outage rate calculations through the end of the 2017/2018 delivery year. Under the Capacity Performance modifications to RPM, effective with the 2018/2019 Delivery Year, OMC outages will no longer be excluded from the EFORd metric used to determine the level of unforced capacity for specific units that must be offered in PJM's Capacity Market. All forced outages will be included.[94]

In 2006, NERC created specifications for certain types of outages deemed to be Outside Management Control (OMC).[95] 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.[96] 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.[97] That choice was made by PJM and can be modified without violating any NERC requirements.[98] 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 chose to exclude only some of the OMC outages from the XEFORd metric.

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 5-32 shows OMC forced outages by cause code, as classified by PJM. OMC forced outages accounted for 4.2 percent of all forced outages in 2015. The largest contributor to OMC outages, other switchyard equipment outages, was the cause of 22.1 percent of OMC outages and 0.9 percent of all forced outages.

Table 5-32 OMC outages: 2015

OMC Cause Code	Percent of OMC Forced Outages	Percent of all Forced Outages
Other switchyard equipment	22.1%	0.9%
Switchyard circuit breakers	16.7%	0.7%
Transmission system problems other than catastrophes	15.9%	0.7%
Lack of fuel	14.6%	0.6%
Transmission line	14.3%	0.6%
Switchyard transformers and associated cooling systems	6.4%	0.3%
Transmission equipment beyond the 1st substation	2.9%	0.1%
Lack of water (hydro)	1.9%	0.1%
Flood	1.2%	0.0%
Other miscellaneous external problems	1.1%	0.0%
Transmission equipment at the 1st substation	0.9%	0.0%
Lightning	0.7%	0.0%
Storms	0.5%	0.0%
Switchyard system protection devices	0.3%	0.0%
Other fuel quality problems	0.2%	0.0%
Tornado	0.2%	0.0%
Other catastrophe	0.1%	0.0%
Total	100.0%	4.2%

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

94 "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region", Schedule 5.B.

95 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/pa/RAPA/gads/DataReportingInstructions/Appendix_K_Outside_Plant_Management_Control.pdf>.

96 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>.

97 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.

98 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.

it is not available, regardless of the reason, and the data and payments to units should reflect that fact.[99]

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. OMC outages will be eliminated under the Capacity Performance rules.

99 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).

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. These incentives will change when the Capacity Performance market design is implemented beginning with Delivery Year 2018/2019 but remain essential reasons why the incentive components of Capacity Performance design are 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. Under the current RPM design, in place in 2015, 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 were not designed to ensure that capacity resources are paid when they perform and not paid when they do not perform.

Until the Capacity Performance market design is fully implemented for the 2020/2021 Delivery Year, EFORp will continue be used in the calculation of non-performance charges for units that are not Capacity Performance capacity resources.

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.[100]

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, which is defined to be the XEFORd calculated for the 12 months ending in September in the year prior to the delivery year.[101]

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.[102]

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.[103]

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.[104] 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.[105]

There is a separate exception for wind and solar capacity resources which are exempt from this performance incentive.[106]

The peak hour availability charge does not apply if the unit unavailability resulted in another performance related charge or penalty.[107]

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.[108]

100 PJM. OATT Attachment DD § 10 (j).
101 PJM. "Manual 18: PJM Capacity Market," Revision 30 (December 17, 2015), Section 4.2.5
102 PJM. "Manual 18: PJM Capacity Market," Revision 30 (December 17, 2015), Section 8.4.5.
103 PJM. "Manual 18: PJM Capacity Market," Revision 30 (December 17, 2015), Section 8.4.5.1.
104 PJM. OATT Attachment DD § 7.10 (e).
105 *Id*
106 *Id.*
107 *Id.*
108 PJM. "Manual 18: PJM Capacity Market," Revision 30 (December 17, 2015)

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.[109] On a systemwide basis, the resultant lost equivalent availability from the forced outages is equal to the equivalent forced outage factor (EFOF).[110]

PJM EFOF was 4.5 percent in 2015. This means there was 4.5 percent lost availability because of forced outages. Table 5-33 shows that forced outages for boiler tube leaks, at 22.6 percent of the systemwide EFOF, were the largest single contributor to EFOF.

Table 5-33 Contribution to EFOF by unit type by cause: 2015

	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Steam	System
Boiler Tube Leaks	4.7%	0.0%	0.0%	0.0%	0.0%	30.3%	22.6%
Boiler Air and Gas Systems	0.1%	0.0%	0.0%	0.0%	0.0%	8.4%	6.2%
Electrical	4.7%	13.4%	7.0%	0.4%	11.8%	5.1%	6.1%
Feedwater System	1.7%	0.0%	0.0%	0.0%	14.7%	5.5%	5.0%
Economic	4.6%	21.5%	8.0%	4.1%	0.0%	2.2%	4.3%
Boiler Fuel Supply from Bunkers to Boiler	0.2%	0.0%	0.0%	0.0%	0.0%	5.3%	3.9%
Reserve Shutdown	3.8%	12.6%	10.1%	14.0%	7.3%	1.6%	3.6%
Generator	8.8%	0.6%	13.2%	31.6%	0.0%	2.1%	3.4%
Fuel Quality	0.3%	0.2%	5.2%	0.0%	0.0%	3.7%	2.8%
Circulating Water Systems	4.4%	0.0%	0.0%	0.0%	2.5%	2.8%	2.5%
Condensing System	0.4%	0.0%	0.0%	0.0%	1.2%	3.1%	2.4%
Miscellaneous (Generator)	2.6%	1.0%	23.6%	9.3%	17.9%	0.9%	2.4%
Wet Scrubbers	0.0%	0.0%	0.0%	0.0%	0.0%	2.9%	2.1%
Controls	4.7%	0.6%	0.1%	0.2%	2.4%	2.1%	2.0%
Boiler Piping System	5.8%	0.0%	0.0%	0.0%	0.0%	2.2%	2.0%
Inlet Air System and Compressors	15.1%	8.8%	0.0%	0.0%	0.0%	0.0%	1.9%
Valves	1.0%	0.0%	0.0%	0.0%	0.3%	1.9%	1.5%
Miscellaneous (Gas Turbine)	8.2%	9.4%	0.0%	0.0%	0.0%	0.0%	1.5%
Slag and Ash Removal	0.0%	0.0%	0.0%	0.0%	0.0%	1.8%	1.3%
All Other Causes	28.8%	31.7%	32.7%	40.4%	41.9%	18.3%	22.5%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Table 5-34 shows the categories which are included in the economic category.[111] Lack of fuel that is considered outside management control accounted for 14.4 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."[112] Only a handful of units use other economic problems to describe outages. Other economic problems are not defined by NERC GADS and are best described as economic problems that cannot be classified by the other NERC GADS economic problem cause codes. Lack of water events occur when a hydroelectric plant does not have sufficient fuel (water) to operate.

Table 5-34 Contributions to Economic Outages: 2015

	Contribution to Economic Reasons
Lack of fuel (Non-OMC)	79.6%
Lack of fuel (OMC)	14.4%
Lack of water (Hydro)	1.9%
Other economic problems	1.9%
Fuel conservation	1.6%
Problems with primary fuel for units with secondary fuel operation	0.5%
Ground water or other water supply problems	0.2%
Wet fuel (biomass)	0.1%
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.

109 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.

110 EFOF incorporates all outages regardless of their designation as OMC.

111 The definitions of these outages are defined by NERC GADS.

112 The definitions of these outages are defined by NERC GADS.

Until the Capacity Performance market design is fully implemented for the 2020/2021 Delivery Year, EFORp will be used in the calculation of non-performance charges for units that are not Capacity Performance capacity resources. Under Capacity Performance, EFORp will not be used.

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.[113] 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 5-35 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.

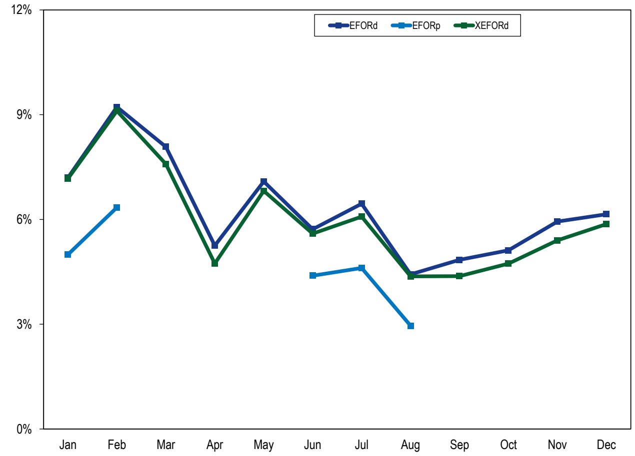
Table 5-35 PJM EFORd, XEFORd and EFORp data by unit type: 2015[114]

	EFORd	XEFORd	EFORp	Difference EFORd and XEFORd	Difference EFORd and EFORp
Combined Cycle	2.7%	2.6%	1.3%	0.1%	1.3%
Combustion Turbine	8.9%	7.8%	4.8%	1.2%	4.1%
Diesel	9.0%	8.3%	4.5%	0.7%	4.5%
Hydroelectric	4.7%	4.2%	3.0%	0.6%	1.7%
Nuclear	1.4%	1.4%	1.2%	0.1%	0.3%
Steam	10.0%	9.8%	6.9%	0.2%	3.1%
Total	6.9%	6.6%	4.5%	0.3%	2.4%

Performance By Month

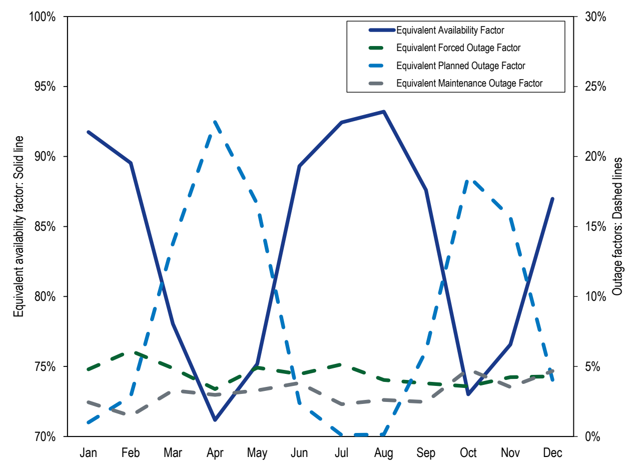
On a monthly basis, EFORp values were significantly less than EFORd and XEFORd values as shown in Figure 5-12, demonstrating that units had fewer non-OMC outages during peak hours than would have been expected based on EFORd.

Figure 5-12 PJM EFORd, XEFORd and EFORp: 2015



On a monthly basis, unit availability as measured by the equivalent availability factor is shown in Figure 5-13.

Figure 5-13 PJM monthly generator performance factors: 2015



113 See PJM. "Manual 22: Generator Resource Performance Indices," Revision 16 (November 16, 2011), Definitions.

114 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 Order No. 745, which provided for payment of demand-side resources at full LMP.[1] 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."[2] On January 25, 2016, the Supreme Court voted 6-2 to reverse the decision of the lower court.[3] The result is that FERC retains jurisdiction over demand-side programs.
- **Demand Response Activity.** Demand response includes the economic program and the emergency program. The economic program includes the response to energy prices in the energy market. The emergency program is the capacity market program which includes both capacity payments and associated energy revenues when the capacity is called on to respond. The emergency program accounted for 98.4 percent of all revenue received by demand response providers, the economic program for 1.0 percent and synchronized reserve for 0.6 percent. In 2015, total emergency revenue increased by $136.4 million, or 20.2 percent, from $675.7 million in 2014 to $812.2 in 2015. Capacity market revenue increased by $178.9 million, or 28.3 percent, from $632.8 million in 2014 to $811.7 million 2015.[4] Emergency energy revenue decreased by $42.5 million, from $43.0 million in 2014 to $0.5 million in 2015. Economic program revenue decreased by $9.5 million, from $17.8 million in 2014 to $8.3 million in 2015, a 53.2 percent decrease.[5] Synchronized reserve revenue increased by $43.3 thousand, a 0.6 percent increase. Total demand response revenue in 2015 increased by 18.2 percent from $675.7 million 2014 to $825.6 million in 2015. Not all DR activities in 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 although emergency demand response can and does set LMP. 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 single system price determined under the net benefits test for that month.[6]
- **Demand Response Market Concentration.** The ownership of economic demand response was highly concentrated in 2014 and 2015. The HHI for economic demand response reductions increased from 7713 in 2014 to 7862 in 2015. The ownership of emergency demand response was moderately concentrated in 2015. The HHI for emergency demand response registrations was 1760 for the 2014/2015 Delivery Year and 1497 for the 2015/2016 Delivery Year. 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 it is 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 as is the case for generation 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 *Id.*

3 FERC v. Electric Power Supply Association, Slip Op. No. 14-840.

4 The total credits and MWh numbers for demand resources were calculated as of February 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.

Recommendations

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 December 31, 2015.

- 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.)
- The MMU recommends that there be only one demand response product, with an obligation to respond when called for all hours of the year, and that the demand response be on the demand side of the capacity market. (Priority: High. First reported 2011. Status: Partially Adopted.[7])
- The MMU recommends that the option to specify a minimum dispatch price under the Emergency and Pre-Emergency Program Full option be eliminated and that participating resources receive the hourly real-time LMP less any generation component of their retail rate. (Priority: Medium. First reported 2010. Status: Not adopted.)
- The MMU recommends that the emergency load response program be classified as an economic program, responding to economic price signals and not an emergency program responding only after an emergency is called and not triggering the definition of a PJM emergency. (Priority: High. First reported 2012. Status: Not adopted.)
- The MMU recommends that the Emergency Program Energy Only option be eliminated because the opportunity to receive the appropriate energy market incentive is already provided in the Economic Program. (Priority: Low. First reported 2010. Status: Not adopted.)
- The MMU recommends that 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.)
- The MMU recommends that 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: Partially adopted.)
- The MMU recommends that demand resources be required to provide their nodal location, comparable to generation resources. (Priority: High. First reported 2011. Status: Not adopted.)
- The MMU recommends that PJM require nodal dispatch of demand resources with no advance notice required or, if nodal location is not required, subzonal dispatch of demand resources with no advance notice required. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM eliminate the measurement of compliance across zones within a compliance aggregation area (CAA). 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. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends capping the baseline for measuring compliance under GLD, for the limited summer product, at the customers' PLC. (Priority: High. First reported 2010. Status: Adopted.)
- The MMU recommends capping the baseline for measuring capacity compliance under winter compliance at the customers' PLC, similar to GLD, to avoid double counting. (Priority: High. First reported 2010. Status: Partially adopted.)
- The MMU recommends that measurement and verification methods for demand resources be modified to reflect compliance more accurately. (Priority: Medium. First reported 2009. Status: Not adopted.)
- 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

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.

and registrations. (Priority: Medium. First reported 2012. Status: Not adopted.)

- The MMU recommends that PJM adopt the ISO-NE five-minute metering requirements in order to ensure that dispatchers have the necessary information for reliability and that market payments to demand resources be calculated based on interval meter data at the site of the demand reductions.[9] (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that demand response event compliance be calculated for each hour and the penalty structure reflect hourly compliance for the base and capacity performance products. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that demand resources whose load drop method is designated as "Other" explicitly record the method of load drop. (Priority: Low. First reported 2013. Status: Adopted Q2, 2014.)
- The MMU recommends that 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 that shutdown cost be defined as the cost to curtail load for a given period that does not vary with the measured reduction or, for behind the meter generators, be the start cost defined in Manual 15 for generators. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that the Net Benefits Test be eliminated and that demand response resources be paid LMP less any generation component of the applicable retail rate. (Priority: Low. New Recommendation. Status: Not adopted.)
- 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 because load has been reduced or eliminated, such as in the case of bankrupt and/or out of service facilities. (Priority: Medium. First reported Q2, 2015. Status: Not adopted.)

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 in the same year in which demand for capacity changes. 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.

In the energy market, if there is to be a demand side program, demand resources should be paid the value of energy, which is LMP less any generation component of the applicable retail rate. There is no reason to have the net benefits test. The necessity for the net benefits test is an illustration of the illogical approach to demand side compensation embodied in paying full LMP to demand resources. The benefit of demand side resources is not that they suppress market prices, but that customers can choose not to consume at the current price of power, that individual customers benefit from their choices and that the choices of all customers are reflected in market prices. If customers face the market price, customers should have the ability to not purchase power and the market impact of that choice does not require a test for appropriateness.

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. This 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

9 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 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 be subject to robust measurement and verification techniques to ensure that transitional DR programs incent the desired behavior. The methods used in PJM programs today are not adequate to determine and quantify deliberate actions taken to reduce consumption.

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. Both subzonal and multi-zone compliance should be eliminated because they are inconsistent with an efficient nodal 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, reductions should be calculated hourly for dispatched DR. The current rules use the average reduction for the duration of an event. The average reduction across multiple hours does not provide an accurate metric for each hour of the event and is inconsistent with the measurement of generation resources. Measuring compliance hourly would provide accurate information to the PJM system. Under the new CP rules, the performance of demand response during Performance Assessment Hours will be measured on an hourly basis. Overall demand response compliance is still measured by performance across the entire event.[10]

In order to be a substitute for generation, any demand resource and its Curtailment Service Provider (CSP), 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 should 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.

10 PJM "Manual 18: Capacity Market," Revision 29 (October 16, 2015), p 148.

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 proposed 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 the Supreme Court decision in EPSA as it does not depend on whether FERC has jurisdiction over the demand side. This approach will allow FERC to more fully realize its overriding policy objective to create competitive and efficient wholesale energy markets. The decision of the Supreme Court addressed jurisdictional issues and did not address the merits of FERC's approach. The Supreme Court's decision has removed the uncertainty surrounding the jurisdictional issues and created the opportunity for FERC to revisit its approach to demand side.

PJM Demand Response Programs

All demand response programs in PJM can be grouped into economic, emergency and pre-emergency programs.[11] Pre-emergency demand response is defined to be dispatchable before an emergency event is declared.[12] Table 6-1 provides an overview of the key features of PJM demand response programs. Demand response program is used here to refer to pre-emergency, emergency and economic programs. Demand Resources is used here to refer to emergency and pre-emergency load response, which participate in the capacity market, and Economic Resources refer to economic load response, which participates solely in the energy market. All Demand Resources must register as pre-emergency unless the participant relies on behind the meter generation or the resource has environmental restrictions that limit the resource's ability to operate only in emergency conditions.[13] In all demand response 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 compensate 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.

11 Throughout this document, emergency demand response refers to both emergency and pre emergency demand response.

12 147 FERC ¶ 61,103 (2014).

13 OATT Attachment K Appendix Section 8.5

Table 6-1 Overview of demand response programs

	Emergency and Pre-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 clearing 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 Order No. 745, which provided for payment of demand-side resources at full LMP.[14] 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."[15] On January 25, 2016, the Supreme Court voted 6-2 to reverse the decision of the lower court.[16] The result is that FERC retains jurisdiction over demand-side programs.

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 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.[17]

In 2015, emergency and pre-emergency revenue, which includes capacity and emergency energy revenue, accounted for 98.4 percent of all revenue received by demand response providers, credits from the economic program were 1.0 percent and revenue from synchronized reserve was 0.6 percent.

Total emergency and pre-emergency revenue increased by $136.4 million, or 20.2 percent, from $675.7 million in 2014 to $812.2 in 2015. Of the total emergency revenue, capacity market revenue increased by $178.9 million, or 28.3 percent, from $632.8 million in 2014 to $811.7 million in 2015, due to higher clearing prices and volumes in the Capacity Market for the 2014/2015 and 2015/2016 delivery years. The weighted average RPM price increased 26.6 percent from $126.40 per MW-day in the 2014/2015 Delivery Year to $160.01 per MW-day in the 2015/2016 Delivery Year.[18] Emergency energy revenue decreased by $42.5 million, from $43.0 million in 2014 to $0.5 million in 2015. Total demand response revenue in 2015 increased by 18.2 percent from $698.4 million in 2014 to $825.4 million in 2015. Total demand response revenue includes economic, pre-emergency, emergency and synchronized reserve revenue.

Total revenue under the economic program decreased by $9.4 million from $17.8 million in 2014 to $8.3 million in 2015, a 53.2 percent decrease.

14 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).

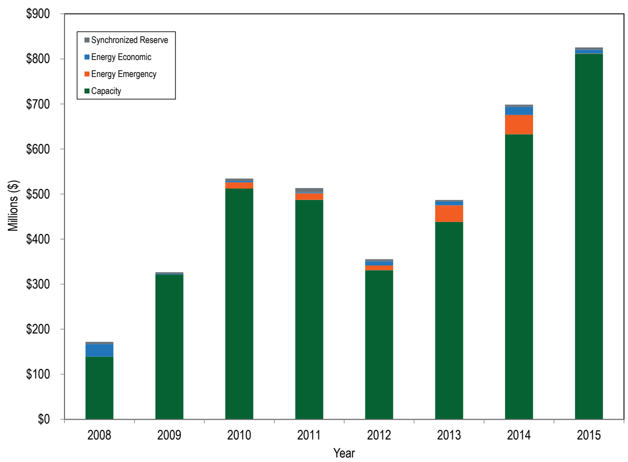
15 *Id.*

16 FERC v. Electric Power Supply Association, Slip Op. No. 14-840.

17 This includes both capacity market revenue and emergency energy revenue for capacity resources.

18 *2015 State of the Market Report for PJM: January through September*, Section 5: Capacity, Figure 5-6.

Figure 6-1 Demand response revenue by market: 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 December 2015. Registration is a prerequisite for CSPs to participate in the economic program. Both the average number of registrations for economic demand response and the average registered MW decreased in 2015 compared to 2014. The average number of monthly registrations decreased by 123 from 1,066 in 2014 to 943 in 2015. The average monthly registered MW for 2015 decreased by 56 MW, or 2.0 percent, from 2,787 MW in 2014 to 2,732 MW in 2015.

Several demand response resources are registered for both the economic and emergency demand response programs. There were 266 registrations and 1,363 nominated MW in the emergency program that were also registered in the economic program during 2015.

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 as registered in the program. Table 6-3 shows the sum of maximum economic MW dispatched by registration each month for January 2010 through December 2015. The monthly maximum is the sum of each registration's monthly noncoincident peak dispatched MW and annual maximum is the sum of each registration's noncoincident peak dispatched MW during the year. This aggregated maximum dispatched MW for all economic demand response registered resources in 2015 increased by 105 MW, from 1,743 MW in 2014 to 1,848 MW in 2015.[19]

Table 6-2 Economic program registrations on the last day of the month: January 2010 through December 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	870	2,609
Aug	1,616	2,398	1,987	2,194	1,013	2,373	1,299	2,527	1,080	3,033	869	2,609
Sep	1,609	2,447	1,962	2,183	1,052	2,421	1,280	2,475	1,077	2,919	867	2,608
Oct	1,606	2,444	1,954	2,179	828	2,269	1,210	2,335	1,060	2,943	858	2,568
Nov	1,605	2,444	1,988	2,255	824	2,267	1,192	2,307	1,063	2,995	851	2,566
Dec	1,598	2,439	1,992	2,259	846	2,283	1,192	2,311	1,071	2,923	850	2,566
Avg.	1,608	2,435	1,699	2,344	1,071	2,200	1,134	2,352	1,066	2,787	943	2,732

19 As a result of the 60 day data lag from event date to settlement, not all settlements for December 2015 are incorporated in this report.

Table 6-3 Sum of peak MW reductions for all registrations per month: 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	161
Jun	209	561	954	433	483	833
Jul	999	561	1,631	1,091	665	1,362
Aug	794	161	952	497	358	272
Sep	276	84	451	549	795	816
Oct	118	81	242	168	214	136
Nov	111	86	165	155	166	127
Dec	114	88	98	168	155	122
Annual	1,209	841	1,947	1,490	1,743	1,858

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.[20] 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 2010 through 2015. The average credits per MWh paid in 2015 decreased by $50.35 per MWh, or 42.3 percent, from $119.15 per MWh in 2014 to $68.80 per MWh dispatched in 2015. The average real-time load weighted PJM LMP in 2015 decreased by $16.98 per MWh, or 31.2 percent, from $53.14 per MWh in 2014 to $36.16 per MWh in 2015. Curtailed energy for the economic program was 121,338 MWh in 2015 and the total payments were $8,347,755.[21] Total credits paid for economic DR in 2015 decreased by $9.5 million or 53.2 percent, compared to 2014.

Table 6-4 Credits paid to the PJM economic program participants: 2010 through 2015

Year	Total MWh	Total Credits	$/MWh
2010	72,757	$4,728,660	$64.99
2011	17,398	$2,052,996	$118.00
2012	145,019	$9,284,118	$64.02
2013	133,963	$8,711,873	$65.03
2014	149,246	$17,704,828	$118.63
2015	121,338	$8,347,755	$68.80

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. 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 December 2015. Higher energy prices and FERC Order No. 745 increased incentives to participate starting in April 2012. The $9.5 million decrease in credits paid to economic DR resources in 2015 when compared to 2014 can largely be attributed to lower energy market prices in the first three months of 2015.

Figure 6-2 Economic program credits and MWh by month: January 2010 through December 2015

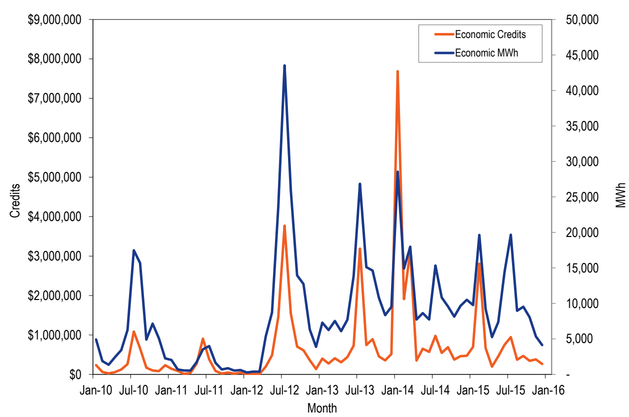


Table 6-5 shows performance for 2014 and 2015 in the economic program by control zone and participation type. Total economic program reductions decreased 19.4 percent from 149,560 MW in 2014 to 121,338 MW in 2015. The economic credits decreased by 54.2 percent from $17,819,607 in 2014, to $8,374,755 in 2015.

20 PJM: "Manual 28: Operating Agreement Accounting," Revision 64 (April 11, 2014), p 70.

21 The total MWh and Total Credits values in this table are the most up to date at the time of this report. Succeeding tables that report on charges paid for economic demand response may vary slightly from these numbers due to the timing of PJM settlement database updates.

Table 6-5 PJM economic program participation by zone: 2014 and 2015[22]

	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	$2,429,613	$535,534	(78.0%)	9,639	4,824	(50.0%)	$252.06	$111.03	(56.0%)
AEP, AP	$323,274	$151,753	(53.1%)	3,629	2,223	(38.8%)	$89.08	$68.28	(23.4%)
ATSI, ComEd, DAY, DEOK, DLCO, EKPC	$1,073,497	$814,821	(24.1%)	11,308	18,695	65.3%	$94.93	$43.59	(54.1%)
BGE, DPL, Met-Ed, PENELEC	$1,280,545	$1,105,865	(13.6%)	13,734	20,527	49.5%	$93.24	$53.87	(42.2%)
Dominion	$9,951,828	$4,799,160	(51.8%)	89,396	59,432	(33.5%)	$111.32	$80.75	(27.5%)
PPL, PSEG	$2,760,850	$940,622	(65.9%)	21,853	15,638	(28.4%)	$126.34	$60.15	(52.4%)
Total	$17,819,607	$8,347,755	(53.2%)	149,560	121,338	(18.9%)	$119.15	$68.80	(42.3%)

Table 6-6 shows total settlements submitted for 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: 2009 through 2015

Year	2009	2010	2011	2012	2013	2014	2015
Number of Settlements	2,227	3,781	732	4,554	2,357	2,356	1,697

Table 6-7 shows the number of CSPs, and the number of participants in their portfolios, submitting settlements by year from 2009 through 2015. There were 48 fewer active participants in 2015 than in 2014. All participants must be included in a CSP.

Table 6-7 Participants and CSPs submitting settlements in the economic program by year: 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
15	212	16	258	15	203	22	428	20	276	18	165	18	116

The ownership of economic demand response was highly concentrated in both 2014 and 2015.[23] Table 6-8 shows the monthly HHI and the HHI for 2015. The table also lists the share of reductions provided by, and the share of credits claimed by the four largest parent companies in each year. In 2015, 79.7 percent of all economic DR reductions and 92.7 percent of economic DR revenue were attributable to the four largest parent companies. The HHI for economic demand response increased 111 points, from 7713 in 2014 to 7824 in 2015.

Table 6-8 HHI and market concentration in the economic program: 2014 and 2015

	HHI			Top Four Companies Share of Reduction			Top Four Companies Share of Credit		
Month	2014	2015	Percent Change	2014	2015	Percent Change	2014	2015	Percent Change
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	7646	7539	(1.4%)	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	7779	(3.9%)	98.8%	98.9%	0.1%	99.1%	99.4%	0.3%
Jun	8141	7971	(2.1%)	91.5%	96.8%	5.3%	87.9%	95.6%	7.6%
Jul	8357	7731	(7.5%)	88.1%	83.1%	(5.0%)	85.6%	78.2%	(7.4%)
Aug	8327	8397	0.8%	97.8%	94.9%	(2.9%)	96.7%	94.0%	(2.7%)
Sep	8632	8024	(7.0%)	89.7%	92.7%	3.0%	87.4%	91.6%	4.2%
Oct	7285	7585	4.1%	91.8%	99.4%	7.6%	92.8%	98.9%	6.0%
Nov	7699	7869	2.2%	100.0%	94.3%	(5.7%)	100.0%	97.0%	(3.0%)
Dec	7712	8480	10.0%	99.5%	97.5%	(2.0%)	99.3%	97.8%	(1.5%)
Total	7713	7824	1.4%	79.8%	79.7%	(0.1%)	87.3%	92.7%	5.3%

22 PJM and the MMU cannot publish more detailed information about the Economic Program Zonal Settlements as a result of confidentiality requirements in the PJM Market Rules.
23 Parent companies may own one CSP or multiple CSPs. All HHI calculations in this section are at the parent company level.

Table 6-9 shows average MWh reductions and credits by hour for 2014 and 2015. In 2014, 90.1 percent of reductions and 86.0 percent of credits occurred in hours ending 0700 to 2100, and in 2015, 94.9 percent of reductions and 92.5 percent of credits occurred in hours ending 0700 to 2100.

Table 6-9 Hourly frequency distribution of economic program MWh reductions and credits: 2014 and 2015

	MWh Reductions			Program Credits		
Hour Ending (EPT)	2014	2015	Percent Change	2014	2015	Percent Change
1	775	344	(56%)	$127,551	$38,507	(70%)
2	723	332	(54%)	$112,251	$33,943	(70%)
3	878	360	(59%)	$149,137	$40,799	(73%)
4	1,550	431	(72%)	$292,816	$46,072	(84%)
5	1,614	424	(74%)	$204,016	$46,877	(77%)
6	2,366	864	(64%)	$319,197	$105,431	(67%)
7	6,353	4,604	(28%)	$945,568	$525,202	(44%)
8	8,295	6,555	(21%)	$1,178,582	$663,641	(44%)
9	9,301	7,419	(20%)	$948,681	$468,425	(51%)
10	8,842	5,614	(37%)	$1,055,720	$396,137	(62%)
11	6,494	4,846	(25%)	$912,614	$332,583	(64%)
12	5,490	5,147	(6%)	$818,427	$331,492	(59%)
13	5,958	5,421	(9%)	$699,418	$310,139	(56%)
14	8,633	7,572	(12%)	$885,323	$422,659	(52%)
15	11,650	8,979	(23%)	$981,805	$489,452	(50%)
16	12,306	11,732	(5%)	$1,045,709	$633,723	(39%)
17	12,680	12,559	(1%)	$1,106,482	$742,171	(33%)
18	13,813	12,648	(8%)	$1,371,388	$807,154	(41%)
19	10,214	10,020	(2%)	$1,178,391	$696,329	(41%)
20	8,437	6,880	(18%)	$1,212,590	$502,101	(59%)
21	6,241	5,133	(18%)	$992,114	$397,128	(60%)
22	3,423	1,899	(45%)	$612,657	$169,504	(72%)
23	1,938	816	(58%)	$380,048	$77,939	(79%)
24	1,588	739	(53%)	$289,122	$70,348	(76%)
Total	149,560	121,338	(19%)	$17,819,607	$8,347,755	(53%)

Table 6-10 shows the distribution of economic program MWh reductions and credits by ranges of real-time zonal, load-weighted, average LMP in 2014 and 2015. Reductions occurred at all price levels. In 2015, 0.6 percent of MWh reductions and 3.3 percent of program credits occurred during 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): 2014 and 2015

	MWh Reductions			Program Credits		
LMP	2014	2015	Percent Change	2014	2015	Percent Change
$0 to $25	722	8,143	1,028%	$12,882	$234,052	1,717%
$25 to $50	60,151	67,157	12%	$2,572,764	$2,775,977	8%
$50 to $75	28,330	18,771	(34%)	$1,878,847	$1,220,214	(35%)
$75 to $100	13,257	9,207	(31%)	$1,295,045	$828,155	(36%)
$100 to $125	7,481	5,255	(30%)	$921,624	$594,150	(36%)
$125 to $150	5,360	2,891	(46%)	$804,728	$409,199	(49%)
$150 to $175	4,351	1,886	(57%)	$776,070	$296,726	(62%)
$175 to $200	3,638	1,872	(49%)	$768,439	$357,606	(53%)
$200 to $225	3,079	1,744	(43%)	$672,056	$333,531	(50%)
$225 to $250	3,132	1,002	(68%)	$713,340	$222,931	(69%)
$250 to $275	2,546	625	(75%)	$637,912	$154,373	(76%)
$275 to $300	1,997	634	(68%)	$558,849	$174,985	(69%)
$300 to $325	1,579	382	(76%)	$459,897	$112,120	(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	1,095	194	(82%)	$333,491	$71,818	(78%)
> $400	10,197	722	(93%)	$4,618,554	$278,431	(94%)
Total	149,549	121,328	(19%)	$17,819,607	$8,347,890	(53%)

Following FERC Order No. 745, all ISO/RTOs are required to calculate an NBT threshold price each month above which the net benefits of DR are deemed to exceed the cost to load. PJM calculates the NBT price threshold by first taking the generation offers from the same month of the previous year. For example, the NBT price calculation for February 2015 was calculated using generation offers from February 2014. PJM then adjusts these offers to account for changes in fuel prices and uses these adjusted offers to create an average monthly supply curve. PJM estimates a function that best fits this supply curve and then finds the point on this curve where the elasticity is equal to 1.[24] The price at this point is the NBT threshold price

The NBT test is a crude tool that is not based in markets logic. The NBT threshold price is a monthly estimate calculated from a monthly supply curve that does not incorporate the real-time or day-ahead prices. In addition, it is a single price used to trigger payments to economic demand response resources throughout the entire RTO, regardless of their location.

The necessity for the NBT test is an illustration of the illogical approach to demand side compensation embodied in paying full LMP to demand resources. The benefit of demand side resources is not that they

24 PJM. "Manual 11: Energy & Ancillary Services Market Operations," Revision 79 (December 17, 2015), p 125.

suppress market prices, but that customers can choose not to consume at the current price of power, that individual customers benefit from their choices and that the choices of all customers are reflected in market prices. If customers face the market price, customers should have the ability to not purchase power and the market impact of that choice does not require a test for appropriateness.

When the LMP is above the NBT threshold price, economic demand response resources that reduce their power consumption are paid the full LMP. When the LMP is below the NBT threshold price, economic demand response resources are not paid for any load reductions. About 0.63 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 December of 2015. Significantly lower fuel prices in 2015 led to lower NBT threshold prices.

Table 6-11 Net benefits test threshold prices: April 2012 through December 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	$23.03
Aug	$24.47	$28.58	$29.85	$23.17
Sep	$24.93	$28.80	$29.83	$21.69
Oct	$25.96	$29.13	$30.20	$21.48
Nov	$25.63	$31.63	$29.17	$22.28
Dec	$25.97	$28.82	$29.01	$22.31
Average	$24.80	$28.09	$30.91	$23.97

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 2015, the highest zonal LMP in PJM was higher than the NBT threshold price 8,192 hours out of the entire 8,760 hours, or 93.5 percent of all hours. Reductions occurred in 7,561 hours, or 92.3 percent, of the 8,192 hours in of 2015. The last three columns illustrate how often economic demand response activity occurred when LMPs exceeded NBT threshold prices in 2014 and 2015.

Table 6-12 Hours with price higher than NBT and DR occurrences in those hours: 2014 through 2015

	Number of Hours	Number of Hours with LMP Higher than NBT			Percentage of NBT Hours with DR		
Month	2014/ 2015	2014	2015	Percent Change	2014	2015	Percent Change
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%	100.0%	14.7%
Jun	720	557	659	18.3%	87.8%	93.3%	5.5%
Jul	744	540	708	31.1%	97.8%	100.0%	2.2%
Aug	744	586	665	13.5%	88.6%	100.0%	11.4%
Sep	720	605	659	8.9%	90.9%	100.0%	9.1%
Oct	744	710	708	(0.3%)	93.4%	88.1%	(5.2%)
Nov	721	719	676	(6.0%)	96.5%	74.1%	(22.4%)
Dec	744	703	654	(7.0%)	87.6%	87.9%	0.3%
Total	8,760	7,921	8,192	3.4%	90.2%	92.3%	2.1%

Economic DR revenues are paid by real-time loads and real-time scheduled exports as an uplift charge. 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 2015.

Table 6-13 Zonal DR charge: 2015

Zone	January	February	March	April	May	June	July	August	September	October	November	December	Total
AECO	$8,144	$32,233	$7,885	$1,675	$6,752	$9,830	$13,208	$5,325	$6,801	$3,002	$1,437	$859	$97,151
AEP	$110,175	$460,039	$108,168	$35,842	$73,540	$120,888	$145,840	$56,877	$67,862	$48,580	$36,216	$23,834	$1,287,861
AP	$46,313	$186,348	$43,950	$14,169	$28,661	$45,064	$55,760	$21,279	$25,583	$18,221	$13,654	$9,491	$508,493
ATSI	$53,788	$218,608	$55,824	$19,925	$39,112	$63,114	$78,631	$30,821	$37,763	$25,846	$18,820	$12,708	$654,958
BGE	$31,720	$124,739	$28,379	$8,934	$20,043	$35,112	$41,528	$16,457	$19,268	$11,789	$8,768	$6,214	$352,949
ComEd	$58,545	$275,905	$69,202	$18,046	$42,842	$82,223	$117,173	$45,452	$58,942	$32,680	$25,804	$15,969	$842,782
DAY	$14,864	$56,946	$14,135	$4,813	$9,977	$16,888	$20,690	$8,084	$9,623	$6,666	$4,894	$3,425	$171,006
DEOK	$20,275	$89,027	$21,328	$6,816	$16,210	$28,087	$33,858	$12,734	$15,622	$10,200	$7,524	$4,841	$266,523
Dominion	$93,812	$388,679	$84,586	$26,191	$60,039	$107,084	$125,545	$48,151	$55,234	$35,569	$26,815	$17,663	$1,069,368
DPL	$18,319	$75,492	$16,560	$3,070	$10,660	$16,842	$20,435	$8,365	$10,947	$5,569	$4,211	$2,611	$193,082
DLCO	$9,970	$35,023	$11,012	$3,864	$9,227	$14,519	$18,241	$6,782	$8,561	$5,284	$3,836	$2,488	$128,806
EKPC	$11,403	$54,120	$11,522	$2,788	$6,507	$11,799	$14,052	$5,224	$6,192	$4,247	$3,537	$2,359	$133,749
JCPL	$18,592	$72,039	$17,775	$4,136	$13,725	$23,025	$30,367	$12,173	$15,694	$7,170	$3,529	$1,845	$220,070
Met-Ed	$13,736	$53,971	$13,034	$2,642	$8,660	$11,134	$14,472	$6,179	$8,403	$4,856	$2,292	$1,271	$140,650
PECO	$34,695	$137,349	$32,562	$6,487	$23,321	$31,876	$42,687	$17,720	$23,928	$11,964	$5,817	$3,416	$371,822
PENELEC	$15,541	$60,547	$15,391	$4,838	$9,599	$14,545	$17,959	$7,212	$8,946	$6,792	$4,520	$3,018	$168,909
Pepco	$29,008	$114,217	$26,061	$8,609	$20,091	$34,254	$40,812	$15,694	$18,509	$11,291	$8,486	$5,687	$332,719
PPL	$38,227	$153,234	$36,723	$6,891	$22,204	$25,649	$38,119	$15,540	$21,233	$12,859	$6,180	$4,052	$380,911
PSEG	$36,731	$133,282	$33,547	$8,416	$24,829	$40,193	$52,829	$21,200	$27,995	$14,223	$6,908	$4,301	$404,454
RECO	$1,231	$4,301	$1,110	$291	$1,076	$1,552	$2,157	$837	$1,099	$508	$298	$184	$14,645
Exports	$33,144	$83,014	$19,015	$5,828	$9,552	$16,723	$21,808	$9,501	$13,128	$9,543	$6,864	$4,889	$233,010
Total	$698,233	$2,809,114	$667,768	$194,270	$456,625	$750,400	$946,170	$371,609	$461,331	$286,860	$200,411	$131,126	$7,973,919

Table 6-14 shows the total zonal DR charge per MWh of real-time load and exports during 2015. On a dollar per MWh basis, real-time load and exports in EKPC, JCPL, and PECO paid the highest charges for economic demand response in 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: 2015

Zone	January	February	March	April	May	June	July	August	September	October	November	December	Zonal Average
AECO	$0.016	$0.046	$0.013	$0.005	$0.010	$0.024	$0.020	$0.008	$0.011	$0.009	$0.007	$0.005	$0.014
AEP	$0.021	$0.046	$0.013	$0.005	$0.010	$0.016	$0.017	$0.007	$0.008	$0.007	$0.007	$0.004	$0.013
AP	$0.017	$0.045	$0.012	$0.005	$0.010	$0.016	$0.017	$0.007	$0.008	$0.007	$0.007	$0.004	$0.013
ATSI	$0.018	$0.043	$0.012	$0.005	$0.010	$0.017	$0.017	$0.007	$0.008	$0.007	$0.007	$0.004	$0.013
BGE	$0.016	$0.046	$0.012	$0.005	$0.010	$0.015	$0.014	$0.006	$0.008	$0.007	$0.006	$0.004	$0.013
ComEd	$0.024	$0.049	$0.014	$0.006	$0.011	$0.018	$0.018	$0.008	$0.009	$0.007	$0.007	$0.004	$0.014
DAY	$0.020	$0.044	$0.013	$0.005	$0.009	$0.016	$0.016	$0.007	$0.008	$0.007	$0.007	$0.004	$0.013
DEOK	$0.022	$0.049	$0.015	$0.006	$0.010	$0.017	$0.017	$0.007	$0.009	$0.007	$0.007	$0.004	$0.014
Dominion	$0.019	$0.048	$0.013	$0.005	$0.010	$0.016	$0.015	$0.007	$0.008	$0.007	$0.007	$0.004	$0.013
DPL	$0.017	$0.048	$0.013	$0.005	$0.009	$0.023	$0.020	$0.008	$0.010	$0.008	$0.006	$0.004	$0.014
DLCO	$0.019	$0.048	$0.012	$0.005	$0.010	$0.018	$0.018	$0.007	$0.009	$0.007	$0.007	$0.004	$0.014
EKPC	$0.024	$0.053	$0.016	$0.006	$0.010	$0.017	$0.017	$0.007	$0.009	$0.007	$0.007	$0.004	$0.015
JCPL	$0.017	$0.047	$0.013	$0.005	$0.011	$0.025	$0.021	$0.008	$0.011	$0.009	$0.007	$0.004	$0.015
Met-Ed	$0.017	$0.047	$0.013	$0.005	$0.010	$0.022	$0.020	$0.008	$0.011	$0.009	$0.007	$0.004	$0.014
PECO	$0.017	$0.047	$0.013	$0.005	$0.010	$0.022	$0.020	$0.008	$0.011	$0.009	$0.008	$0.005	$0.015
PENELEC	$0.016	$0.042	$0.012	$0.006	$0.009	$0.018	$0.018	$0.007	$0.009	$0.007	$0.008	$0.005	$0.013
Pepco	$0.017	$0.047	$0.012	$0.005	$0.010	$0.016	$0.015	$0.007	$0.008	$0.007	$0.006	$0.004	$0.013
PPL	$0.017	$0.047	$0.013	$0.005	$0.010	$0.021	$0.021	$0.008	$0.011	$0.008	$0.007	$0.005	$0.014
PSEG	$0.015	$0.041	$0.012	$0.005	$0.010	$0.023	$0.021	$0.008	$0.010	$0.008	$0.007	$0.005	$0.014
RECO	$0.016	$0.040	$0.012	$0.005	$0.011	$0.023	$0.022	$0.008	$0.011	$0.008	$0.008	$0.005	$0.014
Exports	$0.012	$0.031	$0.009	$0.004	$0.005	$0.009	$0.011	$0.004	$0.004	$0.005	$0.004	$0.003	$0.008
Monthly Average	$0.018	$0.045	$0.013	$0.005	$0.010	$0.019	$0.018	$0.007	$0.009	$0.007	$0.007	$0.004	$0.014

Table 6-15 shows the monthly day-ahead and real-time DR charges and the per MWh DR charges in 2014 and 2015. The day-ahead DR charges decreased by $5.10 million, or 70.6 percent, from $7.22 million in 2014 to $2.12 million in 2015. The real-time DR charges decreased $4.84 million, or 45.7 percent, from $10.6 million in 2014 to $5.76 million in 2015. The per MWh charge paid by all real-time load and exports for economic DR decreased $0.02/MWh, or 54.5 percent, from $0.04/MWh in 2014 to $0.2/MWh in 2015.

Table 6-15 Monthly day-ahead and real-time DR charge: 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	$262,336	73%	$498,703	$194,289	(61%)	$0.024	$0.015	(38%)
Jun	$309,885	$300,585	(3%)	$259,651	$449,816	73%	$0.018	$0.021	18%
Jul	$506,523	$269,317	(47%)	$471,085	$676,853	44%	$0.031	$0.020	(36%)
Aug	$158,297	$94,046	(41%)	$386,444	$277,563	(28%)	$0.019	$0.008	(56%)
Sep	$143,293	$71,642	(50%)	$546,589	$389,690	(29%)	$0.029	$0.011	(63%)
Oct	$97,563	$56,564	(42%)	$277,857	$230,296	(17%)	$0.014	$0.008	(41%)
Nov	$167,769	$15,710	(91%)	$294,371	$173,022	(41%)	$0.013	$0.008	(33%)
Dec	$121,823	$0	(100%)	$349,946	$48,372	(86%)	$0.017	$0.004	(73%)
Total	$7,215,799	$2,118,153	(71%)	$10,603,747	$5,761,334	(46%)	$0.043	$0.020	(54%)

Emergency and Pre-Emergency Programs

The emergency and pre-emergency load response programs consist of the limited, extended summer and annual demand response product in the capacity market during the 2014/2015 and 2015/2016 Delivery Years. 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 at a predefined strike price 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 recommends that the option to specify a minimum dispatch price under the Emergency and Pre-Emergency Program Full option be eliminated and that participating resources receive the hourly real-time LMP less any generation component of their retail rate.[25]

Demand Resources were moderately concentrated in 2015. The HHI for Demand Resources was 1760 for the 2014/2015 Delivery Year and 1497 for the 2015/2016 Delivery Year. In 2015, the four largest companies contributed 65.3 percent of all registered Demand Resources.

Table 6-16 shows the HHI value for LDAs by delivery year. The HHI values are calculated by the cleared UCAP MW in each delivery year for Demand Resources. The ownership of DR in two LDAs was moderately concentrated in the 2014/2015 Delivery Year and the ownership of DR in five LDAs was moderately concentrated in the 2015/2016 Delivery Year. The ownership of DR in six LDAs was highly concentrated in the 2014/2015 Delivery Year and the ownership of DR in four LDAs was highly concentrated in the 2015/2016 Delivery Year.

Table 6-16 HHI value for LDAs by delivery year: 2014/2015 and 2015/2016 Delivery Year

Delivery Year	LDA	UCAP MW	HHI Value
2014/2015	DPL-SOUTH	220.9	2131
	EMAAC	1,756.5	1879
	MAAC	2,207.1	2355
	PEPCO	920.0	2643
	PS-NORTH	468.4	1558
	PSEG	531.1	1548
	RTO	7,490.6	2373
	SWMAAC	1,348.4	3564
2015/2016	ATSI	2,167.9	2257
	DPL-SOUTH	86.3	2923
	EMAAC	1,750.4	1355
	MAAC	2,029.0	1607
	PEPCO	867.7	2462
	PS-NORTH	263.5	1622
	PSEG	523.8	1381
	RTO	6,610.4	1734
	SWMAAC	1,154.7	3541

25 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 shows zonal monthly capacity market revenue to demand resources for 2015. Capacity market revenue increased in 2015 by $178.9 million, or 28.3 percent, compared to 2014, from $632.8 million to $811.7 million, as a result of higher RPM prices and more cleared DR in RPM for the 2014/2015 and 2015/2016 delivery years.

Table 6-17 Zonal monthly capacity revenue: January through December 2015

Zone	January	February	March	April	May	June	July	August	September	October	November	December	Total
AECO	$832,282	$751,739	$832,282	$805,435	$832,282	$985,380	$1,018,226	$1,018,226	$985,380	$1,018,226	$985,380	$1,018,226	$11,083,065
AEP, EKPC	$6,410,228	$5,789,884	$6,410,228	$6,203,447	$6,410,228	$6,659,173	$6,881,145	$6,881,145	$6,659,173	$6,881,145	$6,659,173	$6,881,145	$78,726,116
AP	$3,492,803	$3,154,790	$3,492,803	$3,380,132	$3,492,803	$3,174,034	$3,279,835	$3,279,835	$3,174,034	$3,279,835	$3,174,034	$3,279,835	$39,654,773
ATSI	$3,841,060	$3,469,344	$3,841,060	$3,717,154	$3,841,060	$18,481,726	$19,097,783	$19,097,783	$18,481,726	$19,097,783	$18,481,726	$19,097,783	$150,545,989
BGE	$5,311,878	$4,797,825	$5,311,878	$5,140,527	$5,311,878	$5,367,246	$5,546,155	$5,546,155	$5,367,246	$5,546,155	$5,367,247	$5,546,155	$64,160,345
ComEd	$6,041,237	$5,456,601	$6,041,237	$5,846,358	$6,041,237	$6,463,717	$6,679,174	$6,679,174	$6,463,717	$6,679,174	$6,463,717	$6,679,174	$75,534,515
DAY	$902,087	$814,788	$902,087	$872,987	$902,087	$736,289	$760,832	$760,832	$736,289	$760,832	$736,289	$760,832	$9,646,234
DEOK	$341,676	$308,610	$341,676	$330,654	$341,676	$1,277,237	$1,319,812	$1,319,812	$1,277,237	$1,319,812	$1,277,237	$1,319,812	$10,775,252
DLCO	$5,338,145	$4,821,550	$5,338,145	$5,165,946	$5,338,145	$5,066,824	$5,235,719	$5,235,719	$5,066,825	$5,235,719	$5,066,825	$5,235,719	$62,145,278
Dominion	$1,593,999	$1,439,741	$1,593,999	$1,542,580	$1,593,999	$2,130,080	$2,201,083	$2,201,083	$2,130,080	$2,201,083	$2,130,080	$2,201,083	$22,958,890
DPL	$868,800	$784,722	$868,800	$840,774	$868,800	$849,964	$878,296	$878,296	$849,964	$878,296	$849,964	$878,296	$10,294,974
JCPL	$1,766,944	$1,595,949	$1,766,944	$1,709,946	$1,766,944	$1,665,010	$1,720,510	$1,720,510	$1,665,010	$1,720,510	$1,665,010	$1,720,510	$20,483,797
Met-Ed	$1,610,323	$1,454,485	$1,610,323	$1,558,377	$1,610,323	$1,613,449	$1,667,231	$1,667,231	$1,613,449	$1,667,231	$1,613,449	$1,667,231	$19,353,102
PECO	$3,358,207	$3,033,220	$3,358,207	$3,249,878	$3,358,207	$3,700,859	$3,824,221	$3,824,221	$3,700,859	$3,824,221	$3,700,859	$3,824,221	$42,757,179
PENELEC	$1,730,838	$1,563,337	$1,730,838	$1,675,004	$1,730,838	$2,540,797	$2,625,490	$2,625,490	$2,540,797	$2,625,490	$2,540,797	$2,625,490	$26,555,209
Pepco	$3,583,429	$3,236,645	$3,583,429	$3,467,834	$3,583,429	$4,096,205	$4,232,745	$4,232,745	$4,096,205	$4,232,745	$4,096,205	$4,232,745	$46,674,363
PPL	$5,389,586	$4,868,013	$5,389,586	$5,215,729	$5,389,586	$5,411,083	$5,591,452	$5,591,452	$5,411,083	$5,591,452	$5,411,083	$5,591,452	$64,851,556
PSEG	$5,642,193	$5,096,174	$5,642,193	$5,460,187	$5,642,193	$3,738,271	$3,862,880	$3,862,880	$3,738,271	$3,862,880	$3,738,271	$3,862,880	$54,149,275
RECO	$122,927	$111,031	$122,927	$118,962	$122,927	$99,707	$103,031	$103,031	$99,707	$103,031	$99,707	$103,031	$1,310,019
Total	$58,178,643	$52,548,452	$58,178,643	$56,301,913	$58,178,643	$74,057,052	$76,525,620	$76,525,620	$74,057,052	$76,525,621	$74,057,052	$76,525,621	$811,659,932

Table 6-18 shows the amount of energy efficiency (EE) resources in PJM for the 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.

Table 6-18 Energy efficiency resources by MW: 2012/2013 through 2015/2016

	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 6-19 shows the number of customer locations 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 demand response, 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.

FERC accepted PJM's proposed 30 minute lead time as a phased in approach on May 9, 2014, effective on June 1, 2015.[26] The quick lead time demand response was defined after Demand Resources cleared in the RPM base residual auctions for the 2014/2015, 2015/2016, 2016/2017 and 2017/2018 delivery years. 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.[27]

26 See "Order Rejecting, in part, and Accepting, in part, Proposed Tariff Changes, Subject to Conditions," Docket No. ER14-822-001 (May 9, 2014).
27 See "PJM Interconnection, L.L.C.," Docket No. ER14-135-000 (October 20, 2014).

Table 6-19 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 6-20 shows the number of customer locations and nominated MW by product type and lead time during the 2015/2016 Delivery Year. The quick lead time 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.[28] 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 6-20 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	697.0
	Limited	1,957	3,057.8
Short Lead (60 Minutes)	Extended Summer and Limited	426	579.8
Quick Lead (30 Minutes)	Annual	191	173.6
	Extended Summer	3,723	2,043.4
	Limited	10,635	5,091.6
Total		17,723	11,643.2

Table 6-21 shows the MW registered by measurement and verification method and by load drop method for the 2014/2015 Delivery Year.

There are three different ways to measure load reductions of Demand Resources. The Firm Service Level (FSL) method measures the difference between a customer's peak load contribution (PLC) and real time load multiplied by the loss factor. The Guaranteed Load Drop (GLD) method calculates the minimum of: the CBL minus real time load multiplied by the loss factor; or the PLC minus the real time load multiplied by the loss factor. The GLD method uses the minimum of the two to avoid the possibility of double counting reductions which could occur if the CBL were used and the CBL were greater than the PLC.[29] The Direct Load Control (DLC) method measures when the CSP turns on and turns off the direct load control switch to remotely control load reductions. DLC customers do not measure metered real time load for reductions. For the 2014/2015 Delivery Year, 2.4 percent use the GLD measurement and verification method, 91.2 percent use the FSL method and 6.3 percent use DLC.

Table 6-21 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%
DLC (Non hourly metered sites)	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 6-22 shows the MW registered by measurement and verification method and by load drop method for the 2015/2016 Delivery Year. For the 2015/2016 Delivery Year, 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.

28 See "Manual 18: Capacity Market," Revision 2 (August 3, 2015), p. 57.
29 135 FERC ¶ 61,212.

Table 6-22 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%
DLC (Non hourly metered sites)	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 6-23 shows the fuel type used in the on-site generators identified in Table 6-21 and Table 6-22 for the 2014/2015 and 2015/2016 Delivery Year. Of the 22.9 percent of emergency demand response identified as using on-site generation for the 2014/2015 Delivery Year, 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. Of the 22.8 percent of emergency demand response identified as using on-site generation for the 2015/2016 Delivery Year, 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: 2014/2015 and 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 and Pre-Emergency Event Reported Compliance

PJM declared two events in the 2014/2015 Delivery Year, one on April 21, 2015 and one on April 22, 2015. PJM dispatched pre emergency and emergency resources for both events. There were 13 events during the 2013/2014 Delivery Year, two events during the 2012/2013 Delivery Year and one event in the 2011/2012 Delivery Year. Since all of the events in the 2014/2015 Delivery Year were called in PENELEC and there were no annual demand resources there, none were considered for a 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 DR Cleared MW UCAP increased by 510.7 MW, from 14,943.0 MW in the 2014/2015 Delivery Year to 15,453.7 MW in the 2015/2016 Delivery Year. The DR percent of capacity decreased by 3.4 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 emergency and pre-emergency load management events declared in PJM in 2015 and the affected zones. Subzonal dispatch of emergency demand resources was mandatory for the 2014/2015 Delivery Year but only if the subzone was defined by PJM no later than the day before the dispatch. There are ten dispatchable subzones in PJM as of August 11, 2015: AEP_CANTON, ATSI_CLE, DPL_SOUTH, PS_NORTH, ATSI_NEWCASOE, PPL_WESCO, ATSI_BLKRIVER, PENELEC_ERIC, APS_EAST, DOM_CHES.[31] Demand resources can be dispatched for voluntary compliance during any hour of any day, but dispatched resources are not measured for compliance outside

30 Extended summer and limited demand response products are not required to respond in April.
31 See "Load Management Subzones," <http://www.pjm.com/~/media/markets-ops/demand-response/subzone-definition-workbook.ashx> (Accessed February 26, 2016).

of the mandatory compliance window for each demand product. A demand response event during a product's mandatory compliance window also may not result in a compliance score. When demand response events occur for partial hours under 30 minutes or for a subzone dispatch that was not defined one business day before dispatch, the events are not measured for compliance. The category of Minutes not Measured for Compliance is the amount of time during which compliance was not measured when demand resources were dispatched.

The Erie Subzone was not defined the day before the PJM event and therefore the subzone could not be dispatched for mandatory curtailment. If Demand Resources were dispatchable by node, PJM could dispatch Demand Resources that would help a constrained area rather than having to dispatch the entire zone. When the Erie Subzone was constrained during these two demand response events, PJM dispatched DR in the entire PENELEC Zone resulting in reductions across that zone to help a localized problem in the Eric Subzone. Demand Resources that reduced received their associated strike price for reducing, even when the reductions occurred in an area that did not help relieve the constraint. 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. The 2015 voluntary events resulted in under compliance and no penalty for under compliant resources.

Table 6-25 PJM declared load management events: 2015

Event Date	Event Times	Compliance Hours	Minutes not Measured for Compliance	Lead Time	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

Demand Resources are paid based on the average performance by registration for the duration of a demand response event. Demand response should measure compliance no less than 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 and is inconsistent with the measurement of generation resources. Measuring compliance hourly would provide accurate information to the PJM system. The MMU recommends demand response event compliance be calculated for each hour and the penalty structure reflect hourly compliance.[32]

PJM allows compliance to be measured across zones within a compliance aggregation area (CAA).[33] 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.[34] The multiple zone approach is even less locational than the zonal and subzonal approaches 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 relief needed and no 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.

32 PJM "Manual 18: Capacity Market," Revision 29 (October 16, 2015), p 148.

33 CAA is "a geographic area of Zones or sub-Zones that are electrically-contiguous and experience for the relevant Delivery Year, based on Resource Clear Prices of, *for Delivery Years through May 31, 2018*, Annual Resources *and for the 2018/2019 Delivery Year and subsequent Delivery Years, Capacity Performance Resources*, the same locational price separation in the Base Residual Auction, the same locational price separation in the First Incremental Auction, the same locational price separation in the Second Incremental Auction, or the same locational price separation in the Third Incremental Auction." OATT Attachment DD.2 Definitions 2.6A.

34 See "Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM," Docket No. ER14-822-002 (July 25, 2014). See "Manual 18: Capacity Market," Revision 28 (August, 3, 2015) p. 152.

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.[35] 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.

Demand Resources that are also registered as Economic Resources have a calculated CBL for the emergency event days. Demand Resources that are not registered as Economic Resources use the hour before a dispatched event as the CBL for measuring energy reductions. A 2011 KEMA report stated that the hour before method performs poorly during early winter hours. "The hour before the reduction event is typically prior to the morning peak, therefore this CBL severely underestimates the morning peak and the subsequent hours."[36] The calculated CBL more accurately measures reductions for Demand Resources.

Table 6-26 shows the performance for the April 21, 2015 and April 22, 2015 events. Before Demand Resources were dispatched, there was a post contingency local relief warning for FE-PN at 5:50 on April 21, 2015. Demand Resources were then dispatched on April 21, 2015 at 18:25 through 18:28, followed by a maximum generation emergency action at 18:45. Demand Resources were dispatched at 5:28 and 5:30 on April 22, 2015 without any warnings on the April 22, 2015. 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 nominated MW are less than the committed MW capacity obligation because these events occurred during the voluntary compliance period. The committed MW are the MW cleared in the RPM auction. The reported load reduction is reported by PJM and does not include load increases. The observed load reduction in MWh includes all reported reduction values, including load increases, 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. Reported and observed compliance is calculated by comparing the reported and observed 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. The response from the limited and extended summer products was voluntary.

35 PJM. OATT Attachment K § PJM Emergency Load Response Program at Reporting and Compliance.
36 See "PJM Empirical Analysis of Demand Response Baseline Methods," KEMA, April 2011, <https://www.pjm.com/~/media/markets-ops/dsr/pjm-analysis-of-dr-baseline-methods-full-report.ashx> (Accessed February 26, 2016).

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 April 21, 2015, and April 22, 2015, events.[37] Table 6-27 includes the participation for all resources dispatched for the emergency events. There was no reduction, load increased or participants did not report data on 45.9 percent of participant event days including 40.9 percent of the nominated MW. There was a reduction of less than 50 percent on 15.5 percent of participant event days including 17.9 percent of the 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 negative performance value. PJM limits compliance shortfall values to zero MW. This is not explicitly stated in the Tariff or supporting Manuals and the compliance formulas for FSL and GLD customers do allow negative values.[38]

Limiting compliance to positive values only incorrectly calculates compliance. 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, PJM calculates compliance for that registration as a 75 MWh load reduction for that event hour. Negative 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 have a calculated 0 MWh reduction in hour one and a 30 MWh reduction in hour two. This has compliance calculated at an average hourly 15 MWh load reduction for that two hour event, compared to a 7.5 MWh observed reduction. Reported compliance is greater than observed compliance, as locations with load increases, i.e. negative reductions, are treated as zero for compliance purposes.

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

37 A participant is a customer.
38 OATT Attachment K Section 8.9.

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 peak 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. To qualify and participate as a Demand Resource, the customer must have the ability to reduce load. "A participant that has the ability to reduce a measurable and verifiable portion of its load, as metered on an EDC account basis."[39] 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.

Emergency Energy Payments

For any PJM declared load management event in 2015, participants registered under the full option, which contains 99.6 percent of registrations, that were dispatched and demonstrated a load reduction were eligible to receive emergency energy payments. The full program option includes an energy payment for load reductions during a pre-emergency or emergency event for demand response events and capacity payments.[40] The Demand Resource 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.[41,42]

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 Demand Resources or Economic Resources.[43]

Table 6-28 shows the distribution of registrations and associated MW in the full option across ranges of minimum dispatch prices for the 2014/2015 Delivery Year. The majority of participants, 94.7 percent, have a minimum dispatch price between $1,000 and $1,100 per MWh, and 0.1 percent of participants have a dispatch price between $1,276 and $1,549 per MWh, which is the maximum price allowed for the 2014/2015 Delivery Year. Energy offers are further increased by submitted shutdown costs, which, in the 2014/2015 Delivery Year, range from $0 to more than $10,000. Depending on the size of the registration, the shutdown costs can significantly increase the effective energy offer. The shutdown cost of resources with $1,101 to $1,275 per MWh strike prices had the highest average at $160.05 per location.

Table 6-28 Distribution of registrations and associated MW in the full option across ranges of minimum dispatch prices: 2014/2015 Delivery Year[44]

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

39 OATT Attachment K Appendix Section 8.2.
40 OATT Attachment K Appendix Section 8.2.
41 139 FERC ¶ 61,057 (2012).
42 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, for 60 minute demand response to be $1,000/MWh + (Shortage Penalty/2) and for 120 minute demand response to be $1,100/MWh from ER14-822-000.
43 PJM. "Manual 15: Cost Development Guidelines," Revision 26 (November 5, 2014), p. 54.
44 In this analysis nominated MW does not include capacity only resources, which do not receive energy market credits.

Table 6-29 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 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: 2015/2016 Delivery Year[45]

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

45 In this analysis nominated MW does not include capacity only resources, which do not receive energy market credits.

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 2015 than in 2014. Net revenues from the energy market for all plant types were affected by the lower prices. Capacity prices for calendar year 2015 were higher than in 2014 in the western zones and helped some of the new entrant gas units fully recover levelized total costs.

- In 2015, average energy market net revenues decreased by 23 percent for a new CT, 27 percent for a new CC, 53 percent for a new CP, 59 percent for a new DS, 38 percent for a new nuclear plant, 30 percent for a new wind installation, and 31 percent for a new solar installation. The comparison to 2014 reflects, in part, the very high net revenues in January 2014.

- Capacity revenues for calendar year 2015 increased over 2014 in the western zones and decreased in the eastern zones. Capacity revenue accounted for 49 percent of total net revenues for a new CT, 38 percent for a new CC, 49 percent for a new CP, 81 percent for a new DS, and 6 percent for a new nuclear plant.

- In 2015, a new CT would have received sufficient net revenue to cover levelized total costs in six of the 20 zones and more than 90 percent of levelized total costs in an additional six zones.

- In 2015, a new CC would have received sufficient net revenue to cover levelized total costs in nine of the 20 zones and more than 90 percent of levelized total costs in an additional four zones.

- In 2015, a new CP would not have received sufficient net revenue to cover levelized total costs in any zone.

- In 2015, a new nuclear plant would not have received sufficient net revenue to cover levelized total costs in any zone.

- In 2015, net revenues covered more than 82 percent of the annual levelized total costs of a new entrant wind installation and 175 percent of the annual levelized total costs of a new entrant solar installation. Production tax credits and renewable energy credits accounted for 47 percent of the total net revenue of a wind installation and 78 percent of the total net revenue of a solar installation.

- In 2015, a substantial portion of units did not achieve full recovery of avoidable costs through net revenue from energy markets alone, illustrating the critical role of the PJM Capacity Market in providing incentives for continued operation and investment. In 2015, RPM capacity revenues were sufficient to cover the shortfall between energy revenues and avoidable costs for the majority of units and technology types in PJM, with the exception of some coal and oil or gas steam units.

- The actual net revenue results show that 28 units with 11,908 MW of capacity in PJM are at risk of retirement in addition to the units that are currently planning to retire. Of the 28 units, 23 are coal units and account for 99 percent of the capacity at risk.

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.

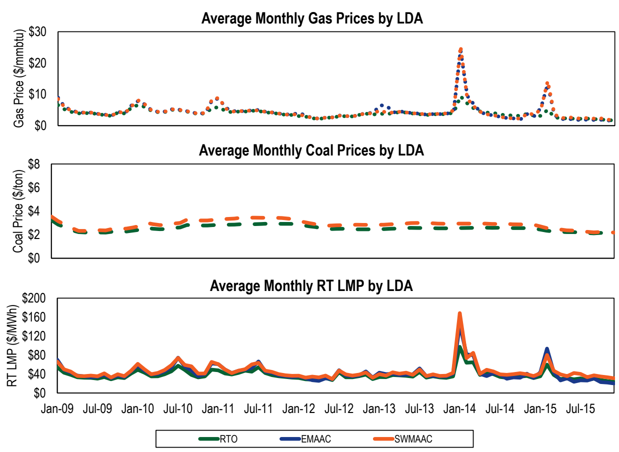
Net Revenue

When compared to annualized fixed costs, net revenue is an indicator of generation investment profitability, and thus is a measure of overall market performance as well as a measure of the incentive to invest in new generation to serve PJM markets. Net revenue equals total revenue received by generators from PJM Energy, Capacity and Ancillary Service Markets and from the provision of black start and reactive services less the variable costs of energy production. In other words, net revenue is the amount that remains, after the short run marginal costs of energy production have been subtracted from gross revenue, to cover fixed costs, which include a return on investment, depreciation, taxes and fixed operation and maintenance expenses. Net revenue is the contribution to total fixed costs received by generators from all PJM markets.

In a perfectly competitive, energy-only market in long-run equilibrium, net revenue from the energy market would be expected to equal the total of all annualized fixed costs for the marginal unit, including a competitive return on investment. The PJM market design includes other markets intended to contribute to the payment of fixed costs. In PJM, the Energy, Capacity and Ancillary Service Markets are all significant sources of revenue to cover the fixed costs of generators, as are payments for the provision of black start and reactive services. Thus, in a perfectly competitive market in long-run equilibrium, with energy, capacity and ancillary service revenues, net revenue from all sources would be expected to equal the annualized fixed costs of generation for the marginal unit. Net revenue is a measure of whether generators are receiving competitive returns on invested capital and of whether market prices are high enough to encourage entry of new capacity. In actual wholesale power markets, where equilibrium seldom occurs, net revenue is expected to fluctuate above and below the equilibrium level based on actual conditions in all relevant markets.

Net revenues are significantly affected by energy prices, fuel prices and capacity prices. The real-time load-weighted average LMP was 31.9 percent lower in 2015 than in 2014, $36.16 per MWh versus $53.14 per MWh. Coal and natural gas prices decreased in 2015. Comparing fuel prices in 2015 to 2014, the price of Northern Appalachian coal was 21.3 percent lower; the price of Central Appalachian coal was 22.7 percent lower; the price of Powder River Basin coal was 12.6 percent lower; the price of eastern natural gas was 42.6 percent lower; and the price of western natural gas was 49.5 percent lower (Figure 7-1). In western zones, capacity prices for calendar year 2015 were higher than in 2014.

Figure 7-1 Energy market net revenue factor trends: 2009 through 2015



Spark Spreads, Dark Spreads, and Quark Spreads

The spark, dark, or quark spread is defined as the difference in between the LMP received for selling power and the cost of fuel used to generate power converted to a cost per MWh. The spark spread compares power prices to the cost of gas, the dark spread compares power prices to the cost of coal, and the quark spread compares power prices to the cost of uranium. The spread is a measure of the approximate difference between revenues and marginal costs and is an indicator of net revenue and profitability.

$$Spread\left(\frac{\$}{MWh}\right) = LMP\left(\frac{\$}{MWh}\right) - Fuel\ Price\left(\frac{\$}{mmBtu}\right) * Heat\ Rate\left(\frac{mmBtu}{MWh}\right)$$

Spread volatility is a result of fluctuations in LMP and the price of fuel. Spreads can be positive or negative.

Figure 7-2 shows the hourly spark spread for peak hours since January 2011 for BGE, ComEd, PSEG, and Western Hub.[1]

Figure 7-2 Hourly spark spread for peak hours: 2011 through 2015

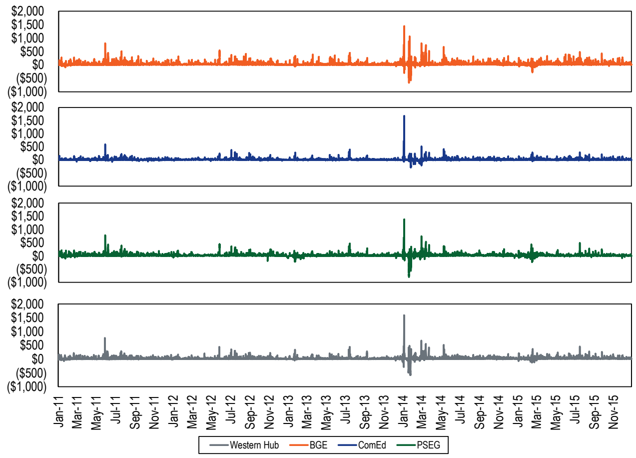
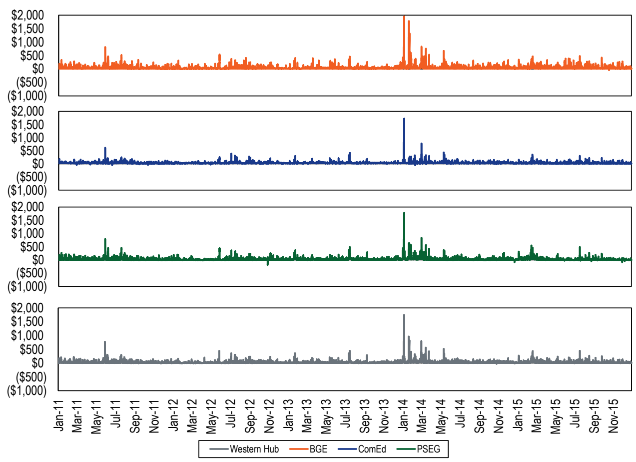


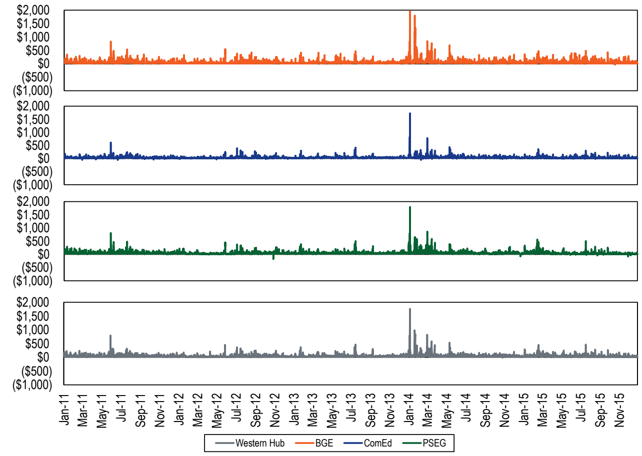
Figure 7-3 Hourly dark spread for peak hours: 2011 through 2015[2]



1 Spark spreads use a combined cycle heat rate of 7,500 Btu/kWh, zonal hourly LMPs and daily gas prices; Chicago City Gate for ComEd, Zone 6 Non-NY for BGE, Zone 6 NY for PSEG, and Texas Eastern M3 for Western Hub.

2 Dark spreads use a heat rate of 10,000 Btu/kWh, zonal hourly LMPs and daily coal prices; Powder River Basin coal for ComEd, Northern Appalachian coal for BGE and Western Hub, and Central Appalachian coal for PSEG.

Figure 7-4 Quark spread for selected zones: 2011 through 2015[3]



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 seven 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.[4]
- The CP has an installed capacity of 600.0 MW and is a sub-critical steam unit, equipped with selective

3 Quark spreads use a heat rate of 10,000 Btu/kWh, zonal hourly LMPs, and daily uranium prices.

4 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.

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 using New York Harbor ultra low sulfur diesel.
- The nuclear plant has an installed capacity of 2,200 MW and consists of two 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.[5,6] Plant heat rates account for the efficiency changes and corresponding cost changes resulting from ambient air temperatures.

CO_2, NO_x and SO_2 emission allowance costs are included in the hourly plant dispatch cost, the short run marginal cost. CO_2, NO_x and SO_2 emission allowance costs were obtained from daily spot cash prices.[7]

A forced outage rate for each class of plant was calculated from PJM data and incorporated into all revenue calculations.[8] Each CT, CC, CP, and DS plant was assumed to take 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 clearing price was compared to the day ahead LMP. If the reference CP could provide regulation more profitably than energy, the unit was assumed to provide regulation during that hour. No black start service capability is assumed for any of the unit types.

CT generators receive revenues for the provision of reactive services based on the average reactive revenue per MW-year received by all CT generators with 20 or fewer operating years. CC generators receive revenues for the provision of reactive services based on the average reactive revenue per MW-year received by all CC generators with 20 or fewer operating years. CP generators receive revenues for the provision of reactive services based on the average reactive revenue per MW-year received by all CP generators with 60 or fewer operating years.

Table 7-1 New entrant ancillary service revenue (Dollars per MW-year)

	Reactive			Regulation
	CT	CC	CP	CP
2009	$923	$1,641	$613	$38
2010	$4,415	$930	$630	$6
2011	$3,675	$1,188	$3,403	$2
2012	$911	$2,715	$2,866	$20
2013	$1,358	$136	$263	$53
2014	$362	$695	$151	$168
2015	$323	$1,561	$36	$65

Zonal net revenues reflect zonal fuel costs based on locational fuel indices and zone specific delivery charges.[9] 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.[10] 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.[11]

Short run marginal cost includes fuel costs, emissions costs, and VOM costs.[12,13] Average short run marginal costs are shown in Table 7-2.

5 Hourly ambient conditions supplied by Schneider Electric.
6 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.
7 CO_2, NO_x and SO_2 emission daily prompt prices obtained from Evolution Markets, Inc.
8 Outage figures obtained from the PJM eGADS database.

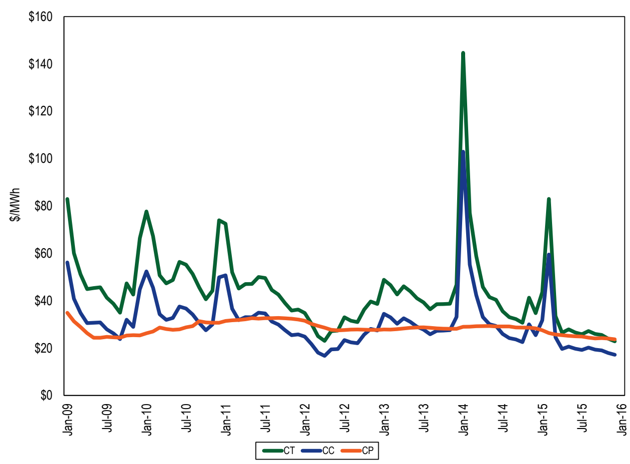
9 Startup fuel burns and emission rates provided by Pasteris Energy, Inc. Startup station power consumption costs were obtained from the station service rates published quarterly by PJM and netted against the MW produced during startup at the preceding applicable hourly LMP. All starts associated with combined cycle units are assumed to be hot starts.
10 Gas daily cash prices obtained from Platts.
11 Coal prompt prices obtained from Platts.
12 Fuel costs are calculated using the daily spot price and may not equal what participants actually paid.
13 VOM rates provided by Pasteris Energy, Inc.

Table 7-2 Average short run marginal costs: 2015

Unit Type	Short Run Marginal Costs ($/MWh)	Heat Rate (Btu/kWh)	VOM ($/MWh)
CT	$32.69	9,437	$0.25
CC	$24.05	6,679	$1.00
CP	$25.03	9,250	$4.00
DS	$109.36	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 short run marginal cost 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 7-5). A significant increase in gas prices on cold days resulted in a corresponding increase in the average short run marginal cost of CTs and CCs in January 2014 and February 2015 (Figure 7-5).

Figure 7-5 Average short run marginal 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.

Capacity Market Net Revenue

Generators receive revenue from the sale of capacity in addition to revenue from the Energy and Ancillary Service Markets. In the PJM market design, the sale of capacity provides an important source of revenues to cover generator going forward costs and fixed costs. Capacity revenue for 2015 includes five months of the 2014/2015 RPM auction clearing price and seven months of the 2015/2016 RPM auction clearing price.[14]

14 The RPM revenue values for PJM are load-weighted average clearing prices across the relevant Base Residual Auctions.

Table 7-3 Capacity revenue by PJM zones (Dollars per MW-year): 2009 through 2015[15]

Zone	2009	2010	2011	2012	2013	2014	2015	Average
AECO	$63,411	$66,187	$49,858	$46,622	$73,529	$66,206	$56,448	$60,323
AEP	$38,736	$52,706	$49,858	$20,242	$8,420	$31,149	$48,128	$35,606
AP	$57,842	$66,187	$49,858	$20,242	$8,420	$31,149	$48,128	$40,261
ATSI	NA	NA	NA	NA	NA	$31,149	$95,422	$63,286
BGE	$82,515	$73,135	$49,858	$45,261	$68,535	$63,360	$56,448	$62,730
ComEd	$38,736	$52,706	$49,858	$20,242	$8,420	$31,149	$48,128	$35,606
DAY	$38,736	$52,706	$49,858	$20,242	$8,420	$31,149	$48,128	$35,606
DEOK	NA	NA	NA	NA	$8,420	$31,149	$48,128	$29,232
DLCO	$38,736	$52,706	$49,858	$20,242	$8,420	$31,149	$48,128	$35,606
Dominion	$38,736	$52,706	$49,858	$20,242	$8,420	$31,149	$48,128	$35,606
DPL	$63,411	$67,098	$50,501	$52,309	$77,542	$66,206	$56,448	$61,931
EKPC	NA	NA	NA	NA	NA	$31,149	$48,128	$39,639
JCPL	$63,411	$66,187	$49,858	$46,622	$73,529	$66,206	$56,448	$60,323
Met-Ed	$57,842	$66,187	$49,858	$45,261	$68,535	$63,360	$56,448	$58,213
PECO	$63,411	$66,187	$49,858	$46,622	$73,529	$66,206	$56,448	$60,323
PENELEC	$57,842	$66,187	$49,858	$45,216	$68,503	$63,360	$56,448	$58,202
Pepco	$82,515	$73,135	$49,858	$45,261	$73,027	$66,529	$56,448	$63,825
PPL	$57,842	$66,187	$49,858	$45,261	$68,535	$63,360	$56,448	$58,213
PSEG	$63,411	$66,187	$49,858	$49,957	$75,882	$72,567	$60,936	$62,686
RECO	NA	NA	NA	NA	NA	NA	NA	NA
PJM	$52,370	$60,604	$49,878	$32,806	$36,601	$46,247	$54,646	$47,593

Net Revenue Adequacy

When total net revenues exceed the annual, nominal levelized total costs for the technology, that technology is covering all its costs including a return on and of capital and all the expenses of operating the facility.

The extent to which net revenues cover the levelized total costs of investment is significantly dependent on technology type and location, which affect both energy and capacity revenue. Table 7-4 includes new entrant levelized total costs for selected technologies. The levelized total costs of all the technologies increase in 2015 over 2014 with the exception of combined cycle which was unchanged.

Net revenues include net revenues from the PJM energy market, from the PJM Capacity Market and from any applicable ancillary service plus production tax credits and RECs for wind installations and SRECs for solar installations.

Levelized Total Costs

Table 7-4 New entrant 20-year levelized total costs (By plant type (Dollars per installed MW-year))[16,17]

	20-Year Levelized Total Cost						
	2009	2010	2011	2012	2013	2014	2015
Combustion Turbine	$128,705	$131,044	$110,589	$113,027	$109,731	$108,613	$111,639
Combined Cycle	$173,174	$175,250	$153,682	$155,294	$150,654	$146,443	$146,300
Coal Plant	$446,550	$465,455	$473,835	$480,662	$491,240	$504,050	$517,017
Diesel Plant	$153,143	$153,143	$153,143	$153,143	$153,143	$161,746	$170,500
Nuclear Plant	$801,100	$801,100	$801,100	$801,100	$801,100	$880,770	$935,659
Wind Installation (with 1603 grant)				$196,186	$196,148	$198,033	$202,874
Solar Installation (with 1603 grant)				$394,855	$263,824	$236,289	$234,151

15 See the *2015 State of the Market Report for PJM*, Appendix A: "PJM Geography," for details on the expansion of the PJM footprint. ATSI was integrated on June 1, 2011.

16 Levelized total costs provided by Pasteris Energy, Inc.

17 Under Section 1603 of the American Recovery and Reinvestment Tax Act of 2009 the United States Department of the Treasury makes payments to owners who place in service specified energy property and apply for such payments. The purpose of the payment is to reimburse eligible applicants for a portion of the capital cost of such property. Solar and Wind energy properties are eligible for a 30 percent payment of the total eligible capital cost of the project. This 30 percent payment reduced the calculated fixed nominal levelized revenue requirements of the solar and wind technologies.

New Entrant Combustion Turbine

Energy market net revenue was calculated for a CT plant economically dispatched by PJM. 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 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 all zones but DEOK in 2015 (Table 7-5).

Table 7-5 Energy net revenue for a new entrant gas-fired CT under economic dispatch (Dollars per installed MW-year)[18]

Zone	2009	2010	2011	2012	2013	2014	2015	Change in 2015 from 2014
AECO	$10,270	$41,776	$63,064	$50,716	$31,431	$62,488	$51,404	(18%)
AEP	$3,798	$12,246	$29,569	$39,768	$19,169	$58,738	$37,225	(37%)
AP	$12,211	$34,656	$49,411	$49,941	$26,767	$78,655	$58,192	(26%)
ATSI	NA	NA	$23,275	$43,763	$25,509	$67,762	$40,147	(41%)
BGE	$14,738	$52,514	$63,755	$71,707	$42,986	$89,712	$80,641	(10%)
ComEd	$2,253	$9,555	$18,515	$25,156	$12,992	$26,298	$13,595	(48%)
DAY	$3,011	$11,984	$30,125	$44,423	$19,910	$59,033	$37,710	(36%)
DEOK	NA	NA	NA	$36,426	$19,775	$78,150	$84,960	9%
DLCO	$3,247	$16,803	$33,064	$42,347	$20,903	$52,608	$31,438	(40%)
Dominion	$14,746	$47,122	$49,223	$53,638	$31,175	$43,721	$37,802	(14%)
DPL	$11,306	$40,871	$57,501	$62,542	$35,129	$78,702	$41,079	(48%)
EKPC	NA	NA	NA	NA	$15,244	$75,630	$75,433	(0%)
JCPL	$9,267	$39,408	$59,820	$49,343	$37,511	$64,876	$49,777	(23%)
Met-Ed	$8,092	$38,275	$50,960	$47,325	$29,546	$55,100	$47,292	(14%)
PECO	$8,598	$37,178	$59,087	$49,037	$27,857	$56,752	$45,876	(19%)
PENELEC	$7,418	$26,960	$47,419	$53,552	$40,971	$120,385	$112,826	(6%)
Pepco	$17,071	$49,586	$56,858	$64,640	$39,789	$80,268	$59,478	(26%)
PPL	$7,426	$31,826	$52,511	$43,024	$28,268	$61,271	$46,193	(25%)
PSEG	$7,067	$35,863	$49,340	$46,919	$30,673	$47,870	$23,810	(50%)
RECO	$5,805	$32,934	$39,366	$42,708	$32,271	$47,536	$25,602	(46%)
PJM	$8,607	$32,915	$46,270	$48,262	$28,394	$65,278	$50,024	(23%)

In 2015, a new CT would have received sufficient net revenue to cover levelized total costs in six of the 20 zones and more than 90 percent of levelized total costs in an additional six zones (Table 7-6). A CT in the zones in which a new CT covered more than 90 percent of levelized total costs in 2014 also covered more than 90 percent of levelized total costs in 2015 with two exceptions. The net revenue results for a new CT reflect a number of factors, including substantially higher capacity market revenues in ATSI and a decline in both capacity and energy revenues in PSEG and DPL. Eastern zones continued to have generally higher net revenues but the net revenues in the western zones increased as a result of higher capacity market prices. Net revenues covered less than 75 percent of levelized total costs in only two zones, ComEd and DLCO.

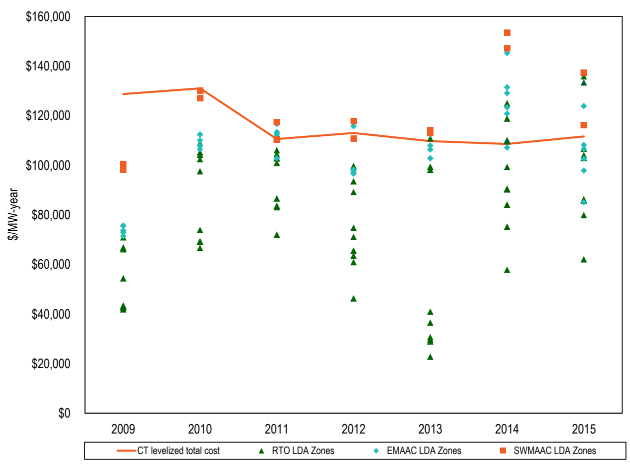
18 The energy net revenues presented for the PJM area in this section represent the zonal average energy net revenues.

Table 7-6 Percent of 20-year levelized total costs recovered by CT energy and capacity net revenue

Zone	2009	2010	2011	2012	2013	2014	2015
AECO	59%	86%	105%	87%	97%	119%	97%
AEP	34%	53%	75%	54%	26%	83%	77%
AP	55%	80%	93%	63%	33%	101%	96%
ATSI	NA	NA	NA	NA	NA	91%	122%
BGE	76%	99%	106%	104%	103%	141%	123%
ComEd	33%	51%	65%	41%	21%	53%	56%
DAY	33%	53%	76%	58%	27%	83%	77%
DEOK	NA	NA	NA	NA	NA	101%	120%
DLCO	33%	56%	78%	56%	28%	77%	72%
Dominion	42%	80%	93%	66%	37%	69%	77%
DPL	59%	86%	101%	102%	104%	134%	88%
EKPC	NA	NA	NA	NA	NA	99%	111%
JCPL	57%	84%	102%	86%	102%	121%	95%
Met-Ed	52%	83%	94%	83%	91%	109%	93%
PECO	57%	82%	102%	85%	94%	114%	92%
PENELEC	51%	74%	91%	88%	101%	170%	152%
Pepco	78%	97%	100%	98%	104%	135%	104%
PPL	51%	78%	96%	79%	89%	115%	92%
PSEG	55%	81%	93%	87%	98%	111%	76%
RECO	NA	NA	NA	NA	NA	NA	NA
PJM	52%	76%	92%	77%	72%	107%	96%

Figure 7-6 shows zonal net revenue and the annual levelized total cost for the new entrant CT by LDA.

Figure 7-6 New entrant CT net revenue and 20-year levelized total cost by LDA (Dollars per installed MW-year): 2009 through 2015



New Entrant Combined Cycle

Energy market net revenue was calculated for a CC plant economically dispatched by PJM. 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.[19] If the unit was not already committed day ahead, it was 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 2015 (Table 7-7).

Table 7-7 Energy net revenue for a new entrant CC under economic dispatch (Dollars per installed MW-year)[20]

Zone	2009	2010	2011	2012	2013	2014	2015	Change in 2015 from 2014
AECO	$37,852	$79,328	$111,306	$92,466	$70,012	$123,761	$90,646	(27%)
AEP	$15,920	$32,720	$70,273	$81,290	$52,898	$94,541	$73,584	(22%)
AP	$41,013	$70,232	$101,830	$93,060	$66,602	$121,059	$97,044	(20%)
ATSI	NA	NA	$47,083	$87,078	$64,344	$108,904	$77,638	(29%)
BGE	$46,193	$91,219	$111,996	$113,212	$86,520	$160,024	$123,490	(23%)
ComEd	$9,224	$20,318	$31,890	$53,616	$28,188	$38,964	$30,984	(20%)
DAY	$14,063	$30,879	$69,799	$86,887	$56,071	$96,827	$75,212	(22%)
DEOK	NA	NA	NA	$75,534	$55,985	$131,815	$126,326	(4%)
DLCO	$14,210	$35,028	$69,664	$81,852	$49,647	$80,373	$63,351	(21%)
Dominion	$48,720	$88,838	$98,117	$94,554	$67,136	$87,913	$74,747	(15%)
DPL	$39,572	$76,906	$105,344	$104,125	$73,857	$144,248	$75,044	(48%)
EKPC	NA	NA	NA	NA	$34,714	$127,207	$116,344	(9%)
JCPL	$37,944	$77,772	$109,562	$92,010	$77,489	$128,858	$89,489	(31%)
Met-Ed	$31,635	$70,703	$95,417	$87,492	$65,530	$112,744	$82,109	(27%)
PECO	$33,551	$73,009	$105,795	$89,597	$63,132	$115,652	$83,816	(28%)
PENELEC	$31,352	$61,287	$97,938	$98,591	$91,135	$188,435	$149,842	(20%)
Pepco	$45,176	$89,540	$103,337	$105,910	$82,294	$144,086	$99,510	(31%)
PPL	$29,740	$62,518	$94,143	$83,418	$62,900	$113,566	$82,866	(27%)
PSEG	$33,366	$73,323	$94,698	$85,877	$67,412	$103,746	$48,489	(53%)
RECO	$28,128	$67,511	$76,967	$80,214	$68,794	$103,181	$48,869	(53%)
PJM	$31,627	$64,772	$88,620	$88,778	$64,233	$116,295	$85,470	(27%)

In 2015, a new CC would have received sufficient net revenue to cover levelized total costs in nine of the 20 zones and more than 90 percent of levelized total costs in an additional four zones (Table 7-8). A CC in the zones in which a new CC covered more than 90 percent of levelized total costs in 2014 also covered more than 90 percent of levelized total costs in 2015 with one exception. The net revenue results for a new CC reflect a number of factors, including substantially higher capacity market revenues in ATSI and a decline in both capacity and energy revenues in PSEG. Eastern zones continued to have generally higher net revenues but the net revenues in the western zones increased as a result of higher capacity market prices. Net revenues covered less than 75 percent of levelized total costs in one zone and that result was 55 percent in ComEd.

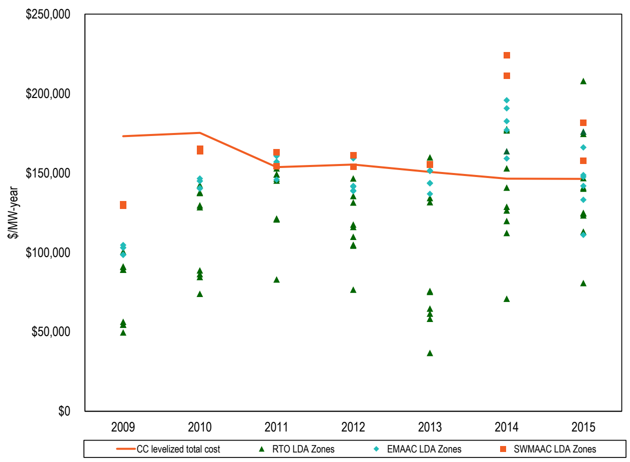
19 All starts associated with combined cycle units are assumed to be warm starts.
20 The energy net revenues presented for the PJM area in this section represent the zonal average energy net revenues.

Table 7-8 Percent of 20-year levelized total costs recovered by CC energy and capacity net revenue

Zone	2009	2010	2011	2012	2013	2014	2015
AECO	59%	84%	106%	91%	95%	130%	102%
AEP	33%	49%	79%	67%	41%	86%	84%
AP	58%	78%	99%	75%	50%	104%	100%
ATSI	NA	NA	NA	NA	NA	96%	119%
BGE	75%	94%	106%	104%	103%	153%	124%
ComEd	29%	42%	54%	49%	24%	48%	55%
DAY	31%	48%	79%	71%	43%	88%	85%
DEOK	NA	NA	NA	NA	NA	112%	120%
DLCO	32%	51%	79%	67%	39%	77%	77%
Dominion	51%	81%	97%	76%	50%	82%	85%
DPL	60%	83%	102%	102%	101%	144%	91%
EKPC	NA	NA	NA	NA	NA	109%	113%
JCPL	59%	83%	105%	91%	100%	134%	101%
Met-Ed	53%	79%	95%	87%	89%	121%	96%
PECO	57%	80%	102%	89%	91%	125%	97%
PENELEC	52%	73%	97%	94%	106%	172%	142%
Pepco	75%	93%	100%	99%	103%	144%	108%
PPL	52%	74%	94%	85%	87%	121%	96%
PSEG	57%	80%	95%	89%	95%	121%	76%
RECO	NA	NA	NA	NA	NA	NA	NA
PJM	52%	73%	93%	84%	76%	114%	99%

Figure 7-7 shows zonal net revenue and the annual levelized total cost for the new entrant CC by LDA.

Figure 7-7 New entrant CC net revenue and 20-year levelized total cost by LDA (Dollars per installed MW-year): 2009 through 2015



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 at the direction of PJM. The regulation clearing price was compared to the day ahead LMP. If the reference CP could provide regulation more profitably than energy, the unit was assumed to provide regulation during that hour.

New entrant CP plant energy market net revenues were lower in all zones in 2015 (Table 7-9).

Table 7-9 Energy net revenue for a new entrant CP (Dollars per installed MW-year)[21]

Zone	2009	2010	2011	2012	2013	2014	2015	Change in 2015 from 2014
AECO	$103,766	$146,624	$92,802	$34,149	$57,755	$177,470	$73,776	(58%)
AEP	$46,160	$94,385	$85,512	$34,944	$66,604	$130,312	$60,723	(53%)
AP	$99,655	$145,822	$105,988	$47,572	$76,645	$154,779	$79,952	(48%)
ATSI	NA	NA	$41,354	$42,673	$74,835	$143,552	$61,397	(57%)
BGE	$121,146	$184,563	$121,183	$62,567	$91,820	$228,990	$145,506	(36%)
ComEd	$109,938	$135,212	$129,279	$111,542	$130,283	$178,450	$97,010	(46%)
DAY	$44,900	$89,635	$81,825	$33,023	$72,665	$135,377	$59,299	(56%)
DEOK	NA	NA	NA	$26,451	$62,130	$122,282	$54,717	(55%)
DLCO	$43,907	$68,504	$49,251	$27,035	$43,321	$97,572	$47,474	(51%)
Dominion	$105,884	$167,920	$101,391	$44,651	$72,880	$180,306	$106,299	(41%)
DPL	$114,738	$166,793	$117,229	$57,505	$81,303	$222,872	$103,772	(53%)
EKPC	NA	NA	NA	NA	$32,626	$118,063	$45,675	(61%)
JCPL	$103,162	$144,597	$90,057	$32,724	$64,305	$181,578	$73,488	(60%)
Met-Ed	$104,285	$152,922	$101,258	$43,092	$68,531	$177,954	$74,648	(58%)
PECO	$98,600	$139,859	$88,317	$32,534	$52,526	$170,974	$70,211	(59%)
PENELEC	$78,821	$113,244	$77,113	$39,044	$67,118	$149,924	$70,797	(53%)
Pepco	$111,966	$164,693	$88,212	$38,656	$73,063	$202,767	$114,025	(44%)
PPL	$92,013	$125,723	$77,783	$26,866	$52,125	$167,421	$68,996	(59%)
PSEG	$96,099	$146,842	$89,665	$31,754	$77,582	$201,663	$83,728	(58%)
RECO	$89,060	$137,591	$71,676	$28,196	$83,010	$196,735	$84,679	(57%)
PJM	$92,006	$136,761	$89,439	$41,841	$70,056	$166,952	$78,809	(53%)

In 2015, a new CP would not have received sufficient net revenue to cover levelized total costs in any zone (Table 7-8). The improved results in 2014 were reversed in 2015 and were relatively close to 2013 results. Zonal energy market net revenues decreased by from 49 percent to 77 percent which was not offset by the increase in some locational capacity market revenues.

21 The energy net revenues presented for the PJM area in this section represent the zonal average energy net revenues.

Table 7-10 Percent of 20-year levelized total costs recovered by CP energy and capacity net revenue

Zone	2009	2010	2011	2012	2013	2014	2015
AECO	38%	46%	31%	17%	27%	48%	25%
AEP	19%	32%	29%	12%	15%	32%	21%
AP	35%	46%	34%	15%	17%	37%	25%
ATSI	NA	NA	NA	NA	NA	35%	30%
BGE	46%	56%	37%	23%	33%	58%	39%
ComEd	33%	41%	39%	28%	28%	42%	28%
DAY	19%	31%	29%	12%	17%	33%	21%
DEOK	NA	NA	NA	NA	NA	31%	20%
DLCO	19%	26%	22%	10%	11%	26%	19%
Dominion	33%	48%	33%	14%	17%	42%	30%
DPL	40%	50%	36%	23%	32%	57%	31%
EKPC	NA	NA	NA	NA	NA	30%	18%
JCPL	37%	45%	30%	17%	28%	49%	25%
Met-Ed	36%	47%	33%	19%	28%	48%	25%
PECO	36%	44%	30%	17%	26%	47%	25%
PENELEC	31%	39%	28%	18%	28%	42%	25%
Pepco	44%	51%	30%	18%	30%	53%	33%
PPL	34%	41%	28%	16%	25%	46%	24%
PSEG	36%	46%	30%	18%	31%	54%	28%
RECO	NA	NA	NA	NA	NA	NA	NA
PJM	33%	43%	31%	17%	24%	43%	26%

Figure 7-8 shows zonal net revenue and the annual levelized total cost for the new entrant CP by LDA.

Figure 7-8 New entrant CP net revenue and 20-year levelized total cost by LDA (Dollars per installed MW-year): 2009 through 2015

New Entrant Diesel

Energy market net revenue was calculated for a DS plant economically dispatched by PJM in real time.

New entrant DS plant energy market net revenues were lower in all zones in 2015 (Table 7-11).

Table 7-11 Energy market net revenue for a new entrant DS (Dollars per installed MW-year)

Zone	2009	2010	2011	2012	2013	2014	2015	Change in 2015 from 2014
AECO	$1,763	$11,217	$6,708	$1,552	$1,082	$37,123	$15,506	(58%)
AEP	$112	$499	$1,717	$820	$484	$15,855	$6,002	(62%)
AP	$886	$1,771	$2,007	$1,061	$741	$20,542	$10,490	(49%)
ATSI	NA	NA	$308	$1,083	$23,643	$15,553	$5,777	(63%)
BGE	$3,712	$14,147	$7,870	$2,577	$2,654	$55,866	$27,241	(51%)
ComEd	$11	$480	$811	$909	$384	$12,427	$3,720	(70%)
DAY	$186	$554	$1,894	$946	$517	$15,671	$6,083	(61%)
DEOK	NA	NA	NA	$689	$462	$14,814	$5,829	(61%)
DLCO	$674	$2,987	$2,165	$914	$1,231	$14,403	$5,428	(62%)
Dominion	$3,639	$10,967	$4,108	$1,664	$1,545	$46,961	$15,836	(66%)
DPL	$2,721	$9,892	$5,769	$2,381	$1,083	$43,946	$25,593	(42%)
EKPC	NA	NA	NA	NA	$289	$15,816	$4,856	(69%)
JCPL	$1,895	$8,673	$6,610	$1,704	$2,016	$37,086	$15,065	(59%)
Met-Ed	$1,620	$8,711	$5,032	$1,833	$1,254	$35,789	$15,174	(58%)
PECO	$1,558	$8,570	$5,379	$1,936	$1,004	$36,186	$14,033	(61%)
PENELEC	$240	$1,124	$2,642	$2,141	$1,104	$18,141	$8,154	(55%)
Pepco	$4,036	$13,277	$6,077	$2,009	$2,249	$56,830	$18,222	(68%)
PPL	$1,428	$7,704	$5,317	$1,747	$1,054	$36,712	$14,906	(59%)
PSEG	$1,394	$7,394	$5,447	$1,695	$1,257	$36,629	$14,566	(60%)
RECO	$1,201	$6,241	$4,255	$1,737	$2,387	$34,756	$16,108	(54%)
PJM	$1,593	$6,718	$4,118	$1,547	$2,322	$30,055	$12,429	(59%)

In 2015, a new DS would not have received sufficient net revenue to cover levelized total costs in any zone. The marginal cost of the DS was relatively high compared to clearing prices in the energy market.

Table 7-12 Percent of 20-year levelized total costs recovered by DS energy and capacity net revenue

Zone	2009	2010	2011	2012	2013	2014	2015
AECO	43%	51%	37%	31%	49%	64%	42%
AEP	25%	35%	34%	14%	6%	29%	32%
AP	38%	44%	34%	14%	6%	32%	34%
ATSI	NA	NA	NA	NA	NA	29%	59%
BGE	56%	57%	38%	31%	46%	74%	49%
ComEd	25%	35%	33%	14%	6%	27%	30%
DAY	25%	35%	34%	14%	6%	29%	32%
DEOK	NA	NA	NA	NA	NA	28%	32%
DLCO	26%	36%	34%	14%	6%	28%	31%
Dominion	28%	42%	35%	14%	7%	48%	38%
DPL	43%	50%	37%	36%	51%	68%	48%
EKPC	NA	NA	NA	NA	NA	29%	31%
JCPL	43%	49%	37%	32%	49%	64%	42%
Met-Ed	39%	49%	36%	31%	46%	61%	42%
PECO	42%	49%	36%	32%	49%	63%	41%
PENELEC	38%	44%	34%	31%	45%	50%	38%
Pepco	57%	56%	37%	31%	49%	76%	44%
PPL	39%	48%	36%	31%	45%	62%	42%
PSEG	42%	48%	36%	34%	50%	68%	44%
RECO	NA	NA	NA	NA	NA	NA	NA
PJM	38%	45%	35%	25%	32%	49%	40%

New Entrant Nuclear Plant

Energy market net revenue was calculated assuming that the nuclear plant was dispatched day ahead by PJM for all available plant hours. The unit runs for all hours of the year other than forced outage hours.[22]

New entrant nuclear plant energy market net revenues were lower in all zones in 2015 (Table 7-13).

Table 7-13 Energy net revenue for a new entrant nuclear plant (Dollars per installed MW-year)[23]

Zone	2009	2010	2011	2012	2013	2014	2015	Change in 2015 from 2014
AECO	$288,632	$367,483	$335,035	$223,539	$262,810	$387,883	$220,023	(43%)
AEP	$218,504	$261,098	$262,335	$198,385	$230,716	$311,569	$204,723	(34%)
AP	$256,721	$314,729	$293,355	$210,232	$244,428	$337,998	$228,936	(32%)
ATSI	NA	NA	$153,888	$204,058	$242,705	$325,433	$208,372	(36%)
BGE	$298,473	$391,960	$341,862	$245,538	$285,910	$444,433	$304,148	(32%)
ComEd	$179,104	$217,838	$212,423	$175,450	$206,746	$272,321	$168,496	(38%)
DAY	$214,090	$258,210	$262,111	$203,992	$234,102	$314,747	$206,825	(34%)
DEOK	NA	NA	NA	$192,158	$221,863	$299,618	$201,391	(33%)
DLCO	$208,801	$257,065	$258,686	$199,094	$227,732	$291,888	$193,791	(34%)
Dominion	$281,069	$373,737	$319,215	$223,740	$263,891	$388,295	$260,516	(33%)
DPL	$291,154	$370,565	$335,597	$236,441	$272,775	$428,044	$250,192	(42%)
EKPC	NA	NA	NA	NA	$127,631	$294,606	$190,936	(35%)
JCPL	$287,875	$365,408	$332,717	$222,496	$271,028	$392,479	$218,452	(44%)
Met-Ed	$279,022	$354,677	$317,652	$217,622	$257,748	$374,408	$211,003	(44%)
PECO	$282,937	$359,927	$329,530	$220,535	$256,201	$378,894	$212,675	(44%)
PENELEC	$250,469	$310,481	$291,867	$215,338	$256,535	$349,950	$217,124	(38%)
Pepco	$298,215	$389,389	$332,675	$238,119	$281,722	$427,666	$279,006	(35%)
PPL	$275,067	$343,190	$316,501	$213,393	$255,433	$374,962	$211,595	(44%)
PSEG	$292,089	$371,365	$338,912	$226,944	$289,418	$416,439	$230,273	(45%)
RECO	$284,023	$360,820	$317,521	$221,087	$295,509	$411,345	$232,025	(44%)
PJM	$263,897	$333,408	$297,327	$215,166	$249,245	$361,149	$222,525	(38%)

In 2015, a new nuclear plant would not have received sufficient net revenue to cover levelized total costs in any zone (Table 7-14). The improved results in 2014 were reversed in 2015 and were relatively close to 2013 results. Zonal energy market net revenues decreased by from 32 percent to 45 percent which was not offset by the increase in some locational capacity market revenues.

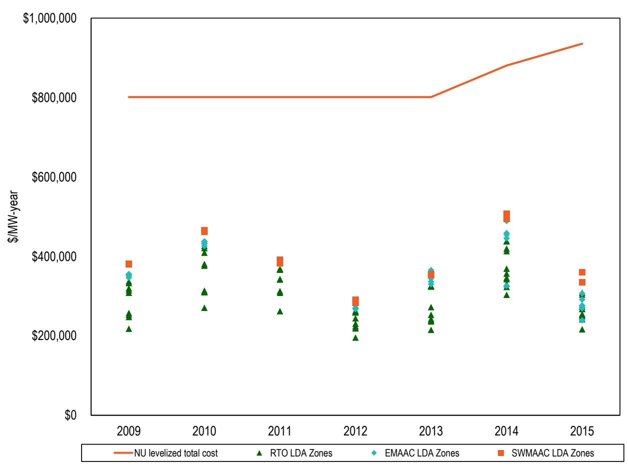
22 The class average forced outage rate was applied to total energy market net revenues.

23 The energy net revenues presented for the PJM area in this section represent the zonal average energy net revenues.

Table 7-14 Percent of 20-year levelized total costs recovered by nuclear energy and capacity net revenue: 2009 through 2015

Zone	2009	2010	2011	2012	2013	2014	2015
AECO	44%	54%	48%	34%	42%	52%	30%
AEP	32%	39%	39%	27%	30%	39%	27%
AP	39%	48%	43%	29%	32%	42%	30%
ATSI	NA	NA	NA	NA	NA	40%	32%
BGE	48%	58%	49%	36%	44%	58%	39%
ComEd	27%	34%	33%	24%	27%	34%	23%
DAY	32%	39%	39%	28%	30%	39%	27%
DEOK	NA	NA	NA	NA	NA	38%	27%
DLCO	31%	39%	39%	27%	29%	37%	26%
Dominion	40%	53%	46%	30%	34%	48%	33%
DPL	44%	55%	48%	36%	44%	56%	33%
EKPC	NA	NA	NA	NA	NA	37%	26%
JCPL	44%	54%	48%	34%	43%	52%	29%
Met-Ed	42%	53%	46%	33%	41%	50%	29%
PECO	43%	53%	47%	33%	41%	51%	29%
PENELEC	38%	47%	43%	33%	41%	47%	29%
Pepco	48%	58%	48%	35%	44%	56%	36%
PPL	42%	51%	46%	32%	40%	50%	29%
PSEG	44%	55%	49%	35%	46%	56%	31%
RECO	NA	NA	NA	NA	NA	NA	NA
PJM	40%	49%	44%	32%	38%	46%	30%

Figure 7-9 New entrant NU net revenue and 20-year levelized total cost by LDA (Dollars per installed MW-year): 2009 through 2015



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 $0.81/MWh in ComEd and $14.80/MWh in PENELEC.[24]

Wind energy market net revenues were lower in 2015 (Table 7-15).

24 REC prices provided by Evolution Markets.

Table 7-15 Net revenue for a wind installation (Dollars per installed MW-year)

	2012				2013				2014				2015				2015 Total
Zone	Energy	Credits	Capacity	Total	Energy	Credits	Capacity	Total	Energy	Credits	Capacity	Total	Energy	Credits	Capacity	Total	Change
ComEd	68,086	-	2,632	70,717	83,764	-	1,095	84,859	108,420	75,325	4,049	187,795	81,650	78,533	6,257	166,439	(11%)
PENELEC	69,632	56,622	5,878	132,132	88,401	78,900	8,905	176,206	127,839	96,234	8,237	232,310	83,937	95,617	7,338	186,892	(20%)

In 2015, a new wind installation would not have received sufficient net revenue to cover levelized total costs in either zone. Production tax credits and renewable energy credits accounted for 47 percent of the total net revenue of a wind installation.

Table 7-16 Percent of 20-year levelized total costs recovered by wind energy and capacity net revenue (Dollars per installed MW-year): 2012 through 2015

Zone	2012	2013	2014	2015
ComEd	36%	43%	95%	82%
PENELEC	67%	90%	117%	92%

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 hourly 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 $174.23/MWh.[25]

Solar energy market net revenues were slightly higher in 2015 (Table 7-17).

Table 7-17 PSEG Energy Market net revenue for a solar installation (Dollars per installed MW-year)

	2012				2013				2014				2015				2015 Total
Zone	Energy	Credits	Capacity	Total	Energy	Credits	Capacity	Total	Energy	Credits	Capacity	Total	Energy	Credits	Capacity	Total	Change
PSEG	48,501	312,580	18,984	380,065	81,122	287,853	28,835	397,811	98,182	281,386	27,575	407,144	67,807	319,866	23,156	410,828	1%

In 2015, a new solar installation would have received sufficient net revenue to cover levelized total costs in PSEG. Production tax credits and renewable energy credits accounted for 78 percent of the total net revenue of a solar installation.

Table 7-18 Percent of 20-year levelized total costs recovered by solar energy and capacity net revenue (Dollars per installed MW-year)

Zone	2012	2013	2014	2015
PSEG	96%	151%	172%	175%

Factors in Net Revenue Adequacy

Although it can be expected that in the long run, in a competitive market, net revenue from all sources will cover the fixed and variable costs of investing in new generating resources, including a competitive return on investment, actual results are expected to vary from year to year. Wholesale energy markets, like other markets, are cyclical. When the markets are long, prices will be lower and when the markets are short, prices will be higher.

The net revenue for a new generation resource varied significantly with the input fuel type and the efficiency of the reference technology. In 2015, the average operating cost of the CC was lower than the average operating costs of the CP for the ten months from March through December, as a result of the relative cost of gas versus coal, compared to only five months in 2014 and 2013. (See Figure 7-5)

25 SREC prices provided by Evolution Markets.

Table 7-19 Internal rate of return sensitivity for CT, CC and CP generators

	CT		CC		CP	
	20-Year Levelized Net Revenue	20-Year After Tax IRR	20-Year Levelized Net Revenue	20-Year After Tax IRR	20-Year Levelized Net Revenue	20-Year After Tax IRR
Sensitivity 1	$119,139	13.9%	$156,300	13.9%	$547,017	13.6%
Base Case	$111,639	12.0%	$146,300	12.0%	$517,017	12.0%
Sensitivity 2	$104,139	10.0%	$136,300	10.0%	$487,017	10.4%
Sensitivity 3	$96,639	7.8%	$126,300	7.8%	$457,017	8.7%
Sensitivity 4	$89,139	5.4%	$116,300	5.6%	$427,017	7.0%
Sensitivity 5	$81,639	2.7%	$106,300	3.0%	$397,017	5.1%
Sensitivity 6	$74,139	(0.8%)	$96,300	0.0%	$367,017	3.1%

The net revenue results illustrate some fundamentals of the PJM wholesale power market. CTs are generally the highest incremental energy cost units and therefore tend to be marginal in the energy market, when load requires them, and set prices in the energy market, when they run. When this occurs, CT energy market net revenues are small and there is little contribution to fixed costs. High demand hours result in less efficient CTs setting prices, which results in higher net revenues for more efficient CTs. Scarcity revenues in the energy market also contribute to covering fixed costs, when they occur, but scarcity revenues are not a predictable and systematic source of net revenue. In the PJM design, the balance of the net revenue required to cover the fixed costs of peaking units comes from the capacity market.

However, there may be a lag in capacity market prices which either offsets the reduction in energy market revenues or exacerbates the reduction in energy market revenues. Capacity market prices are a function of a three year historical average net revenue offset which is generally an inaccurate estimate of actual net revenues in the current operating year and an inaccurate estimate of expected net revenues for the forward capacity market. Capacity market prices and revenues have a substantial impact on the profitability of investing in CTs and CCs. In 2015, zonal energy net revenues decreased across all units, while capacity market prices increased over 2014 in the western zones.

Coal units (CP) are marginal in the PJM system for a substantial number of hours. When this occurs, CP energy market net revenues are small and there is little contribution to fixed costs. The same is true when efficient CCs are on the margin. However, when CTs or less efficient coal units are on the margin net revenues are higher for more efficient coal units.

The returns earned by investors in generating units are a direct function of net revenues, the cost of capital, and the fixed costs associated with the generating unit. Positive returns may be earned at less than the annualized fixed costs, although the returns are less than the target. A sensitivity analysis was performed to determine the impact of changes in net revenue on the return on investment for a new generating unit. The internal rate of return (IRR) was calculated for a range of 20-year levelized net revenue streams, using 20-year levelized total costs from Table 7-4 The results are shown in Table 7-19.[26]

Additional sensitivity analyses were performed for the CT and the CC technologies for the debt to equity ratio; the term of the debt financing; and the costs of interconnection. Table 7-20 shows the levelized annual revenue requirements associated with a range of debt to equity ratios holding the 12 percent IRR constant. The base case assumes 50/50 debt to equity ratio. As the percent of equity financing decreases, the levelized annual revenue required to earn a 12 percent IRR falls.

Table 7-20 Debt to equity ratio sensitivity for CT and CC assuming 20 year debt term and 12 percent internal rate of return

	Equity as a percent of total financing	CT levelized annual revenue requirement	CC levelized annual revenue requirement
Sensitivity 1	60%	$118,155	$154,644
Sensitivity 2	55%	$114,897	$150,472
Base Case	50%	$111,639	$146,300
Sensitivity 3	45%	$108,382	$142,128
Sensitivity 4	40%	$105,125	$137,956
Sensitivity 5	35%	$101,867	$133,785
Sensitivity 6	30%	$98,610	$129,612

26 This analysis was performed for the MMU by Pasteris Energy, Inc. The annual costs were based on a 20-year project life, 50/50 debt to equity capital structure with a target IRR of 12 percent and a debt rate of 7 percent. For depreciation, the analysis assumed a 15-year modified accelerated cost-recovery schedule (MACRS) for the CT plant and 20-year MACRS for the CC and CP plants. An annual rate of cost inflation of 2.5 percent was used in all calculations.

Table 7-21 Debt term sensitivity for CT and CC assuming 50/50 debt to equity ratio and 12 percent internal rate of return

	Term of debt in years	CT levelized annual revenue requirement	CC levelized annual revenue requirement
Sensitivity 1	30	$101,440	$133,239
Sensitivity 2	25	$105,294	$138,174
Base Case	20	$111,639	$146,300
Sensitivity 3	15	$116,985	$153,135
Sensitivity 4	10	$124,078	$162,197

Table 7-22 Interconnection cost sensitivity for 2015 CT and CC

	CT			CC		
	Capital cost ($000)	Percent of total capital cost	Annualized revenue requirement ($/ICAP-Year)	Capital cost ($000)	Percent of total capital cost	Annualized revenue requirement ($/ICAP-Year)
Sensitivity 1	$0	0.0%	$108,017	$0	0.0%	$142,383
Sensitivity 2	$8,321	1.8%	$109,828	$12,738	1.4%	$144,341
Base Case	$16,643	3.6%	$111,639	$25,477	2.8%	$146,300
Sensitivity 3	$24,964	5.4%	$113,451	$38,215	4.2%	$148,259
Sensitivity 4	$33,286	7.3%	$115,262	$50,953	5.7%	$150,218
Sensitivity 5	$41,607	9.1%	$117,074	$63,692	7.1%	$152,177
Sensitivity 6	$50,000	10.9%	$118,901	$76,430	8.5%	$154,136
Sensitivity 7	$75,000	16.3%	$124,343	$100,000	11.1%	$157,760
Sensitivity 8	$100,000	21.8%	$129,785	$150,000	16.7%	$165,449

Table 7-21 shows the levelized annual revenue requirements associated with various terms for the debt financing, assuming a 50/50 debt to equity ratio and 12 percent rate of return. As the term of the debt financing decreases, more net revenue is required annually to maintain a 12 percent rate of return.

Table 7-22 shows the impact of a range of assumed interconnection costs on the levelized annual revenue requirement for the CT and the CC technologies. Interconnection costs vary significantly by location across PJM and even within PJM zones and can significantly impact the profitability of investing in peaking and midmerit generation technologies in a specific location. The impact on the annualized revenue requirements is more substantial for CTs than for CCs as interconnection costs are a larger proportion of overall project costs for CTs and as the new entrant CC has a higher energy output over which to spread the costs than the new entrant CT.

Actual Net Revenue

This analysis of net revenues is based on actual net revenues for actual units operating in PJM. Net revenues from energy and capacity markets are compared to avoidable costs to determine the extent to which the revenues from PJM markets provide sufficient incentive for continued operations in PJM Markets. Avoidable costs are the costs which must be paid each year in order to keep a unit operating. Avoidable costs are less than total costs, which include the return on and of capital, and more than marginal costs, which are the purely short run incremental costs of producing energy. It is rational to operate a unit whenever the price is greater than its short run marginal costs. It is rational for an owner to continue to operate a unit rather than retire the unit if the unit is covering or is expected to cover its avoidable costs and therefore contributing to covering fixed costs. It is not rational for an owner to continue to operate a unit rather than retire the unit if the unit is not covering and is not expected to cover its avoidable costs. As a general matter, under those conditions, retirement of the unit is the logical option. Thus, this comparison of actual net revenues to avoidable costs is a measure of the extent to which units in PJM may be at risk of retirement.

The definition of avoidable costs, based on the RPM rules, includes both avoidable costs and the annualized fixed costs of investments required to maintain a unit as a capacity resource (APIR). When actual net revenues are compared to actual avoidable costs in this analysis, the actual avoidable costs are adjusted to exclude APIR. Existing APIR is a sunk cost and a rational decision about retirement would ignore such sunk costs. For example, APIR may reflect investments in environmental technology which were made in prior years to keep units in service. These costs are sunk costs.

The MMU calculated actual unit specific energy and ancillary service net revenues for several technology classes. These net revenues were compared to avoidable costs to determine the extent to which PJM Energy and Ancillary Service Markets alone provide sufficient incentive for continued operations in PJM markets. Energy and Ancillary Service revenues were then combined with the actual capacity revenues, and compared to actual avoidable costs to determine the extent to which the capacity market revenues covered any shortfall between energy and ancillary net revenues and avoidable costs. The comparison of the two results is an indicator of the significance of the role of the capacity market in maintaining the viability of existing generating units.

Actual energy net revenues include day-ahead and balancing market energy revenues, less short run marginal costs, plus any applicable day-ahead or balancing operating reserve credits. Ancillary service revenues include actual unit credits for regulation services, synchronized reserves and black start service, in addition to reactive revenues.

The MMU calculated average avoidable costs in dollars per MW-year based on submitted avoidable cost rate (ACR) data for units associated with the most recent 2014/2015 and 2015/2016 RPM Auctions.[27] For units that did not submit ACR data, the default ACR was used.

Any unit with a significant portion of installed capacity designated as FRR committed was excluded from the analysis.[28] For units exporting capacity, the applicable Base Residual Auction (BRA) clearing price was applied.

Net revenues were analyzed for most technologies for which avoidable costs are developed in the RPM. The analysis was done on a unit specific basis, using individual unit actual net revenues and individual unit avoidable costs. Table 7-23 provides a summary of results by technology class, as well as the total installed capacity associated with each technology analyzed. Net revenues in Table 7-23 are calculated using units' cost-based offers. A more accurate method would be to use the lower of the unit's price-based or cost-based offers.[29]

Table 7-23 Class average net revenue from energy and ancillary markets and associated recovery of class average avoidable costs and total revenue from all markets and associated recovery of class average avoidable costs: 2015

Technology	Total Installed Capacity (ICAP)	Class average energy and ancillary net revenue ($/MW-year)	Class average energy net revenue and capacity revenue ($/MW-year)	Class average avoidable costs ($/MW-year)
CC - NUG Cogeneration Frame B or E Technology	2,032	$53,405	$109,826	$50,677
CC - Two or Three on One Frame F Technology	17,524	$56,828	$108,290	$19,030
CT - First & Second Generation Aero (P&W FT 4)	3,155	$5,173	$43,679	$10,661
CT - First & Second Generation Frame B	3,242	$891	$54,081	$11,446
CT - Second Generation Frame E	8,783	$12,296	$64,884	$10,170
CT - Third Generation Aero	3,696	$20,699	$75,356	$20,853
CT - Third Generation Frame F	9,691	$11,588	$58,922	$10,219
Diesel	461	$14,539	$64,782	$10,799
Hydro	7,363	$101,458	$152,650	$27,124
Nuclear	31,661	$177,868	$230,829	NA
Oil or Gas Steam	9,096	$9,552	$60,189	$40,230
Sub-Critical Coal	27,253	$21,044	$59,416	$59,215
Super Critical Coal	23,408	$21,660	$277,188	$129,569

The RPM capacity market design provides supplemental signals to the market based on the locational and forward looking need for generation resources to maintain system reliability. For this analysis, unit specific capacity revenues associated with the 2014/2015 and 2015/2016 delivery years, reflecting commitments made in Base Residual Auctions (BRA) and subsequent Incremental Auctions, net of any performance penalties, were added to unit specific energy and ancillary net revenues to determine total revenue from PJM Markets in 2015.

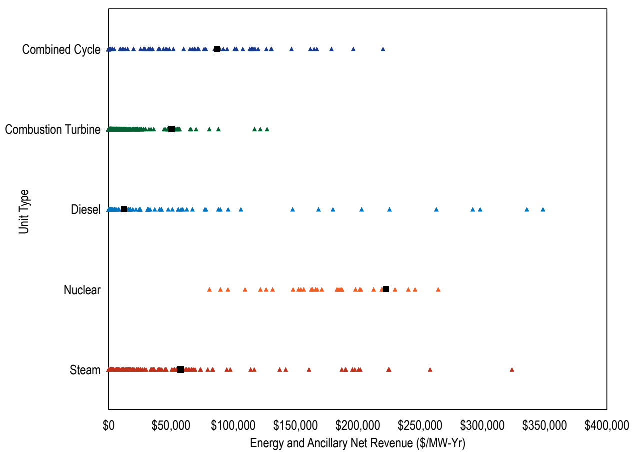
27 If a unit submitted updated ACR data for an incremental auction, that data was used instead of the ACR data submitted for the Base Residual Auction.

28 The MMU cannot assess the risk of FRR designated units because the incentives associated with continued operations for these units are not transparent and are not aligned with PJM market incentives. For the same reasons, units with significant FRR commitments are excluded from the analysis of units potentially facing significant capital expenditures associated with environmental controls.

29 *See* 148 FERC ¶ 61,140 (2014).

The average net revenue results do not show the underlying distribution of actual net revenues by unit type. This underlying distribution of energy and ancillary net revenues by unit type is shown in Figure 7-10. Each generating unit is represented by a single point, and the new entrant PJM average theoretical energy and ancillary net revenue is represented by a solid square.

Figure 7-10 PJM distribution of energy and ancillary net revenue by unit type (Dollars per installed MW-year): 2015



The actual unit specific energy and ancillary net revenues, avoidable costs and capacity revenues underlying the class averages shown in Table 7-23 represent a wide range of results. In order to illustrate this underlying variability while preserving confidentiality of unit specific information, the data are aggregated and summarized by quartile. Within each technology, quartiles were established based on the distribution of total energy net revenue received per installed MW-year. These quartiles remain constant throughout the analysis and are used to present the range of data. The three break points between the four quartiles are presented. Table 7-24 shows average energy and ancillary service net revenues by quartile for select technology classes.

Differences in energy net revenue within technology classes reflect differences in incremental costs which are a function of plant efficiencies, input fuels, variable operating and maintenance (VOM) expenses and emission rates, as well as differences in location which affect both the LMP and delivery costs associated with input fuels. The average net revenues for diesel units, the oil or gas-fired steam technology, and several of the older CT technologies reflect both units burning natural gas and units burning oil distillates. The geographic distribution of units for a given technology class across the PJM footprint determines individual unit price levels and thus average energy net revenue for that technology class.

Table 7-24 Energy and ancillary service net revenue by quartile for select technologies: 2015

	Energy and ancillary net revenue ($/MW-year)		
Technology	First quartile	Second quartile	Third quartile
CC - NUG Cogeneration Frame B or E Technology	$9,096	$19,623	$51,533
CC - Two or Three on One Frame F Technology	$8,218	$33,652	$93,539
CT - First & Second Generation Aero (P&W FT 4)	$363	$2,123	$4,069
CT - First & Second Generation Frame B	($1,053)	$673	$2,587
CT - Second Generation Frame E	$208	$3,069	$10,670
CT - Third Generation Aero	$5,693	$11,717	$26,596
CT - Third Generation Frame F	$1,458	$7,910	$17,308
Diesel	($332)	$0	$17,449
Hydro	$44,478	$79,978	$112,523
Nuclear	$154,267	$184,035	$212,658
Oil or Gas Steam	($593)	$2	$6,528
Sub-Critical Coal	($18)	$15,649	$40,826
Super Critical Coal	($1,459)	$11,498	$39,603

Table 7-25 shows capacity market net revenues by quartile for select technology classes.

Table 7-25 Capacity revenue by quartile for select technologies: 2015

	Capacity revenue ($/MW-year)		
Technology	First quartile	Second quartile	Third quartile
CC - NUG Cogeneration Frame B or E Technology	$55,002	$55,434	$60,591
CC - Two or Three on One Frame F Technology	$46,671	$48,748	$55,877
CT - First & Second Generation Aero (P&W FT 4)	$19,775	$35,468	$53,884
CT - First & Second Generation Frame B	$41,348	$49,536	$54,559
CT - Second Generation Frame E	$47,174	$48,065	$54,929
CT - Third Generation Aero	$47,883	$49,829	$54,058
CT - Third Generation Frame F	$45,698	$47,307	$48,262
Diesel	$45,475	$50,020	$56,447
Hydro	$47,734	$56,365	$57,179
Nuclear	$47,398	$47,901	$55,961
Oil or Gas Steam	$46,907	$53,626	$54,864
Sub-Critical Coal	$17,154	$45,032	$51,046
Super Critical Coal	$44,834	$52,087	$55,239

Table 7-26 shows total net revenues by quartile for select technology classes.

Table 7-26 Combined revenue from all markets by quartile for select technologies: 2015

	Energy, ancillary, and capacity revenue ($/MW-year)		
Technology	First quartile	Second quartile	Third quartile
CC - NUG Cogeneration Frame B or E Technology	$64,098	$75,057	$112,124
CC - Two or Three on One Frame F Technology	$54,889	$82,400	$149,416
CT - First & Second Generation Aero (P&W FT 4)	$20,139	$37,591	$57,953
CT - First & Second Generation Frame B	$40,295	$50,209	$57,146
CT - Second Generation Frame E	$47,381	$51,134	$65,599
CT - Third Generation Aero	$53,576	$61,545	$80,653
CT - Third Generation Frame F	$47,156	$55,217	$65,570
Diesel	$45,143	$50,020	$73,896
Hydro	$92,212	$136,343	$169,703
Nuclear	$201,665	$231,936	$268,618
Oil or Gas Steam	$46,314	$53,628	$61,392
Sub-Critical Coal	$17,137	$60,681	$91,873
Super Critical Coal	$43,375	$63,586	$94,841

Table 7-27 shows the avoidable cost recovery from PJM energy and ancillary services markets by quartiles. In 2015, a substantial portion of units did not achieve full recovery of avoidable costs through energy markets alone. The results do not include nuclear power plants because there is not good public data on nuclear unit avoidable costs.

Table 7-27 Avoidable cost recovery by quartile from energy and ancillary net revenue for select technologies: 2015

	Recovery of avoidable costs from energy and ancillary net revenue		
Technology	First quartile	Second quartile	Third quartile
CC - NUG Cogeneration Frame B or E Technology	11%	33%	56%
CC - Two or Three on One Frame F Technology	73%	126%	376%
CT - First & Second Generation Aero (P&W FT 4)	5%	25%	44%
CT - First & Second Generation Frame B	NA	11%	26%
CT - Second Generation Frame E	5%	18%	78%
CT - Third Generation Aero	25%	46%	102%
CT - Third Generation Frame F	14%	64%	168%
Diesel	NA	101%	534%
Hydro	167%	292%	399%
Nuclear	NA	NA	NA
Oil or Gas Steam	NA	2%	18%
Sub-Critical Coal	NA	21%	65%
Super Critical Coal	5%	14%	43%

Table 7-28 shows the avoidable cost recovery from all PJM markets by quartiles. The net revenues from all markets cover avoidable costs for even the first quartile of most technology types but this is not the case for every individual unit.

Table 7-28 Avoidable cost recovery by quartile from all PJM Markets for select technologies: 2015

	Recovery of avoidable costs from all markets		
Technology	First quartile	Second quartile	Third quartile
CC - NUG Cogeneration Frame B or E Technology	132%	158%	183%
CC - Two or Three on One Frame F Technology	448%	529%	1,021%
CT - First & Second Generation Aero (P&W FT 4)	258%	405%	495%
CT - First & Second Generation Frame B	383%	470%	587%
CT - Second Generation Frame E	474%	523%	608%
CT - Third Generation Aero	227%	385%	421%
CT - Third Generation Frame F	453%	533%	676%
Diesel	409%	630%	1,298%
Hydro	348%	493%	778%
Nuclear	NA	NA	NA
Oil or Gas Steam	150%	193%	263%
Sub-Critical Coal	39%	88%	129%
Super Critical Coal	27%	88%	115%

Table 7-29 and Table 7-30 show the proportion of units recovering avoidable costs from energy and ancillary services markets and from all markets. In 2015, RPM capacity revenues were sufficient to cover the shortfall between energy revenues and avoidable costs for the majority of units and technology types in PJM, with the exception of coal and oil or gas steam units.

Table 7-29 Proportion of units recovering avoidable costs from energy and ancillary markets: 2009 through 2015

	Units with full recovery from energy and ancillary services markets						
Technology	2009	2010	2011	2012	2013	2014	2015
CC - NUG Cogeneration Frame B or E Technology	41%	39%	56%	45%	63%	53%	50%
CC - Two or Three on One Frame F Technology	22%	34%	54%	55%	56%	53%	66%
CT - First & Second Generation Aero (P&W FT 4)	27%	47%	14%	10%	14%	68%	8%
CT - First & Second Generation Frame B	28%	43%	27%	19%	9%	48%	9%
CT - Second Generation Frame E	52%	60%	41%	41%	35%	63%	51%
CT - Third Generation Aero	20%	35%	35%	43%	28%	48%	42%
CT - Third Generation Frame F	32%	47%	33%	63%	56%	52%	44%
Diesel	62%	73%	63%	51%	52%	71%	66%
Hydro and Pumped Storage	60%	53%	95%	99%	99%	99%	96%
Nuclear	NA	NA	NA	NA	NA	NA	NA
Oil or Gas Steam	42%	52%	48%	44%	46%	55%	36%
Sub-Critical Coal	28%	38%	51%	30%	41%	67%	38%
Super Critical Coal	37%	40%	53%	24%	29%	75%	27%

Table 7-30 Proportion of units recovering avoidable costs from all markets: 2009 through 2015

	Units with full recovery from all markets						
Technology	2009	2010	2011	2012	2013	2014	2015
CC - NUG Cogeneration Frame B or E Technology	91%	96%	96%	90%	100%	100%	94%
CC - Two or Three on One Frame F Technology	100%	100%	81%	85%	74%	82%	100%
CT - First & Second Generation Aero (P&W FT 4)	98%	100%	100%	100%	94%	100%	100%
CT - First & Second Generation Frame B	99%	99%	93%	90%	88%	97%	97%
CT - Second Generation Frame E	100%	99%	93%	94%	99%	100%	100%
CT - Third Generation Aero	74%	99%	99%	90%	75%	96%	100%
CT - Third Generation Frame F	100%	100%	93%	93%	91%	97%	100%
Diesel	100%	98%	90%	84%	76%	93%	94%
Hydro and Pumped Storage	100%	100%	100%	100%	100%	100%	100%
Nuclear	NA	NA	NA	NA	NA	NA	NA
Oil or Gas Steam	95%	89%	82%	75%	83%	93%	87%
Sub-Critical Coal	80%	85%	76%	46%	57%	79%	62%
Super Critical Coal	77%	94%	82%	41%	59%	89%	50%

Units At Risk

Units that have either already started the deactivation process or are expected to request deactivation are excluded from the at risk analysis.[30]

Unit revenues are a combination of energy and ancillary service revenues and capacity market revenues. Units that fail to recover avoidable costs from total market revenues, including capacity market revenues, are at risk of retirement particularly if the results are expected to continue. In addition, units that failed to clear the most recent capacity auction(s) are at increased risk of retirement particularly if this result is expected to continue. The profile of units that have not recovered avoidable costs from total market revenues in two of the last three years or have not cleared either the 2016/2017 or the 2017/2018 capacity auctions is shown in Table 7-31.[31] These units are considered at risk of retirement.

These results mean that 11,908 MW of capacity in PJM are at risk of retirement in addition to the units that are currently planning to retire.

Table 7-31 Profile of units that did not recover avoidable costs from total market revenues in two of the last three years or did not clear the 16/17 BRA or 17/18 BRA but cleared in previous auctions

Technology	No. Units	ICAP (MW)	Avg. 2015 Run Hrs	Avg. Heat Rate	Avg. Unit Age (Yrs)
CT	3	139	403	11,295	21
Coal	23	11,736	5,697	10,291	47
Diesel	1	4	191	10,550	46
Oil or Gas Steam	1	30	4,765	14,226	28
Total	28	11,908	3,197	11,391	34

30 This analysis excludes nuclear units due to a lack of data.
31 Avoidable costs are ACR values and exclude APIR.

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 Cross-State Air Pollution Rule (CSAPR) will 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 the Regional Greenhouse Gas Initiative (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 established a compliance deadline of April 16, 2015.

  In a related EPA rule also issued on December 16, 2011, 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] On December 15, 2015, the D.C. Circuit Court remanded the matter to EPA while keeping the rule effective, noting that the "EPA has represented that it is on track to issue a final finding ... by April 15, 2016."[3]

- **Air Quality Standards (NO_X and SO_2 Emissions).** The CAA requires each state to attain and maintain compliance with fine PM and ozone national ambient air quality standards (NAAQS). Much recent regulatory activity concerning emissions has concerned the development and implementation of a transport rule to address the CAA's requirement that each state prohibit emissions that significantly interfere with the ability of another state to meet NAAQS.[4]

  On April 29, 2014, the U.S. Supreme Court upheld the 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).[5,6]

  In the same decision, the U.S. Supreme Court remanded "particularized as-applied challenge[s]" to the EPA's 2014 emissions budgets.[7] On July 28, 2015, on remand, the U.S. Court of Appeals for the

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 White Stallion Energy Center, LLC v EPA, Slip Op. No. 12-1100 (D.C. Cir. 2015) (per curiam).
4 CAA § 110(a)(2)(D)(i)(I).
5 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).
6 See EME Homer City Generation, L.P. v EPA et al., No. 11-1302.
7 134 S. Ct. at 1609.

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.[8] The court directed the EPA to reconsider the 2015 emissions budgets for these states based on the actual amount of reduced emissions that states in upwind states needed to attain in order to bring each downwind state into attainment.[9] Under the invalidated approach, the EPA calculated how much pollution each upwind state could eliminate if all of its sources applied pollution control at particular cost thresholds.[10] A new approach likely will significantly reduce the emission budgets (lower emissions levels will be allowed) for the indicated states. The court did not vacate the currently assigned budgets which remain effective until replaced.[11]

On November 21, 2014, the EPA issued a rule tolling by three years CSAPR's original deadlines. The rule means that 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.[12]

- **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.[13] As a result, the national emissions standards uniformly apply to all RICE.[14] 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."[15] Specifically, the Court found that the 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.[16]
- **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 (the Clean Power Plan).[17] The rule requires that individual state plans be submitted by September 6, 2016. However, on February 9, 2016, the U.S. Supreme Court issued a stay on the rule that will prevent its taking effect until judicial review is completed.[18]
- **Cooling Water Intakes.** The EPA has promulgated a rule implementing Section 316(b) of the Clean Water Act (CWA), which requires that cooling water intake structures reflect the best technology available for minimizing adverse environmental impacts.[19] The rule is implemented as National Pollutant Discharge Elimination System (NPDES) permits are issued, with exceptions in certain cases for permits expiring prior to July 14, 2018.
- **Waste Disposal.** On December 19, 2014, the EPA issued its Coal Combustion Residuals rule (CCRR), effective October 19, 2015. The CCRR likely will raise the costs of disposal of CCRs to meet the EPA criteria.

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.[20] New Jersey's HEDD rule, which became effective May 19, 2009, applies to HEDD units, which include units that

8 EME Homer City Generation , L.P. v EPA et al., Slip Op. No. 11-1302 (July 28, 2015).

9 *Id.* at 11–12.

10 *Id.* at 11.

11 Emissions Budget Decision at 24–25.

12 *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).

13 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).

14 *Id.*

15 DENREC v. EPA at 3, 20–21.

16 *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.

17 *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."

18 North Dakota v. EPA, et al., Order 15A793.

19 See EPA, *National Pollutant Discharge Elimination System—Final Regulations to Establish Requirements for Cooling Water Intake Structures at Existing Facilities and Amend Requirements at Phase I Facilities*, EPA-HQ-OW-2008-0667, 79 Fed. Reg. 48300 (Aug. 15, 2014).

20 N.J.A.C. § 7:27–19.

have a NO_X emissions rate on HEDD equal to or exceeding 0.15 lbs/MMBtu and lack identified emission control technologies.[21]

- **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").[22] 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 $7.50 per ton. The clearing price is equivalent to a price of $8.27 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 December 31, 2015, 76.7 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 December 31, 2015, Delaware, Illinois, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, and Washington D.C. had renewable portfolio standards. Virginia and Indiana have enacted voluntary renewable portfolio standards. 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.[23] West Virginia had a voluntary standard, but the state Legislature repealed the West Virginia 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 the REC is sold as part of a transaction that also includes a wholesale sale of electric energy in a bundled transaction.[24]

Renewable energy credits (RECs), federal investment tax credits 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.

21 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).

22 35 Ill. Admin. Code §§ 225.233 (Multi-Pollutant Standard (MPS)), 224.295 (Combined Pollutant Standard: Emissions Standards for NO_x and SO_2 (CPS)).

23 See Ohio Senate Bill 310.

24 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.").

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 for all PJM states. 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 emissions credits are included in energy offers. PJM markets also provide a flexible mechanism that incorporates renewable resources and the impacts of 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 and prescriptive 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.[25,26] 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.[27]

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.[28] The rule establishes a compliance deadline of April 16, 2015.

In a related EPA rule also issued on December 16, 2011, 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).[29]

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.[30] On November 20, 2015, the EPA proposed a rule with a supplemental finding that considering costs does not alter the determination that the MATS rule is appropriate.[31] If finalized, this action would supply the initial cost determination that the U.S. Supreme Court found lacking, and which was the sole basis for remand.

25 42 U.S.C. § 7401 et seq. (2000).

26 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.

27 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.

28 *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).

29 NSPS are promulgated under CAA § 111.

30 Michigan et al. v. EPA, Slip Op. No. 14-46.

31 *Supplemental Finding That It Is Appropriate and Necessary To Regulate Hazardous Air Pollutants From Coal- and Oil-Fired Electric Utility Steam Generating Units*, EPA Docket No. EPA-HQ-OAR-2009-0234, 80 Fed. Reg. 75025 (Dec. 1, 2015).

On December 15, 2015, the D.C. Circuit Court remanded the matter to the EPA while keeping the rule effective, noting that “EPA has represented that it is on track to issue a final finding … by April 15, 2016.”[32]

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).[33] 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.[34]

The EPA finalized the CSAPR on July 6, 2011. CSAPR requires specific states in the eastern and central United States to reduce power plant emissions of SO_2 and NO_X that cross state lines and contribute to ozone and fine particle pollution in other states, to levels consistent with the 1997 ozone and fine particle and 2006 fine particle NAAQS.[35] The CSAPR covers 28 states, including all of the PJM states except Delaware, and also excluding the District of Columbia.[36]

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.[37] Group 2 does not include any states in the PJM region.[38] 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[39] 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.

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

32 White Stallion Energy Center, LLC v EPA, Slip Op. No. 12-1100 (D.C. Cir. 2015) (per curiam),

33 Nitric Oxides (NO_x), Sulfur Dioxide (SO_2), Ozone (O3), Particulate Matter (PM), Carbon Monoxide (CO) and Lead (Pb).

34 CAA § 110(a)(2)(D)(i)(I).

35 *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").

36 *Id.*

37 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.

38 Group 2 states include: Minnesota, Nebraska, Kansas, Texas, Alabama, Georgia and South Carolina.

39 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.

the way for the EPA to implement this rule and to replace the Clean Air Interstate Rule (CAIR).[40]

In the same decision, the U.S. Supreme Court remanded "particularized as-applied challenge[s]," to the EPA's 2014 emissions budgets.[41] 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.[42] The court directed the EPA to reconsider the 2015 emissions budgets for these states based on the actual amount of reduced emissions that states in upwind states needed to attain in order to bring each downwind state into attainment.[43] Under the invalidated approach, the EPA calculated how much pollution each upwind state could eliminate if all of its sources applied pollution control at particular cost thresholds.[44] A new approach likely will significantly reduce the emission budgets (lower emissions levels will be allowed) for the indicated states. The court did not vacate the currently assigned emissions budgets, which remain effective until replaced.[45]

Table 8-1 Current and Proposed CSPAR Ozone Season NO_X Budgets for Electric Generating Units (before accounting for variability)[46]

State	Current CSPAR Ozone Season NO_X Budget for Electric Generating Units (before accounting for variability) (Tons)	Proposed Updated CSPAR Ozone Season NO_X Budget for Electric Generating Units (before accounting for variability) (Tons)	Percent Change	Assurance Level (Tons)
Illinois	21,208	12,078	(43.0%)	14,614
Indiana	46,175	28,284	(38.7%)	34,224
Kentucky	32,674	21,519	(34.1%)	26,038
Maryland	7,179	4,026	(43.9%)	4,871
Michigan	24,727	19,115	(22.7%)	23,129
New Jersey	3,382	2,015	(40.4%)	2,438
North Carolina	18,455	12,275	(33.5%)	14,853
Ohio	37,792	16,660	(55.9%)	20,159
Pennsylvania	51,912	14,387	(72.3%)	17,408
Tennessee	8,016	5,481	(31.6%)	6,632
Virginia	14,452	6,818	(52.8%)	8,250
West Virginia	23,291	13,390	(42.5%)	16,202

On November 16, 2015, the EPA proposed a rule updating the CSAPR ozone season NO_X emissions program to reflect the decrease to the ozone season NAAQS that occurred in 2008 ("CSPAR Update NOPR").[47] The CSAPR had been finalized in 2011 based on the 1997 ozone season NAAQS. The 2008 ozone season NO_X emissions level was lowered to 0.075 ppm from 0.08 in 1997.[48] The CSAPR Update NOPR would increase the reductions required from upwind states to assist downwind states' ability to meet the lower 2008 standard.

Starting May 1, 2017, the CSPAR Update NOPR would reduce summertime NO_X from power plants in certain PJM states: Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia and West Virginia.[49] Table 8-1 shows the reduced NO_X emissions budgets for each PJM affected state. Table 8-1 also shows the assurance level, which is a hard cap on emissions, meaning that emissions above the assurance cannot be covered by emissions allowances, even if available.

During the delay of CSAPR implementation from 2012–2015, the EPA estimates that banked emissions allowances "could be in excess of 210,000 tons by the start of the 2017 ozone-season compliance period."[50] The EPA is concerned that "unrestricted use of the bank … could allow emissions to exceed the state budgets,

40 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.

41 134 S. Ct. at 1609.

42 EME Homer City Generation, L.P. v EPA et al., Slip Op. No. 11-1302 (July 28, 2015).

43 *Id.* at 11–12.

44 *Id.* at 11.

45 Emissions Budget Decision at 24–25.

46 CSAPR at 48270; CSAPR Supp.at 40666; CSAPR Update NOPR at 75745.

47 *Cross-State Air Pollution Rule Update for the 2008 Ozone NAAQS*, NOPR, EPA-HQ-OAR-2015-0500, 80 Fed. Reg. 75706 (Dec. 3 2015) ("CSAPR Update"); *Federal Implementation Plans for Iowa, Michigan, Missouri, Oklahoma, and Wisconsin and Determination for Kansas Regarding Interstate Transport of Ozone*, EPA-HQ-OAR-2009-0491, 76 Fed. Reg. 40662 (July 11, 2011) ("CSAPR Supp.").

48 *Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone*, NOPR, EPA-HQ-OAR-2009-0491, 75 Fed. Reg. 45210, 45220 (Aug. 2, 2010).

49 *Id.* at 75742.

50 CSAPR Update NOPR at 75746.

up to the assurance level [an annual cap on use of allowances], year after year."[51] EPA does not propose to address excess allowances by reducing state emissions budgets. Instead, EPA proposes a greater than 1-to-1 surrender ratio for allowances.[52] The analysis in the CSPAR Update Rule assumes a 4-to-1 surrender ratio, but the ratio may differ in the final rule.[53]

On November 21, 2014, the 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.[54]

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).[55] 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").[56]

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).[57]

On May 22, 2012, the EPA proposed amendments to the RICE NESHAP Rule.[58] 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 included demand resources in RPM.[59]

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.[60] 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."[61] 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.[62]

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

51 *Id.*
52 *Id.*
53 *Id.* at 75747.
54 *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).
55 *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").
56 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.
57 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."
58 *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.
59 If FERC approves PJM's proposal on this issue in Docket No. ER14-822-000, demand resources that use 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.
60 PJM Tariff filing, FERC Docket No. ER14-822-000 (December 24, 2014).
61 *Id.* at 8–9.
62 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.

these units, or (ii) remove the exemption for behind-the-meter demand response resources from its tariff."[63] In its compliance filing, PJM attempted to justify the exception.[64] An order from the Commission on PJM's compliance filing is now pending.

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.[65] As a result, the national emissions standards uniformly apply to all RICE.[66] The Court held that the "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."[67] Specifically, the Court found that the 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.[68]

Regulation of Greenhouse Gas Emissions

The EPA regulates CO_2 as a pollutant using CAA provisions that apply to pollutants not subject to NAAQS.[69,70]

On September 20, 2013, the EPA proposed national limits on the amount of CO_2 that new power plants would be allowed to emit.[71,72] The proposed rule includes two limits for fossil fuel fired utility boilers and integrated gasification combined cycle (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: 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" or Clean Power Plan).[73] On February 6, 2016, the U.S. Supreme Court issued a stay on the CPE Guidelines that will prevent them from taking effect until judicial review is completed.

States have flexibility to meet the EPA's GHG goals, including through participation in multistate CO_2 credit trading programs. The CPE Guidelines provided that a state must submit an individual final compliance plan by September 6, 2016, or request a two-year extension, including for the purpose of developing a multistate plan. The EPA has begun to develop a federal plan applicable in states that do not submit plans, which the EPA plans to finalize in the summer of 2016.

The CPE Guidelines set state by state rate and mass based CO_2 emissions targets.[74] 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.[75] 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.[76]

63 See 147 FERC ¶ 61,103 at P 41.

64 See PJM compliance filing, FERC Docket No. ER14-822-002 (June 2, 2014) at 4–8.

65 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).

66 *Id.*

67 DENREC v. EPA at 3, 20–21.

68 *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.

69 See CAA § 111.

70 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.

71 *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>.

72 79 Fed. Reg. 1352 (January 8, 2014).

73 *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."

74 *Id.* at 1560.

75 *Id.* at 1559.

76 *Id.* at 34839.

The EPA has calculated rate and mass-based goals based on EGU emissions rates for each state.[77] The EPA uses three building blocks to calculate state goals.[78] The EPA calculates emissions as of 2005 from EGUs in each state, and then assumes reduced emissions based on implementation of the building blocks.[79]

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 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.[80]

The interim and final targets for CO_2 emissions goals for PJM states, in order of highest to lowest, are included in Table 8-2.

Table 8-2 Interim and final targets for CO_2 emissions goals for PJM states[81]

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.[82]

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.

Each state would be required to develop an EPA approved plan to meet its interim and final goals.[83] 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."[84] 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.[85]

77 A mass-based goal is expressed as maximum number of tons of CO_2 that may be emitted over a time period, while a rate-based goal is expressed as a number of pounds of CO_2 per MWh.
78 *Id.* at 1559.
79 *Id.* at 1559–1560.
80 *Id.* 1559.
81 The District of Columbia has no affected EGUs and is not subject to the CPE Guidelines (at 1560).
82 CPE Guidelines 1559–1560.
83 *Id.*
84 *Id.* at 1560.
85 *Id.* at 898.

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.[86] 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.[87]

The CPE Guidelines permit states to partner and submit multistate plans to reduce CO_2 emissions from EGUs.[88]

Federal Regulation of Environmental Impacts on Water

Section 316(b) of the Clean Water Act (CWA) requires that cooling water intake structures reflect the best technology available (BTA) for minimizing adverse environmental impacts. EPA's rule implementing Section 316(b) requires an existing facility to use BTA to reduce impingement of aquatic organisms (pinned against intake structures) if the facility withdraws 25 percent or more of its cooling water from waters of the United States and has a design intake flow of greater than two million gallons per day (mgd).[89]

Existing facilities withdrawing 125 mgd must conduct studies that may result in a requirement to install site-specific controls for reducing entrainment of aquatic organisms (drawn into intake structures). If a new generating unit is added to an existing facility, the rule requires addition of BTA that either (i) reduces actual intake flow at the new unit to a level at least commensurate with what can be attained using a closed-cycle recirculating system or (ii) reduces entrainment mortality of all stages of aquatic organisms that pass through a sieve with a maximum opening dimension of 0.56 inches to a prescribed level.

Although the rule is now generally effective, it is implemented with respect to particular facilities as National Pollutant Discharge Elimination System (NPDES) permits are issued, with exceptions in certain cases for permits expiring prior to July 14, 2018.

Federal Regulation of Waste Disposal

The EPA administers the Resource Conservation and Recovery Act (RCRA), which governs the disposal of solid and hazardous waste.[90] Solid waste is regulated under subtitle D, which encourages state management of nonhazardous industrial solid waste and sets non-binding criteria for solid waste disposal facilities. Subtitle D prohibits open dumping. Subtitle D criteria are not directly enforced by EPA. However, the owners of solid waste disposal facilities are exposed under the act to civil suits, and criteria set by EPA under subtitle D can be expected to influence the outcome of such litigation.

Subtitle C governs the disposal of hazardous waste. Hazardous waste is subject to direct regulatory control by the EPA from the time it is generated until its ultimate disposal.

On December 19, 2014, the EPA issued its Coal Combustion Residuals rule (CCRR) under RCRA, the more lenient subtitle D, effective October 19, 2015.[91] The CCRR sets criteria for the disposal of coal combustion residues (CCRs) produced by electric utilities and independent power producers. CCRs include fly ash (trapped by air filters), bottom ash (scooped out of boilers) and scrubber sludge (filtered using wet limestone scrubbers). These residues are typically stored on site in ponds (surface impoundments) or sent to landfills. In 2012, beneficial use was made of approximately 40 percent of residues, such as in the manufacture of cement, concrete, wallboard and roadbed.[92]

The CCRR exempts: (i) beneficially used CCRs that are encapsulated (i.e. physically bound into a product); (ii) coal mine filling; (iii) municipal landfills; (iv) landfills

86 *Id.* at 1560.
87 *Id.* at 34910.
88 *Id.* at 1560.
89 See EPA, *National Pollutant Discharge Elimination System—Final Regulations to Establish Requirements for Cooling Water Intake Structures at Existing Facilities and Amend Requirements at Phase I Facilities*, EPA-HQ-OW-2008-0667, 79 Fed. Reg. 48300 (Aug. 15, 2014).
90 42 U.S.C. §§ 6901 *et seq.*
91 *See Hazardous and Solid Waste Management System; Disposal of Coal Combustion Residuals From Electric Utilities*, 80 Fed. Reg. 21302 (April 17, 2015).
92 CCRR at 21303.

receiving CCRs before the effective date; (v) surface impoundments closed by the effective date; and (vi) landfills and surface impoundments on the site of generation facilities that deactivate prior to the effective date. Less restrictive criteria may also apply to some surface impoundments deemed inactive under not yet clarified criteria.

Table 8-3 describes the criteria and anticipated implementation dates.

Table 8-3 Minimum Criteria for Existing CCR Ponds (Surface Impoundments) and Landfills and Date by which Implementation is Expected

Requirement	Description of requirement to be completed	Implementation Date
Location Restrictions (§ 257.60–§ 257.64)	For Ponds: Complete demonstration for placement above the uppermost aquifer, for wetlands, fault areas, seismic impact zones and unstable areas.	October 17, 2018
	For Landfills: Complete demonstration for unstable areas.	
Design Criteria (§ 257.71)	For Ponds: Document whether CCR unit is either a lined or unlined CCR surface impoundment.	October 17, 2016
Structural Integrity (§ 257.73)	For Ponds: Install permanent marker.	December 17, 2015
	For Ponds: Compile a history of construction, complete initial hazard potential classification assessment, initial structural stability assessment, and initial safety factor assessment.	October 17, 2016
	Prepare emergency action plan.	April 17, 2017
Air Criteria (§ 257.80)	Ponds and Landfills: Prepare fugitive dust control plan.	October 17, 2015
Run-On and Run-Off Controls (§ 257.81)	For Landfills: Prepare initial run-on and run-off control system plan.	October 17, 2016
Hydrologic and Hydraulic Capacity (§ 257.82)	Prepare initial inflow design flood control system plan.	October 17, 2016
Inspections (§ 257.83)	For Ponds and Landfills: Initiate weekly inspections of the CCR unit.	October 17, 2015
	For Ponds: Initiate monthly monitoring of CCR unit instrumentation.	October 17, 2015
	For Ponds and Landfills: Complete the initial annual inspection of the CCR unit.	January 17, 2016
Groundwater Monitoring and Corrective Action (§ 257.90–§ 257.98)	For Ponds and Landfills: Install the groundwater monitoring system; develop the groundwater sampling and analysis program; initiate the detection monitoring program; and begin evaluating the groundwater monitoring data for statistically significant increases over background levels.	October 17, 2017
Closure and Post-Closure Care (§ 257.103–§ 257.104)	For Ponds and Landfills: Prepare written closure and post-closure care plans.	October 17, 2016
Recordkeeping, Notification, and Internet Requirements (§ 257.105–§ 257.107)	For Ponds and landfills: Conduct required recordkeeping; provide required notifications; establish CCR website.	October 17, 2015

The CCRR likely will raise the costs of disposal of CCRs for the owners of surface impoundments and landfills to meet the EPA criteria.

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.[93] 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.[94] NO_X emissions limits for coal units became effective December 15, 2012.[95] NO_X emissions limits for other unit types became effective May 1, 2015.[96]

93 N.J.A.C. § 7:27-19.

94 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).

95 N.J.A.C. § 7:27-19.4.

96 N.J.A.C. § 7:27-19.5.

Table 8-4 shows the HEDD emissions limits applicable to each unit type.

Table 8-4 HEDD maximum NO_X emission rates[97]

Fuel and Unit Type	NO_x Emission Limit (lbs/MWh)
Coal Steam Unit	1.50
Heavier than No. 2 Fuel Oil Steam Unit	2.00
Simple Cycle Gas CT	1.00
Simple Cycle Oil CT	1.60
Combined Cycle Gas CT	0.75
Combined Cycle Oil CT	1.20
Regenerative Cycle Gas CT	0.75
Regenerative Cycle Oil CT	1.20

Illinois Air Quality Standards (NO_X, SO_2 and Hg)

The State of Illinois has promulgated its own standards for NO_X, SO_2 and Hg (mercury) known as Multi-Pollutant Standards ("MPS") and Combined Pollutants Standards ("CPS").[98] MPS and CPS establish standards that are more stringent and take effect earlier than comparable Federal regulations, such as the 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.[99] 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.[100]

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.[101,102] RGGI generates revenues for the participating states which have spent approximately 62 percent of revenues to date on energy efficiency, 8 percent on clean and renewable energy, 9 percent on greenhouse gas abatements and 15 percent on direct bill assistance.[103]

Table 8-5 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 December 31, 2015, in short tons and metric tonnes. Prices for auctions held December 2, 2015, for the 2015-2017 compliance period were at the highest clearing price to date, $7.50 per allowance (equal to one ton of CO_2), above the current price floor of $2.05 for RGGI auctions.[104] 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 $6.02 in September 2015, as the result of a 2.5 percent reduction in the quantity of allowances offered in this auction for the 2015-2017 compliance period. The September 3, 2015, auction included additional Cost Containment Reserves (CCRs) since the clearing price for allowances was above the CCR trigger price of $6.00 per ton in 2015. The auctions on March 5, 2014, and September 3, 2015, were the only auction to use CRRs.

97 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.

98 35 Ill. Admin. Code §§ 225.233 (Multi-Pollutant Standard (MPS)), 224.295 (Combined Pollutant Standard: Emissions Standards for NO_X and SO_2 (CPS)).

99 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).

100 See *Id.*

101 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>.

102 For more details see the *2013 State of the Market Report for PJM*, Volume 2: Section 8, "Environmental and Renewables."

103 *Investment of RGGI Proceeds Through 2013*, The Regional Greenhouse Gas Initiative, April 2015 <http://www.rggi.org/docs/ProceedsReport/Investment-RGGI-Proceeds-Through-2013.pdf> (Accessed February 24, 2016).

104 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 8-5 RGGI CO_2 allowance auction prices and quantities in short tons and metric tonnes: 2009-2011, 2012-2014 and 2015-2017 Compliance Periods[105]

	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
September 3, 2015	$6.02	25,374,294	25,374,294	$6.64	23,019,179	23,019,179
December 2, 2015	$7.50	15,374,274	15,374,274	$8.27	13,947,311	13,947,311

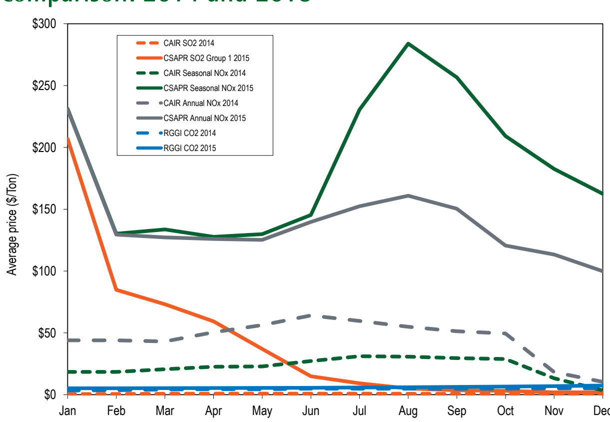
CAIR and CSAPR

On April 29, 2014, the U.S. Supreme Court upheld the 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.[106,107] On November 21, 2014, EPA issued a 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.[108] 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 2015.[109] 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 2015, CSAPR annual NO_x prices were 207 percent higher than the CAIR annual NO_x prices in 2014. The price difference is due to the new stricter CSAPR rules for emissions compared to the old CAIR rules. The average price of CSAPR SO_2 in 2015 was $41.78 compared the average price of $0.72 for CAIR SO_2 in 2014 although the price of CSAPR SO_2 declined substantially between January and September 2014.

Figure 8-1 Spot monthly average emission price comparison: 2014 and 2015[110]



105 See Regional Greenhouse Gas Initiative, "Auction Results," <http://www.rggi.org/market/co2_auctions/results> (Accessed January 28, 2016).

106 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).

107 Order, City Generation, L.P. EPA et al. v. EME Homer et al., No. 11-1302.

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 The NOx 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.

110 Spot monthly average emission price information obtained through Evomarkets, <http://www.evomarkets.com> (Accessed January 29, 2016).

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 December 31, 2015, Delaware, Illinois, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, and Washington D.C. had renewable portfolio standards. Virginia and Indiana have enacted voluntary renewable portfolio standards. 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.[111] West Virginia had a voluntary standard, but the state legislature repealed their renewable portfolio standard on January 27, 2015, effective February 3, 2015.[112]

Table 8-6 Renewable standards of PJM jurisdictions: 2015 to 2028[113]

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													

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 8-6, 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.

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 revenues for PJM resources earned in addition to revenues earned from the sale of the same MWh in PJM markets. The FERC has found that such costs can be appropriately considered in the rates established through the operation of wholesale organized markets.[114]

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

111 See Ohio Senate Bill 310.

112 See Enr. Com. Sub. For H. B. No. 2001.

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

114 See 146 FERC ¶ 61,084 at P 32 ("We disagree with Exelon's argument that the Production Tax Credit and Renewable Energy Credits should be considered [out-of-market (OOM)] revenues. The relevant, Commission-approved Tariff provision defines OOM revenues as any revenues that are (i) not tradable throughout the New England Control Area or that are restricted to resources within a particular state or other geographic sub-region; or (ii) not available to all resources of the same physical type within the New England Control Area, regardless of the resource owner. [footnote omitted] Neither Production Tax Credit nor Renewable Energy Credits revenues fall within this definition. We also find that ISO-NE's use of an inflation rate in determining the price of Renewable Energy Credits is a reasonable estimate of Renewable Energy Credits for the 2018-2019 Capacity Commitment Period.").

photovoltaic generation and fuel cells using renewable fuels that are installed on or before December 31, 2014.[115] 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.[116]

In addition to GATS, there are several other REC tracking systems used by states in the PJM footprint. Illinois, Indiana and Ohio use both GATS and M-RETS, the REC tracking system for resources located in the Midcontinent ISO, to track the sales of RECs used to fulfill their RPS requirements. Michigan and North Carolina have created their own state-wide tracking systems, MIRECS and NC-RETS, through which all RECs used to satisfy these states' RPS requirements must ultimately be traded. Table 8-7 shows the REC tracking systems used by each state within the PJM footprint.

Table 8-7 REC Tracking Systems in PJM States with Renewable Portfolio Standards

Jurisdiction with RPS	REC Tracking System Used			
Delaware	PJM-GATS			
Illinois	PJM-GATS	M-RETS		
Indiana	PJM-GATS	M-RETS		
Maryland	PJM-GATS			
Michigan			MIRECS	
New Jersey	PJM-GATS			
North Carolina				NC-RETS
Ohio	PJM-GATS	M-RETS		
Pennsylvania	PJM-GATS			
Virginia	PJM-GATS			
Washington, D.C.	PJM-GATS			

Table 8-8 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													

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 8-8 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 electricity sales within the state be served by solar resources. As Table 8-6 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.

Some PJM jurisdictions have also added specific requirements to their renewable portfolio standards for other technologies. The standards shown in Table 8-9 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 2020, 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 8-9).

115 See Delaware Renewable Portfolio Standard, <http://programs.dsireusa.org/system/program/detail/1231> (Accessed October 1, 2015).

116 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 8-9 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%	0.07%	0.14%	0.14%	0.14%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%
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%

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 $231 per SREC in 2015. The DC SREC prices are currently the highest at $488 per SREC.[117]

Figure 8-2 Average solar REC price by jurisdiction: 2009 through 2015

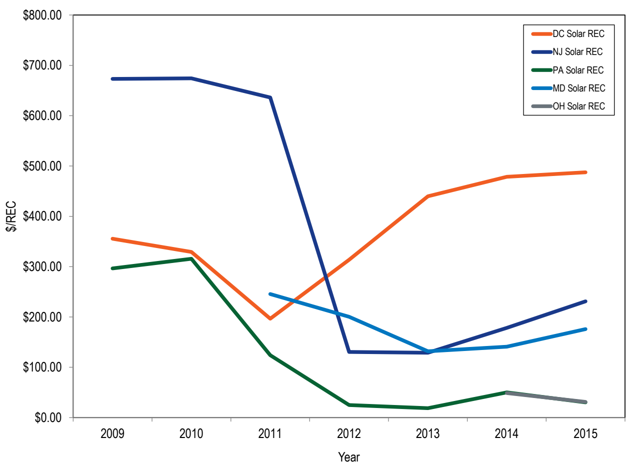
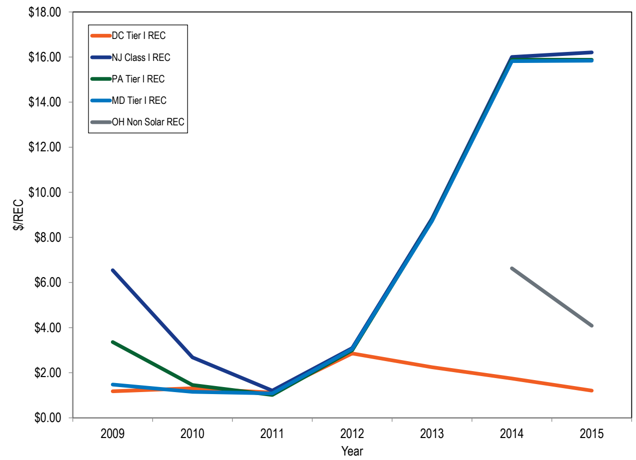


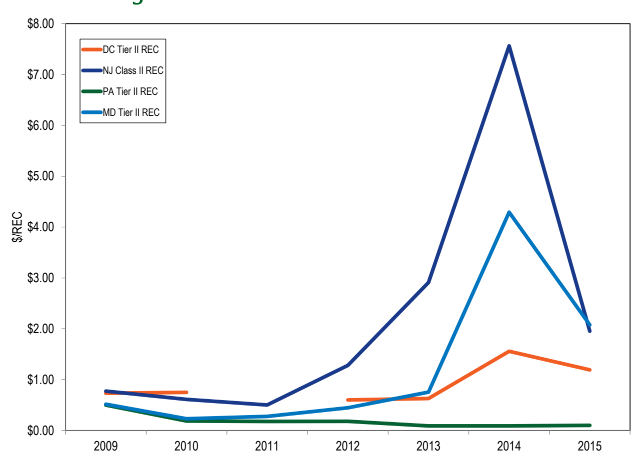
Figure 8-3 shows the average Tier I REC price by jurisdiction from 2009 through 2015. Tier I REC prices are lower than SREC prices. Ohio and Pennsylvania had the lowest SREC prices at $33 per SREC and $34 per SREC while New Jersey and Maryland have the highest Tier I REC prices at $16 per REC and $16 per REC.[118]

Figure 8-3 Average Tier I REC price by jurisdiction: 2009 through 2015



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 $2.08 per REC in Maryland for 2015.[119]

Figure 8-4 Average Tier II REC price by jurisdiction: 2009 through 2015



117 Solar REC average price information obtained through Evomarkets, <http://www.evomarkets.com> (Accessed January 29, 2016).

118 Tier I REC price information obtained through Evomarkets, <http://www.evomarkets.com> (Accessed January 29, 2016).

119 Tier II REC price information obtained through Evomarkets <http://www.evomarkets.com> (Accessed January 29, 2016). There is no data reported by Evomarkets for DC in 2011.

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 $323.00 per MWh.[120] 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. For all states with an alternative compliance payment, it is cheaper to buy the REC than pay the for the alternative compliance payment.

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 8-10 shows the alternative compliance standards in PJM jurisdictions, where such standards exist.

Table 8-10 Renewable alternative compliance payments in PJM jurisdictions: As of December 31, 2015[121]

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	$350.00
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 8-11 shows renewable resource generation by jurisdiction and resource type 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 16,442.1 GWh of 27,432.3 Tier I GWh, or 60.0 percent, in the PJM footprint. As shown in Table 8-11, 49,891.9 GWh were generated by renewable resources, including both Tier II and Tier I renewable credits, of which, Tier I type resources accounted for 55.0 percent. Total renewable generation was 5.9 percent of total generation in PJM for 2015. Landfill gas, solid waste and waste coal were 19,429.2 GWh of renewable resource generation or 38.9 percent of the total Tier I and Tier II.

120 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> (Accessed January 29, 2016).

121 See PJM – EIS (Environmental Management System). "Program Information," <http://www.pjm-eis.com/> (Accessed January 4, 2016).

Table 8-11 Renewable resource generation by jurisdiction and renewable resource type (GWh): 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	45.0	0.0	0.0	0.0	0.0	0.0	0.0	45.0	90.0
Illinois	135.3	0.0	0.0	14.0	0.0	0.0	6,326.7	6,476.0	6,476.0
Indiana	54.7	0.0	38.9	0.0	0.0	0.0	3,600.1	3,693.7	3,693.7
Kentucky	0.0	0.0	87.5	0.0	0.0	0.0	0.0	87.5	87.5
Maryland	86.4	0.0	1,577.8	62.0	983.2	0.0	422.3	2,148.5	3,131.7
Michigan	25.5	0.0	56.5	0.0	0.0	0.0	0.0	82.0	82.0
New Jersey	326.1	445.8	10.1	368.5	1,449.1	0.0	9.8	714.5	2,609.4
North Carolina	0.0	0.0	602.3	42.0	0.0	0.0	0.0	644.3	644.3
Ohio	341.1	0.0	440.0	1.4	0.0	0.0	1,147.2	1,929.7	1,929.7
Pennsylvania	1,278.8	1,703.4	3,256.5	26.7	1,363.3	7,583.9	3,333.0	7,895.1	18,545.7
Tennessee	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Virginia	544.1	3,721.9	588.4	0.0	1,304.7	2,986.5	0.0	1,132.6	9,145.6
Washington, D.C.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
West Virginia	3.7	0.0	976.8	0.0	0.0	917.9	1,603.1	2,583.5	3,501.4
Total	2,837.1	5,871.1	6,658.0	514.7	5,100.3	10,570.3	14,839.0	27,432.3	49,891.9
Percent Total	5.7%	11.8%	15.3%	1.0%	10.2%	23%	33.0%	55.0%	100.0%

Table 8-12 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, 284.5 MW, or 74.3 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 $231 per REC. Wind resources are located primarily in western PJM, in Illinois and Indiana, which include 3,814.7 MW, or 58.8 percent of the total wind capacity.

Table 8-12 PJM renewable capacity by jurisdiction (MW): January 4, 2016

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	2,362.4	2,414.5
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	79.7	0.0	0.0	453.0	11.5	284.5	162.0	0.0	4.5	995.2
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	13,062.0	63.4	580.0	156.0	0.0	119.1	1.1	0.0	0.0	403.0	14,384.6
Pennsylvania	0.0	208.0	2,346.0	0.0	1,269.0	888.3	19.5	345.8	1,611.0	1,337.7	8,025.3
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	21,834.0	669.6	5,242.0	255.0	6,888.2	2,565.2	383.0	1,130.9	2,361.0	6,488.2	47,817.1

Table 8-13 shows renewable capacity registered in the PJM generation attribute tracking system (GATS). This includes solar capacity of 2,191.4 MW of which 1,223.6 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 8-13 Renewable capacity by jurisdiction, non-PJM units registered in GATS (MW), on January 4, 2016[122]

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	65.3	0.0	2.1	69.6
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	76.9	0.0	0.6	0.0	38.0	0.0	600.5	722.6
Indiana	0.0	0.0	43.2	0.0	6.2	219.4	3.7	0.0	180.0	452.6
Iowa	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	475.0	475.1
Kentucky	600.0	2.2	17.6	0.0	0.0	0.0	1.7	93.0	0.0	714.5
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	11.7	129.0	0.0	0.0	313.2	11.2	0.3	530.4
Michigan	55.0	1.3	3.2	0.0	0.0	0.0	1.7	0.0	0.0	61.2
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	1,223.6	0.0	4.9	1,291.9
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	12.0	0.0	0.0	0.0	152.7	30.0	0.0	437.2
Ohio	0.0	1.0	33.6	92.6	16.4	32.4	117.2	109.3	26.2	428.8
Pennsylvania	109.7	37.0	44.7	91.0	12.6	5.0	202.5	38.6	3.3	544.3
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	14.5	0.0	0.5	0.0	12.3	287.6	0.0	333.0
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	2.6	0.0	0.0	44.6
District of Columbia	0.0	0.0	0.0	0.0	0.0	0.0	17.3	0.0	0.0	17.3
Total	829.7	705.4	314.6	312.6	62.5	256.8	2,191.4	1,147.6	1,738.4	7,559.0

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.[123] Many PJM units burning fossil fuels have installed emission control technology.

Coal has the highest SO_2 emission rate, while natural gas and diesel oil have lower SO_2 emission rates.[124] Of the current 70,850.8 MW of coal capacity in PJM, 56,105.0 MW of capacity, 79.2 percent, has some form of FGD (flue-gas desulfurization) technology to reduce SO_2 emissions. Table 8-14 shows SO_2 emission controls by fossil fuel fired units in PJM.[125,126]

Table 8-14 SO_2 emission controls by fuel type (MW), as of December 31, 2015[127]

	SO_2 Controlled	No SO_2 Controls	Total	Percent Controlled
Coal	56,105.0	14,745.8	70,850.8	79.2%
Diesel Oil	0.0	6,856.8	6,856.8	0.0%
Natural Gas	0.0	52,676.3	52,676.3	0.0%
Other	325.0	4,920.7	5,245.7	6.2%
Total	56,430.0	79,199.6	135,629.6	41.6%

NO_x emission control technology is used by all fossil fuel fired unit types. Of current fossil fuel fired units in PJM, 125,898.6 MW, 92.8 percent, of 135,629.6 MW of capacity in PJM, have emission controls for NO_x. Table 8-15 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

122 See PJM – EIS (Environmental Information Services), "Renewable Generators Registered in GATS," <http://www.pjm-eis.com/reports-and-news/public-reports.aspx> (Accessed January 4, 2016).

123 See EPA. "National Ambient Air Quality Standards (NAAQS)," <https://www3.epa.gov/ttn/naaqs/criteria.html> (Accessed February 24, 2016).

124 Diesel oil includes number 1, number 2, and ultra-low sulfur diesel. See EPA. "Electronic Code of Federal Regulations, Section 72.2" <http://www.ecfr.gov/cgi-bin/retrieveECFR?gp=&SID=5584e589aef37add39257c1f0c1617e4&r=PART&n=40y17.0.1.1.1#se40.17.72>_2 (Accessed February 24, 2016).

125 See EPA. "Air Market Programs Data," <http://ampd.epa.gov/ampd/> (Accessed January 4, 2016).

126 The total MW for each fuel type are less than the 177,682.8 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 January 4, 2016).

127 The "other" category includes petroleum coke, wood, process gas, residual oil, other gas, and other oil.

or water injection technology for peaking combustion turbine units.[128]

Table 8-15 NO_x emission controls by fuel type (MW), as of December 31, 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	50,856.9	1,819.4	52,676.3	96.5%
Other	2,799.7	2,446.0	5,245.7	53.4%
Total	125,898.6	9,731.0	135,629.6	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.[129] Fabric filters work by allowing the flue gas to pass through a tightly woven fabric which filters out the particulates. Table 8-16 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 December 31, 2015. Most coal steam units in PJM have particulate emission controls in the form of ESPs, but many units have also installed baghouse technology, or a combination of an FGD and SCR to meet the state and federal emissions limits established by the MATS EPA regulations.[130] Currently, 139 of the 211 coal steam units have baghouse or FGD technology installed, representing 54,322 MW out of the 70,850.8 MW total coal capacity, or 76.7 percent.

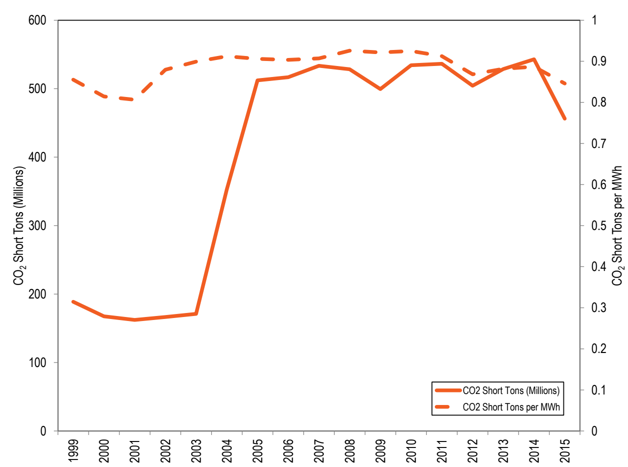
Table 8-16 Particulate emission controls by fuel type (MW), as of December 31, 2015

	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	52,416.3	52,676.3	0.5%
Other	3,102.0	2,143.7	5,245.7	59.1%
Total	73,878.8	61,750.8	135,629.6	54.5%

Figure 8-5 shows the total CO_2 short ton emissions (in millions) and the CO_2 short ton emissions per MWh within PJM.[131] Since 1999 the amount of CO_2 produced per MWh was at a minimum of 0.81 short tons per MWh in 2001, and a maximum of 0.93 short tons per MWh in 2010. In 2015, CO_2 short tons emissions were 0.85 per MWh.

Figure 8-6 shows the total SO_2 and NO_x short ton emissions (in thousands) and the short ton emissions per MWh within PJM. Since 1999 the amount of SO_2 produced per MWh was at a minimum of 0.001174 short tons per MWh in 2015, and a maximum of 0.006387 short tons per MWh in 2004. Since 1999, the amount of NO_x produced per MWh was at a minimum of 0.000672 short tons per MWh in 2012, and a maximum of 0.001964 short tons per MWh in 1999. In 2015, SO_2 short ton emissions were 0.001174 per MWh and NO_x short ton emissions were 0.000685 per MWh.

Figure 8-5 CO_2 emissions by year (millions of short tons), by PJM units: 1999 through 2015[132]



128 See EPA. "Mercury and Air Toxics Standards," <http://www.epa.gov/mats/index.html> (Accessed January 29, 2016).

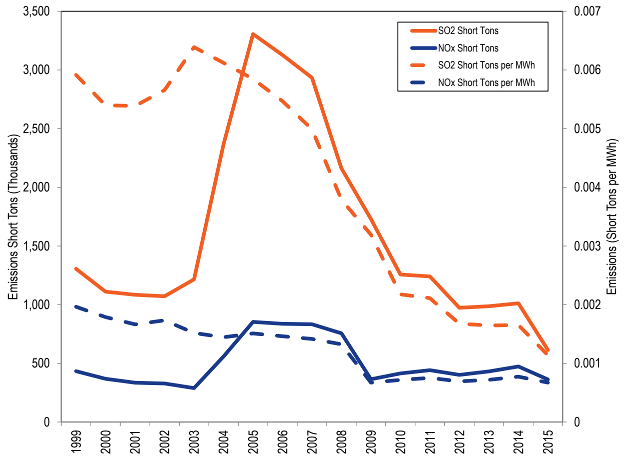
129 See EPA, "Air Pollution Control Technology Fact Sheet," <http://www.epa.gov/ttnchie1/mkb/documents/ff-pulse.pdf> (Accessed January 29, 2016).

130 These regulations became effective April 16, 2015. See EPA. "Mercury and Air Toxics Standards," <http://www.epa.gov/mats/index.html> (Accessed January 29, 2016).

131 Unless otherwise noted, emissions are measured in short tons. A short ton is 2,000 pounds.

132 The emissions are calculated from the continuous emission monitoring system (CEMS) data from generators located within the PJM footprint.

Figure 8-6 SO_2 and NO_x emissions by year (thousands of short tons), by PJM units: 1999 through 2015[133]



Wind Units

Table 8-17 shows the capacity factor of wind units in PJM. In 2015, the capacity factor of wind units in PJM was 28.3 percent. Wind units that were capacity resources had a capacity factor of 29.1 percent and an installed capacity of 6,338 MW. Wind units that were classified as energy only had a capacity factor of 17.9 percent and an installed capacity of 619 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.[134]

Table 8-17 Capacity factor of wind units in PJM: 2015[135]

Type of Resource	Capacity Factor	Installed Capacity (MW)
Energy-Only Resource	17.9%	619
Capacity Resource	29.1%	6,338
All Units	28.3%	6,957

Figure 8-7 shows the average hourly real-time generation of wind units in PJM, by month. The highest average hour, 3,128.9 MW, occurred in November, and the lowest average hour, 528.7 MW, occurred in July. Wind output in PJM is generally higher in off-peak hours and lower in on-peak hours.

Figure 8-7 Average hourly real-time generation of wind units in PJM: 2015

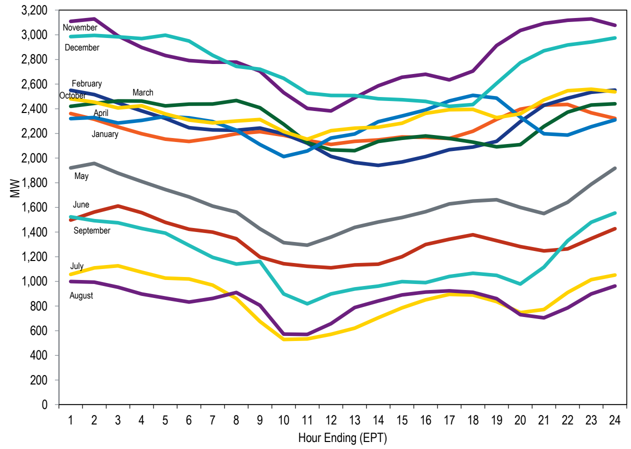


Table 8-18 shows the generation and capacity factor of wind units in each month of 2014 and 2015.

Table 8-18 Capacity factor of wind units in PJM by month: 2014 and 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%	639,381.7	13.0%
August	566,425.3	12.0%	623,873.6	12.4%
September	721,411.2	15.8%	846,505.6	17.3%
October	1,416,878.2	30.0%	1,756,221.4	34.8%
November	1,949,112.9	41.5%	2,023,340.0	41.3%
December	1,451,542.0	29.7%	2,037,436.4	39.8%
Annual	15,540,492.0	27.8%	16,609,738.2	28.3%

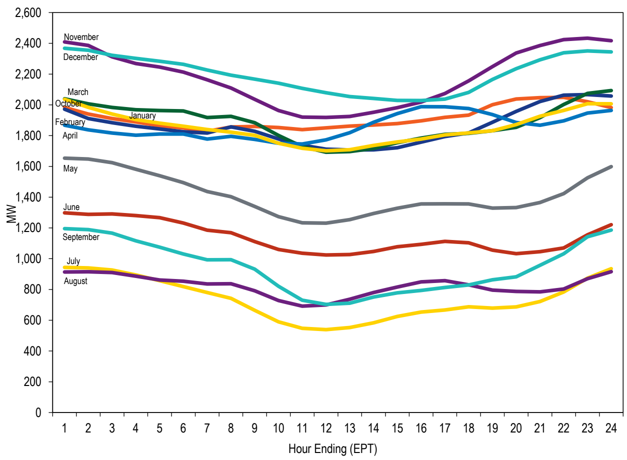
Wind units that are capacity resources are required, like all capacity resources except Demand Resources, to offer the energy associated with their cleared capacity in the Day-Ahead Energy Market and in the Real-Time Energy Market. Wind units may offer non-capacity related wind energy at their discretion. Figure 8-8 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.

133 The emissions are calculated from the continuous emission monitoring system (CEMS) data from generators located within the PJM footprint.

134 Wind resources are derated to 13 percent unless demonstrating higher availability during peak periods.

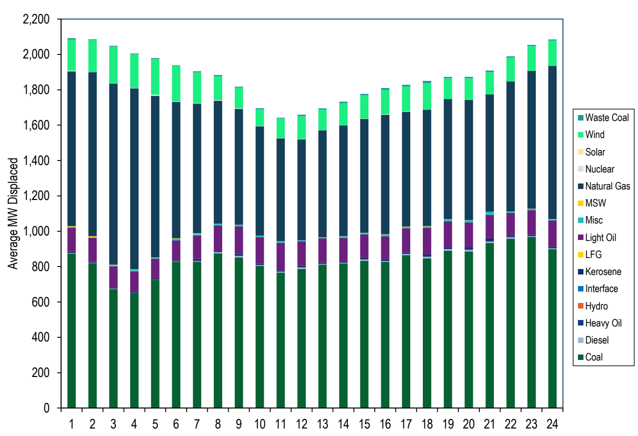
135 Capacity factor is calculated based on online date of the resource.

Figure 8-8 Average hourly day-ahead generation of wind units in PJM: 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 8-9 shows the hourly average proportion of marginal units by fuel type mapped to the hourly average MW of real-time wind generation in 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.

Figure 8-9 Marginal fuel at time of wind generation in PJM: 2015



Solar Units

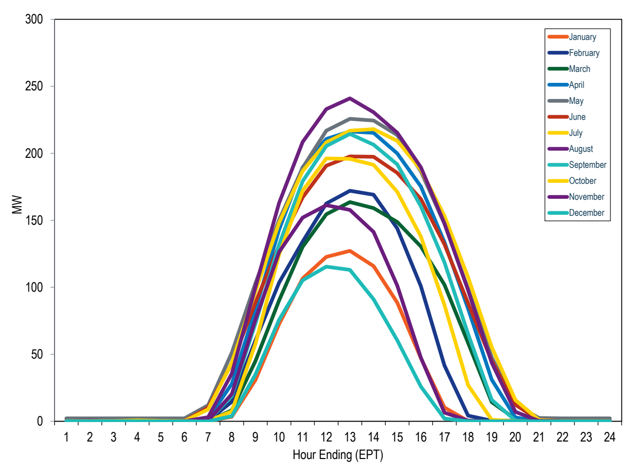
Table 8-19 shows the capacity factor of solar units in PJM. In 2015, the capacity factor of solar units in PJM was 16.0 percent. Solar units that were capacity resources had a capacity factor of 16.1 percent and an installed capacity of 323 MW. Solar units that were classified as energy only had a capacity factor of 15.8 percent and an installed capacity of 175 MW. Solar capacity in RPM is derated to 38 percent of nameplate capacity for the capacity market, and energy only resources are not included in the capacity market.[136]

Table 8-19 Capacity factor of wind units in PJM: 2015

Type of Resource	Capacity Factor	Installed Capacity (MW)
Energy-Only Resource	15.8%	175
Capacity Resource	16.1%	323
All Units	16.0%	498

Solar output differs from month to month, based on seasonal variation and daylight hours during the month. Figure 8-10 shows the average hourly real-time generation of solar units in PJM, by month. Solar generation was highest in August, the month with the highest average hour, 227.6 MW, compared to 355.7 MW of solar installed capacity in PJM. Solar generation in PJM is highest during the hours of 11:00 through 13:00 EPT.

Figure 8-10 Average hourly real-time generation of solar units in PJM: 2015



136 Solar resources are derated to 38 percent unless demonstrating higher availability during peak periods.

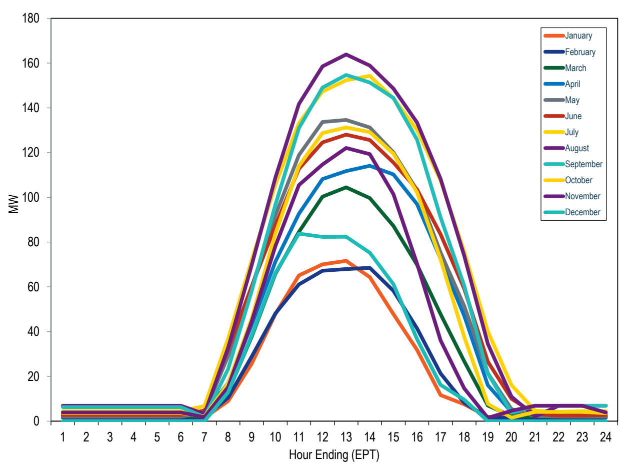
Table 8-20 shows the generation and capacity factor of wind units in each month of 2014 and 2015.

Table 8-20 Capacity factor of solar units in PJM by month: 2014 and 2015

	2014		2015	
Month	Generation (MWh)	Capacity Factor	Generation (MWh)	Capacity Factor
January	13,764.4	7.9%	19,935.6	8.8%
February	17,232.4	10.7%	27,609.2	13.3%
March	27,178.0	15.3%	32,677.1	13.7%
April	37,334.7	21.7%	45,376.5	19.5%
May	36,570.8	20.6%	53,368.8	22.2%
June	40,402.1	21.9%	45,158.2	19.4%
July	43,031.6	21.9%	52,125.7	21.7%
August	39,747.3	19.9%	52,751.5	22.0%
September	33,869.2	17.6%	42,099.8	18.1%
October	26,942.5	13.3%	37,085.5	15.4%
November	20,502.5	10.2%	25,881.6	11.1%
December	12,782.5	5.9%	17,067.0	7.1%
Annual	349,357.8	15.5%	451,136.5	16.1%

Solar 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. Solar units may offer non-capacity related solar energy at their discretion. Figure 8-11 shows the average hourly day-ahead generation offers of solar units in PJM, by month.[137]

Figure 8-11 Average hourly day-ahead generation of solar units in PJM: 2015



137 The average day-ahead generation of solar units in PJM is greater than 0 for hours when the sun is down due to some solar units being paired with landfill units.

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.** In 2015, PJM was a net exporter of energy in the Real-Time Energy Market in September, and a net importer in the remaining 11 months.[1] In 2015, the real-time net interchange of 15,717.4 GWh was higher than net interchange of 1,137.8 GWh in 2014.
- **Aggregate Imports and Exports in the Day-Ahead Energy Market.** In 2015, PJM was a net exporter of energy in the Day-Ahead Energy Market in February, August, September, October, November and December, and a net importer in the remaining six months. In 2015, the total day-ahead net interchange of 1,603.1 GWh was higher than net interchange of -14,305.5 GWh in 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 2015, gross imports in the Day-Ahead Energy Market were 81.7 percent of gross imports in the Real-Time Energy Market (109.5 percent in 2014). In 2015, gross exports in the Day-Ahead Energy Market were 114.5 percent of the gross exports in the Real-Time Energy Market (143.2 percent in 2014).
- **Interface Imports and Exports in the Real-Time Energy Market.** In 2015, there were net scheduled exports at eight of PJM's 20 interfaces in the Real-Time Energy Market.
- **Interface Pricing Point Imports and Exports in the Real-Time Energy Market.** In 2015, there were net scheduled exports at 10 of PJM's 18 interface pricing points eligible for real-time transactions in the Real-Time Energy Market.[3]
- **Interface Imports and Exports in the Day-Ahead Energy Market.** In 2015, there were net scheduled exports at eight of PJM's 20 interfaces in the Day-Ahead Energy Market.
- **Interface Pricing Point Imports and Exports in the Day-Ahead Energy Market.** In 2015, there were net scheduled exports at 11 of PJM's 19 interface pricing points eligible for day-ahead transactions in the Day-Ahead Energy Market.
- **Up to Congestion Interface Pricing Point Imports and Exports in the Day-Ahead Energy Market.** In 2015, up to congestion transactions were net exports at five of PJM's 19 interface pricing points eligible for day-ahead transactions in the Day-Ahead Market.
- **Inadvertent Interchange.** In 2015, net scheduled interchange was 15,717 GWh and net actual interchange was 15,368 GWh, a difference of 349 GWh. In 2014, the difference was 82 GWh. This difference is inadvertent interchange.
- **Loop Flows.** In 2015, the Wisconsin Energy Corporation (WEC) interface had the largest loop flows of any interface with -846 GWh of net scheduled interchange and 9,985 GWh of net actual interchange, a difference of 10,831 GWh. (Table 9-18.) In 2015, the SouthEXP interface pricing point had the largest loop flows of any interface pricing point with -718 GWh of net scheduled interchange and -10,960 GWh of net actual interchange, a difference of 10,242 GWh.

Interactions with Bordering Areas

PJM Interface Pricing with Organized Markets

- **PJM and MISO Interface Prices.** In 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 55.4 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. 18 CFR § 385.213

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

- **PJM and New York ISO Interface Prices.** In 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 58.2 percent of the hours.
- **Neptune Underwater Transmission Line to Long Island, New York.** In 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 58.2 percent of the hours.
- **Linden Variable Frequency Transformer (VFT) Facility.** In 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 53.0 percent of the hours.
- **Hudson DC Line.** In 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 42.1 percent of the hours.

Interchange Transaction Issues

- **PJM Transmission Loading Relief Procedures (TLRs).** PJM issued 22 TLRs of level 3a or higher in 2015, compared to eight such TLRs issued in 2014.
- **Up to congestion.** On August 29, 2014, FERC issued an Order which created an obligation for up to congestion transactions 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 42.8 percent and the average cleared volume of up to congestion bids decreased by 61.1 percent in 2015, compared to 2014, but there was an increase in up to congestion volume in December 2015, coincident with the expiration of the fifteen month resettlement period for the proceeding related to uplift charges for UTC transactions.[5]
- **45 Minute Schedule Duration Rule.** Effective May 19, 2014, PJM removed the 45 minute scheduling duration rule in response to FERC Order No. 764.[6,7] 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.[8]

Recommendations

- The MMU recommends that PJM eliminate the IMO interface pricing point, and assign the transactions that originate or sink in the IESO balancing authority to the MISO interface pricing point. (Priority: Medium. First reported 2013. 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. 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 1800 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 used to meet load in the most economic manner. (Priority: Medium. First reported Q3 2014. Status: Adopted partially, Q1 2015.)
- The MMU recommends that PJM explore an interchange optimization solution with its neighboring balancing authorities that would 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 uses supply curves and treats seams between balancing authorities as constraints, similar to other constraints within an LMP market.

4 148 FERC ¶ 61,144 (2014). *Order Instituting Section 206 Proceeding and Establishing Procedures.*

5 16 U.S.C. § 824e.

6 *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).

7 *See* Letter Order, Docket No. ER14-381-000 (June 30, 2014).

8 *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>.

(Priority: Medium. First reported 2014. 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 by concealing the true source or sink of the transaction. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM implement a validation method for submitted transactions that would require market participants to submit transactions on market paths that reflect the expected actual 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 requests that, in order to permit a complete analysis of loop flow, FERC and NERC ensure that the identified data are made available to market monitors as well as other industry entities determined appropriate by FERC. (Priority: Medium. First reported 2003. Status: Not adopted.)
- 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 eliminate the NIPSCO, Southeast and Southwest 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 PJMSettlement Inc. immediately request a credit evaluation from all companies that engaged in up to congestion transactions between September 8, 2014, and December 31, 2015. If PJM has the authority, PJM should ensure that the potential exposure to uplift for that period be included as a contingency in the companies' calculations for credit levels and/or collateral requirements. If PJM does not have the authority to take such steps, PJM should request guidance from FERC. (Priority: High. New recommendation. Status: Not adopted.)
- The MMU recommends that the emergency interchange cap be replaced with a market based solution. (Priority: Low. New recommendation. 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 competitive generator offers results in an efficient dispatch and efficient prices. The goal of designing interface transaction rules should be to match the outcome that would exist in an LMP market.

Interchange Transaction Activity

Aggregate Imports and Exports

In 2015, PJM was a monthly net exporter of energy in the Real-Time Energy Market in September, and a net importer in the remaining months (Figure 9-1).[9] In 2015, the total real-time net interchange of 15,717.4 GWh was higher than the net interchange of 1,137.8 GWh in 2014. In 2015, the peak month for net importing interchange was April, 2,293.9 GWh; in 2014 it was January, 1,556.0 GWh. Gross monthly export volumes in 2015 averaged 2,852.0 GWh compared to 3,849.0 GWh in 2014, while gross monthly imports in 2015 averaged 4,161.7 GWh compared to 3,943.8 GWh in 2014.

In 2015, PJM was a monthly net exporter of energy in the Day-Ahead Energy Market in February, August, September, October, November and December, and a net importer in the remaining months (Figure 9-1). In 2015, the total day-ahead net interchange of 1,603.1 GWh was higher than the net interchange of -14,305.5 GWh in 2014. The large difference in the day-ahead net interchange totals was a result of the reduction in up to congestion transaction volumes.[10] In 2015, the peak month for net exporting interchange was September, -886.1 GWh; in 2014 it was April, -1,992.1 GWh. Gross monthly export volumes in 2015 averaged 3,265.3 GWh compared to 5,511.9 GWh in 2014, while gross monthly imports in 2015 averaged 3,398.8 GWh compared to 4,319.7 GWh in 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.

In 2015, gross imports in the Day-Ahead Energy Market were 81.7 percent of gross imports in the Real-Time Energy Market (109.5 percent in 2014). In 2015, gross exports in the Day-Ahead Energy Market were 114.5 percent of gross exports in the Real-Time Energy Market (143.2 percent in 2014). In 2015, net interchange was 1,603.1 GWh in the Day-Ahead Energy Market and 15,717.4 GWh in the Real-Time Energy Market compared to -14,305.5 GWh in the Day-Ahead Energy Market and 1,137.8 GWh in the Real-Time Energy Market in 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.[11] In 2015, the total day-ahead gross imports and exports were higher than the real-time gross 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.

Figure 9-1 PJM real-time and day-ahead scheduled imports and exports: 2015

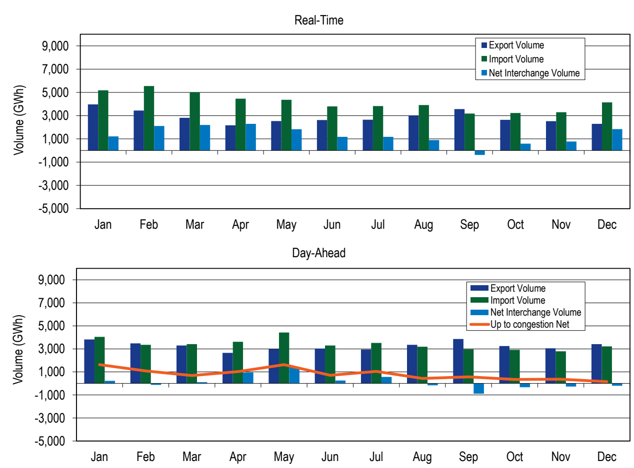


Figure 9-2 shows the real-time and day-ahead import and export volume for PJM from 1999 through 2015. PJM shifted from a consistent net importer of energy to relatively consistent net exporter of energy in 2004 in both the Real-Time and Day-Ahead Energy Markets, coincident with the expansion of the PJM footprint that

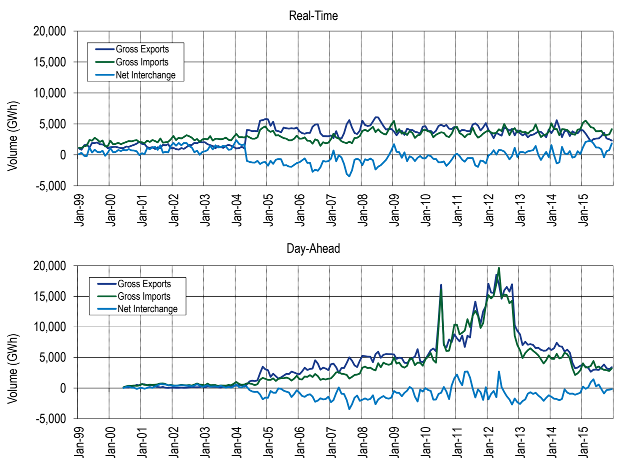
9 Calculated values shown in Section 9, "Interchange Transactions," are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

10 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.

11 Up to congestion transactions create financial obligations to deliver in real time, but do not pay operating reserve charges.

included the integrations of Commonwealth Edison, American Electric Power and Dayton Power and Light into PJM. 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 every up to congestion transaction include an interface pricing point as either the source or sink. 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 decreased, PJM has remained primarily a net exporter in the Day-Ahead Energy Market.

Figure 9-2 PJM real-time and day-ahead scheduled import and export transaction volume history: 1999 through 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 2015. Figure 9-3 shows the approximate geographic location of the interfaces. In 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 scheduled interchange totals at the individual NYISO interfaces, as well as with the NYISO as a whole. Similarly, the scheduled interchange totals at the individual interfaces between PJM and MISO are shown, as well as with MISO as a whole. Net scheduled interchange in the Real-Time Energy Market is shown by interface for 2015 in Table 9-1, while gross scheduled imports and exports are shown in Table 9-2 and Table 9-3.

In the Real-Time Energy Market, in 2015, there were net scheduled exports at eight 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 scheduled exports: PJM/MidAmerican Energy Company (MEC) with 35.4 percent, PJM/Neptune (NEPT) with 25.5 percent and PJM/New York Independent System Operator (NYIS) with 13.8 percent of the net scheduled export volume. The four separate interfaces that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT, PJM/HUDS and PJM/Linden (LIND)) together represented 45.8 percent of the total net PJM scheduled exports in the Real-Time Energy Market. In 2015, MISO had net scheduled imports; however, there were net scheduled exports in the Real-Time Energy Market at three of the ten separate interfaces that connect PJM to MISO. Those three exporting interfaces represented 53.4 percent of the total net PJM scheduled exports in the Real-Time Energy Market. Eleven PJM interfaces had net scheduled imports, with three importing interfaces accounting for 61.0 percent of the total net scheduled imports: PJM/Ohio Valley Electric Corporation (OVEC) with 23.1 percent, PJM/Ameren-Illinois (AMIL) with 21.8 percent and PJM/Tennessee Valley Authority (TVA) with 16.1 percent of the net scheduled import volume.[12] The four separate interfaces that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT, PJM/HUDS and PJM/Linden (LIND)) had net scheduled exports in the Real-Time Energy Market. In 2015, there were net imports in the Real-Time Energy Market at six of the ten separate

12 In the Real-Time Energy Market, one PJM interface had a net interchange of zero (PJM/City Water Light & Power (CWLP)).

interfaces that connect PJM to MISO. Those six interfaces represented 41.1 percent of the total net PJM scheduled imports in the Real-Time Energy Market.

The Ohio Valley Electric Corporation (OVEC) consists of two coal fired generating stations. The Clifty Creek plant has a nameplate rating of 1,300 MW and is located in Madison, Indiana. The Kyger Creek plant has a nameplate rating of 1,000 MW and is located in Cheshire, Ohio. Thirteen investor-owned utilities and affiliates of generation and transmission rural electric cooperatives, the Sponsoring Companies, share OVEC's generation output. The Sponsoring Companies purchase power from OVEC according to the terms of the Inter-Company Power Agreement (ICPA), which has a current termination date of June 30, 2040.[13] Approximately 90 percent of OVEC is owned by load serving entities or their affiliates located in the PJM footprint.[14]

Table 9-1 Real-time scheduled net interchange volume by interface (GWh): 2015

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
CPLE	(19.8)	(27.2)	(34.2)	(18.3)	(0.4)	(28.4)	(31.9)	(38.9)	(42.3)	64.5	55.8	(11.6)	(132.7)
CPLW	0.0	0.0	0.0	0.0	0.0	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.2
DUK	423.3	377.0	443.5	528.0	367.9	110.9	210.5	162.2	149.9	249.0	372.7	751.6	4,146.3
LGEE	233.4	277.9	225.6	157.0	221.2	196.1	216.6	192.1	213.7	155.6	81.6	153.1	2,324.1
MISO	521.9	1,287.7	1,369.8	630.1	150.9	195.4	393.4	310.1	(795.0)	(382.8)	174.0	511.2	4,366.9
ALTE	(346.8)	(76.5)	279.7	(230.8)	(111.0)	(351.6)	(252.9)	(258.8)	(361.2)	(321.6)	(44.6)	(139.6)	(2,215.6)
ALTW	2.6	(0.1)	(0.7)	(2.9)	(38.3)	(0.8)	(0.7)	(21.9)	5.3	7.7	30.9	44.6	25.9
AMIL	778.3	863.7	394.9	518.6	445.9	577.6	612.3	577.5	329.2	549.0	708.5	799.2	7,154.6
CIN	281.9	355.4	336.2	399.5	71.6	25.7	81.8	26.0	(3.4)	40.7	(131.9)	143.0	1,626.6
CWLP	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
IPL	145.7	294.5	292.0	166.9	119.5	86.2	91.4	54.9	(37.4)	(94.6)	(74.7)	(9.8)	1,034.5
MEC	(483.8)	(422.6)	(348.3)	(465.5)	(500.2)	(460.5)	(511.8)	(479.2)	(720.6)	(644.7)	(507.8)	(485.0)	(6,029.9)
MECS	260.2	347.2	412.9	292.5	263.0	357.3	379.5	489.9	63.1	115.3	265.2	245.7	3,491.7
NIPS	1.4	18.9	31.1	23.9	34.9	3.3	7.7	1.6	0.0	0.0	0.0	2.5	125.4
WEC	(117.7)	(92.9)	(27.9)	(72.1)	(134.4)	(41.8)	(14.0)	(80.0)	(69.9)	(34.6)	(71.5)	(89.4)	(846.4)
NYISO	(1,571.6)	(1,341.2)	(1,109.3)	(129.3)	75.1	(198.7)	(457.3)	(815.3)	(1,005.3)	(448.8)	(391.3)	(413.9)	(7,807.0)
HUDS	(117.6)	(82.7)	(49.0)	(0.1)	(5.2)	(5.4)	(12.6)	(31.5)	(57.1)	(79.2)	(40.3)	(24.2)	(504.9)
LIND	(218.7)	(130.3)	(156.3)	7.4	76.9	38.0	(23.4)	(58.7)	(102.8)	18.2	(17.2)	(46.7)	(613.7)
NEPT	(326.4)	(318.6)	(437.9)	(289.5)	(167.5)	(309.1)	(432.4)	(431.5)	(437.3)	(406.0)	(408.0)	(373.5)	(4,337.7)
NYIS	(908.9)	(809.6)	(466.2)	152.9	170.9	77.8	11.1	(293.5)	(408.1)	18.2	74.3	30.4	(2,350.7)
OVEC	875.5	765.9	828.2	635.4	560.3	641.1	619.6	754.2	728.7	582.9	299.0	263.3	7,554.1
TVA	750.1	766.4	473.6	491.1	453.5	262.0	227.2	334.5	369.8	366.1	181.9	589.4	5,265.5
Total	1,212.7	2,106.6	2,197.2	2,293.9	1,828.4	1,178.6	1,178.1	899.0	(380.4)	586.6	773.7	1,843.2	15,717.4

13 See OVEC, "Annual Report – 2014: Ohio Valley Electric Corporation and subsidiary Indiana-Kentucky Electric Corporation," <http://www.ovec.com/FinancialStatements/AnnualReport-2014-Signed.pdf>.
14 See OVEC, "Ohio Valley Electric Corporation: Company Background," <http://www.ovec.com/OVECHistory.pdf>.

Table 9-2 Real-time scheduled gross import volume by interface (GWh): 2015

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
CPLE	7.6	7.8	6.6	6.4	12.2	2.8	10.5	5.2	8.4	104.5	90.2	23.4	285.7
CPLW	0.0	0.0	0.0	0.0	0.0	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.2
DUK	586.1	510.0	485.3	563.1	460.9	271.0	331.0	310.1	213.0	283.3	391.6	756.9	5,162.2
LGEE	233.8	277.9	225.6	157.4	221.2	196.9	217.4	193.4	215.7	166.0	86.9	153.2	2,345.4
MISO	1,720.3	1,966.0	1,935.1	1,575.0	1,617.8	1,361.4	1,412.4	1,362.0	906.1	953.4	1,452.2	1,576.9	17,838.6
ALTE	3.1	16.9	379.5	6.8	326.1	1.6	2.3	1.7	122.1	59.3	353.4	123.5	1,396.2
ALTW	2.8	0.4	0.0	0.0	0.0	1.3	0.0	0.3	14.9	8.3	31.6	44.6	104.2
AMIL	794.4	866.7	405.6	526.3	451.5	587.4	619.5	578.6	340.7	558.5	709.0	801.0	7,239.3
CIN	360.4	369.6	378.8	461.8	175.3	159.1	181.8	142.5	203.7	169.0	27.4	280.2	2,909.8
CWLP	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
IPL	220.2	337.6	311.0	237.7	241.9	129.7	113.6	97.9	67.3	6.3	39.0	49.1	1,851.4
MEC	0.8	0.1	0.0	0.0	0.4	0.1	0.6	0.4	2.0	0.3	0.0	0.6	5.2
MECS	337.2	355.4	421.1	318.4	386.8	479.0	440.3	538.6	155.2	150.9	291.8	275.3	4,150.1
NIPS	1.4	18.9	31.1	23.9	35.8	3.3	7.7	1.6	0.0	0.0	0.0	2.5	126.3
WEC	0.0	0.4	7.9	0.0	0.0	0.0	46.8	0.4	0.0	0.8	0.0	0.1	56.3
NYISO	959.9	1,196.4	1,020.1	1,013.1	1,000.7	992.1	962.8	919.7	715.2	752.4	763.8	748.1	11,044.3
HUDS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.0	0.1	0.0	0.3
LIND	2.2	28.4	1.8	41.3	84.8	55.0	20.1	23.8	8.7	46.5	29.8	10.4	352.9
NEPT	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3
NYIS	957.7	1,168.0	1,018.3	971.7	915.8	937.0	942.6	895.8	706.5	705.9	733.9	737.6	10,690.8
OVEC	901.8	790.7	849.6	651.8	576.6	655.7	635.1	770.1	743.9	599.4	317.2	283.7	7,775.7
TVA	769.8	794.5	486.4	496.7	476.7	316.7	255.5	347.0	381.2	372.6	194.5	597.2	5,488.8
Total	5,179.2	5,543.3	5,008.7	4,463.6	4,366.2	3,796.9	3,824.8	3,907.5	3,183.4	3,231.6	3,296.4	4,139.4	49,940.9

Table 9-3 Real-time scheduled gross export volume by interface (GWh): 2015

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
CPLE	27.4	35.0	40.8	24.7	12.7	31.2	42.4	44.1	50.7	40.0	34.4	35.0	418.4
CPLW	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
DUK	162.8	132.9	41.8	35.1	93.0	160.1	120.5	147.9	63.2	34.3	18.9	5.2	1,015.8
LGEE	0.3	0.0	0.0	0.4	0.0	0.8	0.8	1.3	1.9	10.4	5.3	0.0	21.3
MISO	1,198.4	678.3	565.2	944.9	1,466.9	1,166.1	1,019.0	1,051.9	1,701.0	1,336.3	1,278.2	1,065.7	13,471.8
ALTE	350.0	93.4	99.8	237.6	437.1	353.2	255.1	260.4	483.3	380.9	398.0	263.1	3,611.9
ALTW	0.2	0.4	0.7	2.9	38.3	2.0	0.7	22.2	9.6	0.6	0.7	0.0	78.3
AMIL	16.1	3.0	10.7	7.7	5.6	9.8	7.2	1.2	11.6	9.5	0.5	1.8	84.6
CIN	78.5	14.1	42.7	62.3	103.7	133.3	100.0	116.5	207.1	128.3	159.3	137.2	1,283.1
CWLP	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
IPL	74.5	43.1	19.0	70.8	122.5	43.5	22.2	43.0	104.8	100.9	113.7	59.0	816.9
MEC	484.6	422.6	348.3	465.5	500.6	460.6	512.4	479.6	722.6	645.0	507.8	485.6	6,035.1
MECS	76.9	8.2	8.3	25.9	123.9	121.7	60.7	48.7	92.1	35.6	26.6	29.7	658.4
NIPS	0.0	0.0	0.0	0.0	0.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.9
WEC	117.7	93.3	35.8	72.1	134.4	41.8	60.7	80.4	69.9	35.4	71.5	89.5	902.7
NYISO	2,531.5	2,537.7	2,129.5	1,142.4	925.6	1,190.9	1,420.1	1,734.9	1,720.5	1,201.2	1,155.1	1,161.9	18,851.3
HUDS	117.6	82.7	49.0	0.1	5.2	5.5	12.7	31.6	57.1	79.2	40.4	24.2	505.2
LIND	220.9	158.8	158.1	33.9	7.9	17.0	43.6	82.5	111.5	28.3	47.0	57.1	966.6
NEPT	326.4	318.6	437.9	289.5	167.6	309.1	432.4	431.5	437.4	406.0	408.1	373.5	4,338.0
NYIS	1,866.6	1,977.5	1,484.5	818.9	744.9	859.2	931.5	1,189.3	1,114.6	687.6	659.6	707.2	13,041.4
OVEC	26.3	24.7	21.4	16.5	16.4	14.6	15.5	15.9	15.2	16.5	18.2	20.4	221.6
TVA	19.7	28.1	12.8	5.7	23.2	54.7	28.4	12.5	11.3	6.5	12.6	7.8	223.3
Total	3,966.5	3,436.7	2,811.6	2,169.7	2,537.8	2,618.3	2,646.7	3,008.5	3,563.8	2,645.1	2,522.7	2,296.2	34,223.5

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.[15] An interface pricing point defines the price at which transactions are priced, and is based on the path of the actual, physical transfer of energy. While a market participant designates a scheduled market path from a generation control area (GCA) to a load control area (LCA), this market path reflects the scheduled path as defined by the transmission reservations only, and may not reflect how the energy actually flows from the GCA to LCA. For example, the import transmission path from LG&E Energy, L.L.C. (LGEE), through MISO and into PJM would show the transfer of power into PJM at the 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 the locational price impact of flows between PJM and external sources of energy and that reflect the underlying economic fundamentals across balancing authority borders.[16]

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.[17] 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. Dynamic interface pricing calculations use actual system conditions to determine a set of weights for each external pricing point in an interface price definition. The weights are designed so that the interface price reflects actual system conditions. However, the weights are an approximation given the complexity of the transmission network outside PJM and the dynamic nature of power flows. Table 9-17 presents the interface pricing points used in 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.

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.[18] 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.

The contract transmission 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. The NERC Tag path is used by PJM to determine the interface pricing point that PJM assigns to 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 breaking of transactions into portions can be a way to manipulate markets and the result of such behavior can be incorrect and noncompetitive pricing of transactions.

There are several pricing points mapped to the region south of PJM. The SouthIMP and SouthEXP pricing

15 A market path is the scheduled path rather than the actual path on which power flows. A market path contains the generation balancing authority, all required transmission segments and the load balancing authority. There are multiple market paths between any generation and load balancing authority. Market participants select the market path based on transmission service availability and the transmission costs for moving energy from generation to load and interface prices.

16 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.

17 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.

18 On June 1, 2015, PJM began using a dynamic weighting factor in the calculation for the Ontario Interface Pricing Point.

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 which have since expired.[19]

In the Real-Time Energy Market, in 2015, there were net scheduled exports at 10 of PJM's 18 interface pricing points eligible for real-time transactions.[20] The top three net exporting interface pricing points in the Real-Time Energy Market accounted for 86.3 percent of the total net scheduled exports: PJM/MISO with 54.2 percent, PJM/NEPTUNE with 20.9 percent and PJM/NYIS with 11.2 percent of the net scheduled 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 37.5 percent of the total net PJM scheduled exports in the Real-Time Energy Market. Six PJM interface pricing points had net scheduled imports, with two importing interface pricing points accounting for 77.9 percent of the total net scheduled imports: PJM/SouthIMP with 57.2 percent and PJM/Ohio Valley Electric Corporation (OVEC) with 20.7 percent of the net scheduled import volume.[21]

Table 9-4 Real-time scheduled net interchange volume by interface pricing point (GWh): 2015

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
IMO	666.5	687.6	890.4	713.1	654.4	427.7	486.0	445.3	262.9	279.6	270.2	301.7	6,085.3
MISO	(1,028.3)	(396.8)	(312.1)	(801.1)	(1,323.3)	(1,027.7)	(846.0)	(930.3)	(1,507.6)	(1,224.7)	(1,087.1)	(744.0)	(11,229.0)
NORTHWEST	(1.0)	0.2	(3.7)	(2.2)	(2.3)	(2.3)	(1.0)	(3.1)	(5.0)	(1.3)	(0.9)	(0.3)	(23.0)
NYISO	(1,568.5)	(1,262.5)	(1,090.7)	(129.7)	70.9	(213.3)	(476.7)	(830.6)	(1,000.0)	(452.0)	(405.5)	(420.4)	(7,779.1)
HUDSONTP	(117.6)	(82.7)	(49.0)	(0.1)	(5.2)	(5.4)	(12.6)	(31.5)	(57.1)	(79.2)	(40.3)	(24.2)	(504.9)
LINDENVFT	(218.7)	(130.3)	(156.3)	7.4	76.9	38.0	(23.4)	(58.7)	(102.8)	18.2	(17.2)	(46.7)	(613.7)
NEPTUNE	(326.4)	(318.6)	(437.9)	(289.5)	(167.5)	(309.1)	(432.4)	(431.5)	(437.3)	(406.0)	(408.0)	(373.5)	(4,337.7)
NYIS	(905.8)	(730.9)	(447.6)	152.5	166.7	63.2	(8.2)	(308.8)	(402.8)	15.0	60.1	23.9	(2,322.8)
OVEC	875.5	765.9	828.2	635.4	560.3	641.1	619.6	754.2	728.7	582.9	299.0	263.3	7,554.1
Southern Imports	2,482.1	2,508.5	1,980.8	1,944.4	1,997.4	1,600.3	1,588.6	1,670.0	1,268.6	1,493.7	1,770.3	2,491.2	22,795.8
CPLEIMP	7.6	7.3	5.2	6.3	11.8	2.4	10.0	5.2	8.4	9.0	8.6	23.3	105.2
DUKIMP	50.4	54.7	36.8	51.5	52.7	42.6	67.1	53.8	45.0	142.0	64.2	113.3	774.2
NCMPAIMP	105.6	47.1	28.9	170.1	164.8	86.4	71.4	82.6	41.8	31.8	119.7	143.0	1,093.3
SOUTHEAST	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
SOUTHWEST	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
SOUTHIMP	2,318.5	2,399.4	1,909.8	1,716.5	1,768.1	1,468.8	1,440.0	1,528.4	1,173.4	1,310.8	1,577.8	2,211.6	20,823.1
Southern Exports	(213.5)	(196.2)	(95.6)	(66.1)	(129.0)	(247.1)	(192.4)	(206.6)	(128.1)	(91.7)	(72.2)	(48.1)	(1,686.8)
CPLEEXP	(19.7)	(31.2)	(36.4)	(24.7)	(10.8)	(31.0)	(40.8)	(43.0)	(50.5)	(33.1)	(33.0)	(32.1)	(386.3)
DUKEXP	(115.6)	(113.1)	(28.9)	(16.8)	(59.8)	(96.3)	(39.8)	(61.1)	(36.2)	(9.9)	(0.7)	(0.0)	(578.2)
NCMPAEXP	0.0	(0.2)	(0.1)	0.0	(0.0)	0.0	(1.0)	(3.0)	(0.2)	(0.1)	0.0	0.0	(4.6)
SOUTHEAST	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
SOUTHWEST	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
SOUTHEXP	(78.2)	(51.7)	(30.3)	(24.5)	(58.4)	(119.9)	(110.9)	(99.6)	(41.3)	(48.5)	(38.5)	(16.0)	(717.7)
Total	1,212.7	2,106.6	2,197.2	2,293.9	1,828.4	1,178.6	1,178.1	899.0	(380.4)	586.6	773.7	1,843.2	15,717.4

19 The MMU does not believe that it is appropriate to allow the use of the Southwest pricing point for grandfathered transactions, and recommends that no further such agreements be entered into.
20 There is one interface pricing point eligible for day-ahead transaction scheduling only (NIPSCO).
21 In the Real-Time Energy Market, two PJM interface pricing points had a net interchange of zero (Southeast and Southwest).

Table 9-5 Real-time scheduled gross import volume by interface pricing point (GWh): 2015

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
IMO	672.1	766.7	909.0	713.7	654.7	428.0	487.2	445.8	279.8	283.1	270.7	301.7	6,212.4
MISO	165.2	280.9	249.0	141.2	141.2	135.8	171.1	117.4	176.3	108.8	188.8	321.4	2,197.1
NORTHWEST	0.0	0.2	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3
NYISO	958.0	1,196.4	1,020.1	1,012.4	996.2	977.2	942.8	904.0	714.8	746.6	749.4	741.5	10,959.6
HUDSONTP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.0	0.1	0.0	0.3
LINDENVFT	2.2	28.4	1.8	41.3	84.8	55.0	20.1	23.8	8.7	46.5	29.8	10.4	352.9
NEPTUNE	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3
NYIS	955.8	1,168.0	1,018.3	971.1	911.4	922.1	922.6	880.2	706.1	700.1	719.5	731.1	10,606.0
OVEC	901.8	790.7	849.6	651.8	576.6	655.7	635.1	770.1	743.9	599.4	317.2	283.7	7,775.7
Southern Imports	2,482.1	2,508.5	1,980.8	1,944.4	1,997.4	1,600.3	1,588.6	1,670.0	1,268.6	1,493.7	1,770.3	2,491.2	22,795.8
CPLEIMP	7.6	7.3	5.2	6.3	11.8	2.4	10.0	5.2	8.4	9.0	8.6	23.3	105.2
DUKIMP	50.4	54.7	36.8	51.5	52.7	42.6	67.1	53.8	45.0	142.0	64.2	113.3	774.2
NCMPAIMP	105.6	47.1	28.9	170.1	164.8	86.4	71.4	82.6	41.8	31.8	119.7	143.0	1,093.3
SOUTHEAST	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
SOUTHWEST	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
SOUTHIMP	2,318.5	2,399.4	1,909.8	1,716.5	1,768.1	1,468.8	1,440.0	1,528.4	1,173.4	1,310.8	1,577.8	2,211.6	20,823.1
Southern Exports	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
CPLEEXP	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
DUKEXP	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
NCMPAEXP	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
SOUTHEAST	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
SOUTHWEST	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
SOUTHEXP	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
Total	5,179.2	5,543.3	5,008.7	4,463.6	4,366.2	3,796.9	3,824.8	3,907.5	3,183.4	3,231.6	3,296.4	4,139.4	49,940.9

Table 9-6 Real-time scheduled gross export volume by interface pricing point (GWh): 2015

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
IMO	5.6	79.1	18.6	0.6	0.3	0.3	1.2	0.5	16.8	3.5	0.5	0.0	127.1
MISO	1,193.5	677.7	561.2	942.3	1,464.4	1,163.4	1,017.1	1,047.8	1,683.8	1,333.5	1,276.0	1,065.4	13,426.0
NORTHWEST	1.0	0.0	3.9	2.2	2.3	2.3	1.0	3.1	5.0	1.3	0.9	0.3	23.3
NYISO	2,526.6	2,459.0	2,110.8	1,142.1	925.3	1,190.5	1,419.4	1,734.7	1,714.9	1,198.6	1,154.9	1,161.9	18,738.7
HUDSONTP	117.6	82.7	49.0	0.1	5.2	5.5	12.7	31.6	57.1	79.2	40.4	24.2	505.2
LINDENVFT	220.9	158.8	158.1	33.9	7.9	17.0	43.6	82.5	111.5	28.3	47.0	57.1	966.6
NEPTUNE	326.4	318.6	437.9	289.5	167.6	309.1	432.4	431.5	437.4	406.0	408.1	373.5	4,338.0
NYIS	1,861.6	1,898.8	1,465.8	818.5	744.7	858.9	930.8	1,189.0	1,108.9	685.1	659.4	707.2	12,928.8
OVEC	26.3	24.7	21.4	16.5	16.4	14.6	15.5	15.9	15.2	16.5	18.2	20.4	221.6
Southern Imports	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
CPLEIMP	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
DUKIMP	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
NCMPAIMP	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
SOUTHEAST	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
SOUTHWEST	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
SOUTHIMP	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
Southern Exports	213.5	196.2	95.6	66.1	129.0	247.1	192.4	206.6	128.1	91.7	72.2	48.1	1,686.8
CPLEEXP	19.7	31.2	36.4	24.7	10.8	31.0	40.8	43.0	50.5	33.1	33.0	32.1	386.3
DUKEXP	115.6	113.1	28.9	16.8	59.8	96.3	39.8	61.1	36.2	9.9	0.7	0.0	578.2
NCMPAEXP	0.0	0.2	0.1	0.0	0.0	0.0	1.0	3.0	0.2	0.1	0.0	0.0	4.6
SOUTHEAST	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
SOUTHWEST	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
SOUTHEXP	78.2	51.7	30.3	24.5	58.4	119.9	110.9	99.6	41.3	48.5	38.5	16.0	717.7
Total	3,966.5	3,436.7	2,811.6	2,169.7	2,537.8	2,618.3	2,646.7	3,008.5	3,563.8	2,645.1	2,522.7	2,296.2	34,223.5

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.[22] 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.[23]

In the Day-Ahead Energy Market, transaction sources and sinks are determined solely by market participants. In Table 9-7, Table 9-8, and Table 9-9, the scheduled 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, 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, a market participant who plans to submit a transaction from SPP to PJM may have a transmission reservation with a point of receipt of MISO and a point of delivery of PJM but may select SouthIMP as the import pricing point when submitting the transaction in the Day-Ahead Energy Market. In the scheduled interface tables, the import transaction would appear as scheduled through the MISO Interface, and in the scheduled 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 scheduled interchange totals at the individual interfaces. Net scheduled interchange in the Day-Ahead Energy Market is shown by interface for 2015 in Table 9-7, while gross scheduled imports and exports are shown in Table 9-8 and Table 9-9.

In the Day-Ahead Energy Market, in 2015, there were net scheduled exports at eight of PJM's 20 interfaces. The top three net exporting interfaces in the Day-Ahead Energy Market accounted for 76.7 percent of the total net scheduled exports: PJM/MidAmerican Energy Company (MEC) with 31.6 percent, PJM/Neptune (NEPT) with 22.9 percent, and PJM/New York Independent System Operator, Inc. (NYIS) with 22.2 percent of the net scheduled export volume. The four separate interfaces that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT, PJM/HUDS and PJM/Linden (LIND)) together represented 46.7 percent of the total net PJM scheduled exports in the Day-Ahead Energy Market (the PJM/LIND Interface had net scheduled imports). In 2015, there were net exports in the Day-Ahead Energy Market at four of the ten separate interfaces that connect PJM to MISO. Those four interfaces represented 52.6 percent of the total net PJM exports in the Day-Ahead Energy Market. Ten PJM interfaces had net scheduled imports, with two importing interfaces accounting for 75.4 percent of the total net imports: PJM/Ohio Valley Electric Corporation

22 Effective September 17, 2010, up to congestion transactions no longer required a willing to pay congestion transmission reservation.

23 See the *2010 State of the Market Report for PJM*, Volume II, Section 4, "Interchange Transactions," for details.

(OVEC) with 50.8 percent and PJM/DUK with 24.6 percent of the net import volume. The four separate interfaces that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT, PJM/HUDS and PJM/Linden (LIND)) had net scheduled exports in the Day-Ahead Energy Market; however, the PJM/LIND Interface had net scheduled imports that represented 0.3 percent of the total PJM net scheduled imports in the Day-Ahead Energy Market. In 2015, there were net imports in the Day-Ahead Energy Market at five of the ten separate interfaces that connect PJM to MISO. Those five interfaces represented 17.7 percent of the total net PJM scheduled imports in the Day-Ahead Energy Market.[24]

Table 9-7 Day-Ahead scheduled net interchange volume by interface (GWh): 2015

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
CPLE	(13.7)	(13.2)	(16.7)	(18.3)	(7.9)	(27.5)	(34.6)	(35.8)	(38.8)	61.8	35.7	(22.7)	(131.6)
CPLW	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
DUK	291.6	240.9	239.7	348.2	332.3	130.2	169.3	165.8	73.2	116.9	195.8	397.9	2,702.0
LGEE	0.0	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3
MISO	(840.5)	(432.2)	(156.1)	(565.4)	(808.8)	(743.2)	(587.4)	(584.0)	(1,213.0)	(900.4)	(705.2)	(559.3)	(8,095.5)
ALTE	(346.7)	(87.6)	(70.8)	(204.1)	(318.8)	(300.5)	(206.8)	(218.3)	(442.3)	(327.8)	(314.3)	(218.3)	(3,056.4)
ALTW	0.0	0.5	0.0	(2.6)	(27.7)	(2.0)	0.0	(21.8)	(8.6)	0.0	0.0	0.0	(62.2)
AMIL	35.1	38.0	51.7	61.2	4.0	38.2	0.0	0.0	0.0	13.6	7.0	54.4	303.3
CIN	10.2	56.8	42.7	32.8	39.0	(0.6)	11.2	(1.1)	8.7	(1.9)	(14.9)	30.8	213.8
CWLP	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
IPL	0.0	6.3	1.0	11.9	35.9	(0.8)	0.0	0.0	16.1	0.0	24.0	2.6	97.0
MEC	(485.4)	(422.6)	(348.0)	(460.5)	(496.4)	(459.2)	(508.7)	(473.7)	(737.1)	(640.9)	(507.2)	(483.6)	(6,023.4)
MECS	65.2	61.4	161.4	64.8	81.8	21.5	177.1	212.7	18.2	91.6	171.2	142.1	1,269.1
NIPS	0.0	8.3	32.4	4.5	7.7	3.2	3.9	0.0	0.0	0.0	0.0	2.3	62.3
WEC	(118.9)	(93.3)	(26.4)	(73.4)	(134.3)	(43.0)	(64.1)	(81.8)	(67.9)	(35.1)	(70.9)	(89.7)	(898.9)
NYISO	(1,551.8)	(1,555.6)	(1,284.5)	(381.6)	(226.7)	(351.0)	(557.7)	(747.8)	(859.9)	(447.3)	(443.8)	(468.0)	(8,875.7)
HUDS	(105.4)	(76.4)	(41.6)	0.0	(1.5)	(1.9)	(9.9)	(15.0)	(7.8)	(15.3)	(6.3)	(18.9)	(299.8)
LIND	(13.1)	(8.4)	(10.7)	0.5	3.3	4.0	(1.5)	(2.0)	(5.4)	44.9	26.9	(1.8)	36.7
NEPT	(329.9)	(317.8)	(441.5)	(294.6)	(170.0)	(307.1)	(434.5)	(433.7)	(441.0)	(409.5)	(415.3)	(371.8)	(4,366.6)
NYIS	(1,103.3)	(1,153.1)	(790.7)	(87.6)	(58.5)	(46.1)	(111.9)	(297.1)	(405.7)	(67.4)	(49.0)	(75.5)	(4,245.9)
OVEC	645.3	515.5	579.0	444.5	414.5	499.1	473.7	560.5	552.6	431.5	237.8	218.2	5,572.1
TVA	60.1	38.1	56.1	105.7	93.1	41.3	59.1	46.9	32.2	58.3	48.7	79.2	718.7
Total without Up to Congestion	(1,408.8)	(1,206.3)	(582.5)	(66.9)	(203.5)	(451.1)	(477.6)	(594.5)	(1,453.6)	(679.2)	(631.0)	(354.7)	(8,109.7)
Up to Congestion	1,633.0	1,083.6	693.6	1,025.9	1,636.5	711.4	1,049.5	436.3	567.5	349.8	367.1	158.5	9,712.8
Total	224.1	(122.7)	111.1	959.0	1,433.0	260.3	572.0	(158.1)	(886.1)	(329.4)	(264.0)	(196.2)	1,603.1

Table 9-8 Day-Ahead scheduled gross import volume by interface (GWh): 2015

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
CPLE	2.2	2.0	2.1	2.2	2.1	2.1	2.2	1.9	3.4	85.8	67.9	2.2	176.3
CPLW	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
DUK	309.3	255.9	241.6	348.2	333.9	155.8	181.3	171.8	73.2	117.4	195.8	397.9	2,782.3
LGEE	0.0	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3
MISO	187.7	193.2	320.9	199.5	225.2	158.7	244.0	255.0	108.8	125.5	215.9	260.4	2,494.8
ALTE	1.2	15.4	9.1	5.3	0.0	0.0	2.8	0.0	1.7	0.3	0.0	2.1	37.9
ALTW	0.0	0.5	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.5
AMIL	35.1	38.0	51.7	61.2	4.0	38.2	0.0	0.0	0.0	13.6	7.0	54.4	303.3
CIN	14.3	57.0	42.9	32.8	42.1	22.3	28.2	28.7	27.3	9.1	1.1	40.9	346.8
CWLP	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
IPL	0.0	6.3	1.0	11.9	35.9	0.0	0.0	0.0	16.1	0.0	24.0	2.6	97.8
MEC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.0	0.0	0.0	0.0	0.3
MECS	137.0	67.7	174.5	83.8	135.5	94.9	209.1	225.9	63.7	102.5	183.8	158.1	1,636.5
NIPS	0.0	8.3	32.4	4.5	7.7	3.2	3.9	0.0	0.0	0.0	0.0	2.3	62.3
WEC	0.0	0.0	9.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	9.4
NYISO	677.5	679.3	617.1	707.4	645.0	742.4	751.0	752.0	563.8	585.4	557.2	528.3	7,806.4
HUDS	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
LIND	0.2	1.5	0.3	0.8	3.5	4.6	2.4	2.9	2.5	45.4	27.7	2.0	93.9
NEPT	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
NYIS	677.4	677.8	616.7	706.6	641.5	737.8	748.5	749.1	561.4	540.0	529.5	526.3	7,712.6
OVEC	672.2	540.2	600.4	459.3	430.9	499.1	476.5	560.5	552.6	431.5	237.8	218.2	5,679.2
TVA	69.8	68.1	63.6	105.7	102.9	75.4	70.5	51.7	32.8	59.7	52.0	79.4	831.6
Total without Up to Congestion	1,918.8	1,739.0	1,845.7	1,822.4	1,740.0	1,633.4	1,725.5	1,792.9	1,334.6	1,405.3	1,326.7	1,486.5	19,770.8
Up to Congestion	2,131.5	1,617.4	1,568.5	1,798.0	2,684.6	1,662.8	1,799.7	1,403.4	1,638.3	1,515.4	1,465.7	1,730.0	21,015.4
Total	4,050.2	3,356.4	3,414.3	3,620.4	4,424.6	3,296.2	3,525.2	3,196.3	2,973.0	2,920.7	2,792.4	3,216.5	40,786.2

24 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 9-9 Day-Ahead scheduled gross export volume by interface (GWh): 2015

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
CPLE	15.9	15.2	18.9	20.5	10.0	29.6	36.8	37.8	42.1	23.9	32.2	25.0	307.9
CPLW	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
DUK	17.6	15.1	1.9	0.0	1.6	25.5	12.0	6.0	0.0	0.5	0.0	0.0	80.2
LGEE	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
MISO	1,028.2	625.4	477.0	764.9	1,033.9	901.9	831.4	839.0	1,321.8	1,025.9	921.1	819.8	10,590.3
ALTE	347.9	103.0	79.9	209.4	318.8	300.5	209.6	218.3	444.0	328.1	314.3	220.4	3,094.3
ALTW	0.0	0.0	0.0	2.6	27.7	2.0	0.0	21.9	8.6	0.0	0.0	0.0	62.8
AMIL	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
CIN	4.1	0.2	0.3	0.0	3.1	23.0	17.0	29.8	18.6	10.9	16.0	10.1	133.0
CWLP	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
IPL	0.0	0.0	0.0	0.0	0.0	0.8	0.0	0.0	0.0	0.0	0.0	0.0	0.8
MEC	485.4	422.6	348.0	460.5	496.4	459.2	508.7	474.0	737.1	640.9	507.2	483.6	6,023.7
MECS	71.9	6.3	13.1	19.0	53.7	73.4	32.0	13.2	45.5	10.9	12.6	16.0	367.5
NIPS	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
WEC	118.9	93.3	35.8	73.4	134.3	43.0	64.1	81.8	67.9	35.1	70.9	89.7	908.3
NYISO	2,229.3	2,235.0	1,901.6	1,089.0	871.7	1,093.4	1,308.6	1,499.8	1,423.8	1,032.7	1,001.1	996.2	16,682.1
HUDS	105.4	76.4	41.6	0.0	1.5	1.9	9.9	15.0	7.8	15.3	6.3	18.9	299.8
LIND	13.3	9.9	11.1	0.3	0.2	0.6	3.9	4.9	7.9	0.6	0.9	3.8	57.2
NEPT	329.9	317.8	441.5	294.6	170.0	307.1	434.5	433.7	441.0	409.5	415.3	371.8	4,366.6
NYIS	1,780.7	1,830.9	1,407.5	794.2	700.0	783.8	860.4	1,046.2	967.1	607.4	578.5	601.8	11,958.5
OVEC	26.9	24.7	21.4	14.9	16.4	0.0	2.8	0.0	0.0	0.0	0.0	0.0	107.1
TVA	9.8	30.0	7.4	0.0	9.9	34.1	11.4	4.8	0.5	1.4	3.3	0.2	112.9
Total without Up to Congestion	3,327.6	2,945.3	2,428.2	1,889.3	1,943.5	2,084.5	2,203.1	2,387.4	2,788.2	2,084.5	1,957.7	1,841.2	27,880.4
Up to Congestion	498.5	533.8	875.0	772.1	1,048.1	951.3	750.2	967.1	1,070.8	1,165.6	1,098.7	1,571.5	11,302.6
Total	3,826.1	3,479.1	3,303.2	2,661.4	2,991.6	3,035.8	2,953.2	3,354.5	3,859.1	3,250.0	3,056.3	3,412.7	39,183.1

Day-Ahead Interface Pricing Point Imports and Exports

Table 9-10 through Table 9-15 show the day-ahead scheduled interchange totals at the interface pricing points. In 2015, up to congestion transactions accounted for 51.5 percent of all scheduled import MW transactions, 28.8 percent of all scheduled export MW transactions and 605.9 percent of the net scheduled interchange volume in the Day-Ahead Energy Market. The day-ahead net scheduled interchange in 2015, including up to congestion transactions, is shown by interface pricing point in Table 9-10. Scheduled up to congestion transactions by interface pricing point in 2015 are shown in Table 9-11. Day-ahead gross scheduled imports and exports, including up to congestion transactions, are shown in Table 9-12 and Table 9-14, while gross scheduled import up to congestion transactions are show in Table 9-13 and gross scheduled export up to congestion transactions are shown in Table 9-15.

There is one interface pricing point eligible for day-ahead transaction scheduling only (NIPSCO). The NIPSCO interface pricing point was created when the individual balancing authorities that integrated to form MISO still 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, and is available for all market participants to use as the pricing point for day-ahead imports, exports and wheels, as well as a source or sink for up to congestion transactions. The NIPSCO interface pricing point remains for the purpose of facilitating the long term day-ahead positions created at the NIPSCO Interface prior to the integration on May 1, 2004. In 2015, the day-ahead net scheduled interchange at the NIPSCO interface pricing point was -1,470.5 GWh (Table 9-10) and the up to congestion net scheduled interchange at the NIPSCO interface pricing point was -1,470.5 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 pricing point with separate import and export prices (SouthIMP 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. The reserve sharing agreement allows for the transfer of energy during emergencies. Interchange transactions created as part of the reserve sharing agreement are currently settled at the Southeast interface price. 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, Southeast and Southwest 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 2015, there were net scheduled exports at 11 of PJM's 19 interface pricing points eligible for day-ahead transactions. The top three net exporting interface pricing points in the Day-Ahead Energy Market accounted for 67.5 percent of the total net scheduled exports: PJM/NEPTUNE with 25.2 percent, PJM/NYIS with 21.2 percent and PJM/Northwest with 21.2 percent of the net scheduled 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 47.7 percent of the total net PJM scheduled exports in the Day-Ahead Energy Market (the PJM/LINDENVFT Interface Pricing Point had net scheduled imports). Eight PJM interface pricing points had net scheduled imports, with three importing interface pricing points accounting for 84.6 percent of the total net scheduled imports: PJM/Ohio Valley Electric Corporation (OVEC) with 38.7 percent, PJM/SouthImp with 30.1 percent and PJM/Southeast with 15.7 percent of the net import volume. The four separate interface pricing points that connect PJM to the NYISO (PJM/NYIS, PJM/NEPTUNE, PJM/HUDSONTP and PJM/LINDENVFT) had net scheduled exports in the Day-Ahead Energy Market; however, the PJM/LINDENVFT Interface Pricing Point had net scheduled imports that represented 1.9 percent of the total PJM net scheduled imports in the Day-Ahead Energy Market.

In the Day-Ahead Energy Market, in 2015, up to congestion transactions had net scheduled exports at five 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 72.5 percent of the total net up to congestion scheduled exports: PJM/NIPSCO with 45.7 percent and PJM/SouthEXP with 26.8 percent of the net scheduled 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) had net scheduled import up to congestion transactions in the Day-Ahead Energy Market; however, the PJM/NEPTUNE Interface Pricing Point had net scheduled up to congestion exports that represented 7.9 percent of the total PJM net scheduled up to congestion exports in the Day-Ahead Energy Market. Eight PJM interface pricing points had net scheduled up to congestion imports, with three importing interface pricing points accounting for 65.2 percent of the total net up to congestion imports: PJM/Southeast with 24.3 percent, PJM/SouthIMP with 23.7 percent and PJM/MISO with 17.2 percent of the net import 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 5.7 percent of the total net scheduled up to congestion exports in the Day-Ahead Energy Market (the PJM/NEPTUNE Interface Pricing Point had net scheduled up to congestion exports).[25]

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 9-10 Day-ahead scheduled net interchange volume by interface pricing point (GWh): 2015

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
IMO	249.6	154.7	182.3	22.2	(57.3)	65.0	212.3	195.8	(91.7)	56.1	244.2	120.9	1,354.1
MISO	(364.2)	(0.2)	198.3	(83.2)	(321.4)	(264.5)	(173.8)	(148.9)	(596.3)	(438.7)	(303.5)	(86.5)	(2,583.0)
NIPSCO	(52.8)	(42.7)	(146.5)	(132.0)	(155.5)	(64.1)	(125.9)	(206.2)	(77.2)	(155.0)	(53.8)	(258.9)	(1,470.5)
NORTHWEST	(449.3)	(418.3)	(279.5)	(299.4)	(171.0)	(223.2)	(362.1)	(470.3)	(386.7)	(240.6)	(313.6)	(277.5)	(3,891.4)
NYISO	(1,494.9)	(1,528.5)	(1,398.2)	(366.2)	(134.3)	(330.6)	(527.4)	(750.5)	(711.6)	(365.8)	(367.2)	(416.7)	(8,392.0)
HUDS	(62.2)	(43.7)	(138.3)	(3.8)	30.9	(8.4)	(10.2)	(15.0)	1.5	0.1	27.9	(30.7)	(251.9)
LINDENVFT	17.5	44.6	27.7	8.3	0.9	2.2	(3.2)	13.8	45.3	87.9	32.2	95.2	372.6
NEPTUNE	(421.7)	(341.7)	(443.8)	(299.5)	(179.5)	(353.1)	(442.1)	(459.9)	(458.1)	(420.7)	(426.5)	(375.7)	(4,622.2)
NYIS	(1,028.5)	(1,187.8)	(843.9)	(71.2)	13.4	28.7	(72.0)	(289.4)	(300.4)	(33.1)	(0.8)	(105.5)	(3,890.5)
OVEC	1,113.6	653.6	715.3	525.2	501.0	688.2	580.5	663.3	762.0	634.1	440.4	451.3	7,728.6
Southern Imports	1,395.3	1,230.8	971.5	1,469.8	2,065.7	829.0	1,202.6	866.8	597.6	707.5	662.9	872.4	12,872.0
CPLEIMP	2.2	2.0	2.1	2.2	2.1	2.1	2.2	1.9	3.4	2.2	2.3	2.2	27.1
DUKIMP	2.4	0.4	2.7	4.9	1.1	3.0	19.7	6.9	0.3	7.1	0.2	82.2	130.9
NCMPAIMP	109.5	51.0	30.5	165.1	158.6	83.8	69.3	78.4	39.7	127.0	148.4	137.3	1,198.8
SOUTHEAST	360.0	150.0	183.5	184.8	664.9	270.1	437.2	400.3	199.8	130.7	130.7	131.2	3,243.2
SOUTHWEST	179.4	135.9	172.3	291.4	315.0	171.7	256.5	152.7	189.1	130.2	101.8	154.6	2,250.6
SOUTHIMP	741.7	891.5	580.4	821.4	923.9	298.3	417.6	226.5	165.3	310.4	279.5	364.9	6,021.4
Southern Exports	(173.3)	(172.1)	(132.0)	(177.5)	(294.2)	(439.6)	(234.3)	(308.1)	(382.2)	(527.0)	(573.3)	(601.2)	(4,014.8)
CPLEEXP	(15.1)	(14.6)	(18.0)	(19.3)	(9.5)	(29.3)	(36.4)	(37.4)	(41.7)	(22.7)	(30.6)	(23.7)	(298.3)
DUKEXP	(8.3)	(13.1)	(1.9)	0.0	0.0	(18.2)	0.0	0.0	0.0	0.0	0.0	0.0	(41.4)
NCMPAEXP	(0.8)	(1.4)	(0.9)	(1.1)	(0.5)	(0.4)	(0.5)	(0.4)	(0.4)	(1.3)	(1.6)	(1.3)	(10.5)
SOUTHEAST	(2.3)	(17.7)	(9.5)	(5.3)	(0.6)	(22.5)	(3.3)	(1.5)	(1.0)	(8.2)	(11.3)	(20.7)	(103.7)
SOUTHWEST	(98.5)	(57.1)	(44.2)	(127.2)	(208.0)	(236.4)	(134.4)	(217.6)	(274.7)	(342.8)	(370.0)	(435.8)	(2,546.7)
SOUTHEXP	(48.3)	(68.2)	(57.6)	(24.5)	(75.6)	(133.0)	(59.7)	(51.3)	(64.4)	(152.1)	(159.8)	(119.8)	(1,014.2)
Total	224.1	(122.7)	111.1	959.0	1,433.0	260.3	572.0	(158.1)	(886.1)	(329.4)	(264.0)	(196.2)	1,603.1

Table 9-11 Up to congestion scheduled net interchange volume by interface pricing point (GWh): 2015

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
IMO	113.6	93.9	1.4	(92.8)	(211.0)	(52.2)	9.2	(22.9)	(162.8)	(50.1)	80.0	(38.9)	(332.5)
MISO	164.3	126.4	247.7	211.4	225.0	152.8	176.0	206.1	265.0	97.7	147.1	203.4	2,222.9
NIPSCO	(52.8)	(42.7)	(146.5)	(132.0)	(155.5)	(64.1)	(125.9)	(206.2)	(77.2)	(155.0)	(53.8)	(258.9)	(1,470.5)
NORTHWEST	36.1	4.3	68.4	161.1	311.3	236.0	110.2	3.7	71.1	243.6	156.8	206.1	1,608.8
NYISO	56.5	22.6	(115.6)	15.4	92.4	20.5	30.2	(2.1)	147.6	81.1	76.3	51.3	476.2
HUDSONTP	43.2	32.7	(96.7)	(3.8)	32.4	(6.6)	(0.3)	(0.0)	9.3	15.3	34.2	(11.8)	48.0
LINDENVFT	30.7	53.0	38.4	7.8	(2.4)	(1.7)	(1.7)	15.7	50.7	43.1	5.3	97.0	335.9
NEPTUNE	(91.8)	(23.9)	(2.3)	(4.9)	(9.5)	(46.0)	(7.7)	(26.1)	(17.0)	(11.2)	(11.1)	(4.0)	(255.6)
NYIS	74.4	(39.1)	(54.9)	16.3	71.9	74.7	40.0	8.3	104.6	33.9	47.9	(30.0)	348.0
OVEC	468.3	138.2	136.3	84.9	86.5	186.4	106.8	102.8	209.4	204.3	201.5	233.1	2,158.4
Southern Imports	977.0	852.8	605.7	934.9	1,560.5	582.3	914.3	614.4	453.9	429.3	297.0	338.5	8,560.7
CPLEIMP	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
DUKIMP	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
NCMPAIMP	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
SOUTHEAST	360.0	150.0	183.5	184.8	664.9	270.1	437.2	400.3	199.8	130.7	130.7	131.2	3,243.2
SOUTHWEST	179.4	135.9	172.3	291.4	315.0	171.7	256.5	152.7	189.1	130.2	101.8	154.6	2,250.6
SOUTHIMP	437.6	566.9	249.9	458.7	580.6	140.5	220.6	61.4	65.0	168.5	64.5	52.7	3,066.9
Southern Exports	(130.0)	(111.9)	(103.9)	(157.0)	(272.7)	(350.3)	(171.5)	(259.6)	(339.5)	(501.1)	(537.8)	(576.0)	(3,511.2)
CPLEEXP	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
DUKEXP	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
NCMPAEXP	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
SOUTHEAST	(2.3)	(17.7)	(9.5)	(5.3)	(0.6)	(22.5)	(3.3)	(1.5)	(1.0)	(8.2)	(11.3)	(20.7)	(103.7)
SOUTHWEST	(98.5)	(57.1)	(44.2)	(127.2)	(208.0)	(236.4)	(134.4)	(217.6)	(274.7)	(342.8)	(370.0)	(435.8)	(2,546.7)
SOUTHEXP	(29.2)	(37.1)	(50.1)	(24.5)	(64.1)	(91.5)	(33.8)	(40.5)	(63.8)	(150.1)	(156.5)	(119.6)	(860.8)
Total Interfaces	1,633.0	1,083.6	693.6	1,025.9	1,636.5	711.4	1,049.5	436.3	567.5	349.8	367.1	158.5	9,712.8
INTERNAL	9,285.6	9,492.4	11,338.1	9,294.5	10,524.3	10,311.4	11,629.8	11,536.0	12,389.5	12,454.4	12,556.4	16,996.2	137,808.7
Total	10,918.6	10,575.9	12,031.7	10,320.5	12,160.8	11,022.9	12,679.3	11,972.3	12,957.0	12,804.2	12,923.4	17,154.7	147,521.5

Table 9-12 Day-ahead scheduled gross import volume by interface pricing point (GWh): 2015

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
IMO	254.0	170.6	240.5	156.0	202.8	159.2	244.5	251.0	108.0	139.8	286.2	213.0	2,425.6
MISO	196.0	221.4	364.0	258.4	295.5	249.0	242.0	275.8	331.7	208.3	231.1	365.6	3,238.9
NIPSCO	16.3	12.7	4.1	44.4	43.3	117.5	33.4	56.9	44.5	56.1	73.4	55.9	558.3
NORTHWEST	115.3	80.7	179.0	223.3	379.2	319.4	284.6	156.0	197.3	311.8	245.0	299.3	2,790.9
NYISO	900.8	873.1	833.4	851.1	810.0	865.1	862.4	850.6	830.2	769.0	732.4	793.2	9,971.3
HUDS	70.9	61.4	29.2	59.6	49.5	16.2	21.3	33.7	43.7	41.1	59.4	46.2	532.1
LINDENVFT	32.4	58.4	59.4	23.3	15.5	20.2	15.5	22.6	67.0	112.6	40.9	136.8	604.5
NEPTUNE	14.1	24.1	33.1	7.6	0.8	6.6	21.2	20.3	39.0	20.5	16.1	34.4	237.6
NYIS	783.4	729.3	711.7	760.6	744.2	822.2	804.4	774.1	680.4	594.9	616.0	575.8	8,597.0
OVEC	1,172.5	767.0	821.7	617.4	628.1	757.0	655.7	739.2	863.7	728.2	561.5	617.1	8,929.1
Southern Imports	1,395.3	1,230.8	971.5	1,469.8	2,065.7	829.0	1,202.6	866.8	597.6	707.5	662.9	872.4	12,872.0
CPLEIMP	2.2	2.0	2.1	2.2	2.1	2.1	2.2	1.9	3.4	2.2	2.3	2.2	27.1
DUKIMP	2.4	0.4	2.7	4.9	1.1	3.0	19.7	6.9	0.3	7.1	0.2	82.2	130.9
NCMPAIMP	109.5	51.0	30.5	165.1	158.6	83.8	69.3	78.4	39.7	127.0	148.4	137.3	1,198.8
SOUTHEAST	360.0	150.0	183.5	184.8	664.9	270.1	437.2	400.3	199.8	130.7	130.7	131.2	3,243.2
SOUTHWEST	179.4	135.9	172.3	291.4	315.0	171.7	256.5	152.7	189.1	130.2	101.8	154.6	2,250.6
SOUTHIMP	741.7	891.5	580.4	821.4	923.9	298.3	417.6	226.5	165.3	310.4	279.5	364.9	6,021.4
Southern Exports	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
CPLEEXP	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
DUKEXP	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
NCMPAEXP	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
SOUTHEAST	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
SOUTHWEST	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
SOUTHEXP	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
Total	4,050.2	3,356.4	3,414.3	3,620.4	4,424.6	3,296.2	3,525.2	3,196.3	2,973.0	2,920.7	2,792.4	3,216.5	40,786.2

Table 9-13 Up to congestion scheduled gross import volume by interface pricing point (GWh): 2015

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
IMO	117.7	105.3	57.8	40.9	49.1	42.0	41.5	32.4	36.9	33.6	122.0	53.1	732.4
MISO	181.7	145.2	284.3	248.6	290.3	223.7	235.3	265.8	328.3	202.6	230.7	319.4	2,956.0
NIPSCO	16.3	12.7	4.1	44.4	43.3	117.5	33.4	56.9	44.5	56.1	73.4	55.9	558.3
NORTHWEST	115.3	80.7	179.0	223.3	379.2	319.4	284.6	156.0	197.3	311.8	245.0	299.3	2,790.9
NYISO	223.3	193.8	216.3	143.7	165.0	122.8	111.5	99.1	266.3	183.6	175.1	264.9	2,165.4
HUDSONTP	70.9	61.4	29.2	59.6	49.5	16.2	21.3	33.7	43.7	41.1	59.4	46.2	532.1
LINDENVFT	32.2	56.8	59.1	22.5	12.0	15.6	13.1	19.6	64.6	67.2	13.1	134.8	510.7
NEPTUNE	14.1	24.1	33.1	7.6	0.8	6.6	21.2	20.3	39.0	20.5	16.1	34.4	237.6
NYIS	106.0	51.5	94.9	54.0	102.7	84.4	55.8	25.5	119.1	54.9	86.5	49.5	885.0
OVEC	500.2	226.8	221.3	162.2	197.3	255.1	179.2	178.7	311.1	298.4	322.6	398.9	3,251.8
Southern Imports	977.0	852.8	605.7	934.9	1,560.5	582.3	914.3	614.4	453.9	429.3	297.0	338.5	8,560.7
CPLEIMP	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
DUKIMP	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
NCMPAIMP	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
SOUTHEAST	360.0	150.0	183.5	184.8	664.9	270.1	437.2	400.3	199.8	130.7	130.7	131.2	3,243.2
SOUTHWEST	179.4	135.9	172.3	291.4	315.0	171.7	256.5	152.7	189.1	130.2	101.8	154.6	2,250.6
SOUTHIMP	437.6	566.9	249.9	458.7	580.6	140.5	220.6	61.4	65.0	168.5	64.5	52.7	3,066.9
Southern Exports	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
CPLEEXP	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
DUKEXP	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
NCMPAEXP	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
SOUTHEAST	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
SOUTHWEST	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
SOUTHEXP	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
Total Interfaces	2,131.5	1,617.4	1,568.5	1,798.0	2,684.6	1,662.8	1,799.7	1,403.4	1,638.3	1,515.4	1,465.7	1,730.0	21,015.4

Table 9-14 Day-ahead scheduled gross export volume by interface pricing point (GWh): 2015

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
IMO	4.4	15.9	58.2	133.7	260.1	94.2	32.2	55.3	199.7	83.7	42.0	92.0	1,071.5
MISO	560.2	221.6	165.8	341.6	617.0	513.5	415.7	424.8	928.0	647.0	534.6	452.2	5,821.9
NIPSCO	69.0	55.3	150.6	176.4	198.8	181.6	159.3	263.1	121.7	211.1	127.1	314.8	2,028.9
NORTHWEST	564.6	499.0	458.5	522.7	550.2	542.7	646.6	626.2	584.0	552.4	558.6	576.8	6,682.3
NYISO	2,395.7	2,401.7	2,231.6	1,217.3	944.3	1,195.7	1,389.8	1,601.1	1,541.8	1,134.8	1,099.6	1,209.9	18,363.3
HUDSONTP	133.1	105.1	167.5	63.3	18.5	24.6	31.5	48.7	42.2	41.0	31.5	76.9	784.0
LINDENVFT	14.8	13.8	31.7	15.0	14.6	17.9	18.7	8.8	21.7	24.7	8.7	41.6	232.0
NEPTUNE	435.8	365.7	476.9	307.1	180.3	359.7	463.3	480.1	497.0	441.2	442.5	410.1	4,859.8
NYIS	1,811.9	1,917.0	1,555.5	831.8	730.9	793.5	876.3	1,063.5	980.9	628.0	616.9	681.3	12,487.5
OVEC	58.9	113.4	106.4	92.2	127.1	68.7	75.2	75.9	101.7	94.0	121.1	165.8	1,200.5
Southern Imports	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
CPLEIMP	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
DUKIMP	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
NCMPAIMP	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
SOUTHEAST	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
SOUTHWEST	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
SOUTHIMP	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
Southern Exports	173.3	172.1	132.0	177.5	294.2	439.6	234.3	308.1	382.2	527.0	573.3	601.2	4,014.8
CPLEEXP	15.1	14.6	18.0	19.3	9.5	29.3	36.4	37.4	41.7	22.7	30.6	23.7	298.3
DUKEXP	8.3	13.1	1.9	0.0	0.0	18.2	0.0	0.0	0.0	0.0	0.0	0.0	41.4
NCMPAEXP	0.8	1.4	0.9	1.1	0.5	0.4	0.5	0.4	0.4	1.3	1.6	1.3	10.5
SOUTHEAST	2.3	17.7	9.5	5.3	0.6	22.5	3.3	1.5	1.0	8.2	11.3	20.7	103.7
SOUTHWEST	98.5	57.1	44.2	127.2	208.0	236.4	134.4	217.6	274.7	342.8	370.0	435.8	2,546.7
SOUTHEXP	48.3	68.2	57.6	24.5	75.6	133.0	59.7	51.3	64.4	152.1	159.8	119.8	1,014.2
Total	3,826.1	3,479.1	3,303.2	2,661.4	2,991.6	3,035.8	2,953.2	3,354.5	3,859.1	3,250.0	3,056.3	3,412.7	39,183.1

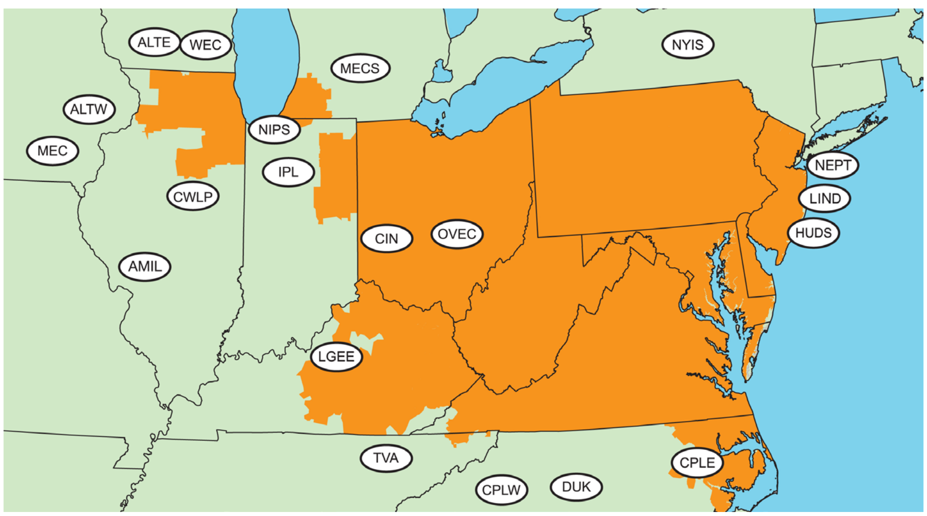
Table 9-15 Up to congestion scheduled gross export volume by interface pricing point (GWh): 2015

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
IMO	4.1	11.5	56.4	133.7	260.1	94.2	32.2	55.3	199.7	83.7	42.0	92.0	1,064.9
MISO	17.4	18.8	36.7	37.2	65.3	70.8	59.2	59.8	63.3	104.9	83.6	116.0	733.0
NIPSCO	69.0	55.3	150.6	176.4	198.8	181.6	159.3	263.1	121.7	211.1	127.1	314.8	2,028.9
NORTHWEST	79.2	76.4	110.5	62.2	68.0	83.4	174.3	152.2	126.2	68.3	88.1	93.2	1,182.1
NYISO	166.8	171.2	331.8	128.3	72.6	102.3	81.2	101.3	118.7	102.5	98.9	213.6	1,689.1
HUDSONTP	27.7	28.7	125.9	63.3	17.0	22.7	21.7	33.7	34.4	25.7	25.2	58.0	484.2
LINDENVFT	1.5	3.9	20.6	14.7	14.4	17.3	14.8	3.9	13.9	24.1	7.8	37.8	174.8
NEPTUNE	105.9	48.0	35.4	12.6	10.4	52.6	28.9	46.4	56.0	31.6	27.2	38.3	493.2
NYIS	31.6	90.6	149.9	37.7	30.8	9.7	15.9	17.3	14.4	21.0	38.7	79.5	537.0
OVEC	32.0	88.7	85.0	77.3	110.7	68.7	72.3	75.9	101.7	94.0	121.1	165.8	1,093.4
Southern Imports	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
CPLEIMP	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
DUKIMP	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
NCMPAIMP	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
SOUTHEAST	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
SOUTHWEST	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
SOUTHIMP	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
Southern Exports	130.0	111.9	103.9	157.0	272.7	350.3	171.5	259.6	339.5	501.1	537.8	576.0	3,511.2
CPLEEXP	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
DUKEXP	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
NCMPAEXP	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
SOUTHEAST	2.3	17.7	9.5	5.3	0.6	22.5	3.3	1.5	1.0	8.2	11.3	20.7	103.7
SOUTHWEST	98.5	57.1	44.2	127.2	208.0	236.4	134.4	217.6	274.7	342.8	370.0	435.8	2,546.7
SOUTHEXP	29.2	37.1	50.1	24.5	64.1	91.5	33.8	40.5	63.8	150.1	156.5	119.6	860.8
Total Interfaces	498.5	533.8	875.0	772.1	1,048.1	951.3	750.2	967.1	1,070.8	1,165.6	1,098.7	1,571.5	11,302.6

Table 9-16 Active real-time and day-ahead scheduling interfaces: 2015[26]

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
ALTE	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
ALTW	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
AMIL	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
CIN	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
CPLE	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
CPLW	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
CWLP	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
DUK	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
HUDS	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
IPL	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
LGEE	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
LIND	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
MEC	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
MECS	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
NEPT	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
NIPS	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
NYIS	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
OVEC	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
TVA	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
WEC	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active

Figure 9-3 PJM's footprint and its external day-ahead and real-time scheduling interfaces



26 On July 2, 2012, Duke Energy Corp. (DUK) completed a merger with Progress Energy Inc. (CPLE and CPLW). As of December 31, 2015, DUK, CPLE and CPLW continued to operate as separate balancing authorities, and are still defined as distinct interfaces in the PJM energy market.

Table 9-17 Active day-ahead and real-time scheduled interface pricing points: 2015[27]

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
CPLEEXP	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
CPLEIMP	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
DUKEXP	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
DUKIMP	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
HUDSONTP	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
LINDENVFT	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
MISO	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
NCMPAEXP	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
NCMPAIMP	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
NEPTUNE	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
NIPSCO	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
Northwest	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
NYIS	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
Ontario IESO	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
OVEC	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
Southeast	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
SOUTHEXP	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
SOUTHIMP	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
Southwest	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active

Loop Flows

Actual energy flows are the real-time metered power flows at an interface for a defined period. The comparable scheduled flows are the real-time power flows scheduled at an interface for a defined period. Inadvertent interchange is the difference between the total actual flows for the PJM system (net actual interchange) and the total scheduled flows for the PJM system (net scheduled interchange) for a defined period. Loop flows are the difference between actual and scheduled power flows at a specific interface. 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.[28]

Loop flows result, in part, from a mismatch between incentives to use a particular scheduled transmission path and the market based price differentials at interface pricing points 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. Correspondingly, 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 2015, there were net scheduled

27 Note that the NIPSCO interface pricing point is valid only in the Day-Ahead Energy Market.

28 See the *2012 State of the Market Report for PJM*, Volume II, Section 8, "Interchange Transactions," for a more detailed discussion.

flows of 9,506 GWh through MISO that received an interface pricing point associated with the southern interface but there were no net scheduled flows across the southern interface that received the MISO interface pricing point.

In 2015, net scheduled interchange was 15,717 GWh and net actual interchange was 15,368 GWh, a difference of 349 GWh. In 2014, net scheduled interchange was 1,138 GWh and net actual interchange was 1,220 GWh, a difference of 82 GWh. This difference is inadvertent interchange. PJM attempts to minimize the amount of accumulated inadvertent interchange by continually monitoring and correcting for inadvertent interchange. PJM can reduce the accumulation of inadvertent interchange using unilateral or bilateral paybacks.[29]

Table 9-18 shows that in 2015, the Wisconsin Energy Corporation (WEC) interface had the largest loop flows of any interface with -846 GWh of net scheduled interchange and 9,985 GWh of net actual interchange, a difference of 10,831 GWh.

Table 9-18 Net scheduled and actual PJM flows by interface (GWh): 2015

	Actual	Net Scheduled	Difference (GWh)
CPLE	7,674	(133)	7,807
CPLW	(1,340)	0	(1,340)
DUK	1,152	4,146	(2,994)
LGEE	2,930	2,324	606
MISO	(6,298)	4,367	(10,665)
ALTE	(6,123)	(2,216)	(3,908)
ALTW	(2,082)	26	(2,108)
AMIL	9,509	7,155	2,355
CIN	(7,103)	1,627	(8,729)
CWLP	(554)	0	(554)
IPL	(662)	1,035	(1,696)
MEC	(3,141)	(6,030)	2,888
MECS	1,736	3,492	(1,756)
NIPS	(7,864)	125	(7,989)
WEC	9,985	(846)	10,831
NYISO	(7,660)	(7,807)	147
HUDS	(505)	(505)	0
LIND	(614)	(614)	0
NEPT	(4,338)	(4,338)	0
NYIS	(2,204)	(2,351)	147
OVEC	10,158	7,554	2,604
TVA	8,752	5,265	3,486
Total	15,368	15,717	(349)

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 MWh of scheduled transactions that will receive the interface pricing point based on the external balancing authority mapping.[30] For example, the MWh for a transaction whose transmission path is SPP through MISO and into PJM would be reflected in the SouthIMP interface pricing point net schedule totals because SPP is mapped to the SouthIMP interface pricing point. 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 MWh mapped to a specific interface pricing point and actual power flows at the interface pricing points provide a better measure of loop flows than differences at the interfaces. The scheduled transactions are mapped to interface pricing points based on the expected flow from the generation balancing authority and load balancing authority, whereas scheduled transactions are assigned to interfaces based solely on the OASIS path that the market participants reflect the transmission path 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 reflect the same physical ties as 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. In the case of PJM's southern border, loop

29 See PJM. "Manual 12: Balancing Operations," Revision 33 (December 1, 2015).

30 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)

flows can be analyzed by comparing the net scheduled and net actual flows as a sum of the pricing points, rather than the individual pricing points. To accurately calculate the loop flows from 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 (30,128 GWh) and the total southern export actual flows (10,960 GWh) for 19,168 GWh of net imports. The net scheduled flows from the southern region are determined by summing the total southern import scheduled flows (22,796 GWh) and the total southern export scheduled flows (1,687 GWh) for 21,109 GWh of net imports. In 2015, the loop flows at the southern region were the difference between the southern region import scheduled flows (22,796 GW) and the southern region import actual flows (19,168 GWh) for a total of 1,940 GWh of loop flows.

The IMO interface pricing point with the Ontario IESO was created to reflect the fact that transactions that originate or sink in the Ontario Independent Electricity System Operator (IMO) balancing authority create physical flows that are split between the MISO and NYISO interface pricing points depending on transmission system conditions, 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): 2015

	Actual	Net Scheduled	Difference (GWh)
IMO	0	6,085	(6,085)
MISO	(6,298)	(11,229)	4,931
NORTHWEST	0	(23)	23
NYISO	(7,660)	(7,779)	119
HUDSONTP	(505)	(505)	0
LINDENVFT	(614)	(614)	0
NEPTUNE	(4,338)	(4,338)	0
NYIS	(2,204)	(2,323)	119
OVEC	10,158	7,554	2,604
Southern Imports	30,128	22,796	7,333
CPLEIMP	0	105	(105)
DUKIMP	0	774	(774)
NCMPAIMP	0	1,093	(1,093)
SOUTHEAST	0	0	0
SOUTHWEST	0	0	0
SOUTHIMP	30,128	20,823	9,305
Southern Exports	(10,960)	(1,687)	(9,273)
CPLEEXP	0	(386)	386
DUKEXP	0	(578)	578
NCMPAEXP	0	(5)	5
SOUTHEAST	0	0	0
SOUTHWEST	0	0	0
SOUTHEXP	(10,960)	(718)	(10,242)
Total	15,368	15,717	(349)

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 IMO entered the PJM energy market. For example, Table 9-22 shows that the 6,085 GW of gross scheduled transactions that were mapped to the IMO Interface Pricing Point, were comprised of 28 GWh of exports through the NYISO and 6,113 GWh of imports through MISO.

Table 9-20 shows that in 2015, the SouthEXP interface pricing point had the largest loop flows of any interface pricing point with -718 GWh of net scheduled interchange and -10,960 GWh of net actual interchange, a difference of 10,242 GWh.

Table 9-20 Net scheduled and actual PJM flows by interface pricing point (GWh) (Adjusted for IMO Scheduled Interfaces): 2015

	Actual	Net Scheduled	Difference (GWh)
MISO	(6,298)	(5,116)	(1,183)
NORTHWEST	0	(23)	23
NYISO	(7,660)	(7,807)	147
HUDSONTP	(505)	(505)	0
LINDENVFT	(614)	(614)	0
NEPTUNE	(4,338)	(4,338)	0
NYIS	(2,204)	(2,351)	147
OVEC	10,158	7,554	2,604
Southern Imports	30,128	22,796	7,333
CPLEIMP	0	105	(105)
DUKIMP	0	774	(774)
NCMPAIMP	0	1,093	(1,093)
SOUTHEAST	0	0	0
SOUTHWEST	0	0	0
SOUTHIMP	30,128	20,823	9,305
Southern Exports	(10,960)	(1,687)	(9,273)
CPLEEXP	0	(386)	386
DUKEXP	0	(578)	578
NCMPAEXP	0	(5)	5
SOUTHEAST	0	0	0
SOUTHWEST	0	0	0
SOUTHEXP	(10,960)	(718)	(10,242)
Total	15,368	15,717	(349)

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 Tag. 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 the 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 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 (1,825 GWh). 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 (721 GWh).

Table 9-21 Net scheduled and actual PJM flows by interface and interface pricing point (GWh): 2015

Interface	Interface Pricing Point	Actual	Net Scheduled	Difference (GWh)	Interface	Interface Pricing Point	Actual	Net Scheduled	Difference (GWh)
ALTE		(6,123)	(2,216)	(3,908)	IPL		(662)	1,035	(1,696)
	IMO	0	1	(1)		IMO	0	1,617	(1,617)
	MISO	(6,123)	(3,533)	(2,591)		MISO	(662)	(685)	23
	SOUTHIMP	0	1,316	(1,316)		SOUTHEXP	0	(1)	1
ALTW		(2,082)	26	(2,108)		SOUTHIMP	0	103	(103)
	MISO	(2,082)	24	(2,105)	LGEE		2,930	2,324	606
	SOUTHIMP	0	2	(2)		SOUTHEXP	(6,221)	(21)	(6,200)
AMIL		9,509	7,155	2,355		SOUTHIMP	9,151	2,345	6,805
	IMO	0	2	(2)	LIND		(614)	(614)	0
	MISO	9,509	1,074	8,435		LINDENVFT	(614)	(614)	0
	SOUTHIMP	0	6,078	(6,078)	MEC		(3,141)	(6,030)	2,888
CIN		(7,103)	1,627	(8,729)		IMO	0	0	(0)
	IMO	0	1,825	(1,825)		MISO	(3,141)	(6,031)	2,890
	MISO	(7,103)	(721)	(6,382)		SOUTHIMP	0	1	(1)
	NORTHWEST	0	(23)	23	MECS		1,736	3,492	(1,756)
	SOUTHEXP	0	(6)	6		IMO	0	2,668	(2,668)
	SOUTHIMP	0	551	(551)		MISO	1,736	(584)	2,320
CPLE		7,674	(133)	7,807		SOUTHEXP	0	(1)	1
	CPLEEXP	0	(386)	386		SOUTHIMP	0	1,410	(1,410)
	CPLEIMP	0	105	(105)	NEPT		(4,338)	(4,338)	0
	DUKIMP	0	120	(120)		NEPTUNE	(4,338)	(4,338)	0
	NCMPAIMP	0	38	(38)	NIPS		(7,864)	125	(7,989)
	SOUTHEXP	(1,179)	(32)	(1,147)		IMO	0	0	(0)
	SOUTHIMP	8,854	23	8,831		MISO	(7,864)	119	(7,982)
CPLW		(1,340)	0	(1,340)		SOUTHIMP	0	6	(6)
	SOUTHEXP	(1,428)	0	(1,428)	NYIS		(2,204)	(2,351)	147
	SOUTHIMP	88	0	88		IMO	0	(28)	28
CWLP		(554)	0	(554)		NORTHWEST	0	0	(0)
	MISO	(554)	0	(554)		NYIS	(2,204)	(2,323)	119
DUK		1,152	4,146	(2,994)	OVEC		10,158	7,554	2,604
	DUKEXP	0	(578)	578		OVEC	10,158	7,554	2,604
	DUKIMP	0	651	(651)	TVA		8,752	5,265	3,486
	NCMPAEXP	0	(5)	5		DUKIMP	0	3	(3)
	NCMPAIMP	0	1,055	(1,055)		SOUTHEXP	(1,568)	(223)	(1,345)
	SOUTHEXP	(564)	(433)	(131)		SOUTHIMP	10,320	5,486	4,834
	SOUTHIMP	1,716	3,455	(1,739)	WEC		9,985	(846)	10,831
HUDS		(505)	(505)	0		MISO	9,985	(892)	10,876
	HUDSONTP	(505)	(505)	0		SOUTHIMP	0	45	(45)
					Grand Total		15,368	15,717	(349)

Table 9-22 shows the net scheduled and actual PJM flows by interface pricing point and interface. The grouping is reversed from Table 9-21. Table 9-22 shows the interfaces where transactions were scheduled which received the individual interface pricing points. For example, Table 9-22 shows that in 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 a market path that entered the PJM energy market at the MECS Interface (2,668 GWh). 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 a market path that exited the PJM energy market at the NYIS Interface (28 GWh).

Table 9-22 Net scheduled and actual PJM flows by interface pricing point and interface (GWh): 2015

Interface Pricing Point	Interface	Actual	Net Scheduled	Difference (GWh)	Interface Pricing Point	Interface	Actual	Net Scheduled	Difference (GWh)
CPLEEXP		0	(386)	386	NCMPAIMP		0	1,093	(1,093)
	CPLE	0	(386)	386		CPLE	0	38	(38)
CPLEIMP		0	105	(105)		DUK	0	1,055	(1,055)
	CPLE	0	105	(105)	NEPTUNE		(4,338)	(4,338)	0
DUKEXP		0	(578)	578		NEPT	(4,338)	(4,338)	0
	DUK	0	(578)	578	NORTHWEST		0	(23)	23
DUKIMP		0	774	(774)		CIN	0	(23)	23
	CPLE	0	120	(120)		NYIS	0	0	(0)
	DUK	0	651	(651)	NYIS		(2,204)	(2,323)	119
	TVA	0	3	(3)		NYIS	(2,204)	(2,323)	119
HUDSONTP		(505)	(505)	0	OVEC		10,158	7,554	2,604
	HUDS	(505)	(505)	0		OVEC	10,158	7,554	2,604
IMO		0	6,085	(6,085)	SOUTHEXP		(10,960)	(718)	(10,242)
	ALTE	0	1	(1)		CIN	0	(6)	6
	AMIL	0	2	(2)		CPLE	(1,179)	(32)	(1,147)
	CIN	0	1,825	(1,825)		CPLW	(1,428)	0	(1,428)
	IPL	0	1,617	(1,617)		DUK	(564)	(433)	(131)
	MEC	0	0	(0)		IPL	0	(1)	1
	MECS	0	2,668	(2,668)		LGEE	(6,221)	(21)	(6,200)
	NIPS	0	0	(0)		MECS	0	(1)	1
	NYIS	0	(28)	28		TVA	(1,568)	(223)	(1,345)
LINDENVFT		(614)	(614)	0	SOUTHIMP		30,128	20,823	9,305
	LIND	(614)	(614)	0		ALTE	0	1,316	(1,316)
MISO		(6,298)	(11,229)	4,931		ALTW	0	2	(2)
	ALTE	(6,123)	(3,533)	(2,591)		AMIL	0	6,078	(6,078)
	ALTW	(2,082)	24	(2,105)		CIN	0	551	(551)
	AMIL	9,509	1,074	8,435		CPLE	8,854	23	8,831
	CIN	(7,103)	(721)	(6,382)		CPLW	88	0	88
	CWLP	(554)	0	(554)		DUK	1,716	3,455	(1,739)
	IPL	(662)	(685)	23		IPL	0	103	(103)
	MEC	(3,141)	(6,031)	2,890		LGEE	9,151	2,345	6,805
	MECS	1,736	(584)	2,320		MEC	0	1	(1)
	NIPS	(7,864)	119	(7,982)		MECS	0	1,410	(1,410)
	WEC	9,985	(892)	10,876		NIPS	0	6	(6)
NCMPAEXP		0	(5)	5		TVA	10,320	5,486	4,834
	DUK	0	(5)	5		WEC	0	45	(45)
					Grand Total		15,368	15,717	(349)

Data Required for Full Loop Flow Analysis

Loop flows are defined as the difference between actual and scheduled power flows at one or more specific interfaces. The differences between actual and scheduled power flows can be the result of a number of underlying causes. To adequately investigate the causes of loop flows, complete data are required.

Loop flows exist because electricity flows on the path of least resistance regardless of the path specified by contractual agreement or regulatory prescription. Loop flows can arise from transactions scheduled into, out of or around a balancing authority on contract paths that do not correspond to the actual physical paths on which energy flows. Outside of LMP-based energy markets, energy is scheduled and paid for based on contract path, without regard to the path of the actual energy flows. Loop flows can also result from actions within balancing authorities.

Loop flows are a significant concern. 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. Loop flows also have poorly understood impacts on non market areas. In general, the detailed sources of the identified differences between scheduled and actual flows remain unclear as a result of incomplete or inadequate access to the required data.

A complete analysis of loop flow could provide additional insight that could lead to enhanced overall market efficiency and clarify the interactions among market and non market areas. A complete analysis of loop flow would improve the overall transparency of electricity transactions. There are areas with transparent markets, and there are areas with less transparent markets (non market areas), but these areas together comprise a market, and overall market efficiency would benefit from the increased transparency that would derive from a better understanding of loop flows.

For a complete loop flow analysis, several types of data are required from all balancing authorities in the Eastern Interconnection. The Commission recently required access to NERC Tag data. In addition to the Tag data, actual tie line data, dynamic schedule and pseudo-tie data are required in order to analyze the differences between actual and scheduled transactions. ACE data, market flow impact data and generation and load data are required in order to understand the sources, within each balancing authority, of loop flows that do not result from differences between actual and scheduled transactions.[31]

NERC Tag Data

An analysis of loop flow requires knowledge of the scheduled path of energy transactions. NERC Tag data includes the scheduled path and energy profile of the transactions, including the Generation Control Area (GCA), the intermediate Control Areas, the Load Control Area (LCA) and the energy profile of all transactions. Additionally, complete tag data include the identity of the specific market participants. FERC Order No. 771 required access to NERC Tag data for the Commission, regional transmission organizations, independent system operators and market monitoring units.[32]

Actual Tie Line Flow Data

An analysis of loop flow requires knowledge of the actual path of energy transactions. Currently, a very limited set of tie line data is made available via the NERC IDC and the Central Repository for Curtailments (CRC) website. Additionally, the available tie line data, and the data within the IDC, are presented as information on a screen, which does not permit analysis of the underlying data.

Dynamic Schedule and Pseudo-Tie Data

Dynamic schedule and pseudo ties represent another type of interchange transaction between balancing authorities. While dynamic schedules are required to be tagged, the tagged profile is only an estimate of what energy is expected to flow. Dynamic schedules are implemented within each balancing authority's Energy Management System (EMS), with the current values shared over Inter-Control Center Protocol (ICCP) links. By definition, the dynamic schedule scheduled and actual values will always be identical from a balancing authority standpoint, and the tagged profile should be removed from the calculation of loop flows to eliminate double counting of the energy profile. Dynamic schedule data from all balancing authorities are required in order to account for all scheduled and actual flows.

Pseudo-ties are similar to dynamic schedules in that they represent a transaction between balancing authorities and are handled within the EMS systems and data are shared over the ICCP. Pseudo-ties only differ from dynamic schedules in how the generating resource is modeled within the balancing authorities' ACE equations. Dynamic schedules are modeled as resources located in one area serving load in another, while pseudo-ties are modeled as resources in one area moved to another area. Unlike dynamic schedules, pseudo-tie transactions are not required to be tagged. Pseudo-tie data from all balancing authorities are required in order to account for all scheduled and actual flows.

Area Control Error (ACE) Data

Area Control Error (ACE) data provides information about how well each balancing authority is matching their generation with their load. This information, combined with the scheduled and actual interchange values will show whether an individual balancing authority is pushing on or leaning on the interconnection, contributing to loop flows.

NERC makes real-time ACE graphs available on their Reliability Coordinator Information System (RCIS) website. This information is presented only in graphical form, and the underlying data is not available for analysis.

31 It is requested that all data be made available in downloadable format in order to make analysis possible. A data viewing tool alone is not adequate.

32 141 FERC ¶ 61,235 (2012). *Availability of E-Tag Information to Commission Staff.*

Market Flow Impact Data

In addition to interchange transactions, internal dispatch can also affect flows on balancing authorities' tie lines. The impact of internal dispatch on tie lines is called market flow. Market flow data are imported in the IDC, but there is only limited historical data, as only market flow data related to TLR levels 3 or higher are required to be made available via a Congestion Management Report (CMR). The remaining data are deleted.

There is currently a project in development through the NERC Operating Reliability Subcommittee (ORS) called the Market Flow Impact Tool. The purpose of this tool is to make visible the impacts of dispatch on loop flows. The MMU supports the development of this tool, and requests that FERC and NERC ensure that the underlying data are provided to market monitors and other approved entities.

Generation and Load Data

Generation data (both real-time scheduled generation and actual output) and load data would permit analysis of the extent to which balancing authorities are meeting their commitments to serve load. If a balancing authority is not meeting its load commitment with adequate generation, the result is unscheduled flows across the interconnections to establish power balance.

Market areas are transparent in providing real-time load while non market areas are not. For example, PJM posts real-time load via its eDATA application. Most non market balancing authorities provide only the expected peak load on their individual web sites. Data on generation are not made publicly available, as this is considered market sensitive information.

The MMU requests, that in order to permit a complete analysis of loop flow, FERC and NERC ensure that the identified data are made available to market monitors as well as other industry entities determined appropriate by FERC.

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 buses that make up PJM's MISO interface pricing point, as well as for all buses in the PJM model, 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. MISO's LMP calculations at the 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.

The appropriate definition of interface prices is an ongoing topic of conversation at the PJM/MISO Joint and Common Market Meetings. 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.[33,34]

33 See "LMP Aggregate Definitions," (December 8, 2015) <http://www.pjm.com/~/media/markets-ops/energy/lmp-model-info/lmp-aggregate-definitions.ashx>. PJM periodically updates these definitions on its web site. See <http://www.pjm.com>.

34 Based on information obtained from MISO's extranet <http://extranet.midwestiso.org> (Accessed January 28, 2016).

PJM modified the definition of the PJM/MISO interface price 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.

Real-Time and Day-Ahead PJM/MISO Interface Prices

In 2015, the direction of flow was consistent with price differentials in 55.4 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.

Figure 9-4 Real-time and day-ahead daily hourly average price difference (MISO/PJM Interface minus PJM/MISO Interface): 2015

Table 9-23 PJM and MISO flow based hours and average hourly price differences: 2015

LMP Difference	Flow Direction	Number of Hours	Average Hourly Price Difference
MISO/PJM LMP > PJM/MISO LMP	Any Flow	4,728	$5.98
	Consistent Flow (PJM to MISO)	3,399	$4.74
	Inconsistent Flow (MISO to PJM)	1,329	$9.16
	No Flow	1	$15.97
PJM/MISO LMP > MISO/PJM LMP	Any Flow	4,032	$8.74
	Consistent Flow (MISO to PJM)	1,454	$13.97
	Inconsistent Flow (PJM to MISO)	2,578	$5.78
	No Flow	1	$19.56

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).

Distribution and Prices of Hourly Flows at the PJM/MISO Interface

In 2015, the direction of hourly energy flows was consistent with PJM and MISO interface price differentials in 4,853 hours (55.4 percent of all hours), and was inconsistent with price differentials in 3,907 hours (44.6 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 3,907 hours where flows were in a direction inconsistent with price differences, 2,939 of those hours (75.2 percent) had a price difference greater than or equal to $1.00 and 1,152 of those hours (29.5 percent) had a price difference greater than or equal to $5.00. The largest price difference with such flows was $297.23. Of the 4,853 hours where flows were consistent with price differences, 3,860 of those hours (79.5 percent) had a price difference greater than or equal to $1.00 and 1,611 of all such hours (33.2 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: 2015

Price Difference Range (Greater Than or Equal To)	Inconsistent Hours	Percent of Total Hours	Consistent Hours	Percent of Total Hours
$0.00	3,907	100.0%	4,853	100.0%
$1.00	2,939	75.2%	3,860	79.5%
$5.00	1,152	29.5%	1,611	33.2%
$10.00	610	15.6%	794	16.4%
$15.00	414	10.6%	522	10.8%
$20.00	295	7.6%	380	7.8%
$25.00	221	5.7%	290	6.0%
$50.00	80	2.0%	111	2.3%
$75.00	37	0.9%	62	1.3%
$100.00	16	0.4%	38	0.8%
$200.00	6	0.2%	7	0.1%
$300.00	0	0.0%	0	0.0%
$400.00	0	0.0%	0	0.0%
$500.00	0	0.0%	0	0.0%

PJM and NYISO Interface Prices

If interface prices were defined in a comparable manner by PJM and the NYISO, if identical rules governed external transactions in PJM and the NYISO, if time lags were not built into the rules governing such transactions and if no risks were associated with such transactions, then prices at the interfaces would be expected to be very close and the level of transactions would be expected to be related to any price differentials. The fact that none of these conditions exists is important in explaining the observed relationship between interface prices and inter-RTO/ISO power flows, and those price differentials.[35]

Real-Time and Day-Ahead PJM/NYISO Interface Prices

In 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. The direction of flow was consistent with price differentials in 58.2 percent of the hours in 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.

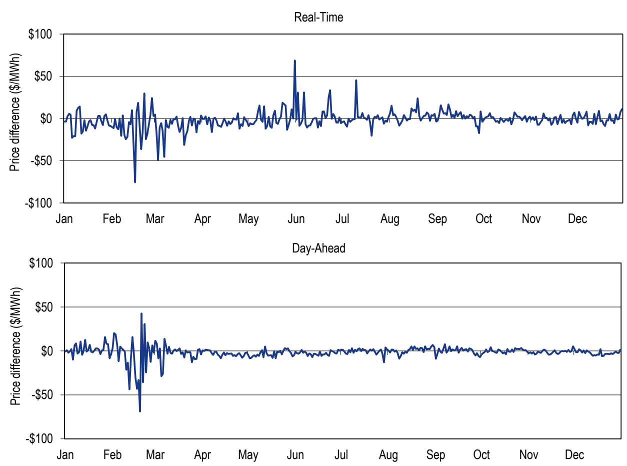
35 See the *2012 State of the Market Report for PJM*, Volume II, Section 8, "Interchange Transactions," for a more detailed discussion.

Table 9-25 PJM and NYISO flow based hours and average hourly price differences: 2015[36]

LMP Difference	Flow Direction	Number of Hours	Average Hourly Price Difference
NYIS/PJM proxy bus LBMP > PJM/NYIS LMP	Any Flow	3,769	$14.97
	Consistent Flow (PJM to NYIS)	2,407	$13.86
	Inconsistent Flow (NYIS to PJM)	1,362	$16.93
	No Flow	0	$0.00
PJM/NYIS LMP > NYIS/PJM proxy bus LBMP	Any Flow	4,991	$13.90
	Consistent Flow (NYIS to PJM)	2,688	$10.50
	Inconsistent Flow (PJM to NYIS)	2,303	$17.87
	No Flow	0	$0.00

The simple average interface price difference does not reflect the underlying hourly variability in prices (Figure 9-5). There are a number of relevant measures of variability, including the number of times the price differential fluctuates between positive and negative, the standard deviation of individual prices and of price differences and the absolute value of the price differences (Figure 9-6).

Figure 9-5 Real-time and day-ahead daily hourly average price difference (NY/PJM proxy - PJM/NYIS Interface): 2015



Distribution and Prices of Hourly Flows at the PJM/NYISO Interface

In 2015, the direction of hourly energy flows was consistent with PJM/NYISO and NYISO/PJM price differences in 5,095 (58.2 percent of all hours), and was inconsistent with price differences in 3,665 hours (41.8 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 3,665 hours where flows where flows were in a direction inconsistent with price differences, 3,285 of those hours (89.6 percent) had a price difference greater than or equal to $1.00 and 2,107 of all those hours (57.5 percent) had a price difference greater than or equal to $5.00. The largest price difference with such flows was $988.45. Of the 5,095 hours where flows were consistent with price differences, 4,701 of those hours (92.3 percent) had a price difference greater than or equal to $1.00 and 3,113 of all such hours (61.1 percent) had a price difference greater than or equal to $5.00. The largest price difference with such flows was $537.57.

Table 9-26 Distribution of hourly flows that are consistent and inconsistent with price differences between PJM and NYISO: 2015

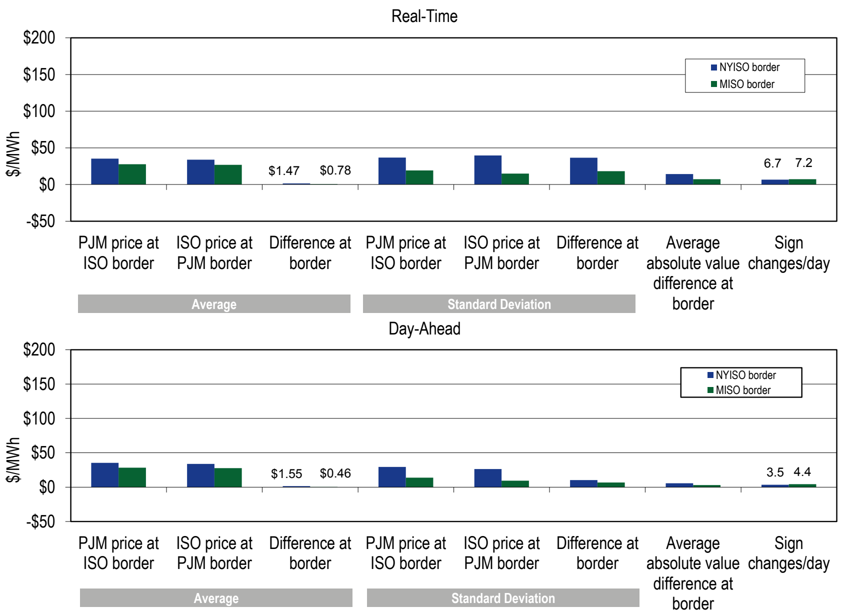
Price Difference Range (Greater Than or Equal To)	Inconsistent Hours	Percent of Total Hours	Consistent Hours	Percent of Total Hours
$0.00	3,665	100.0%	5,095	100.0%
$1.00	3,285	89.6%	4,701	92.3%
$5.00	2,107	57.5%	3,113	61.1%
$10.00	1,346	36.7%	1,640	32.2%
$15.00	960	26.2%	925	18.2%
$20.00	762	20.8%	628	12.3%
$25.00	633	17.3%	480	9.4%
$50.00	307	8.4%	175	3.4%
$75.00	152	4.1%	96	1.9%
$100.00	91	2.5%	60	1.2%
$200.00	17	0.5%	18	0.4%
$300.00	8	0.2%	4	0.1%
$400.00	7	0.2%	1	0.0%
$500.00	4	0.1%	1	0.0%

36 The NYISO Locational Based Marginal Price (LBMP) is the equivalent term to PJM's Locational Marginal Price (LMP).

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: 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. The flows were consistent with price differentials in 58.2 percent of the hours in 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): 2015

LMP Difference	Flow Direction	Number of Hours	Average Hourly Price Difference
NYIS/Neptune Bus LBMP > PJM/NEPT LMP	Any Flow	5,214	$23.32
	Consistent Flow (PJM to NYIS)	5,102	$23.38
	Inconsistent Flow (NYIS to PJM)	0	$0.00
	No Flow	112	$20.46
PJM/NEPT LMP > NYIS/Neptune Bus LBMP	Any Flow	3,546	$16.14
	Consistent Flow (NYIS to PJM)	0	$0.00
	Inconsistent Flow (PJM to NYIS)	3,452	$16.34
	No Flow	94	$8.90

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").[37] The PJM Out Service is covered by normal PJM OASIS business operations.[38] The Neptune Service falls under the

37 See OASIS "PJM Business Practices for Neptune Transmission Service," <http://www.pjm.com/~/media/etools/oasis/merch-trans-facilities/neptune-oasis-Business-practices-doc-clean.ashx>.
38 See OASIS "Regional Transmission and Energy Scheduling Practices," <http://www.pjm.com/~/media/etools/oasis/regional-practices-clean-doc.ashx>.

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 use the service, the available transmission will be released by default at 12:00, one business day before the start of service. On December 31, 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 interchange across the Neptune Line by the primary rights holder since commercial operations began in July, 2007. Table 9-28 shows that in 2015, the primary rights holder was responsible for 100 percent of the scheduled interchange across the Neptune Line in all months except April. Figure 9-7 shows the hourly average flow across the Neptune Line for 2015.

Figure 9-7 Neptune hourly average flow: 2015

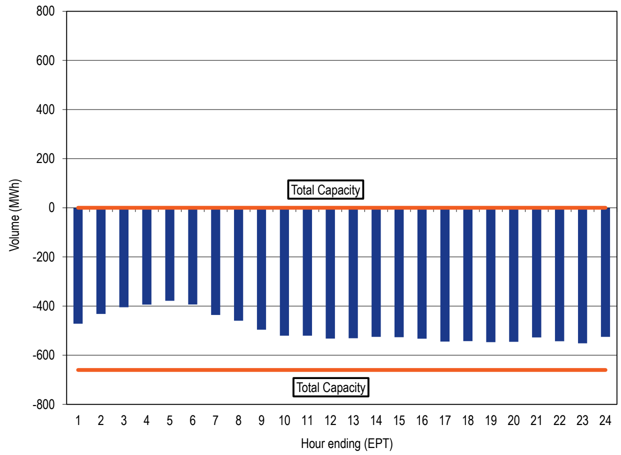


Table 9-28 Percent of scheduled interchange across the Neptune line by primary rights holder: July 2007 through 2015

	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%	100.00%
August	100.00%	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%	100.00%
October	100.00%	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%	100.00%
December	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

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). The flows were consistent with price differentials in 53.0 percent of the hours in 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): 2015

LMP Difference	Flow Direction	Number of Hours	Average Hourly Price Difference
NYIS/Linden Bus LBMP > PJM/LIND LMP	Any Flow	4,770	$16.07
	Consistent Flow (PJM to NYIS)	4,645	$16.23
	Inconsistent Flow (NYIS to PJM)	0	$0.00
	No Flow	125	$9.88
PJM/LIND LMP > NYIS/Linden Bus LBMP	Any Flow	3,990	$12.90
	Consistent Flow (NYIS to PJM)	0	$0.00
	Inconsistent Flow (PJM to NYIS)	3,925	$13.00
	No Flow	65	$6.75

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").[39] The PJM Out Service is covered by normal PJM OASIS business operations.[40] 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 service, and does not use the service, the available transmission will be released by default at 12:00, one business day before the start of service. On December 31, 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 interchange across the Linden VFT Line by the primary rights holder since commercial operations began in November, 2009. Table 9-30 shows that in 2015, the primary rights holder was responsible for 100 percent of the scheduled interchange across the Linden VFT Line from January through September. Figure 9-8 shows the hourly average flow across the Linden VFT line for 2015.

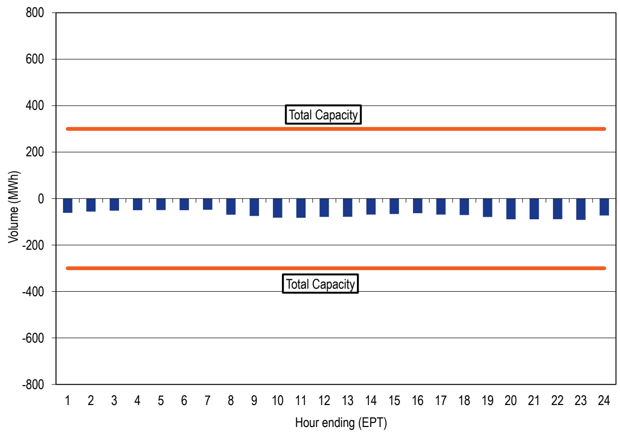
39 See OASIS "PJM Business Practices for Linden VFT Transmission Service," <http://www.pjm.com/~/media/etools/oasis/merch-trans-facilities/linden-vft-oasis-Business-practices-doc-clean.ashx>.

40 See OASIS "Regional Transmission and Energy Scheduling Practices," <http://www.pjm.com/~/media/etools/oasis/regional-practices-clean-doc.ashx>.

Table 9-30 Percentage of scheduled interchange across the Linden VFT Line by primary rights holder: November 2009 through 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%	100.00%
August	NA	100.00%	100.00%	100.00%	100.00%	82.46%	100.00%
September	NA	100.00%	100.00%	100.00%	100.00%	81.68%	100.00%
October	NA	100.00%	100.00%	100.00%	100.00%	100.00%	35.05%
November	100.00%	100.00%	100.00%	100.00%	99.86%	100.00%	61.45%
December	100.00%	100.00%	100.00%	98.22%	100.00%	100.00%	84.57%

Figure 9-8 Linden hourly average flow: 2015[41]



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). The flows were consistent with price differentials in 42.1 percent of the hours in 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): 2015

LMP Difference	Flow Direction	Number of Hours	Average Hourly Price Difference
NYIS/Hudson Bus LBMP > PJM/HUDS LMP	Any Flow	3,902	$17.53
	Consistent Flow (PJM to NYIS)	3,688	$17.76
	Inconsistent Flow (NYIS to PJM)	0	$0.00
	No Flow	214	$13.63
PJM/HUDS LMP > NYIS/Hudson Bus LBMP	Any Flow	4,858	$28.83
	Consistent Flow (NYIS to PJM)	0	$0.00
	Inconsistent Flow (PJM to NYIS)	4,478	$28.69
	No Flow	380	$30.47

41 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.

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").[42] The PJM Out Service is covered by normal PJM OASIS business operations.[43] 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.

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 use the service, the available transmission will be released by default at 12:00, one business day before the start of service. On December 31, 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 interchange across the Hudson line by the primary rights holder since commercial operations began in May, 2013. Table 9-32 shows that in 2015, the primary rights holder was responsible for 100 percent of the scheduled interchange across the Hudson Line in April, May and December. Figure 9-9 shows the hourly average flow across the Hudson Line for 2015.

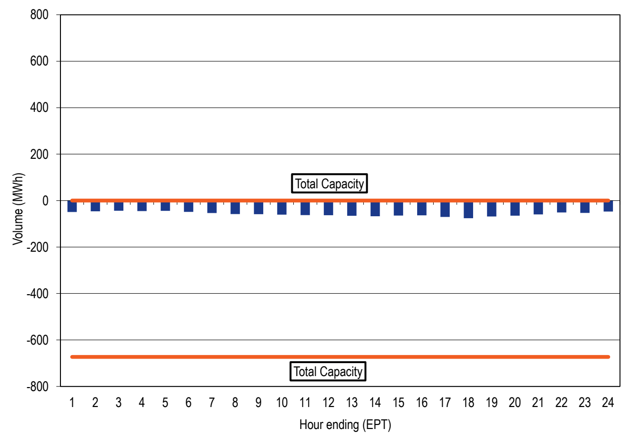
42 See OASIS "PJM Business Practices for Hudson Transmission Service," <http://www.pjm.com/~/media/etools/oasis/merch-trans-facilities/htp-Business-practices.ashx>.

43 See OASIS "Regional Transmission and Energy Scheduling Practices," <http://www.pjm.com/~/media/etools/oasis/regional-practices-clean-doc.ashx>.

Table 9-32 Percentage of scheduled interchange across the Hudson Line by primary rights holder: May 2013 through 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%	84.34%
August	100.00%	75.17%	65.48%
September	100.00%	75.31%	78.73%
October	100.00%	99.71%	18.65%
November	85.57%	99.60%	24.67%
December	28.32%	1.68%	100.00%

Figure 9-9 Hudson hourly average flow: 2015



Operating Agreements with Bordering Areas

To improve reliability and reduce potential competitive seams issues, PJM and its neighbors have developed operating agreements. These agreements include operating agreements with MISO and the NYISO, a 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: whether PJM and its neighbor include exchange 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
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[44]

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.[45]

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 along the PJM/MISO border to calculate the PJM/MISO interface pricing point LMP while MISO uses all of the PJM generator buses in its model of the PJM system in its calculation of the MISO/PJM interface pricing point.[46]

Coordinated flowgates (CF) are flowgates that are monitored or controlled by either PJM or MISO, 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 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 2015, PJM added 61 flowgates and deleted 33 flowgates, leaving 130 flowgates eligible for M2M coordination as of December 31, 2015. As of January 1, 2015, MISO had 275 flowgates eligible for M2M coordination. In 2015, MISO added 78 and deleted

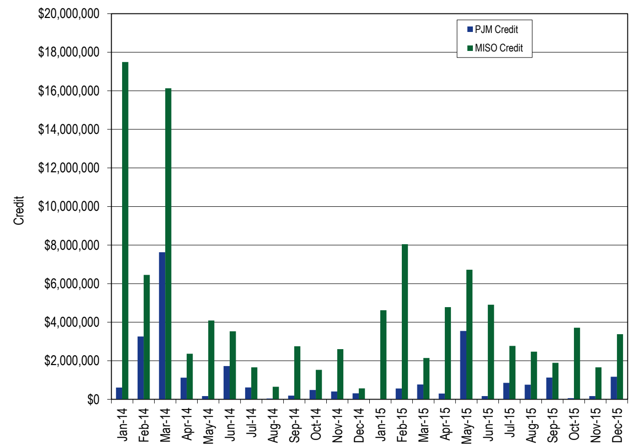
44 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.," (December 11, 2008) <http://www.pjm.com/media/documents/merged-tariffs/miso-joa.pdf>.
45 See "2012 PJM/MISO Joint and Common Market Initiative," <http://www.pjm.com/media/documents/merged-tariffs/miso-joa.pdf>.
46 See the *2012 State of the Market Report for PJM*, Volume II, Section 8, "Interchange Transactions," for a more detailed discussion.

146 flowgates, leaving 207 flowgates eligible for M2M coordination as of December 31, 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 revenue adequacy issues. 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.

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 2015, 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.

Figure 9-10 Credits for coordinated congestion management: 2014 and 2015[47]



PJM and New York Independent System Operator Joint Operating Agreement (JOA)[48]

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 NYISO calculates the PJM interface price (represented by the Keystone proxy bus) based on the assumption that 40 percent of the scheduled energy will flow across the PJM/NYISO border on the Branchburg to Ramapo PAR controlled tie, and the remaining 60 percent will enter the NYISO on their free flowing A/C tie lines.

Coordinated flowgates (CF) are flowgates that are monitored or controlled by either PJM or NYISO, on which only one has a significant impact (defined as a greater than 5 percent impact based on transmission distribution factors and generation to load distribution factors). A reciprocal coordinated flowgate (RCF) is a CF that is monitored and controlled by either PJM or NYISO, on which both have significant impacts. Only

47 The totals represented in this figure represent the settlements as of the time of this report and may not include adjustments or resettlements.

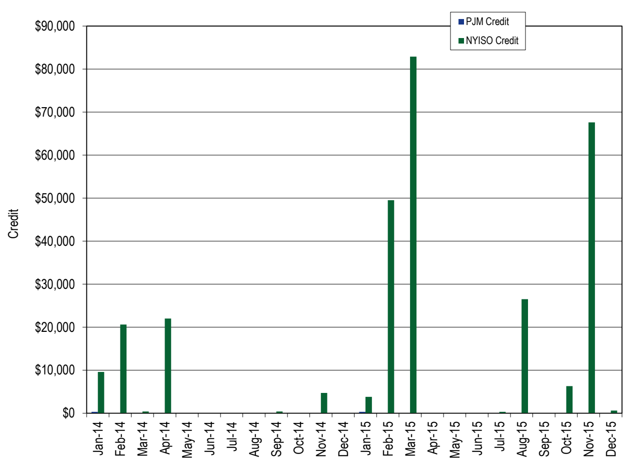
48 See "New York Independent System Operator, Inc., Joint Operating Agreement with PJM Interconnection, L.L.C.," (January 20, 2015) <http://www.pjm.com/~/media/documents/agreements/nyiso-joa.ashx>.

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.

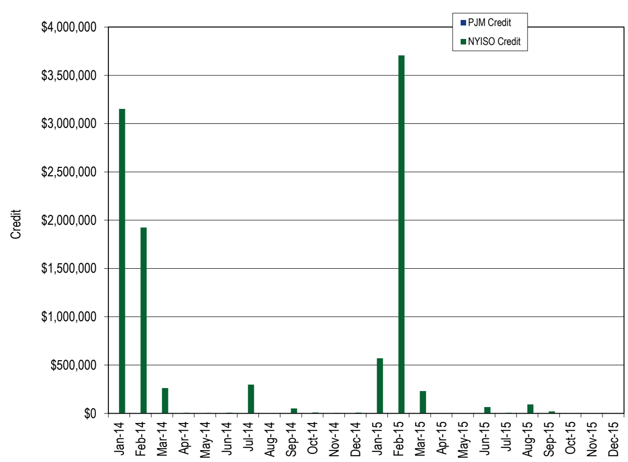
In 2015, market to market operations resulted in NYISO and PJM redispatching units to control congestion on M2M flowgates and in the exchange of payments for this redispatch. Figure 9-11 shows credits for coordinated congestion management between PJM and NYISO.

Figure 9-11 Credits for coordinated congestion management (flowgates): 2014 and 2015[49]



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.[50] For each M2M flowgate, a Ramapo PAR settlement will occur for each interval during coordinated operations. The Ramapo PAR settlements are determined based on whether the measured real-time flow on each of the Ramapo PARs is greater than or less than the calculated target value. If the actual flow is greater than the target flow, NYISO will make a payment to PJM. This payment is calculated as the product of the M2M flowgate shadow price, the PAR shift factor and the difference between the actual and target PAR flow. If the actual flow is less than the target flow, PJM will make a payment to NYISO. This payment is calculated as the product of the M2M flowgate shadow price, the PAR shift factor and the difference between the target and actual PAR flow. In 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): 2014 and 2015[51]



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 "New York Independent System Operator, Inc., Joint Operating Agreement with PJM Interconnection, L.L.C.," <http://www.pjm.com/~/media/documents/agreements/nyiso-joa.ashx>. (November 4, 2014)

51 The totals represented in this figure represent the settlements as of the time of this report and may not include adjustments or resettlements.

PJM and TVA Joint Reliability Coordination Agreement (JRCA)[52]

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 the 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 remained in 2015.

PJM and Duke Energy Progress, Inc. Joint Operating Agreement[53]

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.[54] 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., now a subsidiary of Duke, 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 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 in the DEP area with marginal costs at or above that of the last unit included in the sum are 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.[55] 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 calculation is based 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

52 See "Joint Reliability Coordination Agreement Among and Between PJM Interconnection, L.L.C., and Tennessee Valley Authority," <http://www.pjm.com/~/media/documents/agreements/joint-reliability-coordination-agreement-miso-pjm-tva.ashx>.(October 15, 2014)

53 See "Amended and Restated Joint Operating Agreement Among and Between PJM Interconnection, L.L.C., and Duke Energy Progress Inc.," <http://www.pjm.com/media/documents/merged-tariffs/progress-joa.pdf>.(December 3, 2014)

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

55 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.

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. 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, but this has not happened. When this occurs, PJM uses 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.[56] 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.[57] The MMU submitted a protest to this filing noting that the existing JOA depends on the specific characteristics of PEC as a standalone company, and the assumptions reflected in the current JOA no longer apply under the DEP joint dispatch agreement.[58] 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."[59] 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[60]

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 which provides for system and outage coordination, emergency procedures and the exchange of data. The parties meet on a yearly basis. The agreement remained in effect in 2015.

56 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).

57 See *Duke Energy Progress, Inc. and PJM Interconnection, L.L.C*, Docket No. ER15-29-000 (October 3, 2014).

58 See Protest and Motion for Rehearing of the Independent Market Monitor for PJM in Docket No. ER15-29-000 (October 24, 2014).

59 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.

60 See "PJM-VACAR South RC Agreement," <http://www.pjm.com/~/media/documents/agreements/executed-pjm-vacar-rc-agreement.ashx>.(November 7, 2014)

Balancing Authority Operations Coordination Agreement between Wisconsin Electric Power Company (WEC) and PJM Interconnection, LLC[61]

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 remained in effect in 2015.

Northeastern ISO-Regional Transmission Organization Planning Coordination Protocol[62]

The Northeastern ISO-RTO Planning Coordination Protocol executed on December 8, 2004, provides for the exchange of information among 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 remained in effect in 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.[63] 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 shows the real-time LMP calculated per the PJM/PEC JOA and the high/low pricing methodology used by Duke and NCMPA for the calendar year 2015. The difference between the LMP under these agreements and PJM's SouthIMP LMP ranged from -$0.26 with PEC to $0.74 with NCMPA.[64] This means that under the specific interface pricing agreements, NCMPA receives, on average, $0.74 more for importing energy into PJM than they would have if they were to receive the SouthIMP pricing point; however, PEC received, on average, $0.26 less for importing energy into PJM than they would have if they were to receive the SouthIMP pricing point. The difference between the LMP under these agreements and PJM's SouthEXP LMP ranged from $0.88 with NCMPA to $1.88 with PEC. This means that under the specific interface pricing agreements, Duke pays, on average, $1.88 more for exporting energy from PJM than they would have if they were to pay the SouthEXP pricing point.

Table 9-34 Real-time average hourly LMP comparison for Duke, PEC and NCMPA: 2015

	Import LMP	Export LMP	SOUTHIMP	SOUTHEXP	Difference IMP LMP - SOUTHIMP	Difference EXP LMP - SOUTHEXP
Duke	$30.12	$31.09	$29.87	$29.87	$0.25	$1.21
PEC	$29.62	$31.75	$29.87	$29.87	($0.26)	$1.88
NCMPA	$30.61	$30.76	$29.87	$29.87	$0.74	$0.88

Table 9-35 shows the day-ahead LMP calculated per the PJM/PEC JOA and the high/low pricing methodology used by Duke and NCMPA for the calendar year 2015. The difference between the LMP under these agreements and PJM's SouthIMP LMP ranged from -$0.50 with Duke to $0.89 with NCMPA. This means that under the specific interface pricing agreements, NCMPA receives, on average, $0.89 more for importing energy into PJM than they would have if they were to receive the SouthIMP pricing point; however, Duke received, on average, $0.50 less for importing energy into PJM than they would have if they were to receive the SouthIMP pricing point. The difference between the LMP under these agreements and PJM's SouthEXP LMP ranged from $1.03 with NCMPA to $1.61 with PEC. This means that under the specific interface pricing agreements, PEC pays, on average, $1.61 more for exporting energy from PJM than they would have if they were to pay the SouthEXP pricing point.

61 See "Balancing Authority Operations Coordination Agreement between Wisconsin Electric Power Company and PJM Interconnection, LLC," <http://www.pjm.com/~/media/documents/agreements/balancing-authority-operations-coordination-agreement.ashx>.(July 20, 2013)

62 See "Northeastern ISO/RTO Planning Coordination Protocol," <http://www.pjm.com/~/media/documents/agreements/northeastern-iso-rto-planning-coordination-protocol.ashx>.(December 8, 2004)

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

64 The Progress Energy Carolinas (PEC) LMP is defined as the Carolina Power and Light (East) (CPLE) pricing point.

Table 9-35 Day-ahead average hourly LMP comparison for Duke, PEC and NCMPA: 2015

	Import LMP	Export LMP	SOUTHIMP	SOUTHEXP	Difference IMP LMP - SOUTHIMP	Difference EXP LMP - SOUTHEXP
Duke	$30.40	$32.12	$30.90	$30.88	($0.50)	$1.23
PEC	$31.70	$32.49	$30.90	$30.88	$0.81	$1.61
NCMPA	$31.79	$31.91	$30.90	$30.88	$0.89	$1.03

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 Jersey on lines controlled by PJM.[65] 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.[66]

After years of litigation concerning whether or on what terms Con Edison's protocol would be renewed, PJM filed a settlement on February 23, 2009, on behalf of the parties to resolve remaining issues with these contracts and their proposed rollover of the agreements under the PJM OATT.[67] By order issued September 16, 2010, the Commission approved this settlement, which extends Con Edison's special protocol indefinitely.[68] 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.[69] 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.[70] 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 22 TLRs of level 3a or higher in 2015, compared to eight such TLRs issued in 2014.[71] The number of different flowgates for which PJM declared a TLR 3a or higher increased from seven in 2014 to nine in 2015. The total MWh of transaction curtailments increased by 899.3 percent from 6,282 MWh in 2014 to 62,778 MWh in 2015.

MISO issued 88 TLRs of level 3a or higher in 2015, compared to 141 such TLRs issued in 2014. The number of different flowgates for which MISO declared a TLR 3a or higher decreased from 35 in 2014 to 24 in 2015. The total MWh of transaction curtailments decreased by 61.6 percent from 304,526 MWh in 2014 to 116,938 MWh in 2015.

65 See the *2015 State of the Market Report for PJM*, 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.

66 See the *2012 State of the Market Report for PJM*, Volume II, Section 8, "Interchange Transactions," for a more detailed discussion.

67 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.

68 132 FERC ¶ 61,221 (2010).

69 *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).

70 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.

71 TLR Level 3a is the first level of TLR that results in the curtailment of transactions. See the *2015 State of the Market Report for PJM*, Volume II, Appendix E, "Interchange Transactions," for a more complete discussion of TLR levels.

NYISO issued four TLRs of level 3a or higher in 2015, compared to two such TLRs issued in 2014. The number of different flowgates for which NYISO declared a TLR 3a or higher decreased from two in 2014 to one in 2015. The total MWh of transaction curtailments increased by 205.4 percent from 991 MWh in 2014 to 3,027 MWh in 2015.

Table 9-36 PJM MISO, and NYISO TLR procedures: 2012 through 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
Jul-15	2	10	0	2	4	0	1,360	9,796	0
Aug-15	0	9	0	0	3	0	0	7,041	0
Sep-15	0	6	0	0	4	0	0	5,789	0
Oct-15	0	4	0	0	4	0	0	4,212	0
Nov-15	0	2	0	0	2	0	0	1,797	0
Dec-15	0	4	0	0	1	0	0	875	0

Table 9-37 Number of TLRs by TLR level by reliability coordinator: 2015[72]

Year	Reliability Coordinator	3a	3b	4	5a	5b	6	Total
2015	MISO	28	32	0	16	12	0	88
	NYIS	4	0	0	0	0	0	4
	ONT	3	1	0	0	0	0	4
	PJM	13	7	0	1	1	0	22
	SOCO	0	0	0	0	0	0	0
	SWPP	102	59	0	32	19	0	212
	TVA	36	64	0	24	36	0	160
	VACS	0	2	0	0	1	0	3
Total		186	165	0	73	69	0	493

Up to Congestion

The original purpose of up to congestion transactions was to allow market participants to submit a maximum congestion charge, up to $25 per MWh, they were willing to pay on an import, export or wheel through transaction in the Day-Ahead Energy Market. This product was offered as a tool for market participants to limit their congestion exposure on scheduled transactions in the Real-Time Energy Market.[73]

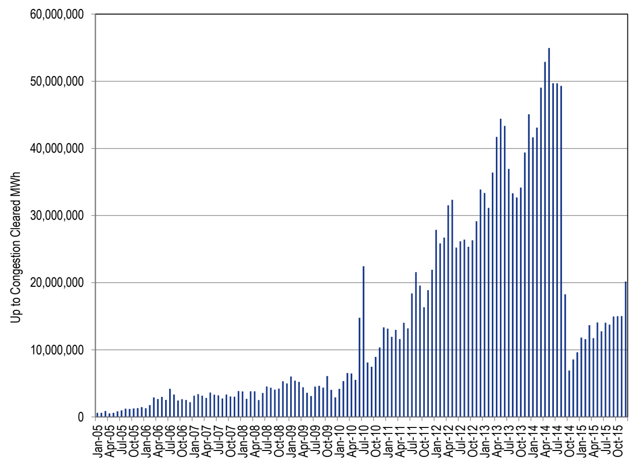
Following the elimination of the requirement to procure and pay for transmission for up to congestion transactions effective September 17, 2010, the volume of transactions increased significantly.

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 negatively affect FTR funding.[74]

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.[75]

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 42.8 percent, from 151,569 bids per day in 2014 to 86,656 bids per day in 2015. The average cleared volume of up to congestion bids submitted in the Day-Ahead Energy Market decreased by 61.1 percent, from 1,188,271 MWh per day in 2014, to 462,118 MWh per day in 2015. But there was an increase in up to congestion volume in December 2015, coincident with the expiration of the fifteen month resettlement period for the proceeding related to uplift charges for UTC transactions (Figure 9-13). Section 206(b) of the Federal Power Act states that "... the Commission may order refunds of any amounts paid, for the period subsequent to the refund effective date through a date fifteen months after such refund effective date..."[76]

Figure 9-13 Monthly up to congestion cleared bids in MWh: 2005 through 2015



72 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.

73 See the *2012 State of the Market Report for PJM*, Volume II, Section 8, "Interchange Transactions," for a more detailed discussion.

74 For more information on up-to congestion transaction impacts on FTRs, see the *2015 State of the Market Report for PJM*, Section 13: FTRs and ARRs, "FTR Forfeitures".

75 148 FERC ¶ 61,144 (2014) *Order Instituting Section 206 Proceeding and Establishing Procedures.*

76 16 U.S.C. § 824e.

Table 9-38 Monthly volume of cleared and submitted up to congestion bids: 2010 through 2015

	Bid MW					Bid Volume				
Month	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
Feb-10	3,841,573	3,937,880	316,150	-	8,095,603	80,876	80,685	2,269	-	163,830
Mar-10	4,877,732	4,454,865	277,180	-	9,609,777	97,149	74,568	2,239	-	173,956
Apr-10	3,877,306	5,558,718	210,545	-	9,646,569	67,632	85,358	1,573	-	154,563
May-10	3,800,870	5,062,272	149,589	-	9,012,731	74,996	78,426	1,620	-	155,042
Jun-10	9,126,963	9,568,549	1,159,407	-	19,854,919	95,155	89,222	6,960	-	191,337
Jul-10	12,818,141	11,526,089	5,420,410	-	29,764,640	124,929	106,145	18,948	-	250,022
Aug-10	8,231,393	6,767,617	888,591	-	15,887,601	115,043	87,876	10,664	-	213,583
Sep-10	7,768,878	7,561,624	349,147	-	15,679,649	184,697	161,929	4,653	-	351,279
Oct-10	8,732,546	9,795,666	476,665	-	19,004,877	189,748	154,741	7,384	-	351,873
Nov-10	11,636,949	9,272,885	537,369	-	21,447,203	253,594	170,470	9,366	-	433,430
Dec-10	17,769,014	12,863,875	923,160	-	31,556,049	307,716	215,897	15,074	-	538,687
Jan-11	20,275,932	11,807,379	921,120	-	33,004,431	351,193	210,703	17,632	-	579,528
Feb-11	18,418,511	13,071,483	800,630	-	32,290,624	345,227	226,292	17,634	-	589,153
Mar-11	17,330,353	12,919,960	749,276	-	30,999,589	408,628	274,709	15,714	-	699,051
Apr-11	17,215,352	9,321,117	954,283	-	27,490,752	513,881	265,334	17,459	-	796,674
May-11	21,058,071	11,204,038	2,937,898	-	35,200,007	562,819	304,589	24,834	-	892,242
Jun-11	20,455,508	12,125,806	395,833	-	32,977,147	524,072	285,031	12,273	-	821,376
Jul-11	24,273,892	16,837,875	409,863	-	41,521,630	603,519	338,810	13,781	-	956,110
Aug-11	23,790,091	21,014,941	229,895	-	45,034,927	591,170	403,269	8,278	-	1,002,717
Sep-11	21,740,208	18,135,378	232,626	-	40,108,212	526,945	377,158	7,886	-	911,989
Oct-11	20,240,161	19,476,556	333,077	-	40,049,794	540,877	451,507	8,609	-	1,000,993
Nov-11	27,007,141	28,994,789	507,788	-	56,509,718	594,397	603,029	13,379	-	1,210,805
Dec-11	34,990,790	34,648,433	531,616	-	70,170,839	697,524	655,222	14,187	-	1,366,933
Jan-12	38,906,228	36,928,145	620,448	-	76,454,821	745,424	689,174	16,053	-	1,450,651
Feb-12	37,231,115	36,736,507	323,958	-	74,291,580	739,200	724,477	8,572	-	1,472,249
Mar-12	38,824,528	39,163,001	297,895	-	78,285,424	802,983	842,857	8,971	-	1,654,811
Apr-12	42,085,326	44,565,341	436,632	-	87,087,299	884,004	917,430	12,354	-	1,813,788
May-12	44,436,245	43,888,405	489,938	-	88,814,588	994,735	885,319	10,294	-	1,890,348
Jun-12	38,962,548	32,828,393	975,776	-	72,766,718	872,764	684,382	21,781	-	1,578,927
Jul-12	45,565,682	41,589,191	855,676	-	88,010,549	1,077,721	911,300	27,173	-	2,016,194
Aug-12	44,972,628	45,204,886	931,161	-	91,108,675	1,054,472	987,293	31,580	-	2,073,345
Sep-12	40,796,522	39,411,713	957,800	-	81,166,035	1,037,179	949,941	29,246	-	2,016,366
Oct-12	35,567,607	42,489,970	1,415,992	-	79,473,570	908,200	1,048,029	46,802	-	2,003,031
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
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
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
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
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
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
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
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
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
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
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
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
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
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
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
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
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
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
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
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
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
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
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
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
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
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
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
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
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
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
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
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
Jul-15	8,797,317	3,600,463	703,906	52,774,024	65,875,710	317,439	121,991	22,398	2,143,611	2,605,439
Aug-15	9,354,801	4,090,172	916,209	61,589,135	75,950,316	328,224	141,549	31,332	2,691,409	3,192,514
Sep-15	9,741,094	4,098,270	737,792	63,708,128	78,285,283	349,715	129,051	28,325	3,027,147	3,534,238
Oct-15	8,508,535	5,028,169	708,089	60,656,099	74,900,892	340,586	154,204	31,377	2,997,443	3,523,610
Nov-15	7,042,648	4,898,979	854,557	49,740,632	62,536,817	287,080	154,016	32,505	2,454,927	2,928,528
Dec-15	7,718,227	5,068,244	700,702	60,230,661	73,717,834	348,160	181,451	36,546	3,035,860	3,602,017
TOTAL	1,180,815,404	1,122,075,145	69,609,360	3,086,866,352	5,459,366,262	29,601,827	25,638,712	1,803,802	108,745,326	165,789,667

Table 9-38 Monthly volume of cleared and submitted up to congestion bids: 2010 through 2015 *(continued)*

	Cleared MW					Cleared Volume				
Month	Import	Export	Wheel	Internal	Total	Import	Export	Wheel	Internal	Total
Jan-10	2,250,689	1,789,018	161,977	-	4,201,684	49,064	33,640	2,318	-	85,022
Feb-10	2,627,101	2,435,650	287,162	-	5,349,913	50,958	48,008	1,812	-	100,778
Mar-10	3,209,064	3,071,712	263,516	-	6,544,292	60,277	48,596	2,064	-	110,937
Apr-10	2,622,113	3,690,889	170,020	-	6,483,022	42,635	54,510	1,154	-	98,299
May-10	2,366,149	3,049,405	112,700	-	5,528,253	47,505	48,996	1,112	-	97,613
Jun-10	6,863,803	6,850,098	1,072,759	-	14,786,660	59,733	55,574	5,831	-	121,138
Jul-10	8,971,914	8,237,557	5,241,264	-	22,450,734	73,232	60,822	16,526	-	150,580
Aug-10	4,430,832	2,894,314	785,726	-	8,110,871	62,526	40,485	8,884	-	111,895
Sep-10	3,915,814	3,110,580	256,039	-	7,282,433	63,405	45,264	3,393	-	112,062
Oct-10	4,150,104	4,564,039	246,594	-	8,960,736	76,042	65,223	3,670	-	144,935
Nov-10	5,765,905	4,312,645	275,111	-	10,353,661	112,250	71,378	4,045	-	187,673
Dec-10	7,851,235	5,150,286	337,157	-	13,338,678	136,582	93,299	7,380	-	237,261
Jan-11	7,917,986	4,925,310	315,936	-	13,159,232	151,753	91,557	8,417	-	251,727
Feb-11	6,806,039	4,879,207	248,573	-	11,933,818	151,003	99,302	8,851	-	259,156
Mar-11	7,104,642	5,603,583	275,682	-	12,983,906	178,620	124,990	7,760	-	311,370
Apr-11	7,452,366	3,797,819	351,984	-	11,602,168	229,707	113,610	8,118	-	351,435
May-11	8,294,422	4,701,077	1,031,519	-	14,027,018	261,355	143,956	11,116	-	416,427
Jun-11	7,632,235	5,361,825	198,482	-	13,192,543	226,747	132,744	6,363	-	365,854
Jul-11	9,585,027	8,617,284	205,599	-	18,407,910	283,287	186,866	7,008	-	477,161
Aug-11	10,594,771	10,875,384	103,141	-	21,573,297	274,398	208,593	3,648	-	486,639
Sep-11	10,219,806	9,270,121	82,200	-	19,572,127	270,088	185,585	3,444	-	459,117
Oct-11	8,376,208	7,853,947	126,718	-	16,356,873	255,206	198,778	4,236	-	458,220
Nov-11	9,064,570	9,692,312	131,670	-	18,888,552	254,851	256,270	5,686	-	516,807
Dec-11	11,738,910	10,049,685	137,689	-	21,926,284	281,304	248,008	6,309	-	535,621
Jan-12	13,610,725	14,120,791	145,773	-	27,877,288	289,524	304,072	5,078	-	598,674
Feb-12	12,883,355	12,905,553	54,724	-	25,843,632	299,055	276,563	2,175	-	577,793
Mar-12	13,328,968	13,306,689	89,262	-	26,724,918	320,210	320,252	3,031	-	643,493
Apr-12	15,050,798	16,297,303	171,252	-	31,519,354	369,273	355,669	4,655	-	729,597
May-12	17,416,386	14,733,838	189,667	-	32,339,891	434,919	343,872	4,114	-	782,905
Jun-12	12,675,852	12,311,609	250,024	-	25,237,485	355,731	295,911	6,891	-	658,533
Jul-12	13,001,225	12,823,361	348,946	-	26,173,532	399,135	321,062	9,958	-	730,155
Aug-12	12,768,023	13,354,850	300,038	-	26,422,911	377,146	343,717	12,738	-	733,601
Sep-12	12,089,136	12,961,955	292,095	-	25,343,186	341,925	329,217	9,620	-	680,762
Oct-12	11,969,576	13,949,871	392,286	-	26,311,733	345,788	376,513	14,089	-	736,390
Nov-12	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	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	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	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	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	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	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	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	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	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	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	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	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	3,189,261	3,234,196	503,666	38,150,077	45,077,200	119,954	122,683	14,318	1,382,736	1,639,691
Jan-14	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	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	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	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	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	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	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	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	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	778,085	527,692	73,370	5,538,329	6,917,477	36,303	27,787	3,557	313,084	380,731
Nov-14	802,153	732,365	106,754	6,931,319	8,572,590	38,126	33,342	7,584	397,534	476,586
Dec-14	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	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	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	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	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	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	1,490,960	779,517	171,815	10,311,431	12,753,722	68,977	27,114	4,044	544,756	644,891
Jul-15	1,669,277	619,731	130,423	11,629,796	14,049,226	74,525	25,144	3,979	604,939	708,587
Aug-15	1,253,587	817,265	149,825	11,536,005	13,756,682	63,587	30,965	7,162	735,877	837,591
Sep-15	1,500,472	932,971	137,868	12,389,538	14,960,850	87,789	34,368	8,008	914,610	1,044,775
Oct-15	1,396,515	1,046,675	118,879	12,454,398	15,016,467	89,960	42,045	7,036	971,644	1,110,685
Nov-15	1,378,299	1,011,236	87,438	12,556,360	15,033,334	82,884	38,897	6,684	928,551	1,057,016
Dec-15	1,612,284	1,453,772	117,749	16,996,215	20,180,020	112,519	55,720	8,200	1,261,471	1,437,910
TOTAL	395,986,739	375,645,500	24,009,141	902,599,830	1,698,241,210	11,374,565	9,829,232	647,879	38,341,113	60,192,789

In 2015, the cleared MW volume of up to congestion transactions was comprised of 11.6 percent imports, 5.8 percent exports, 1.0 percent wheeling transactions and 81.7 percent internal transactions. Less than 0.1 percent of the up to congestion transactions had matching real-time energy market transactions.

Up to Congestion Credit Risk

On August 29, 2014, FERC issued an Order which created an obligation for UTCs to pay any uplift determined to be appropriate after Commission review, effective from September 8, 2014.[77] As of December 31, 2015, the Commission had not ruled on whether up to congestion transactions will be charged for uplift accrued during this time. Between September 8, 2014, and December 31, 2015, 201,344,624 MWh of up to congestion transactions cleared and are subject to potential uplift charges for that period. Based on the volume of cleared up to congestion transactions and the potential uplift obligation on a per MWh basis, the obligation to pay is estimated to be between $20.1 million and $402.7 million. As potential obligations, this exposure creates a credit risk for those UTC traders who engaged in UTC transactions during this period. Table 9-39 shows the levels of credit risk associated with the cleared up to congestion transactions, depending on the uplift charge that may be imposed on these transactions.

Table 9-39 Credit risk associated with varying levels of potential uplift: September 8, 2014 through December 31, 2015

Uplift ($/MWh)	Credit risk if uplift is applied to both sides of UTC
$0.05	$20,134,462
$0.10	$40,268,925
$0.15	$60,403,387
$0.20	$80,537,850
$0.25	$100,672,312
$0.30	$120,806,775
$0.35	$140,941,237
$0.40	$161,075,700
$0.45	$181,210,162
$0.50	$201,344,624
$0.55	$221,479,087
$0.60	$241,613,549
$0.65	$261,748,012
$0.70	$281,882,474
$0.75	$302,016,937
$0.80	$322,151,399
$0.85	$342,285,861
$0.90	$362,420,324
$0.95	$382,554,786
$1.00	$402,689,249

PJM market participants that cleared UTCs since the specified refund date of September 8, 2014, would be responsible to pay uplift based on their cleared up to congestion volume and the uplift charge if FERC orders that UTCs pay such uplift charges. Analysis of the cleared up to congestion transactions between September 8, 2014, and December 31, 2015, showed that the top 10 market participants would be responsible for 53.4 percent of the uplift.

The credit risk exposure to companies that traded UTCs during this period is substantial, including the possible bankruptcy of one or more companies if FERC orders that UTCs pay such uplift charges. The actual risk depends in significant part on how the companies have managed their potential exposure as they continued to trade UTCs with knowledge of the risks. These companies do not appear to have informed PJM of how or if they have managed this exposure.

The total uplift amount has already been paid by other PJM members. Thus, the risk to other PJM members has been realized. The risk that UTC traders will not be able to cover their credit exposure otherwise related to their trading activity is addressed by existing PJM credit policies. If a UTC trader went into bankruptcy as a result of the uplift risk, the exposure to other PJM members is that they will not be repaid the level of uplift that should have been paid by UTC transactions.

Absent further Commission action, the increase in UTC uplift payment risk appears to have ended as a result of the expiration of the fifteen month resettlement period for the proceeding related to uplift charges for UTC transactions.[78]

77 148 FERC ¶ 61,144 (2014) *Order Instituting Section 206 Proceeding and Establishing Procedures.*

78 16 U.S.C. § 824e.

Attachment Q: PJM Credit Policy of the PJM Open Access Transmission Tariff provides that:

> Each Participant is also required to provide with its application information any known Material litigation, commitments or contingencies as well as any prior bankruptcy declarations or Material defalcations by the Participant or its predecessors, subsidiaries or Affiliates, if any. These disclosures shall be made upon application, upon initiation or change, and at least annually thereafter, or as requested by PJMSettlement.[79]

The MMU recommends that PJMSettlement Inc. immediately request a credit evaluation from all companies that engaged in up to congestion transactions between September 8, 2014, and December 31, 2015. If PJM has the authority, PJM should ensure that the potential exposure to uplift for that period be included as a contingency in the companies' calculations for credit levels and/or collateral requirements. PJM should also calculate the UTC uplift charge contingency in a manner appropriate for the evaluation of any contingency. By definition, assessing a contingency requires a reasonable exercise of discretion. PJM should develop a reasonable assessment of the risk associated with the UTC uplift allocation and the appropriate approach to managing this risk. Zero risk is not within a reasonable range. The MMU recognizes that the exact amount of the exposure is not known. If PJM does not have the authority to take such steps, PJM should request guidance from FERC.

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 result in 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 that would prohibit breaking transactions into smaller segments to defeat the interface pricing rule and that would require market participants to submit transactions on market paths that reflect the expected actual power flow, would address sham scheduling.

Elimination of Ontario Interface Pricing Point

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.

Prior to June 1, 2015, the PJM/IMO interface pricing point was defined as the LMP at the IESO Bruce bus. 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

79 See OATT Attachment Q § I.A.4.

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 use 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.

A new PJM/IMO interface price method was implemented on June 1, 2015. The new method uses 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 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.[80]

The dynamic weights were not used until an error was brought to PJM's attention by the MMU on August 30, 2015. From June 1, 2015, through August 30, 2015, PJM calculated the PJM/IMO interface pricing using static weights of 60 percent of the PJM/MISO interface price and 40 percent of the PJM/NYIS interface price. During this time, the weights should have varied such that in some five minute intervals, the PJM/IMO interface price was 100 percent of the PJM/MISO interface price, and in some five minute intervals, the PJM/IMO interface price was 100 percent of the PJM/NYIS interface price. While the weights varied significantly over the first four months of operations, the hourly integrated PJM/IMO interface price using the static weightings remained within $1.00 of the hourly integrated PJM/IMO interface price using the dynamic ratings in 77.6 percent of the hours, and within $5.00 in 96.5 percent of the hours.

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.

In 2015, of the 6,414 GWh of the net scheduled transactions between PJM and IESO, 6,113 GWh wheeled through MISO (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

80 See "IMO Interface Definition Methodology Report," presented to the MIC <http://www.pjm.com/~/media/committees-groups/committees/mic/20150211/20150211-item-08b-imo-interface-definition-methodology-report.ashx>.(February 11, 2015)

IESO balancing authority to the PJM/MISO interface pricing point.[81]

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.[82] 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.

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 2015. Table 9-40 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 36.8 percent of the intervals. In those intervals, the average price difference between the ITSCED forecasted LMP and the actual real-time LMP was $1.87 per MWh. In 12.8 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. The average price differences were $83.33 when the price difference was greater than $20.00, and $101.23 when the price difference was greater than -$20.00.

Table 9-40 Differences between forecast and actual PJM/NYIS interface prices: 2015

Range of Price Differences	Percent of All Intervals	Average Price Difference
> $20	6.4%	$83.33
$10 to $20	4.7%	$13.86
$5 to $10	8.9%	$7.00
$0 to $5	36.8%	$1.87
$0 to -$5	28.6%	$1.70
-$5 to -$10	5.0%	$6.99
-$10 to -$20	3.1%	$14.09
< -$20	6.4%	$101.23

Table 9-41 shows how the accuracy of the ITSCED forecasted LMPs changes as the cases approach real-time. 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 66.4 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 63.2 percent in the 135 minute ahead ITSCED results.

81 On October 1, 2013, a sub-group of PJM's Market Implementation Committee started stakeholder discussions to address this inconsistency in market pricing.

82 PJM and the NYISO implemented CTS on November 4, 2014. 146 FERC ¶ 61,096 (2014).

Table 9-41 Differences between forecast and actual PJM/NYIS interface prices: 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 of Price Differences	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	5.9%	$60.27	6.4%	$70.85	4.8%	$64.50	7.9%	$117.75
$10 to $20	4.9%	$13.85	4.8%	$13.70	4.1%	$13.77	4.8%	$13.95
$5 to $10	9.5%	$7.03	9.9%	$6.95	8.3%	$6.97	7.7%	$7.04
$0 to $5	34.9%	$1.95	37.9%	$1.96	39.2%	$1.78	36.9%	$1.74
$0 to -$5	28.3%	$1.85	27.2%	$1.71	29.5%	$1.61	29.5%	$1.60
-$5 to -$10	6.0%	$6.96	4.8%	$7.03	4.5%	$6.98	4.5%	$6.97
-$10 to -$20	3.6%	$13.94	2.8%	$14.14	3.2%	$14.14	2.9%	$14.16
< -$20	7.0%	$122.64	6.2%	$81.93	6.5%	$87.23	5.8%	$103.06

In 13.7 percent of the intervals in the thirty-minute ahead forecast, 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, the average price difference was $117.75 when the price difference was greater than $20.00, and $103.06 when the price difference was greater than -$20.00.

Table 9-42 and Table 9-43 show the monthly differences between forecasted and actual PJM/NYIS interface prices. Analysis of the data on a monthly basis shows that there is a substantial decline in the accuracy of the ITSCED forecast ability during periods of cold weather. For example, Table 9-42 shows that in February 2015, the absolute value of the average price difference between the ITSCED forecasted LMP and the actual real-time interface LMP in the thirty-minute ahead forecast, was greater than $20.00 in 51.3 percent of the intervals, compared to 10.6 percent of the intervals in September 2015.

Table 9-42 Monthly Differences between forecast and actual PJM/NYIS interface prices (percent of intervals): 2015

Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD Avg
~ 30 Minutes Prior to Real-Time	> $20	10.7%	28.8%	9.6%	7.6%	8.9%	5.7%	5.2%	5.0%	5.4%	1.8%	2.9%	5.3%	7.9%
	$10 to $20	7.0%	7.0%	4.3%	4.3%	5.5%	5.3%	5.7%	5.7%	4.3%	3.5%	2.4%	3.4%	4.8%
	$5 to $10	7.9%	5.7%	5.4%	9.2%	9.6%	9.1%	8.5%	8.9%	6.1%	7.4%	5.8%	8.4%	7.7%
	$0 to $5	33.4%	12.8%	31.9%	40.4%	33.0%	38.3%	38.9%	39.5%	39.4%	42.9%	46.2%	44.0%	36.9%
	$0 to -$5	24.8%	10.9%	27.7%	27.5%	31.4%	31.4%	31.6%	32.7%	33.1%	36.5%	35.1%	29.5%	29.5%
	-$5 to -$10	4.8%	5.0%	4.4%	5.3%	5.2%	4.6%	4.5%	3.6%	3.6%	4.1%	3.5%	5.3%	4.5%
	-$10 to -$20	4.5%	7.3%	3.3%	2.2%	2.7%	2.5%	2.7%	2.2%	3.1%	1.6%	2.0%	1.2%	2.9%
	< -$20	6.9%	22.5%	13.4%	3.6%	3.8%	3.1%	2.8%	2.3%	5.2%	2.3%	2.3%	3.0%	5.8%
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD Avg
~ 45 Minutes Prior to Real-Time	> $20	6.9%	25.8%	5.3%	2.1%	4.6%	2.4%	2.2%	1.9%	3.7%	0.6%	1.8%	1.6%	4.8%
	$10 to $20	6.8%	8.2%	3.1%	4.0%	5.7%	3.9%	4.3%	3.4%	3.8%	2.9%	1.7%	1.6%	4.1%
	$5 to $10	9.0%	6.1%	5.3%	9.8%	10.3%	8.8%	9.7%	10.5%	8.1%	6.8%	6.5%	8.1%	8.3%
	$0 to $5	33.1%	13.9%	33.1%	44.1%	38.4%	42.1%	41.7%	43.6%	38.3%	44.7%	46.9%	48.1%	39.2%
	$0 to -$5	25.0%	9.7%	28.4%	28.9%	29.6%	31.7%	30.8%	31.9%	33.7%	35.9%	35.0%	31.3%	29.5%
	-$5 to -$10	5.5%	5.1%	5.2%	4.6%	3.8%	5.6%	5.0%	3.3%	3.2%	4.7%	3.6%	4.5%	4.5%
	-$10 to -$20	5.1%	7.2%	4.6%	2.6%	2.8%	2.5%	2.7%	2.8%	3.4%	2.0%	2.0%	1.6%	3.2%
	< -$20	8.6%	23.8%	14.9%	3.9%	4.7%	3.0%	3.5%	2.8%	5.9%	2.5%	2.6%	3.1%	6.5%
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD Avg
~ 90 Minutes Prior to Real-Time	> $20	10.8%	36.1%	8.2%	1.9%	5.3%	3.1%	3.5%	1.9%	4.1%	0.7%	1.7%	1.7%	6.4%
	$10 to $20	8.2%	8.6%	3.6%	4.9%	6.8%	5.0%	4.3%	4.1%	4.6%	3.0%	2.7%	2.3%	4.8%
	$5 to $10	9.9%	6.7%	5.7%	13.4%	13.2%	12.0%	9.7%	10.8%	9.6%	8.4%	9.6%	9.5%	9.9%
	$0 to $5	30.6%	12.1%	29.4%	43.9%	39.4%	40.9%	39.8%	42.7%	37.8%	45.1%	45.2%	46.0%	37.9%
	$0 to -$5	21.7%	6.7%	29.6%	25.5%	24.1%	28.4%	32.2%	30.4%	30.6%	32.9%	31.9%	31.0%	27.2%
	-$5 to -$10	5.3%	3.8%	4.9%	4.1%	4.5%	5.6%	4.9%	4.7%	4.6%	5.3%	4.3%	5.0%	4.8%
	-$10 to -$20	5.1%	4.8%	4.2%	2.4%	2.2%	2.5%	2.2%	2.5%	2.5%	2.1%	2.0%	1.5%	2.8%
	< -$20	8.5%	21.1%	14.4%	3.8%	4.6%	2.6%	3.4%	2.9%	6.2%	2.4%	2.6%	3.1%	6.2%
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD Avg
~ 135 Minutes Prior to Real-Time	> $20	7.8%	28.5%	6.7%	2.5%	7.0%	3.5%	4.7%	2.9%	5.2%	0.7%	1.3%	1.6%	5.9%
	$10 to $20	6.1%	6.9%	4.1%	3.6%	9.0%	4.7%	6.1%	4.7%	3.8%	3.5%	4.0%	2.4%	4.9%
	$5 to $10	9.6%	6.3%	7.2%	10.9%	11.0%	10.5%	10.5%	10.4%	8.3%	9.1%	9.1%	10.1%	9.5%
	$0 to $5	29.5%	11.5%	34.9%	42.1%	36.0%	32.5%	34.5%	37.3%	34.9%	42.3%	38.8%	42.9%	34.9%
	$0 to -$5	23.2%	9.4%	21.9%	28.5%	24.6%	33.2%	31.9%	32.5%	31.8%	34.3%	35.4%	31.4%	28.3%
	-$5 to -$10	6.2%	5.5%	5.4%	5.5%	4.9%	8.7%	6.2%	5.8%	6.3%	5.3%	5.8%	6.5%	6.0%
	-$10 to -$20	6.3%	6.9%	4.3%	2.9%	2.8%	3.7%	2.6%	3.3%	3.4%	2.2%	2.8%	2.0%	3.6%
	< -$20	11.3%	25.1%	15.4%	3.9%	4.7%	3.2%	3.6%	3.1%	6.4%	2.6%	2.7%	3.1%	7.0%

Table 9-43 Monthly differences between forecast and actual PJM/NYIS interface prices (average price difference): 2015

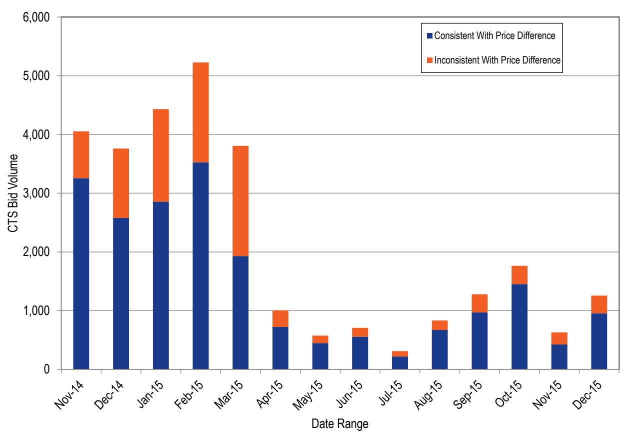
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD Avg
~ 30 Minutes Prior to Real-Time	> $20	$68.58	$135.04	$89.08	$82.08	$147.79	$123.97	$154.83	$76.40	$159.80	$139.89	$100.97	$141.37	$117.75
	$10 to $20	$14.56	$14.96	$13.86	$13.97	$13.70	$13.92	$13.87	$13.70	$13.80	$12.89	$13.38	$13.66	$13.95
	$5 to $10	$7.10	$7.30	$7.24	$7.06	$6.94	$6.87	$7.11	$7.16	$7.01	$7.03	$6.99	$6.87	$7.04
	$0 to $5	$1.57	$2.02	$1.57	$1.98	$1.86	$1.78	$1.79	$1.73	$1.65	$1.66	$1.69	$1.80	$1.74
	$0 to -$5	$1.48	$2.11	$1.46	$1.70	$1.80	$1.60	$1.53	$1.57	$1.46	$1.53	$1.57	$1.70	$1.60
	-$5 to -$10	$7.18	$7.45	$7.21	$6.84	$7.11	$6.96	$7.00	$6.69	$7.09	$6.86	$6.55	$6.67	$6.97
	-$10 to -$20	$14.48	$14.46	$14.47	$13.94	$14.30	$13.49	$13.91	$13.61	$14.53	$13.24	$14.20	$13.87	$14.16
	< -$20	$72.83	$90.33	$91.64	$72.68	$359.68	$103.64	$187.46	$69.75	$72.62	$68.70	$58.85	$71.64	$103.06
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD Avg
~ 45 Minutes Prior to Real-Time	> $20	$44.08	$70.99	$68.22	$52.49	$61.02	$47.18	$46.39	$65.29	$72.94	$72.85	$77.22	$84.62	$64.50
	$10 to $20	$14.48	$14.66	$13.49	$13.36	$13.29	$13.30	$13.81	$13.01	$13.60	$13.51	$13.44	$13.45	$13.77
	$5 to $10	$7.12	$7.19	$6.78	$6.99	$7.01	$6.94	$6.87	$6.93	$7.03	$7.02	$6.78	$6.97	$6.97
	$0 to $5	$1.64	$2.04	$1.51	$1.94	$1.88	$1.83	$1.72	$1.83	$1.77	$1.74	$1.77	$1.78	$1.78
	$0 to -$5	$1.46	$1.96	$1.49	$1.69	$1.76	$1.62	$1.54	$1.58	$1.51	$1.66	$1.57	$1.68	$1.61
	-$5 to -$10	$7.15	$7.27	$7.07	$7.26	$6.96	$6.88	$6.73	$6.92	$7.16	$6.93	$6.60	$6.76	$6.98
	-$10 to -$20	$14.49	$14.33	$14.19	$14.06	$14.11	$13.96	$13.92	$13.70	$14.62	$13.41	$13.78	$14.09	$14.14
	< -$20	$75.95	$97.61	$96.81	$75.24	$66.90	$49.56	$159.63	$73.37	$77.96	$65.07	$55.13	$71.92	$87.23
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD Avg
~ 90 Minutes Prior to Real-Time	> $20	$50.23	$73.42	$99.48	$41.04	$77.06	$48.04	$60.82	$75.41	$81.66	$55.48	$58.27	$77.93	$70.85
	$10 to $20	$14.51	$14.54	$14.21	$13.42	$13.26	$13.04	$13.17	$13.31	$13.87	$13.47	$13.21	$12.55	$13.70
	$5 to $10	$7.05	$7.18	$6.81	$6.93	$6.93	$7.15	$7.06	$7.08	$6.96	$6.84	$6.62	$6.81	$6.95
	$0 to $5	$1.82	$2.33	$1.60	$2.24	$2.02	$2.06	$1.91	$1.97	$1.89	$1.89	$1.94	$2.01	$1.96
	$0 to -$5	$1.56	$2.06	$1.60	$1.73	$1.69	$1.72	$1.65	$1.72	$1.68	$1.83	$1.73	$1.75	$1.71
	-$5 to -$10	$7.31	$7.44	$7.27	$7.01	$7.09	$6.95	$6.88	$7.04	$6.98	$6.96	$6.66	$6.82	$7.03
	-$10 to -$20	$14.40	$14.64	$14.40	$14.09	$14.16	$13.52	$13.73	$14.01	$14.16	$14.14	$13.58	$13.62	$14.14
	< -$20	$73.45	$100.99	$94.50	$74.15	$62.56	$51.23	$70.07	$69.29	$75.11	$59.74	$54.10	$69.62	$81.93
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD Avg
~ 135 Minutes Prior to Real-Time	> $20	$48.81	$71.33	$66.50	$34.95	$54.53	$43.06	$40.58	$60.52	$59.85	$56.92	$57.44	$75.55	$60.27
	$10 to $20	$14.11	$15.06	$13.97	$13.71	$14.03	$13.59	$13.85	$13.46	$14.22	$12.86	$13.04	$12.82	$13.85
	$5 to $10	$7.24	$7.36	$6.77	$6.97	$7.13	$6.98	$7.08	$7.13	$7.05	$6.96	$6.76	$6.98	$7.03
	$0 to $5	$1.83	$2.25	$1.82	$2.15	$1.99	$1.96	$1.90	$1.96	$1.93	$1.91	$1.96	$1.91	$1.95
	$0 to -$5	$1.78	$2.04	$1.71	$1.85	$1.96	$1.96	$1.84	$1.80	$1.83	$1.90	$1.77	$1.89	$1.85
	-$5 to -$10	$7.20	$7.51	$7.14	$6.81	$6.98	$6.96	$6.81	$6.94	$7.05	$6.90	$6.65	$6.69	$6.96
	-$10 to -$20	$14.18	$14.23	$14.38	$14.08	$13.82	$13.26	$13.94	$13.86	$14.04	$13.41	$13.55	$13.58	$13.94
	< -$20	$66.12	$96.26	$97.71	$72.85	$170.03	$368.10	$622.02	$67.65	$79.17	$57.90	$55.30	$69.18	$122.64

The NYISO uses 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 charges are applied and CTS transactions are optional, the CTS proposal represents a small incremental step toward better interface pricing. The 75 minute time lag associated with scheduling energy transactions in the NYISO should be shortened. Reducing this time lag could significantly improve pricing efficiency at the PJM/NYISO border for non-CTS transactions and for CTS transactions.

CTS transactions were evaluated for each 15 minute interval. From November 4, 2014, through December 31, 2015, 29,626 15 minute CTS schedules 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 9,072 (30.6 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 30.6 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 69.4 percent of the intervals, the forecast price differentials were consistent with real-time PJM/NYISO and NYISO/PJM price differences. Figure 9-14 shows the monthly volume of cleared PJM/NYIS CTS bids. Figure 9-14 also shows the percentage of cleared bids that resulted in flows consistent and inconsistent with price differences.

Figure 9-14 Monthly cleared PJM/NYIS CTS bid volume: November, 2014 through 2015



The data reviewed 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 interface pricing between PJM and NYISO.

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 adjustments to transactions on its other interfaces in order to bring total system ramp back to within its limit. The default ramp limit in PJM is +/- 1,000 MW. For example, the ramp in a given interval is currently -1,000 MW, consisting of 2,000 MW of imports from the NYISO to PJM and 3,000 MW of exports from PJM on its other interfaces. If, through the NYISO real-time market clearing process, the NYISO only approves 1,000 MW of the imports, the other 1,000 MW of import transactions from the NYISO would be curtailed. The ramp in this interval would then be -2,000 MW, consisting of the 1,000 MW of cleared imports from the NYISO to PJM and 3,000 MW of exports from PJM on its other interfaces. 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 +/- 1,000. 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, does PJM perform a ramp evaluation on transactions scheduled with the NYISO. If, in the event the NYISO market clearing process would violate 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 NYISO has completed its economic evaluation and the transactions are approved through the NYISO market clearing process.

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). Unlike the PJM/NYISO CTS process in which the NYISO performs the evaluation, the PJM/MISO CTS process will use a joint clearing process in which both RTOs will share forward looking prices. MISO does not currently have an application comparable to PJM's ITSCED to provide forward-looking prices but is developing a tool.

Table 9-44 Differences between forecast and actual PJM/MISO interface prices: 2015

Range of Price Differences	Percent of All Intervals	Average Price Difference
> $20	4.3%	$78.11
$10 to $20	5.2%	$14.00
$5 to $10	8.4%	$7.05
$0 to $5	42.3%	$1.72
$0 to -$5	29.0%	$1.50
-$5 to -$10	4.3%	$7.07
-$10 to -$20	2.7%	$13.98
< -$20	3.8%	$111.01

Table 9-45 Differences between forecast and actual PJM/MISO interface prices: 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 of Price Differences	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	4.9%	$45.09	2.8%	$49.22	2.4%	$55.43	6.4%	$118.50
$10 to $20	6.3%	$14.15	4.8%	$13.90	4.2%	$13.81	5.1%	$14.01
$5 to $10	8.9%	$7.03	8.5%	$7.03	7.8%	$7.02	7.9%	$7.08
$0 to $5	42.1%	$1.83	43.8%	$1.75	44.1%	$1.64	41.1%	$1.65
$0 to -$5	27.2%	$1.54	29.1%	$1.48	30.3%	$1.43	29.4%	$1.49
-$5 to -$10	4.2%	$7.10	4.3%	$7.10	4.3%	$7.06	4.2%	$7.01
-$10 to -$20	2.6%	$13.89	2.7%	$14.17	2.9%	$14.00	2.7%	$14.01
< -$20	3.8%	$154.18	4.0%	$77.99	4.0%	$85.22	3.3%	$116.45

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 2015. Table 9-44 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 42.3 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 8.1 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. The average price differences were $78.11 when the price difference was greater than $20.00, and $111.01 when the price difference was greater than -$20.00.

Table 9-45 shows how the accuracy of the ITSCED forecasted LMPs change as the cases approach real-time.

Table 9-45 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 70.5 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 69.3 percent in the 135 minute ahead ITSCED results.

In 9.7 percent of the intervals in the thirty-minute ahead forecast, 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, the average price differences were $118.50 when the price difference was greater than $20.00, and $116.45 when the price difference was greater than -$20.00.

Table 9-46 and Table 9-47 show the monthly differences between forecasted and actual PJM/MISO interface prices. Analysis of the data on a monthly basis shows that there is a substantial decline in the accuracy of the ITSCED forecast ability during periods of cold weather. For example, Table 9-46 shows that in February, 2015, the absolute value of the average price difference between the ITSCED forecasted LMP and the actual real-time interface LMP in the thirty-minute ahead forecast, was greater than $20.00 in 20.8 percent of the intervals, compared to 7.5 percent of the intervals in September, 2015.

Table 9-46 Monthly Differences between forecast and actual PJM/MISO interface prices (percent of intervals): 2015

Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD Avg
~ 30 Minutes Prior to Real-Time	> $20	5.0%	13.4%	6.3%	9.1%	8.8%	7.5%	5.4%	6.4%	4.1%	2.5%	2.6%	5.9%	6.4%
	$10 to $20	4.0%	6.0%	4.7%	6.6%	8.3%	6.7%	6.1%	4.6%	4.5%	4.1%	2.7%	3.0%	5.1%
	$5 to $10	5.6%	7.5%	6.1%	8.8%	9.9%	7.7%	8.2%	8.6%	8.2%	8.9%	7.0%	7.7%	7.9%
	$0 to $5	49.1%	33.8%	39.6%	40.7%	30.5%	38.2%	39.1%	39.6%	39.7%	47.2%	49.6%	45.6%	41.1%
	$0 to -$5	29.3%	23.3%	30.3%	25.4%	27.6%	29.7%	32.7%	32.6%	32.4%	29.5%	30.2%	29.5%	29.4%
	-$5 to -$10	3.1%	4.7%	5.5%	3.3%	5.7%	4.4%	4.2%	3.2%	5.1%	3.5%	3.3%	4.9%	4.2%
	-$10 to -$20	2.0%	3.9%	3.2%	2.9%	4.6%	3.1%	2.0%	2.0%	2.7%	1.9%	2.4%	1.2%	2.7%
	< -$20	1.9%	7.4%	4.3%	3.2%	4.6%	2.7%	2.3%	2.9%	3.4%	2.4%	2.1%	2.3%	3.3%
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD Avg
~ 45 Minutes Prior to Real-Time	> $20	1.9%	7.3%	3.0%	2.2%	4.4%	2.0%	2.3%	1.9%	1.8%	1.0%	1.3%	0.8%	2.4%
	$10 to $20	2.7%	5.5%	3.1%	5.4%	7.7%	6.0%	5.4%	3.5%	4.4%	3.6%	2.3%	0.9%	4.2%
	$5 to $10	4.4%	6.8%	5.6%	9.0%	10.0%	8.2%	9.2%	9.8%	9.1%	7.5%	6.7%	7.2%	7.8%
	$0 to $5	48.7%	36.8%	40.2%	46.5%	35.0%	40.4%	42.6%	44.6%	39.7%	49.8%	51.7%	52.6%	44.1%
	$0 to -$5	33.4%	23.8%	33.0%	26.5%	27.4%	32.0%	31.8%	30.9%	33.2%	29.9%	30.1%	30.6%	30.3%
	-$5 to -$10	4.1%	5.6%	5.5%	3.8%	6.1%	4.3%	3.3%	3.5%	4.8%	3.8%	3.2%	4.0%	4.3%
	-$10 to -$20	2.1%	4.1%	4.2%	2.8%	4.9%	3.1%	2.4%	2.5%	3.0%	2.0%	2.2%	1.1%	2.9%
	< -$20	2.6%	10.1%	5.5%	3.8%	4.5%	3.8%	3.0%	3.4%	4.1%	2.4%	2.5%	2.8%	4.0%
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD Avg
~ 90 Minutes Prior to Real-Time	> $20	2.2%	7.4%	3.1%	2.4%	4.8%	2.9%	3.7%	2.3%	2.1%	0.9%	1.6%	0.6%	2.8%
	$10 to $20	2.6%	6.7%	3.5%	6.5%	8.5%	6.6%	5.1%	4.2%	5.0%	4.6%	3.0%	1.3%	4.8%
	$5 to $10	4.9%	8.2%	5.6%	9.5%	11.4%	10.1%	9.1%	9.2%	9.6%	8.6%	8.6%	7.7%	8.5%
	$0 to $5	47.8%	35.1%	37.8%	45.6%	36.4%	41.7%	41.9%	43.5%	39.6%	48.8%	51.9%	54.4%	43.8%
	$0 to -$5	33.7%	23.5%	34.1%	26.6%	24.1%	28.1%	31.1%	30.5%	31.7%	28.9%	27.4%	28.6%	29.1%
	-$5 to -$10	3.9%	5.0%	5.8%	3.7%	6.0%	3.9%	3.8%	4.5%	5.1%	3.7%	2.8%	3.5%	4.3%
	-$10 to -$20	2.3%	4.0%	4.5%	2.2%	4.1%	2.9%	2.5%	2.2%	2.6%	2.1%	1.9%	1.2%	2.7%
	< -$20	2.7%	10.1%	5.7%	3.5%	4.7%	3.8%	2.9%	3.7%	4.2%	2.4%	2.8%	2.7%	4.0%
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD Avg
~ 135 Minutes Prior to Real-Time	> $20	3.3%	17.2%	6.8%	3.9%	8.0%	3.7%	6.5%	3.2%	3.7%	1.2%	1.4%	0.6%	4.9%
	$10 to $20	3.4%	6.4%	4.9%	8.2%	11.6%	8.1%	8.8%	6.7%	5.6%	4.8%	5.0%	2.8%	6.3%
	$5 to $10	5.3%	7.5%	6.4%	10.8%	11.7%	10.0%	7.8%	9.5%	7.8%	10.8%	9.5%	10.1%	8.9%
	$0 to $5	48.6%	32.9%	44.4%	46.1%	33.2%	37.7%	38.1%	39.4%	37.4%	47.9%	47.6%	50.6%	42.1%
	$0 to -$5	30.3%	21.9%	24.9%	22.8%	21.2%	28.7%	29.6%	30.0%	31.7%	27.5%	29.0%	27.7%	27.2%
	-$5 to -$10	4.4%	3.7%	4.3%	3.1%	4.6%	4.1%	3.9%	5.0%	6.4%	3.3%	3.0%	4.0%	4.2%
	-$10 to -$20	2.3%	2.9%	3.4%	1.7%	4.4%	3.4%	1.8%	2.6%	3.3%	2.1%	1.8%	1.8%	2.6%
	< -$20	2.5%	7.6%	4.9%	3.3%	5.3%	4.3%	3.4%	3.6%	4.0%	2.4%	2.7%	2.5%	3.8%

Table 9-47 Monthly differences between forecast and actual PJM/MISO interface prices (average price difference): 2015

Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD Avg
~ 30 Minutes Prior to Real-Time	> $20	$72.32	$179.98	$77.48	$67.93	$131.21	$112.13	$143.50	$73.80	$174.88	$110.64	$110.44	$137.74	$118.50
	$10 to $20	$14.47	$14.20	$14.32	$13.91	$14.32	$14.46	$13.81	$13.73	$13.95	$13.12	$14.03	$12.98	$14.01
	$5 to $10	$7.08	$7.17	$6.92	$7.08	$7.14	$7.17	$7.22	$7.02	$7.09	$7.15	$6.86	$7.00	$7.08
	$0 to $5	$1.38	$1.71	$1.57	$1.89	$1.81	$1.70	$1.47	$1.50	$1.49	$1.72	$1.77	$1.80	$1.65
	$0 to -$5	$1.20	$1.66	$1.47	$1.55	$1.71	$1.51	$1.33	$1.33	$1.40	$1.56	$1.53	$1.70	$1.49
	-$5 to -$10	$7.06	$6.93	$7.15	$7.08	$6.99	$7.05	$7.06	$6.90	$7.00	$7.08	$6.95	$6.83	$7.01
	-$10 to -$20	$14.57	$14.38	$13.83	$13.94	$14.40	$14.36	$13.59	$14.11	$13.69	$13.32	$13.61	$13.35	$14.01
	< -$20	$64.95	$89.16	$81.81	$61.00	$302.93	$117.24	$242.09	$57.56	$73.22	$77.09	$93.25	$79.08	$116.45
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD Avg
~ 45 Minutes Prior to Real-Time	> $20	$38.38	$76.48	$47.38	$47.83	$55.94	$45.61	$35.59	$52.44	$61.51	$34.42	$62.04	$60.25	$55.43
	$10 to $20	$13.86	$14.16	$14.53	$14.00	$13.81	$14.57	$13.44	$13.54	$13.28	$13.17	$13.45	$12.77	$13.81
	$5 to $10	$6.83	$7.06	$6.98	$7.06	$7.01	$7.18	$7.17	$7.05	$7.14	$7.07	$6.77	$6.79	$7.02
	$0 to $5	$1.39	$1.71	$1.51	$1.78	$1.87	$1.71	$1.48	$1.47	$1.51	$1.78	$1.73	$1.77	$1.64
	$0 to -$5	$1.16	$1.65	$1.37	$1.54	$1.68	$1.44	$1.27	$1.28	$1.37	$1.53	$1.43	$1.57	$1.43
	-$5 to -$10	$7.00	$7.15	$7.15	$7.15	$7.15	$7.01	$7.15	$6.95	$7.25	$7.01	$7.05	$6.57	$7.06
	-$10 to -$20	$14.20	$14.29	$14.03	$14.07	$14.34	$13.82	$13.51	$14.18	$13.76	$13.70	$13.58	$13.97	$14.00
	< -$20	$65.24	$87.97	$79.77	$60.42	$61.17	$64.39	$210.33	$75.47	$76.45	$81.72	$93.67	$90.13	$85.22
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD Avg
~ 90 Minutes Prior to Real-Time	> $20	$35.50	$49.65	$34.82	$36.85	$75.57	$34.78	$59.65	$47.82	$63.03	$33.22	$33.66	$33.75	$49.22
	$10 to $20	$14.57	$13.92	$14.26	$14.38	$13.89	$13.82	$13.90	$13.75	$13.66	$13.42	$14.09	$12.28	$13.90
	$5 to $10	$7.02	$7.08	$7.01	$7.02	$7.09	$7.19	$7.19	$7.00	$7.09	$6.93	$6.79	$6.87	$7.03
	$0 to $5	$1.50	$1.84	$1.52	$1.90	$1.95	$1.85	$1.59	$1.54	$1.71	$1.83	$1.86	$1.88	$1.75
	$0 to -$5	$1.27	$1.64	$1.49	$1.55	$1.69	$1.47	$1.38	$1.39	$1.42	$1.53	$1.43	$1.62	$1.48
	-$5 to -$10	$6.99	$7.14	$7.07	$7.07	$7.22	$7.31	$7.08	$7.19	$7.30	$6.82	$6.87	$6.86	$7.10
	-$10 to -$20	$13.96	$14.36	$14.12	$14.37	$13.93	$14.73	$14.01	$14.15	$14.02	$14.01	$14.04	$14.36	$14.17
	< -$20	$63.58	$92.77	$77.28	$64.82	$56.22	$64.80	$107.12	$66.59	$75.33	$82.91	$86.82	$91.78	$77.99
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD Avg
~ 135 Minutes Prior to Real-Time	> $20	$40.26	$59.00	$51.79	$28.67	$47.84	$33.85	$36.65	$41.51	$30.25	$27.67	$30.09	$35.08	$45.09
	$10 to $20	$14.22	$14.55	$14.36	$14.42	$14.40	$14.09	$14.45	$14.08	$14.52	$13.32	$13.45	$12.41	$14.15
	$5 to $10	$6.89	$6.93	$6.91	$7.06	$7.13	$7.01	$7.17	$7.05	$7.21	$6.96	$6.95	$7.00	$7.03
	$0 to $5	$1.55	$1.83	$1.83	$1.97	$1.96	$1.82	$1.71	$1.72	$1.78	$1.96	$1.96	$1.90	$1.83
	$0 to -$5	$1.41	$1.64	$1.50	$1.55	$1.78	$1.54	$1.45	$1.51	$1.55	$1.53	$1.50	$1.63	$1.54
	-$5 to -$10	$7.03	$6.97	$7.03	$7.03	$7.07	$7.38	$7.06	$7.17	$7.20	$7.22	$6.87	$7.00	$7.10
	-$10 to -$20	$13.58	$14.14	$14.07	$14.20	$13.95	$14.02	$13.73	$13.79	$13.84	$13.68	$13.79	$13.71	$13.89
	< -$20	$61.06	$95.73	$75.57	$63.59	$144.64	$300.30	$679.32	$67.48	$89.01	$81.25	$89.97	$94.30	$154.18

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 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 participant pays 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 addressed most of the MMU concerns, as there can no longer be uncollected congestion charges for imports to PJM or exports from PJM (Table 9-48 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 appropriate to address this exposure.

Table 9-48 Monthly uncollected congestion charges: 2010 through 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	$0
Aug	$731,539	$37	$0	$0	$0	$0
Sep	$119,162	$0	$0	$0	$0	$0
Oct	$257,448	($31,443)	($6,870)	$0	$0	$0
Nov	$30,843	($795)	($4,678)	$0	$0	$0
Dec	$127,176	($659)	($209)	$0	$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, all termed willing to pay congestion (WPC), were part of the PJM LMP energy market design implemented on April 1, 1998. Under this approach, market participants could offer energy into or bid to buy from the PJM spot market at the border/interface as price takers without restrictions based on estimated available transmission capability (ATC). Price and PJM system conditions, rather than ATC, were the only limits on interchange.

However, PJM has interpreted its JOA with MISO to require restrictions on spot imports and exports although MISO has not implemented a corresponding restriction.[83]

The result is that the availability of spot import service is limited by ATC and not all spot transactions are approved. Spot import service (a network service) is provided at no charge to the market participant offering into the PJM spot market.

The new spot import rules provide incentives to hoard spot import capability. 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.[84] 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.

These changes did not fully resolve the issue. 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 queue time of the reservations intraday, and two hours when queued the day prior. On June 23, 2009, PJM implemented the new business rules.

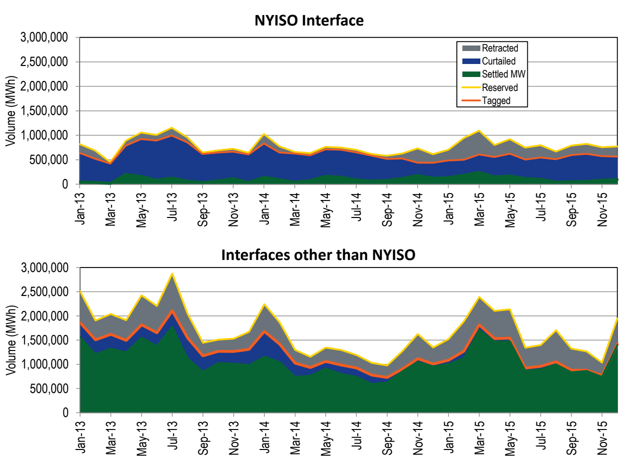
Figure 9-15 shows the spot import service use for the NYISO Interface, and for all other interfaces, from 2013 through 2015. The yellow line shows the total monthly MWh of spot import service reserved and the orange line shows the total monthly MWh of tagged spot import service. The gray shaded area between the yellow and orange lines represents the MWh of retracted spot import service and may represent potential hoarding volumes. This ATC was initially reserved, but not tagged (used). It is possible that in some instances the reserved transmission consisted of the only available ATC which could have been used by another market participant had it not been reserved and not used. The blue shaded area between the orange line and green shaded area represents the MWh of curtailed transactions using spot

83 See OASIS "Modifications to the Practices of Non-Firm and Spot Market Import Service," <http://www.pjm.com/~/media/etools/oasis/wpc-white-paper.ashx>.(April 20, 2007)

84 See OASIS "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)

import service. This area may also represent hoarding opportunities, particularly at the NYISO interface. In this instance, it is possible that while the market participant reserved and scheduled the transmission, they may have submitted purposely uneconomic bids in the NYISO market so that their transaction would be curtailed, yet their transmission would not be retracted. The NYISO allows for market participants to modify their bids on an hourly basis, so these market participants can hold their transmission service and evaluate their bids hourly, while withholding the transmission from other market participants that may wish to use it. The green shaded area represents the total settled MWh of spot import service. Figure 9-15 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.

Figure 9-15 Spot import service use: 2013 through 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. 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 for PJM system operators 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 1800 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 used 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 affect the duration of interchange transactions.

The MMU recommends that PJM explore an interchange optimization solution with its neighboring balancing authorities that would 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 uses supply curves and treats seams between balancing authorities as constraints, similar to other constraints within an LMP market.

Interchange Cap During Emergency Conditions

An interchange cap is a limit on the level of interchange permitted for nondispatchable energy using spot import or hourly point-to-point transmission. An interchange cap is a non-market intervention which should be a temporary solution and should be replaced with a market based solution as soon as possible. Since the approval of this process on October 30, 2014, PJM has not yet needed to implement an interchange cap.

The purpose of the interchange cap is to help ensure that actual interchange more closely meets operators' expectations of interchange levels when internal PJM resources, e.g. CTs or demand response, were dispatched to meet the peak load. Once these resources have been called on, PJM must honor their minimum operating constraints regardless of whether additional interchange then materializes; therefore any interchange received in excess of what was expected can have a suppressive effect on energy and reserve pricing and result in increased uplift.[85]

PJM will notify market participants of the possible use of the interchange cap the day before. The interchange cap will be implemented for the forecasted peak and surrounding hours during emergency conditions.

The interchange cap will limit the acceptance of spot import and hourly non-firm point to point interchange (imports and exports) not submitted as real-time with price transactions once net interchange has reached the interchange cap value. Spot imports and hourly non-firm point to point transactions submitted prior to the implementation of the interchange cap will not be limited. In addition, schedules with firm or network designated transmission service will not be limited either, regardless of whether net interchange is at or above the cap.

The calculation of the interchange cap is based on the operator expectation of interchange at the time the cap is calculated plus an additional margin. The margin is set at 700 MW, which is half of the largest contingency on the system. The additional margin also allows interchange to adjust to the loss of a unit or deviation between actual load and forecasted load. The interchange cap is based on the maximum sustainable interchange from PJM reliability studies.

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, which required transmission providers to give transmission customers the option to schedule transmission service at 15 minute intervals to reflect more accurate power production forecasts, load and system conditions.[86,87] On April 17, 2014, FERC issued its order which found that PJM's 45 minute duration rule was inconsistent with Order 764.[88]

PJM and the MMU issued a statement indicating ongoing concern about market participants' scheduling behavior, and a commitment to address any scheduling

85 The material in this section is based in part on the *Energy and Reserve Pricing & Interchange Volatility Final Proposal Report*. See PJM. <http://www.pjm.com/~/media/committees-groups/committees/mrc/20141030/20141030-item-04-erpiv-final-proposal-report.ashx>.

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 Order No. 764 at P 51.

88 See *Id.* at P 12.

behavior that raises operational or market manipulation concerns.[89]

Interchange Transaction Credit Screening Process

On November 3, 2014, to address potential default risk, PJM implemented a credit screening process for export interchange transactions submitted to PJM which requires participants to create reserves equal to the MWh of each transaction times a price for each transaction. The price is the higher of 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. 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. If the full amount of reserves is not created, the transaction is curtailed.

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>.

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 formulaic rates or cost.

The Market Monitoring Unit (MMU) analyzed measures of market structure, conduct and performance for the PJM Regulation Market, the PJM Synchronized Reserve Market, and the PJM DASR Market for 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 2015 because the Regulation Market failed the three pivotal supplier (TPS) test in 97.8 percent of the hours in 2015.
- Participant behavior in the Regulation Market was evaluated as competitive for 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, 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 design has failed to correctly incorporate a consistent implementation of the marginal benefit factor in optimization, pricing and settlement. The market results continue to include the incorrect definition of opportunity cost.

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 Tier 2 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, although there is concern about failure to comply with the must offer requirement.
- 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 nonzero 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

- The Day-Ahead Scheduling Reserve Market structure was evaluated as not competitive because market participants failed the three pivotal supplier test in 6.4 percent of all cleared hours in 2015.
- Participant behavior was evaluated as mixed because while most offers were equal to marginal costs, a significant proportion of offers reflected economic withholding.
- Market performance was evaluated as competitive because there were adequate offers in every hour to satisfy the requirement and the clearing prices reflected those offers, although there is concern

1 75 FERC ¶ 61,080 (1996).
2 Energy imbalance service refers to the Real-Time Energy Market.

about offers above the competitive level affecting prices.

- Market design was evaluated as mixed because while the market is functioning effectively to provide DASR, the three pivotal supplier test and appropriate market power mitigation should be added to the market to ensure that market power cannot be exercised at times of system stress.

Overview

Primary Reserve

PJM's primary reserves are made up of resources, both synchronized and non-synchronized, that can provide energy within ten minutes. Primary reserve is PJM's implementation of the NERC 15-minute contingency reserve requirement.[3]

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 available to start 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 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 Zone in 2015 was 2,210.3 MW. The actual demand for primary reserve in the MAD Subzone in 2015 was 1,713.3 MW.

Tier 1 Synchronized Reserve

Synchronized reserve is energy or demand reduction synchronized to the grid and capable of increasing output or decreasing load within ten minutes. Synchronized reserve is of two distinct types, tier 1 and tier 2.

Tier 1 synchronized reserve is part of primary reserve and is 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. There is no formal market for tier 1 synchronized reserve.

- **Supply.** No offers are made for tier 1 synchronized reserve. The market solution estimates tier 1 synchronized reserve as available 10-minute ramp from the energy dispatch. In 2015, there was an average hourly supply of 1,363.9 MW of tier 1 for the RTO Synchronized Reserve Zone, and an average hourly supply of 1,159.6 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. The requirement can be met with tier 1 or tier 2 synchronized reserves.
- **Tier 1 Synchronized Reserve Event Response.** Tier 1 synchronized reserve is paid when a synchronized reserve event occurs and it responds. When a synchronized reserve event is called, all tier 1 response is paid the average of five-minute LMPs during the event, rather than hourly integrated LMP, plus $50/MW. This is the Synchronized Energy Premium Price. The synchronized reserve event response credits for tier 1 response are independent of the tier 2 synchronized reserve market clearing price and independent of the non-synchronized reserve market clearing price.

  Of tier 1 synchronized reserve estimated at market clearing, 65.7 percent actually responded during the seven distinct synchronized reserve events longer than ten minutes in 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 offer 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 and the appropriate payment for responding to an event is the five-minute LMP plus $50 per MWh. A tariff change included in the shortage pricing tariff changes (October 1, 2012) added the requirement to pay

3 See PJM. "Manual 10: Pre-Scheduling Operations," Revision. 33 (December 22, 2015), p. 24.

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 $10,406,363 to tier 1 resources in 2014, and $34,135,671 in 2015.

Tier 2 Synchronized Reserve Market

Tier 2 synchronized reserve is part of primary reserve 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 met with tier 1 synchronized reserve, PJM conducts a market to satisfy the balance of 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 2015, the supply of offered and eligible synchronized reserve was 8,549 MW in the RTO Zone of which 3,114 MW (including DSR) was available to the MAD Subzone. This 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 the RTO Reserve Zone and 1,450 MW for the Mid-Atlantic Dominion Reserve Subzone. The requirement can be met with tier 1 or tier 2 synchronized reserves.
- **Market Concentration.** In 2015, the weighted average HHI for cleared tier 2 synchronized reserve in the Mid-Atlantic Dominion Subzone was 5436 which is classified as highly concentrated. The MMU calculates that 55.7 percent of hours would have failed a three pivotal supplier test in the Mid-Atlantic Dominion Subzone.

  In 2015, the weighted average HHI for cleared tier 2 synchronized reserve in the RTO Synchronized Reserve Zone was 4617 which is classified as highly concentrated. The MMU calculates that 40.2 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 2015.

Market Conduct

- **Offers.** There is a must offer requirement for tier 2 synchronized reserve. All non-emergency generation capacity resources are required to submit a daily offer for tier 2 synchronized reserve. 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 for tier 2 synchronized reserve for all cleared hours in the Mid-Atlantic Dominion (MAD) Subzone was $10.12 per MW in 2015, a decrease of $5.38, 34.7 percent from 2014.

  The weighted average price for tier 2 synchronized reserve for all cleared hours in the RTO Synchronized Reserve Zone was $11.88 per MW in 2015, a decrease of $1.06, 8.2 percent from 2014.

Non-Synchronized Reserve Market

Non-synchronized reserve is part of primary reserve and includes 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. There is no formal market for non-synchronized reserve.

Market Structure

- **Supply.** In 2015, the supply of eligible non-synchronized reserve was 2,550.1 MW in the RTO Zone and 1,860.8 MW in MAD Subzone.[4]
- **Demand.** Demand for non-synchronized reserve is the remaining primary reserve requirement after tier 1 synchronized reserve is estimated and tier 2 synchronized reserve is scheduled. In the RTO Zone, the market cleared an hourly average of 345.1 MW of non-synchronized reserve in 2015. In the MAD Subzone, the market cleared an hourly average of 390.3 MW of non-synchronized reserve.
- **Market Concentration.** In 2015, the weighted average HHI for cleared non-synchronized reserve in the Mid-Atlantic Dominion Subzone was 4133 which is classified as highly concentrated. In the RTO Zone the weighted average HHI was 4533 which is also highly concentrated. The MMU calculates that 95.1 percent of hours would have failed a three pivotal supplier test in the Mid-Atlantic Dominion Subzone and 68.0 hours would have failed a three pivotal supplier test in the RTO Zone.

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.** 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 $1.15 per MW in 2015 and in 87.9 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 $1.03 and in 87.6 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.[5] The DASR Market has no performance obligations.

Market Structure

- **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 2015, the average available hourly DASR was 36,396.0 MW.
- **Demand.** The DASR requirement in 2015 was 5.93 percent of peak load forecast, down from 6.27 percent in 2014. The average DASR MW purchased was 6,245.0 MW per hour 2015.
- **Concentration.** In 2015, the DASR Market would have failed a three pivotal supplier test in 4.1 percent of hours.

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. In 2015 a daily average of 37.9 percent of units offered above $0. In 2015 a daily average of 11.6 percent of units offered above $5.
- **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 for all cleared hours in 2015 was $2.99 per MW, an increase from $0.63 per MW in 2014.

4 See PJM. "Manual 11; Energy & Ancillary Services Markets," Revision 79 (December 17, 2015), p. 81. "Because Synchronized Reserve may be utilized to meet the Primary Reserve requirement, there is no explicit requirement for non-synchronized reserves. "

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

Regulation Market

The PJM Regulation Market is a 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 in actual MW into effective MW.

Market Structure

- **Supply.** In 2015, the average hourly eligible supply of regulation was 1,157.8 actual MW (889.9 effective MW). This is a decrease of 122.5 actual MW (27.5 effective MW) from the same period of 2014, when the average hourly eligible supply of regulation was 1,280.3 actual MW (917.4 effective MW).
- **Demand.** The average hourly regulation demand was 640.9 actual MW (663.7 effective MW) in 2015. This is a decrease of 19.8 actual MW (0 effective MW) in the average hourly regulation demand of 660.7 actual MW (663.7 effective MW) from the same period of 2014.
- **Supply and Demand.** The ratio of the average hourly eligible supply of regulation to average hourly regulation demand required was 1.81. This is a 6.70 percent decrease from the same period of 2014 when the ratio was 1.94.
- **Market Concentration.** In 2015, the weighted average (HHI) was 1358 which is classified as moderately concentrated. In 2015, the three pivotal supplier test was failed in 97.8 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 and may 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.[6] In 2015, there were 291 resources following the RegA signal and 57 resources following the RegD signal.

Market Performance

- **Price and Cost.** The weighted average clearing price for regulation was $31.92 per effective MW of regulation in 2015, a decrease of $12.55 per MW, or 28.2 percent, from the same period of 2014. The cost of regulation in 2015 was $38.36 per effective MW of regulation, a decrease of $15.46 per MW, or 28.7 percent, from the same period of 2014. The decreases in regulation price and regulation cost resulted primarily from high energy prices in 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 the same price per effective MW.
- **Marginal Benefit Factor Function.** The marginal benefit factor (MBF) measures the substitutability of RegD resources for RegA resources. The marginal benefit factor function is incorrectly applied in the market clearing and incorrectly describes the operational relationship between RegA and RegD.
- **Interim changes to the MBF function.** On December 14, 2015, PJM changed the MBF curve. The modification to the marginal benefit curve did not correct the identified issues with the optimization engine.

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 (automatic load rejection or ALR).[7]

In 2015, total black start charges were $53.6 million with $48.4 million in revenue requirement charges

6 See the *2015 State of the Market Report for PJM*, Volume II, Appendix F "Ancillary Services Markets."

7 OATT Schedule 1 § 1.3BB.

and $5.2 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 ALR option or for black start testing. Black start zonal charges in 2015 ranged from $0.04 per MW-day in the PPL Zone (total charges were $118,541) to $3.81 per MW-day in the BGE Zone (total charges were $9,277,796).

Reactive

Reactive service, reactive supply and voltage control are 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 2015, total reactive service charges were $289.0 million, a 6.1 percent decrease from $307.7 million in 2014. Revenue requirement charges decreased from $281.2 million to $278.4 million and operating reserve charges fell from $26.5 million to $10.7 million. Total charges in 2015 ranged from $2,488 in the RECO Zone to $38.5 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, per MWh of load. 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. 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 changes in total load.

Table 10-4 History of ancillary services costs per MWh of Load: 2004 through 2015[8]

Year	Regulation	Scheduling, Dispatch, and System Control	Reactive	Synchronized Reserve	Total
2004	$0.50	$0.60	$0.25	$0.13	$1.48
2005	$0.79	$0.47	$0.26	$0.11	$1.63
2006	$0.53	$0.48	$0.29	$0.08	$1.38
2007	$0.63	$0.47	$0.29	$0.06	$1.45
2008	$0.68	$0.40	$0.31	$0.08	$1.47
2009	$0.34	$0.32	$0.37	$0.05	$1.08
2010	$0.34	$0.38	$0.41	$0.07	$1.20
2011	$0.32	$0.34	$0.42	$0.10	$1.18
2012	$0.26	$0.40	$0.43	$0.04	$1.13
2013	$0.24	$0.39	$0.80	$0.04	$1.47
2014	$0.31	$0.37	$0.37	$0.20	$1.25
2015	$0.23	$0.41	$0.37	$0.12	$1.13

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 2012. Status: Not adopted.)
- The MMU recommends a number of market design changes to improve the performance of the Regulation Market, including use of a single clearing price based on actual LMP, modifications to the LOC calculation methodology, a software change to save some data elements necessary for verifying market outcomes, and further documentation of the implementation of the market design through SPREGO. (Priority: Medium. First reported 2010. Status: Partially adopted in 2012.)
- The MMU recommends that the lost opportunity cost in the ancillary services markets be calculated using the schedule on which the unit was scheduled to run in the energy market. (Priority: High. First reported 2010. Status: Partially Adopted.)
- The MMU recommends that the single clearing price for synchronized reserves be determined based on the actual LMP and not the forecast LMP. (Priority: Low. First reported 2010. Status: Adopted, 2012.)

8 Table 10-4 no longer includes the heading for "Supplemental Operating Reserve" costs. This heading included day-ahead and balancing operating reserve charges. These charges are accounted for in the Energy Uplift (Operating Reserves) section.

- 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. The MMU also recommends that documentation of the Tier 1 synchronized reserve deselection process be published. (Priority: High. First reported Q3, 2014. Status: Adopted July 2014.)
- The MMU recommends that the tier 2 synchronized reserve must offer requirement be enforced. The MMU recommends that PJM define a set of acceptable reasons why a unit can be made unavailable daily or hourly and require operators to select a reason in eMkt whenever making a unit unavailable. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM be explicit about why tier 1 biasing is used in the Tier 2 Synchronized Reserve Market. The MMU recommends that PJM define explicit rules for the use of tier 1 biasing during any phase of the market solution and 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: Partially adopted, 2014.)
- The MMU recommends that the three pivotal supplier test and market power mitigation 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 market operations adds additional DASR MW. (Priority: Medium. First reported Q2, 2015. 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. The market design has failed to correctly incorporate the marginal benefit factor in optimization, pricing and settlement. The market design uses 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 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 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. However, compliance with calls to respond to actual synchronized reserve events has been an issue. The must offer requirement for tier 2 synchronized reserve has not been enforced.

The rule that requires payment of the tier 2 synchronized reserve price to tier 1 synchronized reserve resources when the non-synchronized reserve price is greater than zero, is inefficient and results in a substantial 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. Tier 1 resources are paid for their response if they do respond. 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. If tier 1 resources wish to be paid as tier 2 resources, that option is available. Application of this rule added $10.4 million to the cost of primary reserve in 2014 and $34.1 million to the cost of primary reserve in 2015.

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 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, although there is concern about offers above the competitive level affecting prices.

Primary Reserve

PJM has an obligation to maintain ten minute reserves (primary reserve) to ensure reliability in the event of disturbances. PJM's primary reserves are made up of resources, both synchronized and non-synchronized, that can provide energy within ten minutes. Primary reserve is PJM's implementation of the NERC 10-minute contingency reserve requirement.[9] 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.[10]

Market Structure

Supply

In 2015, PJM's primary reserve requirement was 2,175 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. The synchronized reserve requirement is 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 the least expensive combination of synchronized and non-synchronized reserves.

Estimated tier 1 is credited against PJM's primary reserve requirement. In the MAD Subzone an average of 1,159.7 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. Tier 1 synchronized reserve fully satisfied the MAD Subzone synchronized reserve requirement in only 1.1 percent of hours in 2015. In the RTO Zone, an average of 1,373.9 MW of tier 1 was available (Table 10-6). Tier 1 synchronized reserve fully satisfied the RTO Zone synchronized reserve requirement in 35.9 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.[11]

After tier 1 is estimated, the remainder of the synchronized reserve requirement is met by tier 2. In the MAD Subzone, there was an average of 3,114.3 MW (including DSR) of eligible tier 2 synchronized reserve available (Figure 10-11) to meet the average tier 2 hourly demand of 314.8 MW (Table 10-5). In the RTO Zone, there was an average of 8,549.2 MW of eligible Tier 2 supply, available to meet the average hourly demand of 456.9 MW (Table 10-6).

In the MAD Subzone, there was an average of 1,860.8 MW of eligible non-synchronized reserve supply available to meet the average hourly demand of 390.3 MW (Table 10-6). In the RTO Zone, an hourly average of 2,550.1 MW supply was available to meet the average hourly demand of 736.3 MW (Table 10-5).

9 PJM. OATT (effective 2/5/2014), p.1740; § 1.3.29 F Primary Reserve.
10 NERC, IVGTF Task 2.4 Report; Operating Practices, Procedures, and Tools, March 2011, p. 20.
11 See PJM, "Manual 11: Energy & Ancillary Services Market Operations," Revision 79 (December 17, 2015), p. 67.

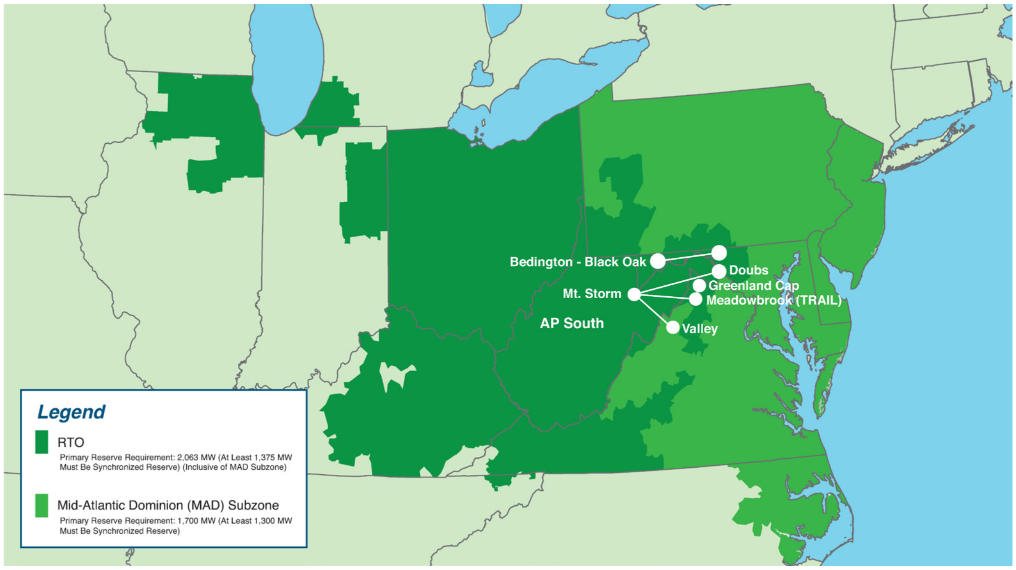
Demand

PJM requires that 150 percent of the largest contingency on the system be maintained as primary reserve. Adjustments to this value can occur when grid maintenance or outages change the largest contingency or in cases of hot weather alerts or cold weather alerts.

On January 8, 2015, the default primary reserve requirement in the RTO Reserve Zone was raised from 2,063 MW to 2,175 MW and remained at 2,175 MW throughout 2015. In 10.2 percent of hours during 2015, PJM increased the primary reserve requirement for the RTO Zone. In 4.9 percent of hours PJM decreased the primary reserve requirement for the RTO Zone. The hourly average RTO primary reserve requirement was 2,210.3 MW in all of 2015. In 1.5 percent of hours in 2015, PJM increased the primary reserve requirement for the MAD Subzone. The actual hourly average demand for primary reserve in the MAD Subzone in all of 2015 was 1,713.3 MW.

Transmission constraints limit the deliverability of reserves within the RTO, requiring the definition of the Mid-Atlantic Dominion (MAD) Subzone.[12] 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 Zone and MAD Subzone geography: 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 79.2 percent of hours in 2015, that constraint was the Bedington – Black Oak Interface. The AP South transfer interface constraint was the limiting constraint in 19.3 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 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: 2015

Year	Month	Average Tier 1 Synchronized Reserve MW	Average Tier 2 Synchronized Reserve MW	Average 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	1,260.3	216.6	372.1
2015	Jul	1,222.4	254.9	437.0
2015	Aug	1,176.9	293.9	421.7
2015	Sep	1,110.8	363.0	351.0
2015	Oct	1,054.4	478.5	263.6
2015	Nov	1,056.3	385.1	319.7
2015	Dec	1,069.1	443.6	288.6
2015	Average	1,159.6	314.8	390.3

12 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 & Ancillary Services Market Operations," Revision 78 (December 1, 2015), p. 69.

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: 2015

Year	Month	Average Tier 1 Synchronized Reserve MW	Average Tier 2 Synchronized Reserve MW	Average 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	1,635.3	300.0	767.4
2015	Jul	1,620.5	320.1	752.3
2015	Aug	1,635.6	357.0	767.3
2015	Sep	1,419.2	449.9	703.1
2015	Oct	1,004.3	727.3	589.2
2015	Nov	1,217.2	616.8	347.9
2015	Dec	1,165.2	727.8	317.1
2015	Average	1,363.9	456.9	736.8

Supply and Demand

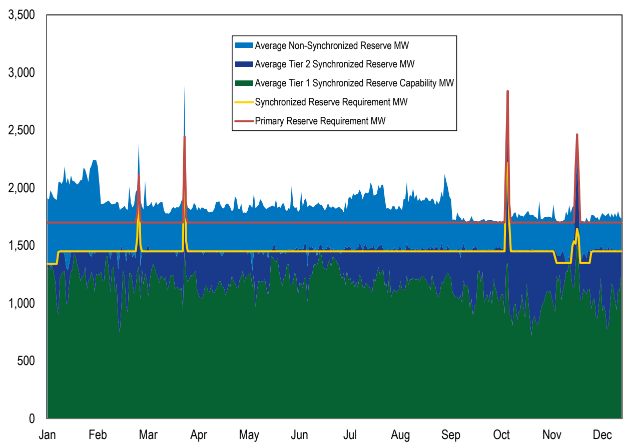
The market solution software relevant to reserves consists of: the Ancillary Services Optimizer (ASO) solving hourly; the intermediate term security constrained economic dispatch market solution (IT-SCED) solving every 15 minutes; and the real-time (short term) security constrained economic dispatch market solution (RT-SCED) solving every five minutes.

The ASO jointly optimizes energy, synchronized reserves, and non-synchronized reserves 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): 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.[13] Figure 10-3 shows how the hour ahead ASO satisfies the primary reserve requirement for the RTO Zone.

13 Although tier 1 has a price of zero, changes made with shortage pricing on November 1, 2012, have given tier 1 a very high cost in some hours. This high cost raises questions about the economics of the solution methodology used by the ASO, IT-SCED, and RT-SCED market solutions which assume zero cost.

Figure 10-3 RTO Reserve Zone primary reserve MW by source (Daily Averages): 2015

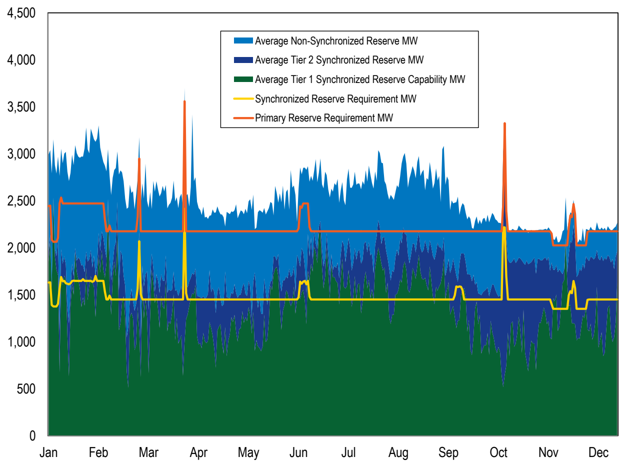


Figure 10-2 and Figure 10-3 show that tier 1 synchronized reserve remains the major contributor to satisfying the synchronized reserve requirements both in the RTO Zone and the Mid-Atlantic Dominion (MAD) Subzone.

Price and Cost

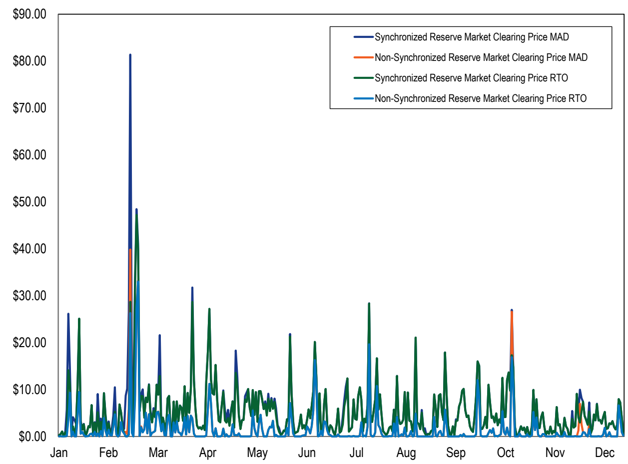
There is a separate price and cost for each component of primary reserve. In the market solution, the cost of tier 1 synchronized reserves is zero except in defined circumstances, as there is no incremental cost associated with the ability to ramp up from the current economic dispatch point nor is there 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 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. Effective June 1, 2014, through May 31, 2015, the penalty factor for both products is $550 per MW. After June 1, 2015, the penalty factor is $850 per MW. PJM will review the penalty factor annually.

Figure 10-4 shows daily average synchronized and non-synchronized market clearing prices in 2015.

Figure 10-4 Daily weighted average market clearing prices ($/MW) for synchronized reserve and non-synchronized reserve: 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 and tier 1 synchronized reserve. 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, RTO Reserve Zone: 2015

Product	Share of Primary Reserve Requirement	MW Scheduled	Credits Paid	Price Per MW Reserve	Cost Per MW Reserve	All-In Cost
Tier 1 Synchronized Reserve Response	NA	7,145	$351,212	NA	$49.15	$0.00
Tier 1 Synchronized Reserve	14.3%	1,715,532	$34,135,671	$0.00	$19.90	$0.04
Tier 2 Synchronized Reserve	26.9%	3,221,120	$58,731,146	$11.41	$18.23	$0.08
Non-synchronized Reserve	58.7%	7,038,700	$13,785,091	$1.15	$1.96	$0.02
Primary Reserve (total of above)	100.0%	$11,982,497	$107,003,120	$0.42	$8.93	$0.14

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, tier 1 resources are not financially obligated to respond 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 2015, in the RTO Reserve Zone the average hourly estimated tier 1 synchronized reserve was 1,363.9 MW (Table 10-6). In 35.9 percent of hours, 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 2015, in the MAD Reserve Subzone the average hour ahead estimated tier 1 synchronized reserve was 1,159.6 MW (Table 10-5). In 1.1 percent 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, 2015

Mid-Atlantic Dominion Reserve Zone						
Year	Month	Average Hourly Tier 1 Local to MAD	Synchronized Reserve Available from RTO	Average Hourly Tier 1 Used	Minimum Hourly Tier 1 Used	Maximum Hourly Tier 1 Used
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	742.4	517.9	1,260.3	515.9	2,573.5
2015	Jul	712.3	510.1	1,222.4	610.2	2,298.0
2015	Aug	682.3	494.6	1,176.9	344.2	2,884.6
2015	Sep	547.1	563.6	1,110.8	398.8	2,316.8
2015	Oct	349.7	704.7	1,054.4	400.2	2,461.0
2015	Nov	518.4	537.9	1,056.3	355.0	2,163.1
2015	Dec	438.3	630.9	1,069.1	284.9	2,200.8
2015	Average	550.1	609.6	1,159.6	381.5	2,208.6

RTO Reserve Zone						
Year	Month	Average Hourly Tier 1 Local to MAD	Synchronized Reserve Available from RTO	Average Hourly Tier 1 Used	Minimum Hourly Tier 1 Used	Maximum Hourly Tier 1 Used
2015	Jan	NA	NA	1,582.7	0.0	3,240.4
2015	Feb	NA	NA	1,469.1	0.0	2,980.4
2015	Mar	NA	NA	1,247.2	0.0	2,727.6
2015	Apr	NA	NA	1,125.1	191.5	2,132.2
2015	May	NA	NA	1,245.1	0.0	3,408.5
2015	Jun	NA	NA	1,635.3	0.0	5,547.7
2015	Jul	NA	NA	1,620.5	0.0	3,443.4
2015	Aug	NA	NA	1,635.6	0.0	3,985.4
2015	Sep	NA	NA	1,419.2	0.0	3,096.5
2015	Oct	NA	NA	1,004.3	0.0	2,499.6
2015	Nov	NA	NA	1,217.2	0.0	2,909.6
2015	Dec	NA	NA	1,165.2	302.0	3,653.7
2015	Average			1,363.9	41.1	3,302.1

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, DGP (Degree of Generator Performance) was introduced as a metric 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 and the available tier 1 MW for that resource is adjusted by the percentage of the DGP. 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.[14]

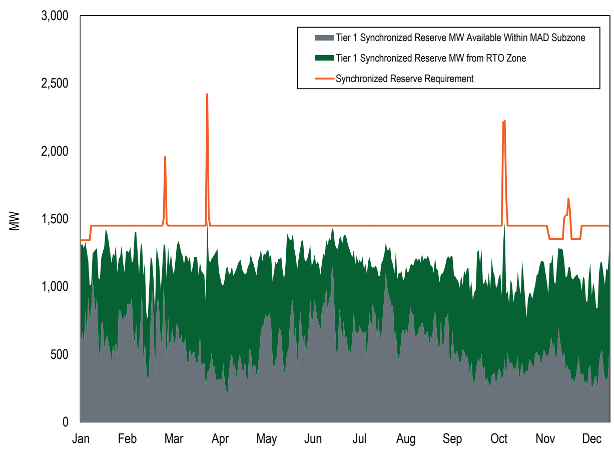
For 2015, PJM estimated Tier 1 MW for an average of 147 units as part of the solution each hour. The average DGP was 84.7 percent for those 147 units.

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 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. 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: 2015



Demand for synchronized reserve in the RTO Zone in 2015, was 2.1 percent higher than in 2014 primarily because the hourly synchronized reserve requirement was increased from 1,375 MW to 1,450 MW. There were temporary increases in the hourly synchronized reserve requirement to 2,688 MW on February 28, 2015 and to 2,615 MW on March 29, 2015 because of emergency outages. Other increases include June 10 through June 15 to 1,644 MW, September 18 through September 23 to 1,588 MW, October 19 through October 21 to 2,217 MW. Usually, the synchronized reserve requirement is increased because of planned outages in the spring and fall for periods of 10 to 14 days sometimes these outages impact the largest contingency requiring an increase in the synchronized reserve requirement. An outage from November 20 through December 12 caused a reduction in the synchronized reserve requirement to 1,350 MW.

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

14 PJM. Ancillary Services, "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> (May 6, 2015).

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 2015, tier 1 synchronized reserve synchronized reserve event response credits of $351,212 were paid for 7,145.0 MW of tier 1 response at an average cost per MW of $50.99, for 22 spinning events (Table 10-9).

Table 10-9 Tier 1 synchronized reserve event response costs: January 2014 through December 2015

Year	Month	Synchronized Reserve Event Response Hours	Total Tier 1 Synchronized Reserve Event Response MW	Total Tier 1 Synchronized Reserve Event Response Credits	Tier 1 Synchronized Reserve Event Response Cost	Average Tier 1 MW Response
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
2014	Total	37	17,962.1	$1,530,978	$57.26	392.2
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
2015	Jul	1	502.2	$25,540	$50.86	502.2
2015	Aug	2	648.3	$7,730	$11.92	324.1
2015	Sep	3	678.5	$30,077	$44.33	226.2
2015	Oct	0	NA	NA	NA	NA
2015	Nov	2	252.9	$15,914	$62.92	126.5
2015	Dec	2	602.9	$79,215	$131.39	301.4
2015	Total	22	7,145.0	$351,212	$50.99	319.8

Paying Tier 1 the Tier 2 Price

The market solutions correctly treat tier 1 synchronized reserve as having zero marginal 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 average synchronized reserve market clearing price of $30.67 per MW and earned $10,406,363 in credits. In 2015, PJM paid $34,135,671 in credits for tier 1 estimated during the 1,089 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 December 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	53,014	$4,874,314	414.9
2014	Feb	15	$40.18	65,332	$337,903	560.5
2014	Mar	67	$44.56	34,150	$1,513,636	509.7
2014	Apr	99	$16.07	57,047	$916,275	576.2
2014	May	61	$15.85	50,455	$799,911	827.1
2014	Jun	4	$35.46	3,335	$118,273	833.9
2014	Jul	5	$17.02	3,941	$67,078	788.1
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
2014	Total	541	$30.67	471,159	$10,406,363	832.9
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	95	$17.64	185,148	$3,183,436	1,948.9
2015	Jul	46	$35.12	64,516	$2,265,614	1,402.5
2015	Aug	38	$22.40	48,479	$1,078,199	1,275.8
2015	Sep	36	$31.53	51,968	$1,522,913	1,060.5
2015	Oct	113	$17.10	126,879	$2,169,670	1,122.8
2015	Nov	29	$14.65	29,156	$427,056	1,005.4
2015	Dec	51	$16.07	53,898	$865,969	1,005.4
2015	Total	1,069	$21.26	1,718,263	$34,135,671	1,441.0

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. In 2015, 89.7 percent of the market solution's estimated tier 1 resource MWh actually responded during synchronized reserve events of greater than ten minutes. Thus, 10.3 percent of tier 1 resource estimated MWh do not respond during spinning events but are paid their full estimated MW 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 cost of all tier 1 MW increases significantly.

In 2015, tier 1 MW were paid $351,212 for responding to synchronized reserve events. Tier 1 synchronized reserve was paid $34.1 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 December 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	53,014	$4,874,314	414.9
2014	Feb	273	$11,153	273	65,332	$337,903	560.5
2014	Mar	3,030	$175,902	606	34,150	$1,513,636	509.7
2014	Apr	389	$6,378	195	57,047	$916,275	576.2
2014	May	717	$34,906	239	50,455	$799,911	827.1
2014	Jun	0	$0	0	3,335	$118,273	833.9
2014	Jul	616	$35,179	308	3,941	$67,078	788.1
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
2014	Total	17,528	1,508,631	382	471,159	10,406,363	833
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
2015	Jul	502	$25,540	502	64,516	$2,265,615	1,403
2015	Aug	648	$7,730	324	48,479	$1,078,199	1,276
2015	Sep	678	$30,077	226	51,968	$1,522,913	1,061
2015	Oct	0	$0	0	126,879	$2,169,670	1,123
2015	Nov	253	$15,914	126	29,156	$427,056	1,005
2015	Dec	603	$79,215	301	53,898	$865,969	1,054
2015	Total	7,145	$351,212	320	1,715,532	$34,135,671	1,446

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, rather than hourly integrated LMP, plus $50/MW, termed the Synchronized Energy Premium Price.

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 * estimated 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.

PJM uses tier 1 estimate biasing in the MAD Subzone of the ASO market solution (Table 10-14). Tier 1 biasing is not used in any IT-SCED solutions.

Table 10-14 ASO tier 1 estimate biasing, January 2014 through December, 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	0.0
2014	May	23	(909.8)	0	0.0
2014	Jun	17	(1,179.4)	3	666.7
2014	Jul	36	(1,011.1)	0	0.0
2014	Aug	31	(891.9)	1	750.0
2014	Sep	15	(1,206.7)	0	0.0
2014	Oct	67	(1,285.8)	1	500.0
2014	Nov	190	(1,134.7)	6	475.0
2014	Dec	166	(1,226.2)	1	300.0
2014	Total	663	(1,164.1)	19	295.1
2015	Jan	51	(1,731.4)	6	500.0
2015	Feb	62	(1,641.1)	0	0.0
2015	Mar	25	(794.0)	3	1,000.0
2015	Apr	31	(430.7)	0	0.0
2015	May	46	(582.6)	8	812.5
2015	Jun	25	(694.0)	1	1,000.0
2015	Jul	9	(588.9)	0	0.0
2015	Aug	1	(750.0)	1	750.0
2015	Sep	4	(475.0)	1	2,000.0
2015	Oct	24	(979.2)	0	0.0
2015	Nov	0	0.0	62	515.3
2015	Dec	1	(500.0)	59	549.2
2015	Total	279	(763.9)	141	593.9

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 and therefore the market results both for tier 2 synchronized reserve and for non-synchronized reserve.

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 estimating 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 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 point. 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.[15]

In 2015, the Mid Atlantic Dominion Reserve Subzone averaged 3,398.7 MW of synchronized reserve offers, and the RTO Reserve Zone averaged 10,565.3 MW of synchronized reserve offers (Figure 10-11).

The supply of tier 2 synchronized reserve in 2015 was sufficient to cover the requirement in both the RTO Reserve Zone and the Mid-Atlantic Dominion Reserve Subzone.

The largest portion of cleared tier 2 synchronized reserve in 2015 is from CTs (Figure 10-6) 52.6 percent of all tier 2 synchronized reserve MW. Demand Resources (DR) remain a significant part of market scheduled tier 2 synchronized reserve. Although demand resources are limited to 33 percent of the total 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

15 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Revision 79 (December 17, 2015), p. 66.

Market was 17.7 percent in 2015.[16] This is an increase from the 15.1 percent share of the tier 2 market in 2014.

Figure 10-6 Cleared tier 2 synchronized reserve average hourly MW per hour by unit type, RTO Zone: 2015

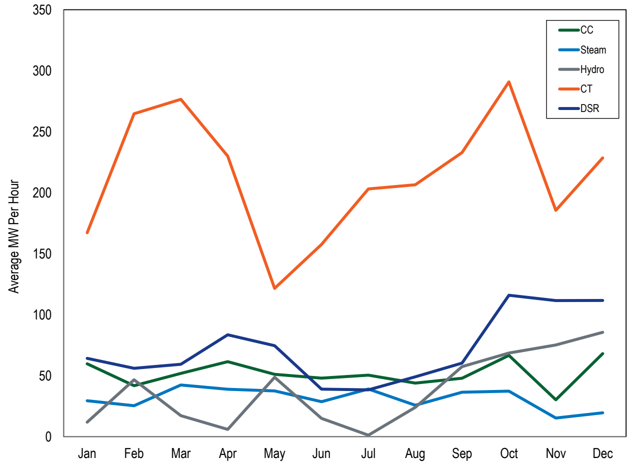
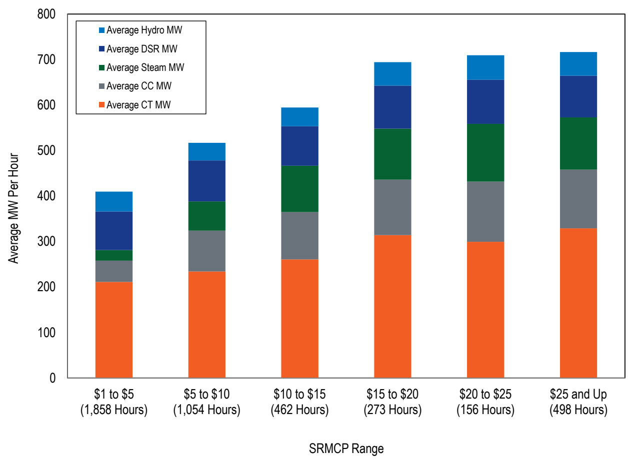


Figure 10-7 provides the average hourly cleared tier 2 MW by unit type by tier 2 clearing price range (SRMCP).

Figure 10-7 Average hourly tier 2 MW by unit type by SRMCP Range: 2015



Mild weather in October, November, and December caused fewer units to be operating therefore lesser tier 1 synchronized reserve availability. As a result, significantly more tier 2 synchronized reserve was cleared in those months (Table 10-18). In addition, PJM market operations utilized tier 1 biasing in an unusual way (Table 10-14) in November and December. The tier 1 estimate in the ASO market solution was biased positively in a large number of hours. In addition, there were 20 days in November and December when the primary reserve requirement was lowered, (orange line in Figure 10-3) reducing the need for non-synchronized reserve.

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 11, § 4.2.2 Synchronized Reserve Requirement Determination) 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.[17] 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

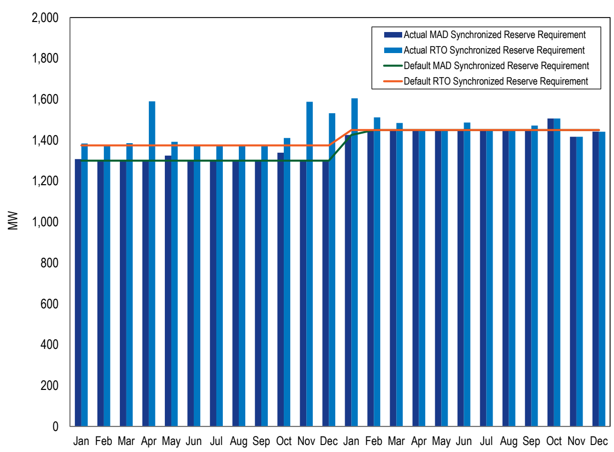
PJM may also change the synchronized reserve requirement from its default value (Figure 10-1) when grid maintenance or outages change the largest contingency. In the first three months of 2015, PJM

16 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.

17 PJM. "Manual 11: Energy & Ancillary Services Market Operations," Revision 79 (December 17, 2015) pp. 70.

increased the synchronized reserve requirement in 38 hours in the RTO Reserve Zone (Figure 10-8) because of grid outages. The RTO synchronized reserve requirement was temporarily raised to 1,624 for 96 hours during a scheduled outage from September 20, through September 23, 2015. The RTO synchronized reserve requirement was raised for 40 hours between October 19 and October 21, 2015, for scheduled outages. The synchronized reserve requirement was reduced for 21 days between November 20, and December 12, 2015, when a scheduled outage changed the largest system contingency. The average actual synchronized reserve requirement in the MAD Subzone was 1,454.1 MW. The average actual synchronized reserve requirement in the RTO Reserve Zone was 1,477.6 MW.

Figure 10-8 Monthly average actual vs default synchronized reserve requirements, RTO Zone and MAD Subzone: January 2014 through December 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, 60.6 percent of hours cleared a Tier 2 Synchronized Reserve Market in 2015 averaging 457.3 MW. This compares with 57.1 percent of hours averaging 831.6 MW in 2014. In the MAD Reserve Subzone, 96.9 percent of hours cleared a Tier 2 Synchronized Reserve Market in 2015 averaging 314.8 MW. This compares with 96.0 percent of hours cleared, averaging 380.1 MW in 2014.

Figure 10-9 and Figure 10-10 show the average monthly synchronized reserve required and the average monthly tier 2 synchronized reserve MW scheduled in 2014 and 2015, for the RTO Reserve Zone and MAD Reserve Subzone.

Figure 10-9 Mid-Atlantic Dominion Reserve Subzone monthly average synchronized reserve required vs. tier 2 synchronized reserve scheduled MW: January 2014 through December 2015

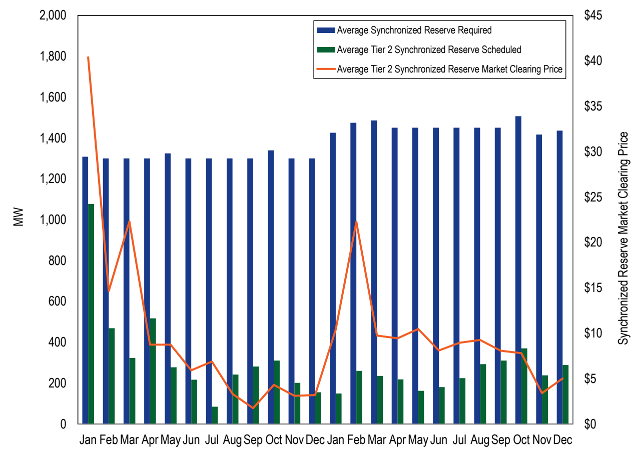
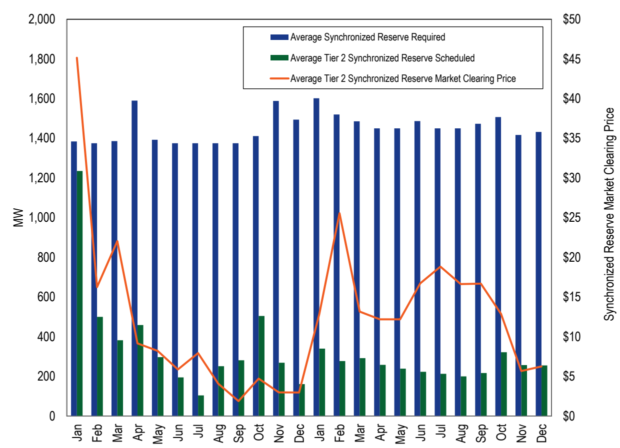


Figure 10-10 RTO Reserve Zone monthly average synchronized reserve required vs. tier 2 synchronized reserve scheduled MW: January 2014 through December 2015



Market Concentration

The HHI for settled tier 2 synchronized reserve during cleared hours of the Mid-Atlantic Dominion Subzone Tier 2 Synchronized Reserve Market for 2015 was 5436, which is defined as highly concentrated. This is an increase from the 5163 HHI in 2014. The largest hourly market share was 100 percent and 88.1 percent of all cleared 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 2015 was 4617, which is defined as highly concentrated. This is a decrease from the 5639 HHI in 2015. The largest hourly market share was 100 percent and 67.6 percent of cleared hours had a maximum market share greater than or equal to 40 percent.

In the MAD Subzone, flexible synchronized reserve was 3.8 percent of all tier 2 synchronized reserve in 2015. In the RTO Zone, flexible synchronized reserve assigned was 3.7 percent of all tier 2 synchronized reserve in 2015.

The MMU calculates that 55.7 percent of hours failed the three pivotal supplier test in the MAD Subzone in 2015 for the inflexible Synchronized Reserve Market (excluding self-scheduled synchronized reserve) in the hour ahead market (Table 10-16) and 40.2 percent of hours failed a three pivotal supplier test in the RTO Zone in 2015.

Table 10-16 Three pivotal supplier test results for the RTO Zone and MAD Subzone: January 2014 through December 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%
2014	Average	41.3%	39.2%
2015	Jan	46.0%	34.2%
2015	Feb	87.0%	29.9%
2015	Mar	42.0%	45.2%
2015	Apr	31.1%	48.4%
2015	May	61.2%	45.3%
2015	Jun	39.2%	26.5%
2015	Jul	32.0%	25.0%
2015	Aug	32.3%	24.9%
2015	Sep	56.1%	23.5%
2015	Oct	81.5%	57.9%
2015	Nov	73.2%	49.3%
2015	Dec	87.7%	73.2%
2015	Average	55.8%	40.3%

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

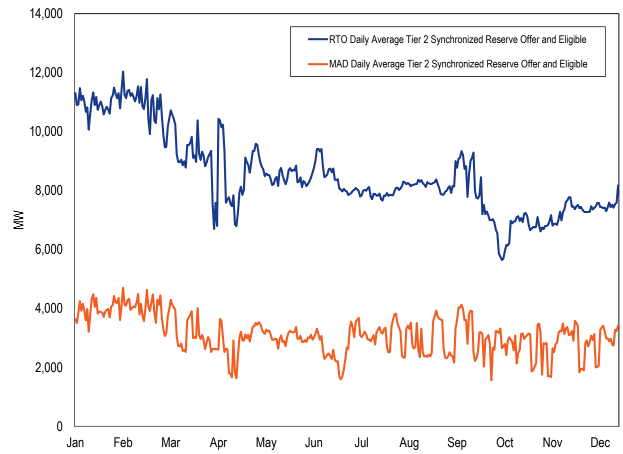
Offers

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 quantity is limited to the economic maximum or less if a spin maximum value is less than economic maximum is supplied (subject to prior authorization by PJM). PJM monitors this offer by checking to ensure that all offers are greater than or equal to 90 percent of the resource's ramp rate times ten minutes. A resource that is unable to participate in the synchronized reserve market during a given hour may set its hourly offer to 0 MW. A resource that cannot reliably provide synchronized reserve may offer 0 MW, e.g. nuclear, wind, solar, and batteries.

Figure 10-11 shows the daily average of hourly offered tier 2 synchronized reserve MW for both the RTO Synchronized Reserve Zone and the Mid-Atlantic Dominion Synchronized Reserve Subzone. In 2015, the ratio of on-line and eligible tier 2 synchronized reserve to synchronized reserve required in the Mid-Atlantic Dominion Subzone was 4.14 averaged over all hours. For the RTO Synchronized Reserve Zone the ratio was 5.91.

On October 1, 2012, PJM adopted a must-offer requirement for tier 2 synchronized reserve for all generation that is online, non-emergency, and physically able to operate with an output less than dictated by economic dispatch. Tier 2 synchronized reserve offers are made on a daily basis with hourly updates permitted. Daily offers can be changed as a result of maintenance status or physical limitations only and are required regardless of online/offline state.[18] Daily offer levels are stable and consistent over time. The Tier 2 Synchronized Reserve Market is not solved from daily offers but based on hourly updates to the daily offers. As a result of hourly updates the actual amount of eligible tier 2 MW can change significantly every hour (Figure 10-11). Changes to hourly eligibility levels are the result of on-line status, minimum/maximum runtimes, minimum notification times, maintenance status and grid conditions including constraints. But changes to the hourly offer status are only permitted when resources are physically unable to provide tier 2. Resource operators can make their units unavailable for an hour or block of hours via the eMKT unavailable option without having to provide a reason. This means that while compliance with the must offer requirement can be done daily it is not possible to verify compliance with the tier 2 must offer requirement on an hourly basis.

Figure 10-11 Tier 2 synchronized reserve hourly offer and eligible volume (MW), averaged daily: 2015



Compliance with the daily must-offer requirement is unambiguously stated in Manual 11 "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)."

Of all non-emergency resources capable of reliably producing synchronized reserve (e.g. excluding batteries, wind, and solar), 12.9 percent have not entered a tier 2 synchronized reserve offer in violation of the must-offer rule. When tier 1 credits are awarded (either for spinning event response or because the NSRMCP is greater than $0) these units can be awarded tier 1 credits. In December 2015, 71 distinct units without a tier 2 offer were awarded a total $98,156 in tier 1 credits. Of this, $85,640 were for hours when the NSRMCP greater than $0 and the units did not have to actually produce any reserve MW.

Tier 2 synchronized reserve is subject to a must offer requirement. To help ensure compliance with this rule, the MMU recommends that PJM define a set of acceptable reasons why a unit can be made unavailable daily or hourly and require operators to select a reason in eMkt whenever making a unit unavailable.

18 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Revision 79 (December 17, 2015) p. 66, "Regardless of online/offline state, all non-emergency generation capacity resources must submit a daily offer for Tier 2 Synchronized Reserve in eMKT…"

Figure 10-12 shows average offer MW volume by market and unit type for the MAD Subzone and Figure 10-13 shows average offer MW volume by market and unit type for the RTO Zone.

Figure 10-12 Mid-Atlantic Dominion subzone average daily tier 2 synchronized reserve offer by unit type (MW): 2012 through 2015

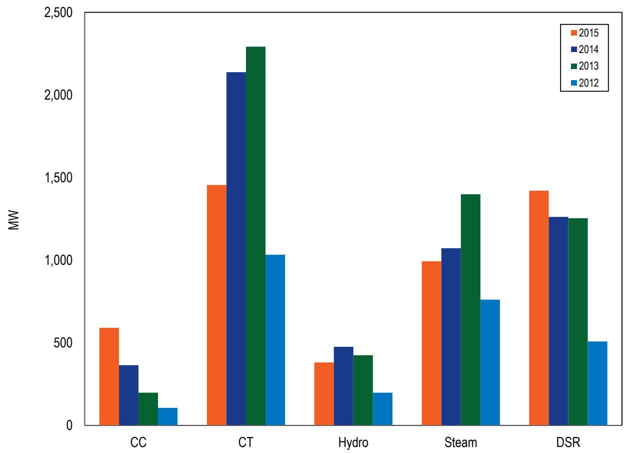
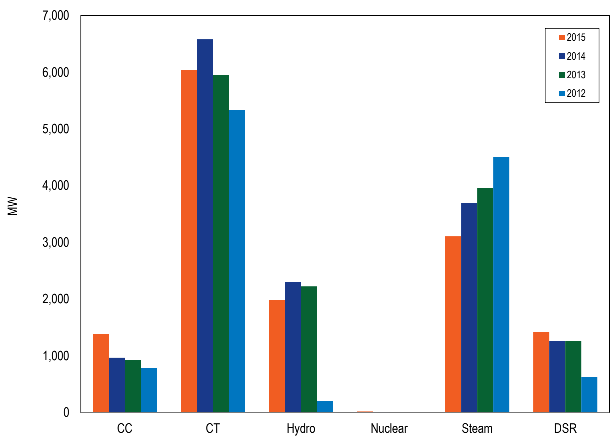


Figure 10-13 RTO Zone average daily tier 2 synchronized reserve offer by unit type (MW): 2012 through 2015



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 314.8 MW (including self-scheduled) with a real-time price greater than $0 in 63.6 percent of hours in 2015, compared to 99.0 percent of hours in the first nine months of 2014.

The RTO Zone cleared a Tier 2 Synchronized Reserve Market averaging 457.3 MW (including self-scheduled) with a real-time price greater than $0 in 58.6 percent of hours in 2015.

In 2015, the weighted average Tier 2 synchronized reserve market clearing price in the MAD Subzone for all cleared hours was $10.12. In 2014, the weighted average synchronized reserve market clearing price in the MAD Subzone was $15.50.

In 2015, the weighted average tier 2 synchronized reserve market clearing price in the RTO Zone for all cleared hours was $11.88. In 2014, the weighted average synchronized reserve market clearing price in the RTO Zone was $12.94.

Supply, performance, and demand are reflected in the price of synchronized reserve (Figure 10-9 and Figure 10-10). 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): 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	$10.76	1,159.4	85.0	218.1
2015	May	$10.16	1,174.4	76.0	162.9
2015	Jun	$10.29	1,515.5	54.5	177.7
2015	Jul	$12.87	1,195.6	41.1	215.7
2015	Aug	$9.25	1,152.9	49.3	247.8
2015	Sep	$10.66	1,106.9	54.2	288.9
2015	Oct	$7.68	1,015.6	118.2	374.4
2015	Nov	$3.30	1,011.6	113.6	290.6
2015	Dec	$4.71	983.4	109.0	349.4
2015	Average	$10.13	1,159.2	72.6	243.4

Table 10-18 RTO Zone only weighted SRMCP and cleared MW (excludes self-scheduled): 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	$13.91	1,417.5	164.8	125.2
2015	Feb	$26.51	1,618.3	46.3	35.4
2015	Mar	$13.44	1,285.0	60.8	140.0
2015	Apr	$13.39	1,228.6	85.0	136.4
2015	May	$13.77	1,239.8	76.0	134.2
2015	Jun	$19.43	1,366.4	54.5	83.6
2015	Jul	$21.46	1,346.1	41.1	65.2
2015	Aug	$18.63	1,353.1	49.3	58.9
2015	Sep	$19.12	1,156.3	54.2	64.3
2015	Oct	$15.87	1,156.3	118.2	233.3
2015	Nov	$6.09	1,089.5	113.6	212.6
2015	Dec	$7.05	784.4	109.0	548.4
2015	Average	$14.98	1,253.4	81.1	153.1

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 2015, the price to cost ratio of the RTO Zone Tier 2 Synchronized Reserve Market averaged 62.6 percent (Table 10-19); and the price to cost ratio of the MAD Subzone averaged 60.6 percent.

Table 10-19 RTO Zone, Mid-Atlantic Subzone tier 2 synchronized reserve MW, credits, price, and cost: 2015

Tier 2 Synchronized Reserve Market	Year	Month	Total MW	Total Credits	Weighted Synchronized Reserve Market Clearing Price	Cost	Price/Cost Ratio
RTO Zone	2015	Jan	225,741	$5,089,807	$12.24	$22.55	54.3%
RTO Zone	2015	Feb	272,371	$12,065,569	$24.68	$44.30	55.7%
RTO Zone	2015	Mar	301,564	$7,323,630	$12.37	$24.29	50.9%
RTO Zone	2015	Apr	278,562	$4,896,351	$11.53	$17.58	65.6%
RTO Zone	2015	May	244,947	$4,231,841	$11.22	$17.28	65.0%
RTO Zone	2015	Jun	174,039	$2,916,195	$12.95	$16.76	77.3%
RTO Zone	2015	Jul	194,178	$3,435,731	$15.28	$17.69	86.4%
RTO Zone	2015	Aug	173,869	$2,329,804	$11.20	$13.40	83.6%
RTO Zone	2015	Sep	253,762	$4,012,473	$12.44	$15.81	78.7%
RTO Zone	2015	Oct	428,175	$5,444,327	$9.61	$12.72	75.6%
RTO Zone	2015	Nov	298,986	$2,821,681	$3.92	$9.44	41.5%
RTO Zone	2015	Dec	374,928	$4,163,737	$5.26	$11.11	47.4%
RTO Zone	2015	Total	3,221,120	$58,731,146	$11.41	$18.23	62.6%
MAD Subzone	2015	Jan	144,214	$3,454,670	$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	123,473	$1,685,393	$10.29	$13.65	75.4%
MAD Subzone	2015	Jul	139,693	$2,093,452	$12.87	$14.99	85.9%
MAD Subzone	2015	Aug	137,663	$1,533,977	$9.25	$11.14	83.0%
MAD Subzone	2015	Sep	200,257	$2,832,648	$10.66	$14.15	75.4%
MAD Subzone	2015	Oct	327,286	$3,310,116	$7.68	$10.11	76.0%
MAD Subzone	2015	Nov	232,670	$1,935,364	$3.30	$8.32	39.6%
MAD Subzone	2015	Dec	286,032	$2,963,084	$4.71	$10.36	45.4%
MAD Subzone	2015	Total	2,367,055	$39,572,874	$10.13	$16.72	60.6%

Compliance

The MMU has identified and quantified the failure of scheduled tier 2 synchronized reserve resources to deliver during synchronized reserve events since 2011.[19] 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.[20] Tier 2 resources are obligated to sustain their final output for the shorter of the length of the event or 30 minutes.[21]

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 10 minutes or longer 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 2015, there were 21 spinning events of which seven were 10 minutes or longer.

19 See the *2011 State of the Market Report for PJM*, Volume II, Section 9, "Ancillary Services" at pg. 250.

20 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Revision 79 (December 17, 2015) § 4.2.10 Settlements, p. 77.

21 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Revision 79 (December 17, 2015) § 4.2.11 Verification, p. 78.

Table 10-20 Synchronized reserve events greater than 10 minutes, Tier 2 response compliance, RTO Reserve Zone: 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	480.4	272.3	56.7%
16-Mar-2015 10	24	248.0	180.2	72.7%
17-Mar-2015 23	17	247.2	232.8	94.2%
23-Mar-2015 23	15	273.5	205.8	75.2%
07-Apr-2015 16	31	485.7	455.5	93.8%
30-Jul-2015 10	10	79.7	24.0	30.1%
28-Sep-2015 19	11	782.0	639.4	81.8%

Tier 1 resource owners are credited for the amount of synchronized reserve they provide in response to a synchronized reserve event.[22] 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 2015, 21.2 percent of all scheduled tier 2 synchronized reserve MW were not delivered and were penalized (Table 10-20). In addition, a tier 2 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.[23] Resource owners are permitted to aggregate the response of multiple units to offset an under response from one unit with an overresponse from 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.[24]

22 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Revision 79 (December 17, 2015) § 4.2.12 Non Performance, p. 78.

23 See PJM. "Manual 28: Operating Agreement Accounting," Revision 71 (June 1, 2015) p. 45. See also "Manual 11: Energy & Ancillary Services Market Operations," Revision 75 (April 9, 2015) § 4.2.12 Non-Performance, p. 77.

24 Report to PJM Operating Committee, "Synchronized Reserve Event Performance and Penalty Days," December 3, 2014.

History of Synchronized Reserve Events

Synchronized reserve is designed to provide relief for disturbances.[25] [26] A disturbance is defined as loss of generation and/or transmission resources. PJM also calls synchronized reserve events for non-disturbance events, which it characterizes as "low ACE." 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. Five spinning events were declared for low ACE in 2015. The risk of using synchronized reserves for energy or any non-disturbance reason 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 secondary reserve is the appropriate source of the response. 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.

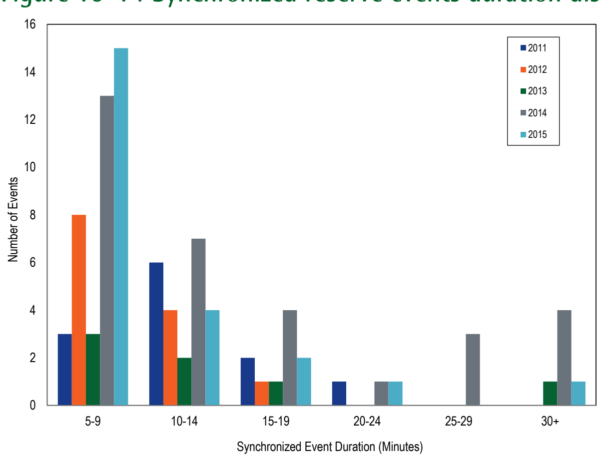
From January 2010 through December 2015, PJM experienced 167 synchronized reserve events (Table 10-21), approximately three events per month. Synchronized reserve events had an average length of 13 minutes. Note that the number of synchronized reserve events with a duration less than ten minutes is higher in 2015 than any prior year (Figure 10-14). This corresponds with the higher rate of compliance by tier 2 synchronized reserve resources, and the higher rate of response by tier 1 resources to spinning event all calls.

25 2013 State of the Market Report for PJM, Appendix F – PJM's DCS Performance, pp 451-452.
26 See PJM. "Manual 12: Balancing Operations," Revision 33 (December 1, 2015) § 4.1.2 Loading Reserves pp. 36.

Table 10-21 Synchronized reserve events, January 2010 through December 2015

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
MAR-18-2010 11:02	RFC	27	FEB-02-2011 01:21	RFC	5	JAN-06-2012 23:25	RFC	8
MAR-23-2010 20:14	RFC	13	FEB-08-2011 22:41	Mid-Atlantic	11	JAN-23-2012 15:02	Mid-Atlantic	8
APR-11-2010 13:12	RFC	9	FEB-09-2011 11:40	Mid-Atlantic	16	MAR-02-2012 19:54	RFC	9
APR-28-2010 15:09	Mid-Atlantic	8	FEB-13-2011 15:35	Mid-Atlantic	14	MAR-08-2012 17:04	RFC	6
MAY-11-2010 19:57	Mid-Atlantic	9	FEB-24-2011 11:35	Mid-Atlantic	14	MAR-19-2012 10:14	RFC	10
MAY-15-2010 03:03	RFC	6	FEB-25-2011 14:12	RFC	10	APR-16-2012 00:20	Mid-Atlantic	9
MAY-28-2010 04:06	Mid-Atlantic	5	MAR-30-2011 19:13	RFC	12	APR-16-2012 11:18	RFC	8
JUN-15-2010 00:46	RFC	34	APR-02-2011 13:13	Mid-Atlantic	11	APR-19-2012 11:54	RFC	16
JUN-19-2010 23:49	Mid-Atlantic	9	APR-11-2011 00:28	RFC	6	APR-20-2012 11:08	Mid-Atlantic	7
JUN-24-2010 00:56	RFC	15	APR-16-2011 22:51	RFC	9	JUN-20-2012 13:35	RFC	7
JUN-27-2010 19:33	Mid-Atlantic	15	APR-21-2011 20:02	Mid-Atlantic	6	JUN-26-2012 17:51	RFC	7
JUL-07-2010 15:20	RFC	8	APR-27-2011 01:22	RFC	8	JUL-23-2012 21:45	RFC	18
JUL-16-2010 20:45	Mid-Atlantic	19	MAY-02-2011 00:05	Mid-Atlantic	21	AUG-03-2012 12:44	RFC	10
AUG-11-2010 19:09	RFC	17	MAY-12-2011 19:39	RFC	9	SEP-08-2012 04:34	RFC	12
AUG-13-2010 23:19	RFC	6	MAY-26-2011 17:17	Mid-Atlantic	20	SEP-27-2012 17:19	Mid-Atlantic	7
AUG-16-2010 07:08	RFC	17	MAY-27-2011 12:51	RFC	6	OCT-17-2012 10:48	RTO	10
AUG-16-2010 19:39	Mid-Atlantic	11	MAY-29-2011 09:04	RFC	7	OCT-23-2012 22:29	RTO	19
SEP-15-2010 11:20	RFC	13	MAY-31-2011 16:36	RFC	27	OCT-30-2012 05:12	RTO	14
SEP-22-2010 15:28	Mid-Atlantic	24	JUN-03-2011 14:23	RFC	7	NOV-25-2012 16:32	RTO	12
OCT-05-2010 17:20	RFC	10	JUN-06-2011 22:02	Mid-Atlantic	9	DEC-16-2012 07:01	RTO	9
OCT-16-2010 03:22	Mid-Atlantic	10	JUN-23-2011 23:26	RFC	8	DEC-21-2012 05:51	RTO	7
OCT-16-2010 03:25	RFCNonMA	7	JUN-26-2011 22:03	Mid-Atlantic	10	DEC-21-2012 10:29	RTO	5
OCT-27-2010 10:35	RFC	7	JUL-10-2011 11:20	RFC	10			
OCT-27-2010 12:50	Mid-Atlantic	10	JUL-28-2011 18:49	RFC	12			
NOV-26-2010 14:24	RFC	13	AUG-02-2011 01:08	RFC	6			
NOV-27-2010 11:34	RFC	8	AUG-18-2011 06:45	Mid-Atlantic	6			
DEC-08-2010 01:19	RFC	11	AUG-19-2011 14:49	RFC	5			
DEC-09-2010 20:07	RFC	5	AUG-23-2011 17:52	RFC	7			
DEC-14-2010 12:02	Mid-Atlantic	24	SEP-24-2011 15:48	RFC	8			
DEC-16-2010 18:40	Mid-Atlantic	20	SEP-27-2011 14:20	RFC	7			
DEC-17-2010 22:09	Mid-Atlantic	6	SEP-27-2011 16:47	RFC	9			
DEC-29-2010 19:01	Mid-Atlantic	15	OCT-30-2011 22:39	Mid-Atlantic	10			
			DEC-15-2011 14:35	Mid-Atlantic	8			
			DEC-21-2011 14:26	RFC	18			

Figure 10-14 Synchronized reserve events duration distribution curve: 2011 through 2015



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.

Startup time for non-synchronized reserve resources is not subject to testing. There is no non-synchronized reserve offer MW or offer price. The market solution software evaluates all eligible resources and schedules them economically.

Table 10-21 Synchronized reserve events, January 2010 through December 2015 *(continued)*

Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)
JAN-22-2013 08:34	RTO	8	JAN-06-2014 22:01	RTO	68	JAN-07-2015 22:36	RTO	8
JAN-25-2013 15:01	RTO	19	JAN-07-2014 02:20	RTO	25	FEB-24-2015 02:51	RTO	5
FEB-09-2013 22:55	RTO	10	JAN-07-2014 04:18	RTO	34	FEB-26-2015 15:20	RTO	6
FEB-17-2013 23:10	RTO	13	JAN-07-2014 11:27	RTO	11	MAR-03-2015 17:02	RTO	11
APR-17-2013 01:11	RTO	11	JAN-07-2014 13:20	RTO	41	MAR-16-2015 10:25	RTO	24
APR-17-2013 20:01	RTO	9	JAN-10-2014 16:46	RTO	12	MAR-17-2015 23:34	RTO	17
MAY-07-2013 17:33	RTO	8	JAN-21-2014 18:52	RTO	6	MAR-23-2015 23:44	RTO	15
JUN-05-2013 18:54	RTO	20	JAN-22-2014 02:26	RTO	7	APR-06-2015 14:23	RTO	8
JUN-08-2013 15:19	RTO	9	JAN-22-2014 22:54	RTO	8	APR-07-2015 17:11	RTO	31
JUN-12-2013 17:35	RTO	10	JAN-25-2014 05:22	RTO	10	APR-15-2015 08:14	RTO	8
JUN-30-2013 01:22	RTO	10	JAN-26-2014 17:11	RTO	6	APR-25-2015 03:21	RTO	9
JUL-03-2013 20:40	RTO	13	JAN-31-2014 15:05	RTO	13	JUL-30-2015 14:04	RTO	10
JUL-15-2013 18:43	RTO	29	FEB-02-2014 14:03	Dominion	8	AUG-05-2015 19:47	RTO	7
JUL-28-2013 14:20	RTO	10	FEB-08-2014 06:05	Dominion	18	AUG-19-2015 16:47	RTO	9
SEP-10-2013 19:48	RTO	68	FEB-22-2014 23:05	RTO	7	SEP-05-2015 01:16	RTO	7
OCT-28-2013 10:44	RTO	33	MAR-01-2014 05:18	RTO	26	SEP-10-2015 10:12	RTO	8
DEC-01-2013 11:17	RTO	9	MAR-05-2014 21:25	RTO	8	SEP-29-2015 00:58	Mid-Atlantic	11
DEC-07-2013 19:44	RTO	7	MAR-13-2014 20:39	RTO	8	NOV-12-2015 16:42	RTO	8
			MAR-27-2014 10:37	RTO	56	NOV-21-2015 17:17	RTO	8
			APR-14-2014 01:16	RTO	10	DEC-04-2015 22:41	RTO	7
			APR-25-2014 17:33	RTO	6	DEC-24-2015 17:42	RTO	8
			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			

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 (ASO) optimizes synchronized reserve, non-synchronized reserve, and energy to satisfy the primary reserve requirement at the lowest cost. Non-synchronized reserve resources are scheduled economically based on LOC until the Primary Reserve requirement is filled. The non-synchronized reserve market clearing price is determined at the end of the hour as the marginal unit's LOC. When a unit clears the non-synchronized reserve market and is scheduled, it is committed to remain off-line for the hour and available to provide ten minute reserves.

Equipment that generally qualifies as non-synchronized reserve include run of river hydro, pumped hydro, combustion turbines, combined cycles and diesels.[27] In 2015, an average of 390.3 MW of non-synchronized reserve was scheduled hourly out of 1,860.8 eligible MW as part of the primary reserve requirement in the Mid-Atlantic Dominion Subzone.[28] In 2015, an average of 345.1 MW of non-synchronized reserve was scheduled hourly out of 2,550.1 MW eligible MW in the RTO Zone.

CTs provided 58.4 percent and hydro 38.8 percent of cleared non-synchronized reserve MW in 2015. The remaining 2.8 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 except in December. The supply of non-synchronized reserves in the RTO Zone was also highly concentrated except in November and December. Moderate weather made more non synchronized resources available in November and December. PJM market operations reduced the required amount of primary reserve from 2175 to 2025 in 20 days in November and December. PJM market operations used positive tier 1 estimate biasing in 121 hours of November and December, reducing the need for non-synchronized reserve to satisfy the primary reserve requirement.

Table 10-22 Non-synchronized reserve market HHIs: 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	Jul	4115	6261
2015	Aug	4237	5555
2015	Sep	3973	5285
2015	Oct	3845	6817
2015	Nov	5375	5155
2015	Dec	5675	2149
2015	Average	4133	4533

Table 10-23 Non-synchronized reserve market pivotal supply test: 2015

Year	Month	Mid Atlantic Dominion Three Pivotal Supplier Hours	Full RTO Three Pivotal Supplier Hours
2015	Jan	100.0%	81.6%
2015	Feb	95.0%	78.9%
2015	Mar	100.0%	90.7%
2015	Apr	100.0%	89.9%
2015	May	98.9%	80.0%
2015	Jun	97.2%	71.1%
2015	Jul	96.5%	83.7%
2015	Aug	97.4%	85.2%
2015	Sep	97.1%	86.4%
2015	Oct	100.0%	60.3%
2015	Nov	99.6%	8.1%
2015	Dec	58.9%	0.3%
2015	Average	95.1%	68.0%

Price

The price of non-synchronized reserve is calculated in real time every five minutes and averaged each hour for the RTO Reserve Zone and the Mid Atlantic Dominion Reserve Subzone. Resources eligible for non-synchronized reserve make no price offer or MW offer.

Figure 10-15 shows the daily average hour ahead non-synchronized reserve market clearing price and average scheduled MW for the MAD Subzone. The MAD Subzone Non-Synchronized Reserve Market had a clearing price greater than zero in 1,089 (12.4 percent) hours in 2015, at a weighted average price of $11.87 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 $1.03 per MW. The maximum hourly clearing price was $291.48 per MW on July 20, 2015. Figure 10-16 shows the daily average hour ahead non-synchronized reserve market clearing price and average scheduled MW for the RTO Zone. The RTO Zone Non-Synchronized Reserve Market had a clearing price greater than zero in 1,055 (12.0 percent) hours in 2015, at a weighted average price of $10.49. The weighted non-synchronized reserve market clearing price for all hours in the RTO Zone including cleared hours when the price was zero, was $1.15.

27 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Revision 79 (December 17, 2015), p. 80.

28 The *2015 State of the Market Report for PJM: January through June* incorrectly stated this figure as 746.4 MW. It should have been 434.3 MW.

Figure 10-15 Daily average MAD subzone non-synchronized reserve market clearing price and MW purchased: 2015

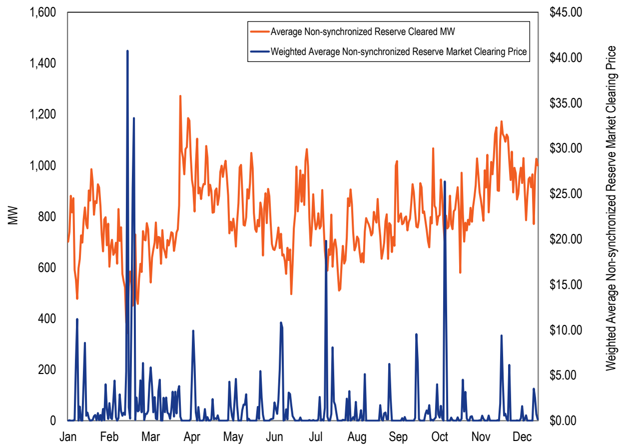
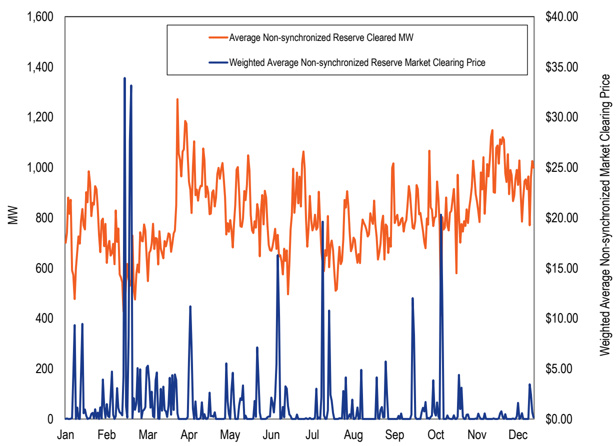


Figure 10-16 Daily average RTO Zone non-synchronized reserve market clearing price and MW purchased: 2015



Price and Cost

As a result of changing grid conditions, load forecasts, and unexpected generator performance, prices sometimes do not cover the full LOC of 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 2015, the price to cost ratio of the RTO Zone Non-Synchronized Reserve Market averaged 58.7 percent; and the price to cost ratio of the MAD Subzone averaged 59.4 percent.

Table 10-24 RTO Zone, MAD Subzone non-synchronized reserve MW, credits, price, and cost: 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
RTO Zone	2015	Jan	576,785	$1,228,205	$1.16	$2.13	54.5%
RTO Zone	2015	Feb	412,564	$2,810,932	$4.09	$6.81	60.1%
RTO Zone	2015	Mar	551,828	$1,387,010	$1.51	$2.51	60.0%
RTO Zone	2015	Apr	688,059	$734,711	$0.90	$1.07	84.1%
RTO Zone	2015	May	633,935	$1,060,846	$0.94	$1.67	55.9%
RTO Zone	2015	Jun	526,821	$1,015,756	$1.35	$1.93	70.0%
RTO Zone	2015	Jul	561,665	$1,060,091	$1.03	$1.89	54.8%
RTO Zone	2015	Aug	547,883	$551,968	$0.54	$1.01	53.8%
RTO Zone	2015	Sep	563,351	$926,350	$0.88	$1.64	53.3%
RTO Zone	2015	Oct	608,554	$1,129,090	$1.47	$1.86	79.2%
RTO Zone	2015	Nov	638,440	$826,524	$0.34	$1.29	26.3%
RTO Zone	2015	Dec	728,815	$1,053,608	$0.67	$1.45	46.6%
RTO Zone	2015	Tot	7,038,700	$13,785,091	$1.15	$1.96	58.7%
MAD Subzone	2015	Jan	486,505	$909,339	$1.07	$1.87	57.2%
MAD Subzone	2015	Feb	326,818	$2,126,008	$3.75	$6.51	57.7%
MAD Subzone	2015	Mar	473,825	$836,501	$1.25	$1.77	70.6%
MAD Subzone	2015	Apr	685,799	$700,577	$0.88	$1.02	86.4%
MAD Subzone	2015	May	623,907	$968,896	$0.89	$1.55	57.3%
MAD Subzone	2015	Jun	510,793	$901,934	$1.24	$1.77	70.1%
MAD Subzone	2015	Jul	553,485	$1,018,749	$0.99	$1.84	53.5%
MAD Subzone	2015	Aug	542,866	$523,260	$0.52	$0.96	53.8%
MAD Subzone	2015	Sep	558,774	$837,491	$0.83	$1.50	55.4%
MAD Subzone	2015	Oct	582,379	$992,071	$1.38	$1.70	80.8%
MAD Subzone	2015	Nov	636,997	$809,715	$0.34	$1.27	26.4%
MAD Subzone	2015	Dec	728,048	$1,032,339	$0.67	$1.42	47.1%
MAD Subzone	2015	Tot	6,710,197	$11,656,879	$1.03	$1.74	59.4%

Secondary Reserve (DASR)

PJM maintains a day-ahead, offer based market for 30-minute day-ahead secondary reserve.[29] The Day-Ahead Scheduling Reserves Market (DASR) has no performance obligations.

Market Structure

Supply

DASR is provided by both generation and demand resources. DASR offers consist of price only. DASR MW are calculated by the market clearing engine. Available DASR MW are 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. In 2015, the average available hourly DASR was 36,396.0 MW. This is a 13.3 percent reduction from 42,017 MW of 2014. The DASR MW purchased averaged 6,113.1 MW per hour for all hours in 2015, a small decrease from 6,245 MW per hour in 2014. Although there was no shortage of DASR in the market solution, the market has no requirements for or link to the availability of scheduled reserve during real-time hours. Spinning events longer than 30 minutes, while rare, do occur. The spinning events of September 10, 2013, March 27, 2014, and April 7, 2015, are examples of when secondary reserve was needed but not enough was available in real time.

All generation resources are required to offer a price for DASR.[30] Of the 6,245 MW hourly average DASR in 2015, 56.0 percent was from CTs, 20.3 percent was from steam, 12.0 percent was from hydro, and 9.8 percent was CCs. Load response resources which are registered in PJM's Economic Load Response and are dispatchable by PJM are eligible to provide DASR. In 2015, six demand resources offered into the DASR Market.

Demand

DASR 30-minute reserve requirements are determined by PJM for each reliability region. In the Reliability*First* (RFC) region, secondary reserve requirements are calculated based on historical under-forecasted load rates and generator forced outage rates.[31] 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. For 2015, the DASR requirement was 5.93 percent of daily peak load forecast. The DASR requirement is applicable for all

29 See PJM. "Manual 35: Definitions and Acronyms," Revision 23 (April 11, 2014), p. 89.

30 See PJM "Manual 11: Energy & Ancillary Services Market Operations," Revision 79 (December 17, 2015), p. 144 §11.2.3 Day-Ahead Scheduling Reserve Market Rules.

31 See PJM. "Manual 13: Emergency Operations," Revision 59 (January 1, 2016), p. 11.

hours of the operating day. If the DASR Market does not procure adequate scheduling reserves, PJM is required to schedule additional operating reserves.[32]

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."[33] The amount of additional DASR MW that may be required is the Adjusted Fixed Demand (AFD) determined by a Seasonal Conditional Demand (SCD) factor.[34] The SCD factor is calculated separately for the winter (November through March) and summer (April through October) seasons. The SCD 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 was 3.87 percent for winter, 5.36 percent for summer. For November 2015 through October 2016, the SCD values are 3.45 percent for winter and 2.88 percent for summer. PJM Dispatch may also schedule additional Day-Ahead Scheduling Reserves as deemed necessary for conservative operations.[35] PJM has defined conservative operations to include, potential fuel delivery issues, forest/brush fires, extreme weather events, environmental alerts, solar disturbances, unknown grid operating state.[36] The net result is substantial discretion for PJM to increase the demand for DASR under a variety of circumstances.

PJM invoked adjusted fixed demand during 14 days in 2015. A record of PJM's use of adjusted fixed demand is in Table 10-25. The use of adjusted fixed demand (and other conservative operations adjustments) impacts the DASR Market in several significant ways.

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

33 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>.

34 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Revision 79, (December 17, 2015) p. 144 at 11.2.1 Day-Ahead Scheduling Reserve Market Requirement.

35 See PJM "Manual 11: Energy & Ancillary Services Market Operations," Revision 79, (December 17, 2015) p. 144 at 11.2.1 Day-Ahead Scheduling Reserve Market Requirement.

36 See PJM, "Manual 13: Emergency Operations" Revision 58, (August 1, 2015), p. 45 at 3.2 Conservative Operations

Table 10-25 Adjusted Fixed Demand Days: 2015

Start Date	End Date	Number of Hours	Average Additional MW
26-May	27-May	44	3,626
12-Jun	13-Jun	48	3,016
20-Jul	21-Jul	38	2,288
29-Jul	30-Jul	48	3,608
17-Aug	17-Aug	24	2,476
1-Sep	3-Sep	72	4,336
8-Sep	9-Sep	48	4,452

An alternative to adjusted fixed demand would be to schedule secondary reserve in the real time market. The MMU recommends that PJM replace the DASR Market with a real-time secondary reserve product that is available and dispatchable in real time.

Market Concentration

Between January 2012 and April 2015, no hours would have failed a three pivotal supplier test in the DASR Market. Beginning in May 2015, when PJM began to invoke adjusted fixed demand for conservative operations, the DASR Market began to fail the three pivotal supplier test (Table 10-26).

Table 10-26 DASR market three pivotal supplier test results and number of hours with DASRMCP above $0: 2015

Year	Month	Number of Hours When DASRMCP > $0	Percent of Hours Pivotal
2015	Jan	151	0.0%
2015	Feb	328	0.0%
2015	Mar	300	0.0%
2015	Apr	301	0.0%
2015	May	323	3.9%
2015	Jun	349	11.2%
2015	Jul	496	28.1%
2015	Aug	482	21.5%
2015	Sep	532	11.4%
2015	Oct	634	0.3%
2015	Nov	568	0.0%
2015	Dec	473	0.4%
2015	Average	411	6.4%

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.[37] Units that do not offer have their offers set to $0.00 per MW.

Economic withholding remains an issue in the DASR Market. The marginal cost of providing DASR is

37 See PJM. "Manual 11: Emergency and Ancillary Services Operations," Revision 79 (December 17, 2015), p. 147.

zero. All offers greater than zero constitute economic withholding. Throughout 2015 daily DASR offers averaged 37.9 percent above $0 per MW and 11.6 percent above $5 per MW.

Market Performance

Two changes to the DASR Market had significant impacts in 2015. In January 2015, the way that DASR available supply was estimated was reduced from day-ahead dispatch up to emergency maximum to day-ahead dispatch up to economic maximum. This reduced the DASR available supply by 13.3 percent. Between May and September 2015, the use of AFD significantly increased the demand in 366 hours. For 43.6 percent of hours in 2015, DASR cleared at a price of $0.00 per MWh (Figure 10-17). This is a significant reduction from the 94.1 percent of hours that the DASR Market cleared at $0 in 2014. In 2015, the weighted average DASR price for all hours when the DASRMCP was above $0 was $2.99. The average cleared MW in all hours when the DASRMCP was above $0 was 5,166 MW. The highest DASR price was $199.83 on February 19, 2015.

Table 10-27 DASR Market, regular hours vs. adjusted fixed demand hours: 2015

		Number of Hours DASRMCP>$0		Weighted DASRMCP		Average PJM Load		Hourly Average Cleared DASR MW		Average DASR Credits	
Year	Month	Normal Hour	AFD Hour	Normal Hour	AFD Hour	Normal Hour	AFD Hour	Normal Hour	AFD Hour	Normal Hour	AFD Hour
2015	Jan	151	0	$0.19	$0.00	112,373	0	4,902	0	$937	$0
2015	Feb	328	0	$4.03	$0.00	113,797	0	4,868	0	$19,610	$0
2015	Mar	300	0	$0.59	$0.00	96,315	0	4,116	0	$2,429	$0
2015	Apr	301	0	$0.04	$0.00	80,798	0	4,085	0	$155	$0
2015	May	279	44	$3.66	$12.34	92,863	96,726	4,574	9,042	$16,750	$111,598
2015	Jun	255	94	$0.92	$13.82	104,388	105,190	5,152	8,895	$4,724	$122,908
2015	Jul	410	86	$1.36	$18.56	106,605	114,868	5,553	9,599	$7,565	$178,164
2015	Aug	459	23	$0.95	$14.79	105,509	110,753	5,766	9,701	$5,483	$143,459
2015	Sep	412	120	$0.31	$14.63	91,491	109,028	5,003	11,337	$1,550	$165,870
2015	Oct	634	0	$0.35	$0	77,657	0	4,231	0	$1,500	$0
2015	Nov	568	0	$0.29	$0	80,844	0	4,477	0	$1,279	$0
2015	Dec	473	0	$0.13	$0	87,166	0	4,807	0	$617	$0

The introduction of Adjusted Fixed Demand on March 1, 2015, created a bifurcated market (Table 10-27). There were 367 hours in 2015 when PJM dispatch added an Adjusted Fixed Demand to the normal 5.93 percent of forecast load. The difference in market clearing price, MW cleared, obligation incurred, and charges to PJM load are substantial. During hours when DASRMCP was greater than $0 and PJM dispatch augmented the requirement via Adjusted Fixed Demand the weighted average DASR price was $15.09 compared to $0.77 for hours when DASRMCP was greater than $0 and PJM dispatch did not augment the requirement.

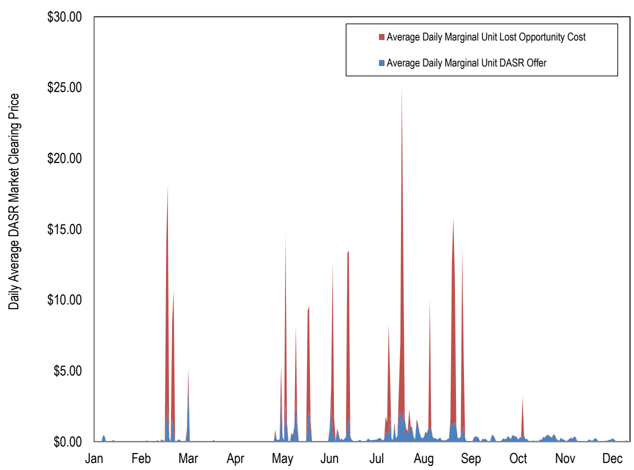
While the new rules allow PJM dispatch substantial discretion to add to DASR demand for a variety of reasons, the rationale for each specific increase is not always clear. The MMU recommends that PJM Market Operations attach a reason code to every hour in which PJM dispatch adds additional DASR MW above the default DASR hourly requirement. 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 implementation of the conservative operations adjustment to the DASR requirement in 367 hours during 2015 has significantly increased the cost of DASR as a result of increases in DASR MW cleared and corresponding increases in the DASR clearing prices (Table 10-28).

Table 10-28 DASR Market all hours of DASR market clearing price greater than $0

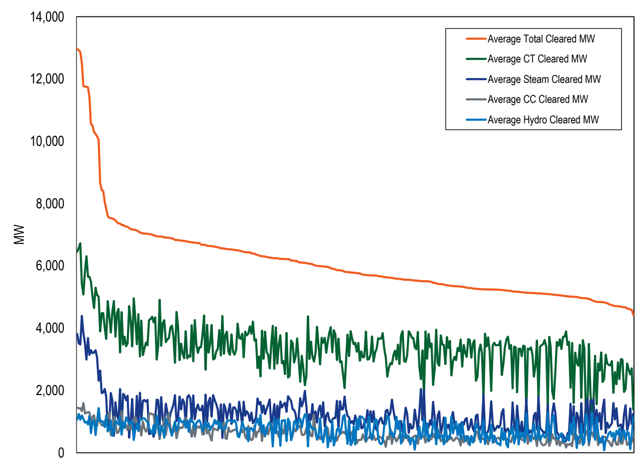
Year	Month	Number of Hours DASRMCP > $0	Weighted DASR Market Clearing Price	Average Hourly RT Load	Total PJM Cleared DASRM MW	Total PJM Cleared Additional DASR MW	Total Charges
2015	Jan	151	$0.19	112,373	740,268	0	$141,561
2015	Feb	328	$4.03	113,797	1,596,639	0	$6,431,987
2015	Mar	300	$0.59	96,315	1,234,905	0	$728,829
2015	Apr	301	$0.04	80,798	1,229,513	0	$46,584
2015	May	323	$5.73	93,389	1,673,983	159,559	$9,583,568
2015	Jun	349	$5.93	104,604	2,150,052	294,881	$12,757,966
2015	Jul	496	$5.94	108,038	3,102,087	260,120	$18,423,687
2015	Aug	482	$2.03	105,759	2,869,630	59,414	$5,816,401
2015	Sep	532	$6.00	95,447	3,421,690	525,883	$20,542,872
2015	Oct	634	$0.35	77,657	2,682,429	0	$951,264
2015	Nov	568	$0.29	80,844	2,542,795	0	$726,549
2015	Dec	473	$0.13	87,166	2,273,497	0	$291,725
2015	Average	411	$2.60	96,349	2,126,457	108,321	$6,370,250

Figure 10-17 Daily average components of DASR clearing price ($/MW), marginal unit offer and LOC: 2015



When the DASR requirement is increased by PJM dispatch, the reserve requirement frequently cannot be filled without redispatching online resources which significantly affects the price. Figure 10-17 shows the impact of LOC on price when online resources must be redispatched to satisfy the DASR requirement. DASR prices increase at peak loads as a result of high LOCs. Figure 10-18 shows that when total DASR MW required is at its peak, a higher percentage of MW come from on line steam and CT units. While CTs have a low DASR related cost, steam units typically incur an LOC when redispatched to provide DASR. The redispatch of steam units to provide DASR has a significant impact on DASR prices.

Figure 10-18 Daily average DASR MW by Unit Type sorted from highest to lowest daily requirement: 2015



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.[38]

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

38 See the *2012 State of the Market Report for PJM*, Volume II, Section 9, "Ancillary Services," p. 271.

meet this objective, the marginal benefit factor (MBF) function describing the engineering substitutability between RegA and RegD must be correctly defined and consistently applied throughout the market design, from optimization to settlement. This is the only way to ensure that the engineering relationship is reflected in the relative value of RegA and RegD resources in the market price signals. That is not the case in PJM's current regulation market design. The MBF function is not correctly defined and it is not consistently applied throughout the market design, from optimization to settlement.

The result has been that the regulation market has over procured RegD relative to RegA in some hours and has provided a consistently inefficient market signal to participants regarding the value of RegD to the market in every hour. This over procurement began to degrade the ability of PJM to control ACE in some hours while at the same time increasing the cost of regulation. When the price paid for RegD is above the competitive level defined by an accurate MBF function, there is an artificial incentive for inefficient entry of RegD resources. This inefficient market signal has contributed to a significant amount of storage capacity (Table 10-29) appearing in PJM's interconnection queue, despite operational evidence that the RegD market, as implemented, is saturated.

Table 10-29 Active battery storage projects in the PJM queue system by submitted year from 2012 to 2015

Year	Number of Storage Projects	Total Capacity (MW)
2012	3	9.1
2013	4	22
2014	11	151
2015	57	534.4

The MBF related issues with the regulation market have been raised in the PJM stakeholder process. In 2015, PJM stakeholders approved an interim, partial fix to the RegD over procurement problem which was implemented on December 14, 2015. The interim fix was designed to reduce the relative value of RegD MW in the optimization in all hours and cap RegD MW during critical performance hours, as well as provide a better measure of effective MW from cleared RegD resources. The interim fix does not address the fundamental issues in the optimization or the lack of consistency in the application of the MBF. The MMU and PJM are pursuing a more complete fix through the Regulation Market Issues Senior Task Force.

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, with slower ramp rates. RegD is PJM's fast-oscillation regulation signal and is designed for resources with limited ability to sustain energy output and with faster ramp rates. Resources must qualify to follow one or both of the RegA and RegD signals, but will be assigned by the market clearing engine to follow only one signal in a given market hour. The PJM regulation market design includes three clearing price components: capability ($/MW, based on the MW being offered); performance ($/mile, based on the total MW movement requested by the control signal, known as mileage); and lost opportunity cost ($/MW of lost revenue from the energy market as a result of providing regulation). The marginal benefit factor and performance score translate a resource's capability (actual) MW into effective MW.

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.[39]

Figure 10-19 and Figure 10-20 show the average performance score by resource type and the signal followed for 2015. In these figures, the MW used are unadjusted regulation capability MW and the performance score is the hourly performance score of the regulation resource.[40] Each category (color bar) is based on the percentage of the full performance score distribution for each resource (or signal) type. As Figure 10-20 shows, 72.6 percent of RegD resources had average performance scores within the 0.91-1.00 range, and 24.1 percent of RegA resources had average performance scores within that range.

Figure 10-19 Hourly average performance score by unit type: 2015

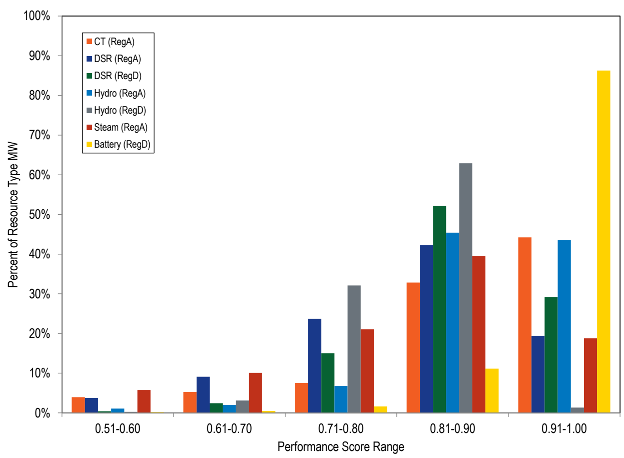
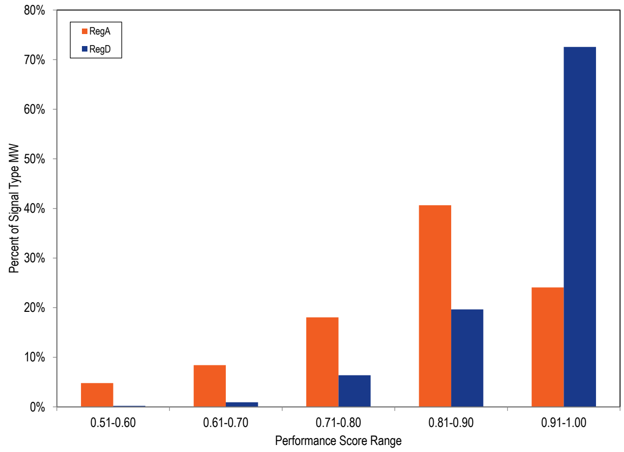


Figure 10-20 Hourly average performance score by regulation signal type: 2015



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 MW into a single measure. The marginal benefit factor (MBF) is the measure of substitutability of RegD resources for RegA resources in satisfying the regulation requirement.

The MBF, as the marginal rate of substitution between RegA and RegD resource MW for a given regulation requirement, defines specific combinations of RegA and RegD MW needed to meet specific regulation performance levels. The MBF should result in the selection of the least cost combination/ratio of RegA and RegD MW when the prices of RegA and RegD are known. PJM's optimization engine has not properly implemented the MBF so that

39 PJM "Manual 12: Balancing Operations" Rev. 33 (December 1, 2015); 4.5.6, p 52.
40 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.

the market clearing combination of RegA and RegD MW is consistent with the combinations defined by the MBF curve.

For purposes of comparing effective MW to the regulation requirement, expressed in terms of effective MW of RegA, cleared regulation MW are converted to effective MW by multiplying each resource's offered capability MW by the product of the resource specific benefit factor and performance score. This resource specific block assignment approach undercounts total effective MW, which are correctly calculated as the area under the MBF curve.

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 1.0 MW RegD resource with a total offer price 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 would be $4 per effective MW ($2/MW offer divided by the 0.5 effective MW).

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. If the marginal benefit factor function is incorrectly defined, the resulting combinations of RegA and RegD do not represent the least cost solution.

The marginal benefit factor is not included in PJM's settlement process. This is a design flaw that results in incorrect payments for regulation. The issue results from 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 1.0 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 the RegD to RegA mileage ratio in the performance credit paid to RegD resources, effective retroactively to October 1, 2012.[41]

The result of the 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 settlement for RegD.

Resources are paid Regulation Market Clearing Price (RMCP) 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.

Figure 10-21 compares the daily average marginal benefit factor and the mileage ratio.

Figure 10-21 Daily average marginal benefit factor and mileage ratio: 2015

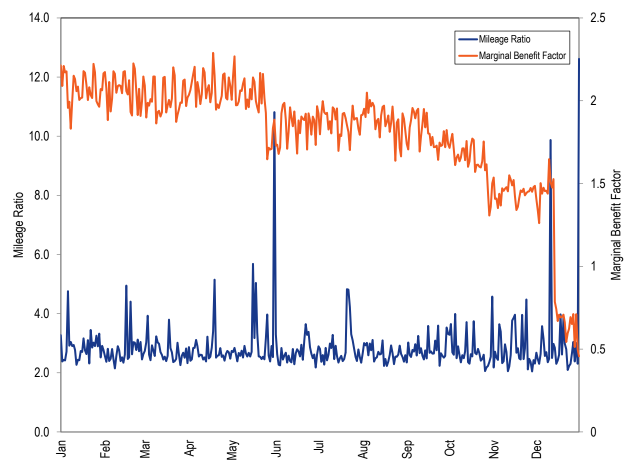
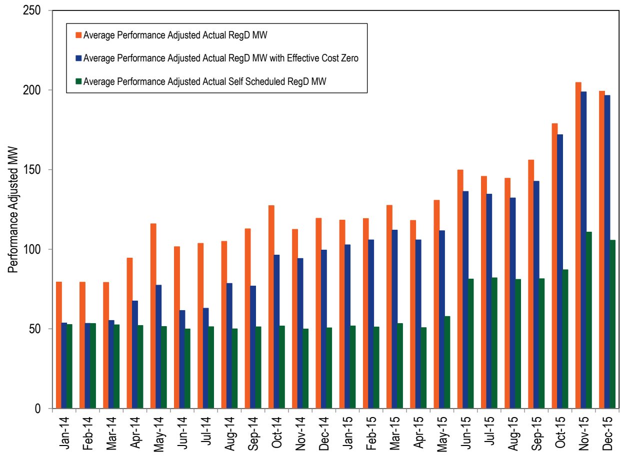


Figure 10-22 shows, by month, both an increasing amount and increasing proportion of cleared RegD MW with an effective price of $0.00. The figure also shows a corresponding increase in the total RegD MW clearing the market in the period between January 1, 2014 and December 30, 2015. Figure 10-22 also shows that self-scheduling, bidding RegD MW at zero, has increased.[42]

41 145 FERC ¶ 61,011 (2013).

42 See the MMU's Regulation Market Review presentation from the May 5, 2015 Operating Committee. available at <http://www.pjm.com/~/media/committees-groups/committees/oc/20150505/20150505-item-17-regulation-market-review.ashx>

Figure 10-22 Average cleared RegD MW and average cleared RegD with an effective price of $0.00 by month: January 2014 through December 2015



The current settlement process does not result in RegA and RegD resources being paid the same price per effective MW. 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 in settlements. When the marginal benefit factor is above one, RegD resources are generally (depending on the mileage ratio) underpaid on a per effective MW basis. When the marginal benefit factor is less than one, RegD resources are generally overpaid on a per effective MW basis.

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 five-minute interval based on the marginal offer in each interval. The performance clearing price ($/effective MW) is based on the marginal performance offer (RMPCP) for the hour. The capability clearing price ($/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.[43] The current market design does not send the correct price signal to the RegD resources as a result of the inconsistent application of the marginal benefit factor.

Figure 10-23 shows, for the period from January 1, 2015, through December 31, 2015, the maximum, minimum and average marginal benefit factor, based on PJM's incorrect marginal benefit factor curve, by month. The decrease in the average marginal benefit factor (MBF) in December is due to the changes in the marginal benefit factor curve put into place on December 14, 2015. The change in the marginal benefit factor curve reduced the relative value of RegD MW in the optimization in all hours (the slope of the benefit factor curve was altered to intercept the x axis, defined in terms of RegD MW as a percent of the regulation requirement, at 40 percent instead of 62 percent) and capped the procurement of RegD MW during what PJM has termed excursion hours (hours ending 7:00, 8:00, 18:00-21:00) at the point where the MBF on the curve is equal to 1.0 (which occurs where the x-axis is equal to 26 percent).

Figure 10-23 Maximum, minimum, and average PJM calculated marginal benefit factor by month: 2015

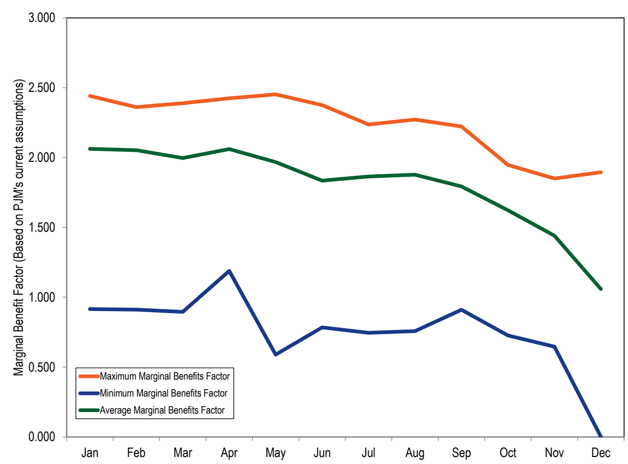
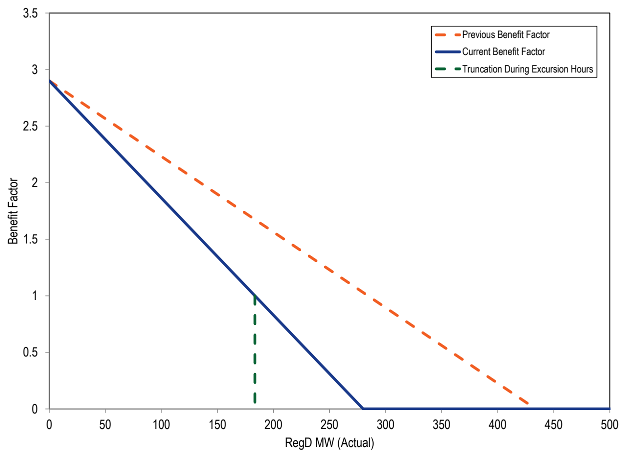


Figure 10-24 illustrates the marginal benefit factor curve before and after the December 14, 2015 modification. The modification to the marginal benefit curve reduced the amount of RegD procured, but did not correct for identified issues with the optimization engine.

43 This is due to the fact that RegA resources performance adjusted MW are their effective MW.

Figure 10-24 Benefit Factor Curve before and after December 14, 2015 revisions by PJM



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.[44]

The Effective MW of Regulation Purchased Are Understated

In 2015, the MMU determined that the regulation market optimization/market solution was understating the amount of effective MW provided by RegD. Rather than correctly calculating the total effective MW contribution of RegD MW on the basis of the area under the marginal benefit function curve, the regulation market optimization assigns the MBF associated with the last MW of a cleared unit to every MW of that unit ("unit block") for purposes of calculating effective MW. PJM then calculates the effective MW as the simple product of the MW and the MBF, rather than the area under the MBF curve for that number of MW. The result of this approach is that 100 MW of RegD (performance adjusted) provided by a single resource (one 100 MW unit) will appear to provide fewer effective MW than 100 MW (performance adjusted) provided by two separate 50 MW units.

In addition, the MMU determined that the regulation market optimization/market solution treats all RegD resources with the same effective price as a single resource ("price block") for purposes of assigning a benefit factor and calculating effective MW. This means that all of the MW associated with multiple units with the same effective price (for example a price of zero) were assigned the MBF of the last MW of the last unit of that block of resources with the same effective price. PJM then calculates the effective MW as the simple product of the MW and the MBF, rather than the area under the MBF curve for that number of MW. This resulted in an undercounting of effective MW from RegD resources cleared at an effective price of zero or self-scheduled.

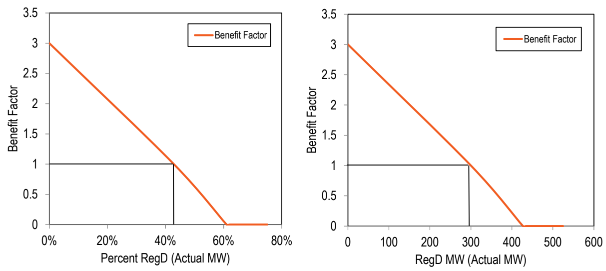
The identified effective MW measurement issue was only incompletely addressed by a modification that was put into effect on December 14, 2015. The modification rank orders self-scheduled MW and assigns the MBF of the last MW of each of these units to all MW of that unit. The result is to break up the RegD MW in the zero price or self-scheduled block into unit specific blocks of MW that are each assigned a unit specific benefit factor. The resulting effective MW calculation better approximates the area under the marginal benefit factor curve for those price block MW. A full correction of the effective MW calculation requires the use of the area under the curve.

The existing approach to calculating effective MW resulted in the purchase of more than the efficient level of regulation MW to meet PJM's defined regulation requirement in 2015.

An example illustrates the issue. Figure 10-25 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 10-25 shows that the 300 MW of cleared RegD are 42.9 percent of total cleared actual MW and that the marginal benefit factor is 1.0.

44 See "Regulation Market Review," presented at the May 5, 2015 Operating Committee meeting. <http://www.pjm.com/~/media/committees-groups/committees/oc/20150505/20150505-item-17-regulation-market-review.ashx>

Figure 10-25 Example marginal benefit line in percent RegD and RegD MW terms



Using PJM's price block/unit block 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. PJM calculates total effective MW from RegD resources to be 300 (300MW x 1.0 = 300 effective MW).

In Figure 10-26, PJM's price block/unit block calculation of total effective MW from RegD is represented by the area of the blue rectangle which is 400 effective MW.

PJM's price block/unit block method is flawed. By assigning a single benefit value to every MW, the price block/unit block methodology undervalues the amount of effective MW provided by RegD MW. 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 10-26. 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 10-26 Illustration of correct method for calculating effective MW

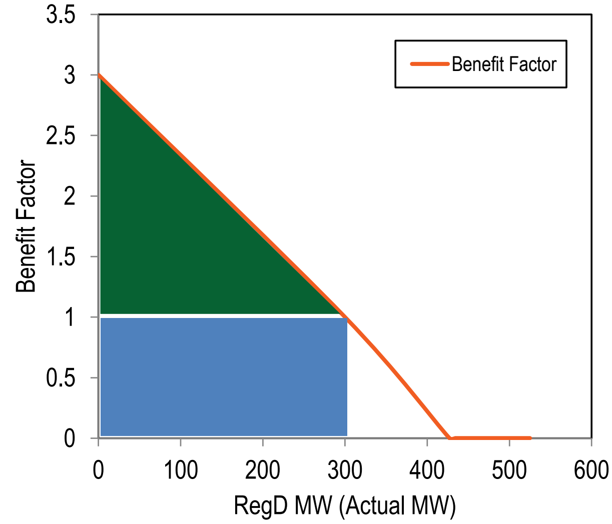


Figure 10-27 illustrates PJM's December 14, 2015, incomplete correction of the price block/unit block calculation as it applies to RegD resources that clear with an effective price of zero ($0.00 offer or self-scheduled). In this example, the PJM market clears two self-scheduled resources, one with 100 MW and one with 83 MW, for a total of 183 MW and a market MBF of 1.0. Prior to the fix put in place on December 14, 2015, all 183 MW of RegD would be assigned the MBF of 1.0.

After December 14, 2015, zero price offer and self scheduled resources are rank ordered by performance score and assigned unit specific MBF numbers based on the MBF associated with the last MW of each unit that cleared. Using this new approach, assuming the 83 MW resource was ranked higher than the 100 MW resource, the 83 MW resource would be assigned a unit specific benefit factor of 2.0 (see figure) and the 100 MW resource would be assigned a unit specific benefit factor of 1.0 (see figure).

PJM still calculates effective MW as the simple product of the MW and the MBF, rather than the area under the MBF curve for cleared MW, which results in an effective MW total of 269.9 MW, due to 169.9 effective MW being attributed to the 83 MW resource (83 MW times 2.0 BF) and 100 effective MW being attributed to the 100 MW resource (100 MW times 1.0 BF). This new method provides a closer approximation of the area under the curve, but this updated approach still under estimates the effective MW from cleared RegD resources. Using the area under the curve approach would correctly result in an effective MW total of 355.9 MW being attributed to the 183 MW cleared in the market, not the 266 effective MW of the post December 14, 2015 method or the 183 effective MW of the pre December 14, 2015 method.

Figure 10-27 Example of Pre and Post December 14, 2015, Effective MW Calculations for RegD MW offered at $0.00 or as Self Supply

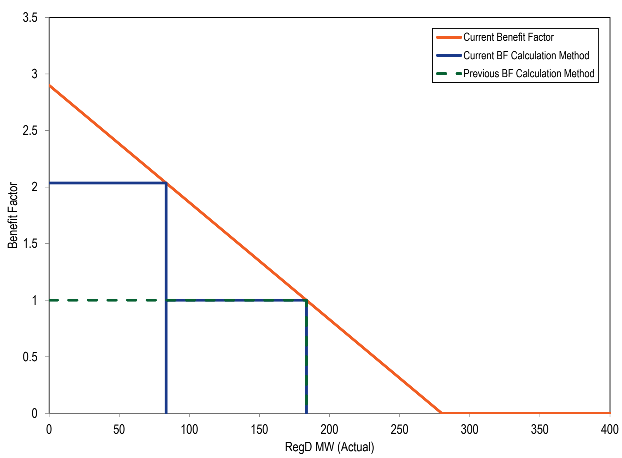
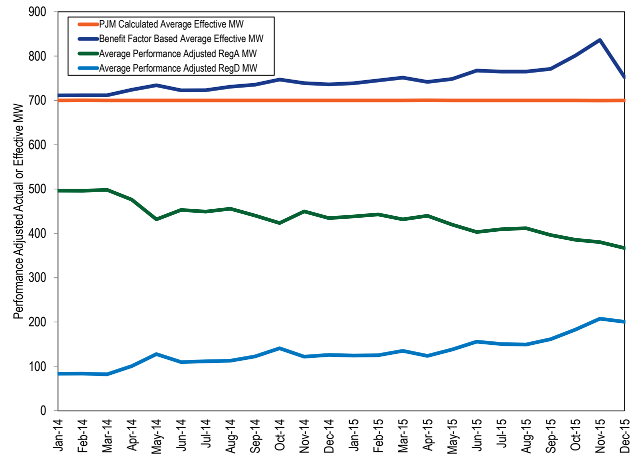


Figure 10-28 shows the average monthly peak total effective MW as calculated by PJM's incorrect effective MW accounting method(s) and as calculated by a correctly applied marginal benefit factor for the January 2014 through December 2015 period. Figure 10-28 shows a reduction in over procurement in December of 2015. The figure also shows the monthly average actual (performance adjusted) RegA and RegD MW 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 10-22, this has been caused by an increasing proportion of RegD MW supply with an effective price of $0.00 in the PJM market.

Figure 10-28 Average monthly peak effective MW: PJM market calculated versus benefit factor based: January 2014 through December 2015

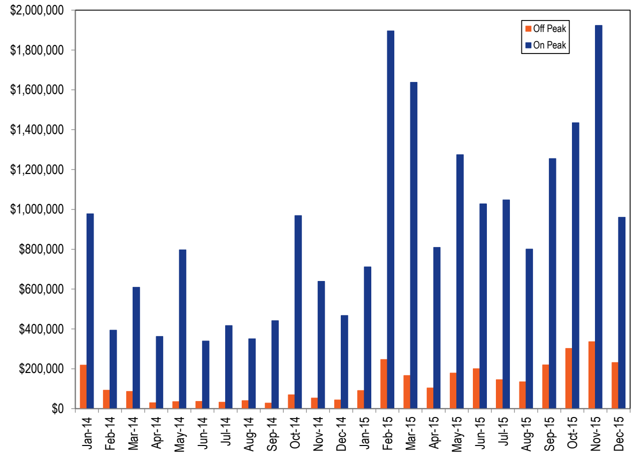


The Cost of Purchasing Too Many Regulation MW Due to Incorrect Effective MW Calculation Approach

Figure 10-29 shows the cost of the excess effective MW cleared by month, peak and off peak, from January 1, 2014, through December 30, 2015, caused by PJM's incorrect approach(s) to calculating effective MW from RegD resources. To determine this excess cost, the total effective MW of RegD are correctly calculated using the full area under the Benefit Factor curve, and the difference between that value and the one used by PJM is multiplied by the price in each hour. This excess cost calculation does not take into account the fact that, if calculated correctly, the change in effective MW from RegD would alter the clearing price. The excess cost calculation also does not correct for the PJM's flawed optimization engine which is currently clearing incorrect proportions of RegA and RegD due to an incorrect and inconsistent application of the assumed marginal benefit factor function.

In 2015, the estimated total cost of excess effective RegD MW during on peak and off peak hours was $14.8 million and $2.4 million. The implementation of the partial fix to the effective MW calculation and the changes in the benefit factor curve in December of 2015 reduced but did not eliminate, the excess effective MW clearing in the regulation market.

Figure 10-29 Cost of excess effective MW cleared by month, peak and off peak: 2014 through 2015



Incorrect MBF and Inconsistent Application of MBF in Optimization Causing Incorrect Proportion of RegD MW Being Purchased

PJM observed issues with regulation performance when the proportion of effective MW from RegD resources exceeds 42 percent.[45] The system issues are a result of PJM buying too much RegD as a proportion of total regulation.

In addition, the current market clearing engine is not correctly maintaining the assumed ratios of RegA and RegD that are the basis of the MBF function describing the rate of substitution between RegA and RegD. The MBF, as a marginal rate of substitution between RegA and RegD resource MW for a given regulation requirement, assumes specific combinations/ratios of RegA and RegD MW that are needed to meet specified regulation performance goals. Properly implemented in the optimization, the use of the MBF should result in the selection of the least cost combination/ratio of RegA and RegD MW from among the specified combinations/ratios that were used to define the MBF curve. The current engine merely uses the MBF function, defined as the MBF for a given amount of RegD regardless of the amount of RegA clearing, to adjust RegD offers for purposes of rank ordering resources in the supply stack, and then clears resources in price order until the calculated effective MW target is reached. This market clearing is done without confirming that the assumed ratios of RegA and RegD that are the basis of the MBF curve have been maintained in the market solution. The issues identified by the MMU related to the incorrect use of the MBF function, combined with an increasing proportion of RegD offering at an effective price of zero, are the reason that the market design results in too much RegD clearing relative to RegA MW in the market.

Table 10-30 illustrates, for both the previous and current benefit factor curve, the relationship between the MBF function's proportion of performance adjusted RegD MW relative to total cleared performance adjusted regulation MW and the proportion of RegD MW that would result if the RegD MW values listed in Table 10-30 were cleared before any RegA MW (due to the MBF adjusted RegD offers being less than the RegA MW offers).

For example, if the market cleared 175 MW of RegD (which would be determined to be 25 percent of the 700 performance adjusted MW needed) priced at zero, the market clearing engine would determine it would need 294.8 MW of RegA to meet the 700 MW requirement using the previous BF curve, and would need 351.1 MW using the current BF curve. The resulting proportion of RegD to total regulation cleared would be 37 percent and 33 percent for the previous and current BF curves respectively, rather than the 25 percent that was assumed by the MBF function. Although there is a smaller difference between the proportion of RegD cleared under the current BF curve and the correct amount, as compared to that of the previous BF curve, the error still persists and is not eliminated by simply adjusting the curve. A full correction will require that the proportions assumed in the curve are maintained through the market clearing process.

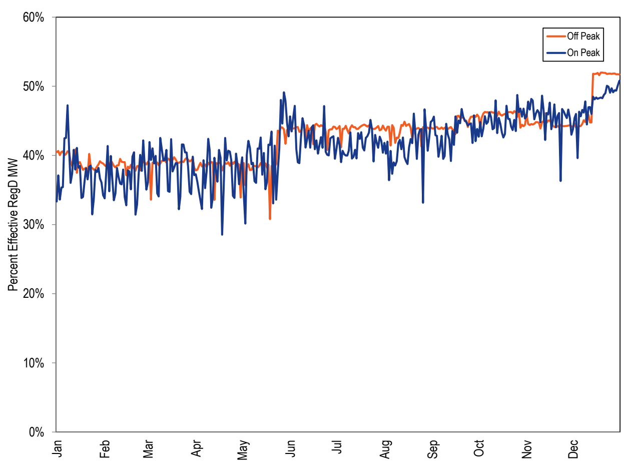
45 See PJM's "Fast Response Regulation (RegD) Resources Operational Impact Problem Statement," presented at the May 5, 2015 Operating Committee meeting. <http://www.pjm.com/~/media/committees-groups/committees/oc/20150505/20150505-item-17-problem-statement-regulation.ashx>

Table 10-30 MBF assumed RegD proportions versus market solution realized RegD proportions[46]

RegD Percent of 700 MW	RegD MW (Performance Adjusted)	MBF (Previous)	MBF (Current)	Effective MW from RegD MW (Previous)	Effective MW from RegD MW (Current)	Residual A (700 MW Target, Previous)	Residual A (700 MW Target, Current)	RegD/ (RegA+RegD, Previous)	RegD/ (RegA+RegD, Current)
5%	35	2.67	2.54	97.41	95.16	602.59	604.84	5%	5%
10%	70	2.43	2.18	186.63	177.63	513.37	522.38	12%	12%
15%	105	2.20	1.81	267.67	247.41	432.33	452.59	20%	19%
20%	140	1.96	1.45	340.52	304.50	359.48	395.50	28%	26%
25%	175	1.73	1.09	405.18	348.91	294.82	351.09	37%	33%
30%	210	1.50	0.73	461.66	380.63	238.34	319.38	47%	40%
35%	245	1.26	0.36	509.96	399.66	190.04	300.34	56%	45%
40%	280	1.03	0.00	550.06	406.00	149.94	294.00	65%	49%
45%	315	0.80	-	581.99	-	118.01	-	73%	-
50%	350	0.56	-	605.73	-	94.27	-	79%	-
55%	385	0.33	-	621.28	-	78.72	-	83%	-
60%	420	0.09	-	628.65	-	71.35	-	85%	-

The proportion of RegD resources used to satisfy the on peak (700 MW) and off peak (525 MW) regulation requirements is shown in Figure 10-30.

Figure 10-30 Daily average percent of RegD effective MW by peak: January through December 2015



The effect of the incorrect accounting of effective MW was 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 these market flaws 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 (Figure 10-22). This guarantees that an increasing proportion of RegD MW in the market incorrectly appears as the cheapest source of incremental effective regulation MW.

Market Structure

Supply

Table 10-31 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 2015. 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.[47] A resource must be either generation or demand. A resource can choose to follow both signals. For that reason, the sum of each signal type's capability can exceed the full regulation capability. Offered MW are calculated based on the daily offers from units that are categorized as available for the day. Eligible MW are calculated from the hourly offers from both units with daily offers and units that are categorized as unavailable for the day, but still offer MW into some hours. Additionally, units with daily offers are permitted to offer above or below their daily offer from hour to hour. Because of these hourly MW adjustments to MW offers beyond what was offered on a daily basis, the average hourly Eligible MW can be higher than the Offered MW.

46 This example assumes that the calculation of effective MW from RegD was calculated correctly as the area under the MBF curve.

47 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.

Table 10-31 PJM regulation capability, daily offer and hourly eligible: January through December 2015[48 49]

		By Resource Type		By Signal Type	
Metric	All Regulation	Generating Resources	Demand Resources	RegA Following Resources	RegD Following Resources
Capability MW	8,701.8	8,680.4	21.4	8,390.5	628.3
Offered MW	2,717.3	2,709.3	8.0	2,504.1	213.2
Actual eligible MW	1,157.8	1,151.7	6.1	907.9	249.9
Effective eligible MW	889.9	882.6	7.3	606.4	283.5
Actual cleared MW	640.9	637.0	3.9	477.6	163.3
Effective cleared MW	663.7	657.5	6.2	387.7	275.9

Table 10-32 PJM regulation by source in 2014 and 2015

	2014				2015			
Source	Number of Units	Adjusted Settled Regulation (MW)	Percent of Scheduled Regulation	Total Regulation Credits	Number of Units	Adjusted Settled Regulation (MW)	Percent of Scheduled Regulation	Total Regulation Credits
Battery	85	807,003.6	16.1%	$29,681,876	143	1,383,557.2	27.6%	$37,447,900
Biomass	12	16,497.6	0.3%	$730,973	12	25,681.8	0.5%	$799,228
Coal	998	543,018.5	10.8%	$44,718,176	711	590,903.6	11.8%	$32,877,595
Hydro	350	910,391.1	18.2%	$57,492,082	356	935,039.5	18.7%	$37,546,622
Light Oil	13	742.7	0.0%	$597,921	0	1.0	0.0%	$0
Natural Gas	835	2,707,792.7	54.0%	$119,434,967	980	2,042,374.2	40.7%	$69,891,947
DR	163	28,958.2	0.6%	$1,301,092	157	35,731.5	0.7%	$1,047,198
Total	2,456	5,014,404.5	100.0%	$253,957,088	2,359	5,013,288.9	100.0%	$179,610,489

Table 10-32 provides the scheduled regulation in MW by source, the total scheduled regulation in MW provided by all resources (including DR), and the percent of scheduled regulation provided by each fuel type. In Table 10-32 the MW have been adjusted by the actual within hour performance score since this adjustment forms the basis of payment for units providing regulation. Total regulation capability MW decreased from 5,014,404.5 MW in 2014 to 5,013,288.9 MW in 2015. The average proportion of regulation provided by battery units had the largest increase, providing 16.1 percent of regulation in 2014 and 27.6 percent of regulation in the 2015. Natural gas units had the largest decrease in average proportion of regulation provided, decreasing from 54.0 percent in 2014, to 40.7 percent in 2015. The total regulation credits in 2015 were $179,610,489 down from $253,957,088 in 2014.

The supply of regulation can be affected by regulating units retiring from service. Table 10-33 shows the impact on the regulation market from all units that retired in 2015. These retirements reduced the supply of regulation in PJM by less than one percent. The MW in Table 10-33 have been adjusted by the actual within hour performance score.

48 Average Daily Offer MW excludes units that have offers but are unavailable for the day.

49 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 10-33 Impact on the PJM Regulation Market of currently regulating units retired in 2015

Current Regulation Units, 2015	Adjusted Settled MW, 2015	Units Retired In 2015	Adjusted Settled MW of Units Retired In 2015	Percent of Regulation MW Retired In 2015
291	4,169,935.6	19	11,477.1	0.3%

Although the marginal benefit factor for RegA resources is 1.0, the effective MW of RegA resources was lower than the offered MW in 2015, because the average performance score was less than 1.00. For 2015, the MW weighted average RegA performance score was 0.81 and there were 291 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 2015, the marginal benefit factor, based on PJM's current assumed marginal benefit factor curve, for cleared RegD following resources ranged from 0.001 to 2.452 with an average over all hours of 1.802. In 2015, the MW weighted average RegD resource performance score was 0.92 and there were 57 resources following the RegD signal.

The cost of each unit is calculated using its capability and performance offer prices, 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 10-41). In 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 2015 was $31.92/MW. The regulation cost for 2015 was $38.36/MW. The ratio of price to cost is higher (83.2 percent) than in 2014 (82.6 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 14, 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 2015.

Table 10-34 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.

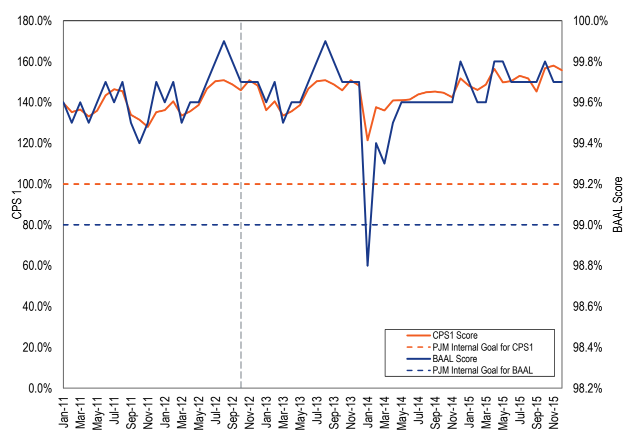
Table 10-34 PJM Regulation Market required MW and ratio of eligible supply to requirement: January through March 2014 and 2015

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	638.3	663.6	663.7	2.05	1.86	1.60	1.35
Feb	681.7	656.3	663.6	663.5	2.00	1.74	1.51	1.37
Mar	682.8	649.8	663.8	663.8	1.99	1.73	1.48	1.35
Apr	681.8	646.0	663.7	663.7	2.04	1.83	1.55	1.34
May	658.1	650.4	663.6	663.6	1.93	1.72	1.44	1.32
Jun	647.0	632.2	663.9	663.7	1.89	1.81	1.29	1.30
Jul	642.0	627.5	663.5	663.8	1.88	1.83	1.29	1.32
Aug	649.7	631.4	663.6	663.6	1.93	1.79	1.30	1.33
Sep	643.1	638.4	663.6	663.5	1.91	1.80	1.26	1.35
Oct	655.2	632.6	663.6	663.4	1.83	1.86	1.26	1.36
Nov	660.9	655.4	663.3	663.2	1.85	1.82	1.28	1.33
Dec	636.5	634.0	663.6	663.9	1.97	1.88	1.34	1.39

PJM's performance as measured by CPS1 and BAAL standards is shown in Figure 10-31 for every month from January 2011 through December 2015 with the dashed vertical line marking the date (October 1, 2012) of the implementation of the Performance Based Regulation Market design.[50] 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.

Figure 10-31 PJM monthly CPS1 and BAAL performance: January 2011 through December 2015



Market Concentration

Table 10-35 shows HHI results for 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 1358 is classified as moderately concentrated and is lower than the HHI for the same period in 2014 of 1936. For 2015, the weighted average HHI of RegA resources was 2573 (highly concentrated, but lower than the 2014 value of 3151 and the weighted average HHI of RegD resources was 2506 (highly concentrated, but lower than the 2014 value of 4330). 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

50 See the *2014 State of the Market Report for PJM*, Appendix F: Ancillary Services.

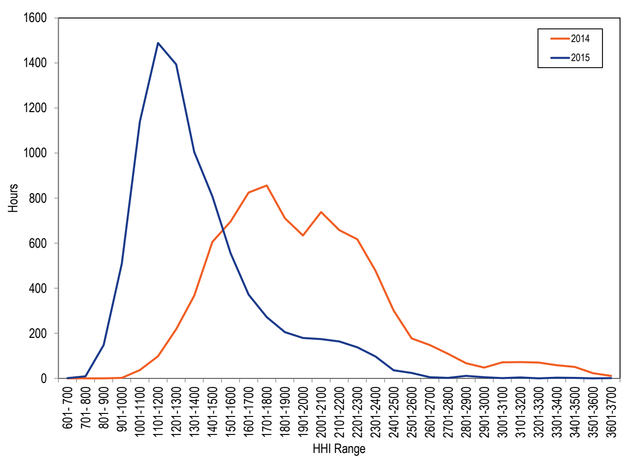
different owners have large market shares in the RegA and RegD markets.

Table 10-35 PJM cleared regulation HHI: 2014 and 2015

Year	Minimum HHI	Weighted Average HHI	Maximum HHI
2014	915	1936	5325
2015	695	1358	3658

Figure 10-32 compares the frequency distribution of HHI for January through December 2014 and 2015. The HHI values are calculated based on effective MW cleared.

Figure 10-32 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 10-36 includes a monthly summary of three pivotal supplier results. In 2015, 97.8 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 10-34). The MMU concludes from these results, that the PJM Regulation Market in 2015 was characterized by structural market power in 97.8 percent of hours.

Table 10-36 Regulation market monthly three pivotal supplier results: 2013 through 2015

	Percent of Hours Pivotal		
Month	2013	2014	2015
Jan	83.0%	96.9%	97.8%
Feb	82.5%	98.7%	96.3%
Mar	97.3%	94.9%	97.3%
Apr	88.0%	89.0%	98.1%
May	93.1%	95.7%	99.3%
Jun	94.6%	99.4%	98.6%
Jul	93.5%	100.0%	98.8%
Aug	91.5%	99.7%	97.7%
Sep	90.4%	99.4%	97.1%
Oct	82.7%	99.1%	96.1%
Nov	88.6%	98.9%	99.2%
Dec	94.9%	98.1%	97.2%
Average	90.0%	97.5%	97.8%

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 nonsteady state. Batteries and flywheels have zero cost for lower efficiency from providing regulation instead of energy, as they are not net energy producers. Instead batteries and flywheels are, due to losses, net consumers of energy when providing regulation service. On April 1, 2015, PJM added an Energy Storage Loss component for batteries and flywheels as a cost component of regulation performance offers to the eMkt Regulation

Offers screen, to reflect the net energy consumed to provide regulation service.[51]

Up until one hour before the operating hour, the regulating resource must input or may change: 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.[52]

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 10-38).[53] Figure 10-33 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.[54] 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 40.3 percent during on peak and 54.9 percent during off peak hours in 2015).

Figure 10-33 Off peak and on peak regulation levels: 2014 through 2015

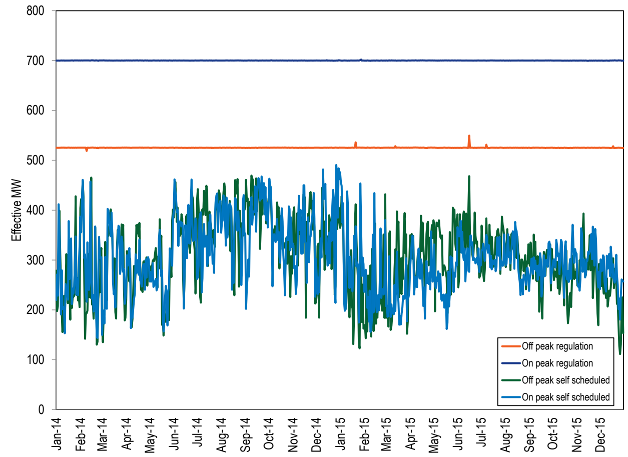


Table 10-37 shows how RegD resources have impacted the regulation market. RegD resources are both a growing proportion of the market (10.9 percent of the total effective MW at the start of the performance based regulation market design in October 2012 and 47.8 percent in December 2015) and a growing proportion of resources that self schedule (10.1 percent in October 2012 and 21.8 percent in December 2015).

51 See PJM. "Manual 15: Cost Development Guidelines," Revision 26, (November 6, 2014); para 11.8, p. 60
52 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Revision 72, (January 16, 2015); para 3.2.2, pp 48.
53 See PJM. "Manual 28: Operating Agreement Accounting," Revision 68, (January 16, 2015); para 4.1, p 15.
54 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Revision 72, (January 16, 2015); para 3.2.9, p 59.

Table 10-37 RegD self-scheduled regulation by month, October 2012 through December 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	66.3	71.8	264.7	658.1	40.2%	10.1%	10.9%
2012	Nov	74.4	88.3	196.5	716.5	27.4%	10.4%	12.3%
2012	Dec	82.5	88.8	188.8	701.1	26.9%	11.8%	12.7%
2013	Jan	35.7	82.5	133.6	720.0	18.6%	5.0%	11.5%
2013	Feb	84.8	90.2	212.2	724.3	29.3%	11.7%	12.5%
2013	Mar	80.1	119.3	279.8	680.7	41.1%	11.8%	17.5%
2013	Apr	82.3	106.9	266.0	594.1	44.8%	13.8%	18.0%
2013	May	74.0	109.0	268.2	616.2	43.5%	12.0%	17.7%
2013	Jun	79.6	122.7	334.9	730.6	45.8%	10.9%	16.8%
2013	Jul	77.6	120.4	303.6	822.9	36.9%	9.4%	14.6%
2013	Aug	83.6	127.6	366.0	756.8	48.4%	11.0%	16.9%
2013	Sep	112.2	152.1	381.6	669.9	57.0%	16.7%	22.7%
2013	Oct	120.2	163.7	349.6	613.3	57.0%	19.6%	26.7%
2013	Nov	133.9	175.7	396.5	663.3	59.8%	20.2%	26.5%
2013	Dec	136.5	180.7	313.6	663.5	47.3%	20.6%	27.2%
2014	Jan	132.9	193.5	261.1	663.6	39.3%	20.0%	29.2%
2014	Feb	134.3	193.4	289.0	663.6	43.5%	20.2%	29.1%
2014	Mar	131.8	193.8	287.2	663.8	43.3%	19.9%	29.2%
2014	Apr	126.8	212.4	270.8	663.7	40.8%	19.1%	32.0%
2014	May	121.7	248.5	265.6	663.6	40.0%	18.3%	37.4%
2014	Jun	123.3	231.0	365.5	663.9	55.0%	18.6%	34.8%
2014	Jul	126.4	235.5	352.7	663.5	53.2%	19.0%	35.5%
2014	Aug	117.6	229.8	368.2	663.6	55.5%	17.7%	34.6%
2014	Sep	121.0	242.6	393.8	663.6	59.3%	18.2%	36.6%
2014	Oct	116.1	255.4	352.7	663.6	53.2%	17.5%	38.5%
2014	Nov	113.5	235.1	347.5	664.2	52.3%	17.1%	35.4%
2014	Dec	116.7	254.3	353.0	663.6	53.2%	17.6%	38.3%
2015	Jan	116.4	250.1	304.8	663.7	45.9%	17.5%	37.7%
2015	Feb	111.3	245.8	242.6	663.5	36.6%	16.8%	37.0%
2015	Mar	113.8	255.2	229.9	663.8	34.6%	17.1%	38.5%
2015	Apr	110.1	248.2	283.7	663.7	42.7%	16.6%	37.4%
2015	May	121.8	265.1	266.7	663.6	40.2%	18.4%	39.9%
2015	Jun	158.9	283.1	321.2	663.7	48.4%	23.9%	42.6%
2015	Jul	161.4	278.3	314.0	663.8	47.3%	24.3%	41.9%
2015	Aug	159.5	276.0	300.7	663.6	45.3%	24.0%	41.6%
2015	Sep	155.4	289.2	286.0	663.5	43.1%	23.4%	43.6%
2015	Oct	147.1	299.0	292.8	663.4	44.1%	22.2%	45.1%
2015	Nov	164.9	302.1	298.1	664.2	44.9%	24.8%	45.5%
2015	Dec	144.6	317.2	260.7	663.9	39.3%	21.8%	47.8%
Average		114.6	100.7	296.5	398.0	44.2%	42.0%	30.1%

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 2015, 54.3 percent was purchased in the PJM market, 40.3 percent was self-scheduled, and 5.3 percent was purchased bilaterally (Table 10-38). Table 10-39 shows the total regulation by source including spot market regulation, self scheduled regulation, and bilateral regulation for each year from 2011 to 2015. Table 10-38 and Table 10-39are based on settled (purchased) MW.

Table 10-38 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	245,923.9	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%	204,360.6	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%	394,659.0
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	186,186.4	48.6%	174,157.4	45.5%	22,613.0	5.9%	382,956.8
2015	Jul	199,332.1	50.5%	172,743.7	43.7%	22,845.0	5.8%	394,920.8
2015	Aug	207,794.6	53.0%	162,197.5	41.3%	22,412.5	5.7%	392,404.7
2015	Sep	207,352.6	54.6%	150,467.7	39.6%	21,863.0	5.8%	379,683.3
2015	Oct	213,982.2	53.4%	169,283.3	42.2%	17,724.5	4.4%	400,990.0
2015	Nov	213,952.0	52.9%	172,561.3	42.7%	17,790.0	4.4%	404,303.3
2015	Dec	220,651.8	54.1%	166,189.2	40.7%	21,342.5	5.2%	408,183.5

Table 10-39 Regulation sources by year: 2011 through 2015

Year	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	6,445,984.6	81.8%	1,226,570.0	15.6%	209,284.0	2.7%	7,881,838.6
2012	6,149,110.0	78.6%	1,484,446.2	19.0%	193,408.0	2.5%	7,826,964.2
2013	3,087,927.5	57.6%	2,064,156.7	38.5%	204,260.5	3.8%	5,356,344.7
2014	2,325,862.6	49.3%	2,161,996.2	45.8%	231,218.0	4.9%	4,719,076.8
2015	2,544,824.4	54.3%	1,888,038.5	40.3%	250,386.1	5.3%	4,683,248.9

In 2015, DR provided an average of 3.6 MW of regulation per hour (3.1 MW of regulation per hour in the same period of 2014). Generating units supplied an average of 637.4 MW of regulation per hour (660.8 MW of regulation per hour in the same period of 2014).

Market Performance

Price

The weighted average RMCP for 2015 was $31.92 per effective MW. This is a 28.2 percent decrease from the weighted average RMCP of $44.47 per MW in 2014. The decrease in the regulation clearing price was the result of significant reduction in energy prices and the related reduction in the LOC component of RMCP in 2015. The significant increase in self supply and $0.00 offers from RegD resources in the second half of 2015 also contributed to lower prices. Figure 10-34 shows the daily weighted 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. This data is based on actual five minute interval operational data. As Figure 10-34 illustrates, the LOC component (blue line) is the dominant component of the clearing price.

Figure 10-34 PJM regulation market daily weighted average market-clearing price, marginal unit opportunity cost and offer price (Dollars per MW): 2015

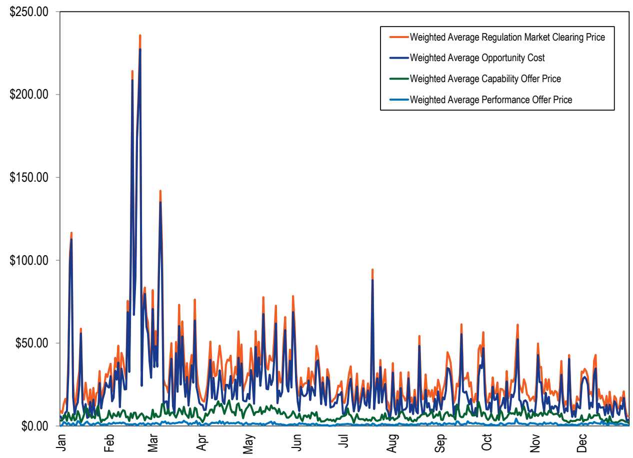


Table 10-40 shows monthly average regulation market clearing price, average marginal unit offer price, and average marginal unit LOC on an unadjusted capability MW basis. This data is based on actual five minute interval operational data.

Table 10-40 PJM regulation market monthly weighted average market-clearing price, marginal unit opportunity cost and offer price from five minute market solution data (Dollars per MW): 2015

Month	Weighted Average Regulation Marginal Unit LOC	Weighted Average Regulation Marginal Unit Capability Offer	Weighted Average Regulation Marginal Unit Performance Offer	Weighted Average Regulation Market Clearing Price
Jan	$20.31	$5.73	$1.22	$27.25
Feb	$64.92	$6.28	$1.30	$72.50
Mar	$36.94	$7.81	$1.79	$46.53
Apr	$21.60	$9.44	$1.57	$32.61
May	$33.12	$8.88	$1.15	$43.15
Jun	$20.25	$4.75	$0.78	$25.78
Jul	$18.61	$4.85	$0.80	$24.25
Aug	$14.06	$5.65	$1.04	$20.76
Sep	$20.75	$7.53	$1.39	$29.67
Oct	$15.52	$6.51	$1.24	$23.27
Nov	$15.14	$5.62	$1.04	$21.81
Dec	$14.20	$3.87	$1.31	$19.37

Monthly and total annual scheduled regulation MW and regulation charges, as well as monthly and monthly average regulation price and regulation cost are shown in Table 10-41. Total scheduled regulation is based on settled (unadjusted capability) MW. The total of all regulation charges for 2015 was $179.6 million, compared to $254.0 million for 2014.

Table 10-41 Total regulation charges: January 2014 through December 2015[55]

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	407,668.0	$65,744,697	$132.55	$161.27	82.2%
2014	Feb	366,529.6	$27,509,975	$63.12	$75.06	84.1%
2014	Mar	411,421.0	$39,901,162	$80.38	$96.98	82.9%
2014	Apr	395,428.9	$15,208,374	$31.74	$38.46	82.5%
2014	May	397,576.2	$16,927,322	$34.40	$42.58	80.8%
2014	Jun	386,949.6	$14,399,445	$30.65	$37.21	82.4%
2014	Jul	395,927.0	$14,458,430	$29.75	$36.52	81.5%
2014	Aug	401,761.9	$9,968,110	$20.45	$24.81	82.4%
2014	Sep	382,127.5	$11,906,005	$25.10	$31.16	80.5%
2014	Oct	395,042.7	$15,461,162	$32.96	$39.14	84.2%
2014	Nov	386,284.4	$12,615,109	$27.50	$32.66	84.2%
2014	Dec	392,359.9	$9,855,652	$21.25	$25.12	84.6%
2014 Annual		4,719,076.8	$253,955,442	$44.15	$53.41	82.7%
2015	Jan	394,350.5	$13,054,006	$27.13	$33.10	81.9%
2015	Feb	356,397.3	$31,757,444	$73.24	$89.11	82.2%
2015	Mar	394,659.0	$21,887,989	$45.79	$55.46	82.6%
2015	Apr	378,682.3	$14,878,908	$32.77	$39.29	83.4%
2015	May	395,717.3	$21,030,737	$43.12	$53.15	81.1%
2015	Jun	382,956.8	$11,544,657	$25.94	$30.15	86.0%
2015	Jul	394,920.8	$11,484,271	$24.40	$29.08	83.9%
2015	Aug	392,404.7	$9,913,785	$20.85	$25.26	82.5%
2015	Sep	379,683.3	$13,639,604	$29.71	$35.92	82.7%
2015	Oct	400,990.0	$10,904,138	$23.12	$27.19	85.0%
2015	Nov	404,303.3	$10,221,684	$21.92	$25.28	86.7%
2015	Dec	408,183.5	$9,323,436	$19.58	$22.84	85.7%
2015 Annual		4,683,248.9	$179,640,660	$32.30	$38.82	83.7%

The capability, performance, and opportunity cost components of the cost of regulation are shown in Table 10-42. Total scheduled regulation is based on settled (unadjusted capability) MW.

Table 10-42 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	394,659.0	$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
Jul	394,920.8	$22.28	$3.07	$3.73	$29.08
Aug	392,404.7	$18.21	$3.76	$3.30	$25.26
Sep	379,683.3	$26.44	$4.90	$4.58	$35.92
Oct	400,990.0	$19.91	$5.08	$2.20	$27.19
Nov	404,303.3	$19.05	$4.52	$1.72	$25.28
Dec	408,183.5	$16.81	$4.33	$1.71	$22.84

Table 10-43 provides a comparison of the average price and cost for PJM regulation. The ratio of regulation market price to the actual cost of regulation in 2015 was 83.2 percent, a 0.6 percent increase from 82.6 percent in 2014.

55 Weighted average market clearing prices presented here are taken from PJM settlements data, and differ from the values reported in Table 10-12, which are from five minute interval operational data. The IMM is investigating the cause of the discrepancies with PJM.

Table 10-43 Comparison of average price and cost for PJM Regulation, 2011 through 2015

Year	Weighted Regulation Market Price	Weighted Regulation Market Cost	Regulation Price as Percent Cost
2011	$16.48	$29.72	55.5%
2012	$19.02	$25.32	75.1%
2013	$30.85	$35.79	86.2%
2014	$44.47	$53.81	82.6%
2015	$31.92	$38.36	83.2%

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.[56] PJM set a September 30, 2013, deadline for resources submitting proposals and requested that resources be able to provide black 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. PJM and the MMU coordinated closely during the selection process.

56 See PJM. "RTO-Wide Five-Year Selection Process Request for Proposal for Black Start Service," (July 1, 2013).

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 are 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 2015, total black start charges were $53.6 million, a -$6.2 million (10.4 percent) decrease from the same period of 2014 level of $59.9 million. Operating reserve charges for black start service declined from $32.9 million in 2014 to $5.2 million in 2015. Table 10-44 shows total revenue requirement charges from 2010 through 2015. (Prior to December 2012, PJM did not define a black start operating reserve category.)

Table 10-44 Black start revenue requirement charges: 2010 through 2015

Year	Revenue Requirement Charges
2010	$11,490,379
2011	$13,695,331
2012	$18,749,617
2013	$20,874,535
2014	$26,945,112
2015	$48,440,990

Table 10-45 Black start zonal charges for network transmission use: 2014 and 2015

	2014					2015				
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	$641,724	$33,266	$674,989	999,808	$0.68	$326,752	$3,131	$329,883	891,878	$0.37
AEP	$1,703,576	$30,721,750	$32,425,326	8,338,900	$3.89	$12,468,326	$4,538,115	$17,006,441	8,908,957	$1.91
APS	$284,634	$3,027	$287,661	3,167,251	$0.09	$205,796	$69,722	$275,518	3,412,495	$0.08
ATSI	$1,129,895	$36,382	$1,166,277	4,796,501	$0.24	$2,770,257	$13,206	$2,783,463	4,512,167	$0.62
BGE	$8,298,910	$5,049	$8,303,959	2,493,060	$3.33	$9,275,300	$2,496	$9,277,796	2,432,798	$3.81
ComEd	$4,245,003	$44,049	$4,289,052	8,128,185	$0.53	$5,114,530	$49,723	$5,164,253	7,198,238	$0.72
DAY	$238,564	$6,511	$245,075	1,244,395	$0.20	$236,259	$7,929	$244,188	1,169,387	$0.21
DEOK	$1,143,983	$15,022	$1,159,004	1,878,290	$0.62	$1,159,327	$12,531	$1,171,858	1,863,325	$0.63
Dominion	$1,002,604	$4,599	$1,007,203	6,848,495	$0.15	$1,014,234	$12,719	$1,026,953	7,221,160	$0.14
DPL	$569,752	$39,708	$609,460	1,466,826	$0.42	$767,906	$19,766	$787,673	1,414,375	$0.56
DLCO	$59,744	$12,520	$72,264	1,077,298	$0.07	$104,264	$12,492	$116,756	982,836	$0.12
EKPC	$414,909	$4,439	$419,348	924,399	$0.45	$425,540	$0	$425,540	1,250,125	$0.34
JCPL	$511,969	$6,257	$518,226	2,328,299	$0.22	$4,745,965	$27,382	$4,773,347	2,057,469	$2.32
Met-Ed	$841,648	$66,776	$908,423	1,099,490	$0.83	$644,821	$72,118	$716,939	1,028,132	$0.70
PECO	$1,514,472	$13,614	$1,528,086	3,145,716	$0.49	$1,598,115	$23,957	$1,622,072	3,013,988	$0.54
PENELEC	$525,451	$3,498	$528,949	1,126,865	$0.47	$543,204	$2,881	$546,085	1,113,834	$0.49
Pepco	$315,940	$17,347	$333,287	2,384,691	$0.14	$1,239,205	$12,775	$1,251,979	2,315,962	$0.54
PPL	$219,986	$0	$219,986	2,698,153	$0.08	$109,610	$8,931	$118,541	2,933,870	$0.04
PSEG	$1,776,639	$32,643	$1,809,283	3,801,256	$0.48	$3,605,402	$12,058	$3,617,459	3,473,048	$1.04
RECO	$0	$0	$0	NA	NA	$0	$0	$0	NA	NA
(Imp/Exp/Wheels)	$1,505,710	$1,837,924	$3,343,634	3,496,705	$0.96	$2,086,179	$273,711	$2,359,890	2,605,456	$0.91
Total	$26,945,112	$32,904,380	$59,849,492	61,444,579	$0.97	$48,440,990	$5,175,643	$53,616,633	59,799,496	$0.90

Black start zonal charges in 2015 ranged from $0.04 per MW-day in the PPL Zone (total charges were $118,541) to $3.81 per MW-day in the BGE Zone (total charges were $9,277,796). For each zone, Table 10-45 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 $0.042 per MW of reserve capacity during 2015.

Table 10-46 provides a revenue requirement estimate by zone for the 2016-2017, 2017-2018 and 2018-2019 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. The estimates are based on the best available data including 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.

Table 10-46 Black start zonal revenue requirement estimate: 2015/2016 through 2018/2019 delivery years

Zone	2016-2017 Revenue Requirement	2017-2018 Revenue Requirement	2018-2019 Revenue Requirement
AECO	$2,850,000	$2,850,000	$2,800,000
AEP	$19,150,000	$19,200,000	$18,950,000
APS	$4,150,000	$4,150,000	$4,150,000
ATSI	$3,100,000	$3,100,000	$3,100,000
BGE	$8,400,000	$8,450,000	$8,400,000
ComEd	$5,100,000	$5,200,000	$4,750,000
DAY	$250,000	$300,000	$250,000
DEOK	$1,250,000	$1,250,000	$1,200,000
DLCO	$100,000	$100,000	$50,000
Dominion	$5,400,000	$5,400,000	$5,400,000
DPL	$2,600,000	$2,600,000	$2,500,000
EKPC	$250,000	$250,000	$150,000
JCPL	$7,200,000	$7,200,000	$7,150,000
Met-Ed	$700,000	$750,000	$600,000
PECO	$1,750,000	$1,900,000	$1,550,000
PENELEC	$4,700,000	$4,750,000	$4,500,000
Pepco	$2,700,000	$2,700,000	$2,650,000
PPL	$800,000	$800,000	$750,000
PSEG	$4,450,000	$4,500,000	$4,450,000
RECO	$0	$0	$0
Total	$74,900,000	$75,450,000	$73,350,000

Reactive Service

Reactive Service, Reactive Supply and Voltage Control are provided by generation and other sources (such as static VAR compensators and capacitor banks) of reactive power (measured in VAR).[57] Reactive power helps maintain appropriate voltages on the transmission system and is essential to the flow of real power (measured in MW).

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 2015, total reactive service charges were $289.4 million, a 6.1 percent decrease from 2014 level of $307.7 million.[58] Revenue requirement charges decreased from $281.2 million to $278.4 million and operating reserve charges fell from $26.5 million to $10.7 million. Total charges in 2015 ranged from $2.5 thousand in the RECO Zone to $38.5 million in the AEP Zone.

For each zone in 2014 and 2015, Table 10-47 shows reactive service operating reserve charges, revenue requirement charges and total charges (the sum of operating reserve and revenue requirement charges).

Table 10-47 Reactive zonal charges for network transmission use: 2014 and 2015

	2014			2015		
Zone	Operating Reserve Charges	Revenue Requirement Charges	Total Charges	Operating Reserve Charges	Revenue Requirement Charges	Total Charges
AECO	$101,458	$6,619,214	$6,720,672	$17,594	$6,575,504	$6,593,098
AEP	$567,379	$39,949,384	$40,516,763	$459,505	$38,052,860	$38,512,365
APS	$258,495	$18,526,432	$18,784,927	$98,962	$16,666,745	$16,765,707
ATSI	$10,740,864	$15,273,809	$26,014,673	$3,855,080	$15,692,347	$19,547,427
BGE	$38,731	$7,703,534	$7,742,265	$63,843	$7,825,069	$7,888,912
ComEd	$91,551	$25,369,783	$25,461,334	$180,576	$26,029,698	$26,210,274
DAY	$20,416	$8,363,678	$8,384,093	$34,169	$8,495,628	$8,529,797
DEOK	$13,975	$5,655,802	$5,669,777	$53,658	$5,153,000	$5,206,658
Dominion	$4,198,879	$29,664,589	$33,863,468	$2,786,438	$29,861,486	$32,647,924
DPL	$7,107,245	$10,767,853	$17,875,098	$2,333,403	$11,293,877	$13,627,280
DLCO	$7,424	$0	$7,424	$25,139	$0	$25,139
EKPC	$6,773	$2,121,517	$2,128,289	$29,296	$2,154,987	$2,184,283
JCPL	$25,990	$7,064,041	$7,090,031	$39,420	$7,175,487	$7,214,907
Met-Ed	$38,160	$7,529,560	$7,567,720	$63,138	$7,730,837	$7,793,975
PECO	$348,912	$17,468,722	$17,817,634	$73,069	$17,744,319	$17,817,389
PENELEC	$2,802,590	$6,386,846	$9,189,436	$312,987	$7,406,800	$7,719,787
Pepco	$34,680	$5,211,678	$5,246,358	$68,773	$5,293,901	$5,362,674
PPL	$24,343	$18,900,104	$18,924,446	$81,352	$18,969,092	$19,050,444
PSEG	$35,157	$27,028,845	$27,064,001	$73,242	$28,937,473	$29,010,715
RECO	$756	$0	$756	$2,448	$0	$2,448
(Imp/Exp/Wheels)	$0	$21,618,826	$21,618,826	$0	$17,330,444	$17,330,444
Total	$26,463,779	$281,224,214	$307,687,993	$10,652,092	$278,389,555	$289,041,647

57 PJM OATT. Schedule 2 "Reactive Supply and Voltage Control from Generation Sources Service," (Effective Date: February 18, 2012).

58 See the *2014 State of the Market Report for PJM*, Volume II, Section 4, "Energy Uplift."

Congestion and Marginal Losses

The locational marginal price (LMP) is the incremental price of energy at a bus. The LMP at a bus is the sum 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 varies with 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. 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.

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 $546.9 million or 28.3 percent, from $1,932.2 million in 2014 to $1,385.3 million in 2015.
- **Day-Ahead Congestion.** Day-ahead congestion costs decreased by $599.1 million or 26.9 percent, from $2,231.3 million in 2014 to $1,632.1 million in 2015.
- **Balancing Congestion.** Balancing congestion costs increased by $52.2 million or 17.5 percent, from -$299.1 million in 2014 to -$246.9 million in 2015.
- **Real-Time Congestion.** Real-time congestion costs decreased by $668.2 million or 30.7 percent, from

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 2013 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 February 18, 2016, and are subject to change, based on continued PJM billing updates.

$2,173.0 million in 2014 to $1,504.9 million in 2015.

- **Monthly Congestion.** In 2015, 31.0 percent ($429.8 million) of total congestion cost was incurred in February and 14.6 percent ($201.9 million) of total congestion cost was incurred in the months of January and March. Monthly total congestion costs in 2015 ranged from $58.4 million in August 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 Bagley – Graceton Line, the Conastone – Northwest Line and the Cherry Valley Flowgate.

- **Congestion Frequency.** Congestion frequency continued to be significantly higher in the Day-Ahead Energy Market than in the Real-Time Energy Market in 2015. The number of congestion event hours in the Day-Ahead Energy Market was about six times higher than the number of congestion event hours in the Real-Time Energy Market.

  Day-ahead congestion frequency decreased by 49.2 percent from 363,463 congestion event hours 2014 to 184,713 congestion event hours in 2015. The day-ahead congestion event hours decreased significantly after September 8, 2014. The reduction was the result of the reduction in up to congestion (UTC) activity which was a result of FERC's UTC uplift refund notice, retroactive to September 8, 2014.

  Real-time congestion frequency decreased by 1.0 percent from 28,802 congestion event hours in 2014 to 28,524 congestion event hours in 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 Conastone – Northwest Line was the largest contributor to congestion costs in 2015. With $108.8 million in total congestion costs, it accounted for 7.9 percent of the total PJM congestion costs in 2015.

- **Zonal Congestion.** ComEd had the largest total congestion costs among all control zones in 2015. ComEd had $311.3 million in total congestion costs, comprised of -$688.9 million in total load congestion payments, -$1,029.4 million in total generation congestion credits and -$29.2 million in explicit congestion costs. The Cherry Valley Flowgate, the Oak Grove - Galesburg Flowgate, the Braidwood - East Frankfort Line, the Bunsonville - Eugene Flowgate and the Rising Flowgate contributed $150.4 million, or 48.3 percent of the total ComEd control zone congestion costs.

- **Ownership.** In 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 2015, financial entities received $133.1 million in congestion credits, a decrease of $93.6 million or 41.3 percent compared to the 2014. In 2015, physical entities paid $1,518.3 million in congestion charges, a decrease of $640.6 million or 29.7 percent compared to 2014. UTCs are in the explicit congestion cost category and comprise most of that category. The total explicit cost is equal to day-ahead explicit cost plus balancing explicit cost. In 2015, the total explicit cost is -$127.3 million and 122.4 percent of the total explicit cost is comprised of congestion cost by UTCs, which is -$155.9 million.

Marginal Loss Cost

- **Total Marginal Loss Costs.** Total marginal loss costs decreased by $497.4 million or 33.9 percent, from $1,466.1 million in 2014 to $968.7 million in 2015. Total marginal loss costs were higher in 2014 as a result of high load and outages caused by cold weather in January 2014. The loss MWh in PJM decreased 5.3 percent, from 17,150.0 GWh in 2014 to 16,241.3 GWh in 2015. The loss component of LMP remained constant, $0.02 in 2014 and $0.02 in 2015.

- **Monthly Total Marginal Loss Costs.** Monthly total marginal loss costs in 2015 ranged from $44.6 million in December to $220.3 million in February.

- **Day-Ahead Marginal Loss Costs.** Day-ahead marginal loss costs decreased by $558.8 million or 35.6 percent, from $1,571.4 million in 2014 to $1,012.6 million in 2015.

- **Balancing Marginal Loss Costs.** Balancing marginal loss costs increased by $61.4 million or 58.3 percent, from -$105.3 million in 2014 to -$43.9 million in 2015.
- **Total Marginal Loss Surplus.** The total marginal loss surplus decreased in 2015 by $145.8 million or 30.2 percent, from $482.1 million in 2014, to $336.3 million in 2015.

Energy Cost

- **Total Energy Costs.** Total energy costs increased by $350.3 million or 35.8 percent, from -$977.7 million in 2014 to -$627.4 million in 2015.
- **Day-Ahead Energy Costs.** Day-ahead energy costs increased by $585.8 million or 43.6 percent, from -$1,343.7 million in 2014 to -$757.9 million in 2015.
- **Balancing Energy Costs.** Balancing energy costs decreased by $242.4 million or 65.5 percent, from $370.2 million in 2014 to $127.8 million in 2015.
- **Monthly Total Energy Costs.** Monthly total energy costs in 2015 ranged from -$141.5 million in February to -$28.9 million in December.

Conclusion

Congestion, as defined, is the total congestion payments by load in excess of the total congestion credits received by generation. The level and distribution of 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.

The current ARR/FTR design does not serve as an efficient way to ensure that load receives all the congestion revenues or has the ability to receive the auction revenues associated with all the potential congestion revenues. Total ARR and self scheduled FTR revenue offset only 59.8 percent of total congestion costs including congestion in the Day-Ahead Energy Market and the balancing energy market for the 2014 to 2015 planning period. For the first seven months of the 2015 to 2016 planning period ARRs and self scheduled FTRs offset 85.8 percent of total congestion costs.

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 first seven months of the 2015 to 2016 planning period (June through December), total ARR and FTR revenues offset 88.7 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 is 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 the sum 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

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>.

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. Congestion is the difference between the total cost of energy paid by load in the transmission constrained area and the total revenue received by generation in the transmission constrained area.

Table 11-1 shows the PJM real-time, load-weighted average LMP components 2009 through 2015.[7]

The load-weighted average real-time LMP decreased $16.98 or 31.9 percent from $53.14 in 2014 to $36.16 in 2015. The load-weighted average congestion component increased $0.06 from -$0.02 in 2014 to $0.04 in 2015. The load-weighted average loss component did not change in 2015 from 2014. The load-weighted average energy component decreased $17.02 or 32.0 percent from $53.13 in 2014 to $36.11 in 2015.

Table 11-1 PJM real-time, load-weighted average LMP components (Dollars per MWh): 2009 through 2015[8]

	Real-Time LMP	Energy Component	Congestion Component	Loss Component
2009	$39.05	$38.97	$0.05	$0.03
2010	$48.35	$48.23	$0.08	$0.04
2011	$45.94	$45.87	$0.05	$0.02
2012	$35.23	$35.18	$0.04	$0.01
2013	$38.66	$38.64	$0.01	$0.02
2014	$53.14	$53.13	($0.02)	$0.02
2015	$36.16	$36.11	$0.04	$0.02

Table 11-2 shows the PJM day-ahead, load-weighted average LMP components for 2009 through 2015.[9]

The load-weighted average day-ahead LMP decreased $16.89 or 31.5 percent from $53.62 in 2014 to $36.73 in 2015. The load-weighted average congestion component decreased $0.02 or 7.6 percent from $0.26 in 2014 to $0.24 in 2015. The load-weighted average loss component decreased -$0.00 or 23.2 percent from -$0.02 in 2014 to -$0.01 in 2015. The load-weighted average energy component decreased $16.88 or 31.6 percent from $53.38 in 2014 to $36.51 in 2015.

Table 11-2 PJM day-ahead, load-weighted average LMP components (Dollars per MWh): 2009 through 2015

	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
2009	$38.82	$38.96	($0.04)	($0.09)
2010	$47.65	$47.67	$0.05	($0.07)
2011	$45.19	$45.40	($0.06)	($0.15)
2012	$34.55	$34.46	$0.11	($0.01)
2013	$38.93	$38.79	$0.13	$0.00
2014	$53.62	$53.38	$0.26	($0.02)
2015	$36.73	$36.51	$0.24	($0.01)

Zonal Components

The real-time components of LMP for each control zone are presented in Table 11-3 for 2014 and 2015. In 2015, BGE had the highest real-time congestion component of all control zones and ComEd had the lowest real-time congestion component.

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 11-3 Zonal and PJM real-time, load-weighted average LMP components (Dollars per MWh): 2014 and 2015

	2014				2015			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AECO	$55.77	$51.69	$2.11	$1.97	$35.85	$35.82	($1.16)	$1.19
AEP	$47.81	$53.32	($4.32)	($1.19)	$33.90	$36.05	($1.39)	($0.76)
AP	$52.94	$53.88	($1.01)	$0.07	$38.04	$36.44	$1.44	$0.17
ATSI	$48.60	$52.07	($4.04)	$0.57	$34.00	$35.60	($1.89)	$0.29
BGE	$67.78	$54.46	$10.86	$2.46	$47.22	$36.78	$8.69	$1.76
ComEd	$42.04	$51.56	($6.92)	($2.60)	$29.85	$35.28	($3.50)	($1.94)
DAY	$47.36	$53.07	($5.87)	$0.17	$34.20	$35.90	($1.86)	$0.17
DEOK	$45.00	$52.87	($5.42)	($2.44)	$33.28	$35.88	($1.17)	($1.42)
DLCO	$44.22	$52.00	($6.12)	($1.66)	$32.21	$35.64	($2.75)	($0.69)
Dominion	$62.99	$54.58	$7.93	$0.48	$41.42	$36.92	$3.98	$0.52
DPL	$65.03	$54.72	$7.24	$3.07	$42.27	$37.02	$3.38	$1.87
EKPC	$47.88	$56.97	($6.57)	($2.52)	$32.93	$37.54	($2.97)	($1.64)
JCPL	$56.07	$52.18	$1.85	$2.04	$35.65	$36.07	($1.53)	$1.11
Met-Ed	$56.08	$53.42	$1.55	$1.11	$35.79	$36.20	($1.07)	$0.67
PECO	$55.94	$52.73	$1.86	$1.35	$35.11	$36.03	($1.68)	$0.76
PENELEC	$51.90	$52.71	($1.31)	$0.50	$36.13	$35.78	($0.28)	$0.63
Pepco	$65.61	$53.92	$10.09	$1.60	$43.04	$36.56	$5.35	$1.12
PPL	$56.97	$54.02	$2.03	$0.91	$35.95	$36.40	($0.95)	$0.51
PSEG	$57.90	$51.43	$4.49	$1.99	$36.97	$35.47	$0.45	$1.04
RECO	$56.79	$51.34	$3.58	$1.87	$37.58	$35.68	$0.84	$1.06
PJM	$53.14	$53.13	($0.02)	$0.02	$36.16	$36.11	$0.04	$0.02

The day-ahead components of LMP for each control zone are presented in Table 11-4 for 2014 and 2015. In 2015, BGE had the highest day-ahead congestion component of all control zones and ComEd had the lowest day-ahead congestion component.

Table 11-4 Zonal and PJM day-ahead, load-weighted average LMP components (Dollars per MWh): 2014 and 2015

	2014				2015			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AECO	$57.24	$51.67	$4.04	$1.53	$36.86	$36.25	($0.13)	$0.75
AEP	$48.83	$54.40	($4.59)	($0.98)	$34.20	$36.56	($1.80)	($0.57)
AP	$52.60	$54.21	($1.36)	($0.26)	$37.95	$36.83	$1.16	($0.05)
ATSI	$49.52	$52.63	($3.58)	$0.47	$34.34	$35.99	($1.97)	$0.32
BGE	$68.52	$54.65	$11.97	$1.90	$47.92	$36.98	$9.61	$1.33
ComEd	$42.82	$52.38	($7.86)	($1.71)	$29.45	$35.76	($4.81)	($1.50)
DAY	$48.95	$53.95	($5.45)	$0.45	$34.39	$36.43	($2.35)	$0.31
DEOK	$46.19	$52.68	($4.71)	($1.77)	$33.90	$36.69	($1.67)	($1.12)
DLCO	$44.95	$52.32	($5.52)	($1.85)	$32.57	$36.07	($2.70)	($0.80)
Dominion	$60.43	$54.75	$5.64	$0.05	$43.09	$37.39	$5.20	$0.50
DPL	$66.60	$54.56	$9.51	$2.52	$42.28	$37.23	$3.62	$1.44
EKPC	$48.80	$57.51	($6.32)	($2.39)	$33.42	$38.22	($3.21)	($1.59)
JCPL	$59.42	$52.87	$4.67	$1.87	$36.86	$36.49	($0.47)	$0.85
Met-Ed	$57.42	$53.10	$3.71	$0.61	$35.82	$36.27	($0.64)	$0.19
PECO	$57.60	$52.75	$3.87	$0.99	$35.96	$36.23	($0.63)	$0.37
PENELEC	$51.32	$51.08	($0.21)	$0.44	$35.90	$36.09	($0.55)	$0.36
Pepco	$64.04	$53.04	$9.85	$1.14	$44.38	$36.72	$6.81	$0.85
PPL	$59.04	$54.13	$4.47	$0.44	$36.62	$36.68	($0.14)	$0.08
PSEG	$61.27	$52.09	$7.33	$1.84	$37.82	$36.07	$0.83	$0.93
RECO	$59.75	$51.71	$6.27	$1.76	$38.10	$36.28	$0.88	$0.94
PJM	$53.62	$53.38	$0.26	($0.02)	$36.73	$36.51	$0.24	($0.01)

Hub Components

The real-time components of LMP for each hub are presented in Table 11-5 for 2014 and 2015.

Table 11-5 Hub real-time, load-weighted average LMP components (Dollars per MWh): 2014 and 2015

	2014				2015			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AEP Gen Hub	$43.51	$53.25	($6.46)	($3.28)	$32.44	$37.65	($3.08)	($2.13)
AEP-DAY Hub	$46.29	$53.41	($5.69)	($1.43)	$33.67	$36.90	($2.24)	($1.00)
ATSI Gen Hub	$47.22	$51.92	($4.47)	($0.23)	$33.04	$35.83	($2.43)	($0.36)
Chicago Gen Hub	$39.52	$50.46	($7.68)	($3.25)	$27.91	$34.41	($4.16)	($2.34)
Chicago Hub	$42.68	$52.35	($7.11)	($2.56)	$30.42	$36.13	($3.75)	($1.95)
Dominion Hub	$64.29	$56.55	$7.84	($0.10)	$41.12	$37.33	$3.63	$0.16
Eastern Hub	$61.27	$52.20	$6.29	$2.78	$40.03	$35.29	$3.03	$1.71
N Illinois Hub	$41.20	$51.02	($6.98)	($2.84)	$29.35	$34.83	($3.44)	($2.04)
New Jersey Hub	$56.21	$51.22	$3.05	$1.94	$36.09	$35.66	($0.62)	$1.06
Ohio Hub	$46.25	$53.32	($5.80)	($1.28)	$32.88	$36.08	($2.32)	($0.87)
West Interface Hub	$50.60	$51.86	($0.42)	($0.83)	$34.67	$36.00	($0.71)	($0.62)
Western Hub	$57.23	$55.07	$2.14	$0.02	$40.83	$38.59	$1.94	$0.30

The day-ahead components of LMP for each hub are presented in Table 11-6 for 2014 and 2015.

Table 11-6 Hub day-ahead, load-weighted average LMP components (Dollars per MWh): 2014 and 2015

	2014				2015			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AEP Gen Hub	$42.22	$48.97	($4.25)	($2.50)	$30.66	$33.21	($1.17)	($1.38)
AEP-DAY Hub	$46.64	$52.38	($4.83)	($0.91)	$32.77	$35.73	($2.32)	($0.64)
ATSI Gen Hub	$50.09	$52.42	($2.47)	$0.14	$29.05	$29.71	($0.60)	($0.05)
Chicago Gen Hub	$43.01	$55.95	($10.23)	($2.71)	$26.65	$32.83	($4.46)	($1.72)
Chicago Hub	$42.50	$51.94	($7.85)	($1.58)	$29.09	$34.97	($4.51)	($1.37)
Dominion Hub	$59.15	$54.48	$5.14	($0.47)	$42.57	$37.38	$4.96	$0.24
Eastern Hub	$64.43	$53.17	$8.65	$2.61	$42.19	$36.99	$3.71	$1.49
N Illinois Hub	$42.47	$52.94	($8.44)	($2.02)	$28.72	$34.91	($4.60)	($1.59)
New Jersey Hub	$59.41	$51.99	$5.66	$1.77	$37.29	$36.26	$0.18	$0.85
Ohio Hub	$46.59	$52.22	($4.97)	($0.66)	$32.60	$35.61	($2.46)	($0.55)
West Interface Hub	$49.78	$50.56	($0.05)	($0.72)	$35.10	$35.43	$0.05	($0.38)
Western Hub	$52.65	$50.52	$2.31	($0.18)	$38.34	$36.29	$2.11	($0.06)

Component Costs

Table 11-7 shows the total energy, loss and congestion component costs and the total PJM billing for 2009 through 2015. These totals are actually net energy, loss and congestion costs. Total congestion and marginal loss costs decreased in 2015 compared to 2014. Total congestion and marginal loss costs in 2014 were higher in 2014 as a result of high load and outages caused by cold weather in January 2014.

Table 11-7 Total PJM costs by component (Dollars (Millions)): 2009 through 2015[10,11]

	Component Costs (Millions)					
	Energy Costs	Loss Costs	Congestion Costs	Total Costs	Total PJM Billing	Total Costs Percent of PJM Billing
2009	($629)	$1,268	$719	$1,358	$26,550	5.1%
2010	($798)	$1,635	$1,423	$2,260	$34,771	6.5%
2011	($794)	$1,380	$999	$1,585	$35,887	4.4%
2012	($593)	$982	$529	$918	$29,181	3.1%
2013	($688)	$1,035	$677	$1,025	$33,862	3.0%
2014	($978)	$1,466	$1,932	$2,421	$50,030	4.8%
2015	($630)	$969	$1,385	$1,724	$42,630	4.0%

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.

- **Day-Ahead Load Congestion Payments.** Day-ahead load congestion payments are calculated for all cleared demand, decrement bids and day-ahead energy market sale transactions. Day-ahead load congestion payments are calculated using MW and the load bus CLMP, the decrement bid CLMP or the CLMP at the source of the sale transaction, as applicable.
- **Day-Ahead Generation Congestion Credits.** Day-ahead generation congestion credits are calculated for all cleared generation, increment offers and day-ahead energy market purchase transactions. Day-ahead generation congestion credits are calculated using MW and the generator bus CLMP, the increment offer's CLMP or the CLMP at the sink of the purchase transaction, as applicable.
- **Balancing Load Congestion Payments.** Balancing load congestion payments are calculated for all deviations between a PJM member's real-time load and energy sale transactions and their day-ahead cleared demand, decrement bids and energy sale transactions. Balancing load congestion payments are calculated using MW deviations and the real-time CLMP for each bus where a deviation exists.
- **Balancing Generation Congestion Credits.** Balancing generation congestion credits are calculated for all deviations between a PJM member's real-time generation and energy purchase transactions and the day-ahead cleared generation, increment offers and energy purchase transactions. Balancing generation congestion credits are calculated using MW deviations and the real-time CLMP for each bus where a deviation exists.
- **Explicit Congestion Costs.** Explicit congestion costs are the net congestion costs associated with point-to-point energy transactions. These costs equal the product of the transacted MW and CLMP differences between sources (origins) and sinks (destinations) in the Day-Ahead Energy Market. Balancing energy market explicit congestion costs equal the product of the deviations between the real-time and day-ahead transacted MW and the differences between the real-time CLMP at the transactions' sources and sinks.
- **Inadvertent Congestion Charges.** Inadvertent congestion charges are congestion charges resulting from the differences between the net actual energy flow and the net scheduled energy flow into or out of the PJM control area each hour. This inadvertent interchange of energy may be positive or negative, where positive interchange typically results in a charge while negative interchange typically results in a credit. Inadvertent congestion charges are common costs, not directly attributable to specific participants that are distributed on a load ratio basis.[14]

The congestion costs associated with specific constraints are the sum of the total day-ahead and balancing congestion costs associated with those constraints. The congestion costs in each zone are the sum of the congestion costs associated with each constraint that affects prices in the zone. The network nature of the transmission system means that congestion costs in a zone are frequently the result of constrained facilities located outside that zone.

Congestion costs can be both positive and negative and consequently load payments and generation credits can be both positive and negative. The CLMP is calculated

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 OA. Schedule 1 (PJM Interchange Energy Market) §3.7.

with respect to the system reference bus LMP, also called the system marginal price (SMP). When a transmission constraint occurs, the resulting CLMP is positive on one side of the constraint and negative on the other side of the constraint and the corresponding congestion costs are positive or negative. For each transmission constraint, the CLMP reflects the cost of a constraint at a pricing node and is equal to the product of the constraint shadow price and the distribution factor at the respective pricing node. The total CLMP at a pricing node is the sum of all constraint contributions to LMP and is equal to the difference between the actual LMP that results from transmission constraints, excluding losses, and the SMP. If an area experiences lower prices because of a constraint, the CLMP in that area is negative.[15]

The congestion metric requires careful review when considering the significance of congestion. The net congestion bill is calculated by subtracting generating congestion credits from load congestion payments. The logic is that congestion payments by load are offset by congestion revenues to generation, for the area analyzed. The net congestion bill is the source of payments to FTR holders. When load pays more for congestion in an area than generation receives, the positive difference is the source of payments to FTR holders as it is a measure of the value of transmission in bringing lower cost generation into the area.

Total congestion costs in PJM in 2015 were $1,385.3 million, which was comprised of load congestion payments of $614.8 million, generation credits of -$897.8 million and explicit congestion of -$127.3 million. Total congestion costs in PJM in 2014 were $1,932.2 million, which was comprised of load congestion payments of $648.1 million, generation credits of -$1,453.0 million and explicit congestion of -$169.0 million. The decrease in total congestion cost from 2014 to 2015 is primarily a result of the decrease in generation credits.

Total Congestion

Table 11-8 shows total congestion for 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.[16,17]

Table 11-8 Total PJM congestion (Dollars (Millions)): 2008 through 2015

	Congestion Costs (Millions)			
	Congestion Cost	Percent Change	Total PJM Billing	Percent of PJM Billing
2008	$2,052	NA	$34,306	6.0%
2009	$719	(65.0%)	$26,550	2.7%
2010	$1,423	98.0%	$34,771	4.1%
2011	$999	(29.8%)	$35,887	2.8%
2012	$529	(47.0%)	$29,181	1.8%
2013	$677	28.0%	$33,862	2.0%
2014	$1,932	185.5%	$50,030	3.9%
2015	$1,385	(28.3%)	$42,630	3.2%

Table 11-9 shows the congestion costs by accounting category by market for 2015. In 2015, PJM total congestion costs were comprised of $614.8 million in load congestion payments, -$897.8 million in generation congestion credits, and -$127.3 million in explicit congestion costs.

Table 11-9 Total PJM congestion costs by accounting category by market (Dollars (Millions)): 2008 through 2015

	Congestion Costs (Millions)									
	Day Ahead				Balancing					
	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
2008	$1,260.3	($1,133.1)	$203.0	$2,596.5	($225.9)	$79.2	($239.5)	($544.6)	$0.0	$2,051.8
2009	$292.3	($525.2)	$83.9	$901.4	($39.0)	$10.1	($133.4)	($182.4)	$0.0	$719.0
2010	$376.4	($1,239.8)	$96.9	$1,713.1	($37.5)	$72.8	($179.5)	($289.8)	($0.0)	$1,423.3
2011	$400.5	($777.6)	$66.9	$1,245.0	$53.5	$109.5	($190.0)	($246.0)	$0.0	$999.0
2012	$122.7	($525.3)	$131.9	$779.9	($7.6)	$57.9	($185.4)	($250.9)	$0.0	$529.0
2013	$281.2	($592.5)	$137.6	$1,011.3	$5.9	$131.3	($209.0)	($334.4)	$0.0	$676.9
2014	$595.5	($1,671.2)	($35.4)	$2,231.3	$52.7	$218.1	($133.6)	($299.1)	$0.0	$1,932.2
2015	$614.2	($967.6)	$50.3	$1,632.1	$0.6	$69.8	($177.6)	($246.9)	$0.0	$1,385.3

Table 11-10 and Table 11-11 show the total congestion costs for each transaction type in 2015 and 2014. The decrease in total congestion cost from 2014 to 2015 is

15 For an example of the congestion accounting methods used in this section, see *MMU Technical Reference for PJM Markets*, at "FTRs and ARRs" <http://www.monitoringanalytics.com/reports/Technical_References/docs/2010-som-pjm-technical-reference.pdf.>

16 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.," (December 11, 2008) Section 6.1 <http://www.pjm.com/documents/agreements.aspx>

17 See "Joint Operating Agreement Among and Between the New York Independent System Operator Inc. and PJM Interconnection, L.L.C.," (January 17, 2013) Section 35.12.1 <http://www.pjm.com/documents/agreements.aspx>.

mainly due to the decrease in negative generation credits incurred by generation in the Day-Ahead Energy Market. Congestion costs incurred by generation in the Day-Ahead Energy Market decreased by $664.0 million or 31.7 percent, from $2,094.0 million in 2014 to $1,429.9 million in 2015. Table 11-10 shows that in 2015 DECs paid $81.4 million in congestion cost in the day-ahead market were paid $97.6 million in congestion credits in the balancing energy market and received $16.2 million in net payment for congestion. In 2015, INCs were paid $24.2 million in congestion credits in the day-ahead market, paid $5.1 million in congestion cost in the balancing energy market and received $19.1 million in net payment for congestion. In 2015, up to congestion paid $25.0 million in congestion cost in the day-ahead market, were paid $180.8 million in congestion credits in balancing market and received $155.9 million in net payment for congestion.

Table 11-10 Total PJM congestion costs by transaction type by market (Dollars (Millions)): 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	$81.4	$0.0	$0.0	$81.4	($97.6)	$0.0	$0.0	($97.6)	$0.0	($16.2)
Demand	$109.5	$0.0	$0.0	$109.5	$69.2	$0.0	$0.0	$69.2	$0.0	$178.7
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	$4.9	$4.9	$0.0	$0.0	($0.0)	($0.0)	$0.0	$4.9
Export	($51.5)	$0.0	$0.7	($50.8)	($4.4)	$0.0	$1.9	($2.4)	$0.0	($53.3)
Generation	$0.0	($1,429.9)	$0.0	$1,429.9	$0.0	$113.7	$0.0	($113.7)	$0.0	$1,316.2
Grandfathered Overuse	$0.0	$0.0	($2.4)	($2.4)	$0.0	$0.0	$0.5	$0.5	$0.0	($1.9)
Import	$0.0	($37.1)	$1.4	$38.5	$0.0	($71.9)	$1.4	$73.3	$0.0	$111.8
INC	$0.0	$24.2	$0.0	($24.2)	$0.0	($5.1)	$0.0	$5.1	$0.0	($19.1)
Internal Bilateral	$449.4	$449.5	$0.1	$0.0	$33.7	$33.7	$0.0	($0.0)	$0.0	($0.0)
Up to Congestion	$0.0	$0.0	$25.0	$25.0	$0.0	$0.0	($180.8)	($180.8)	$0.0	($155.9)
Wheel In	$0.0	$25.6	$20.6	($5.0)	$0.0	($0.5)	($0.6)	($0.1)	$0.0	($5.1)
Wheel Out	$25.6	$0.0	$0.0	$25.6	($0.5)	$0.0	$0.0	($0.5)	$0.0	$25.1
Total	$614.2	($967.6)	$50.3	$1,632.1	$0.6	$69.8	($177.6)	($246.9)	$0.0	$1,385.3

Table 11-11 Total PJM congestion costs by transaction type by market (Dollars (Millions)): 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	$79.9	$0.0	$0.0	$79.9	($57.8)	$0.0	$0.0	($57.8)	$0.0	$22.1
Demand	$130.2	$0.0	$0.0	$130.2	$142.4	$0.0	$0.0	$142.4	$0.0	$272.6
Demand Response	($1.1)	$0.0	$0.0	($1.1)	$1.0	$0.0	$0.0	$1.0	$0.0	($0.1)
Explicit Congestion Only	$0.0	$0.0	$3.2	$3.2	$0.0	$0.0	$0.3	$0.3	$0.0	$3.5
Export	($95.0)	$0.0	($0.8)	($95.7)	($44.2)	$0.0	$6.3	($37.9)	$0.0	($133.6)
Generation	$0.0	($2,094.0)	$0.0	$2,094.0	$0.0	$296.4	$0.0	($296.4)	$0.0	$1,797.6
Grandfathered Overuse	$0.0	$0.0	($11.4)	($11.4)	$0.0	$0.0	$0.9	$0.9	$0.0	($10.5)
Import	$0.0	($46.7)	$8.6	$55.3	$0.0	($125.1)	$3.8	$128.9	$0.0	$184.3
INC	$0.0	($12.7)	$0.0	$12.7	$0.0	$35.7	$0.0	($35.7)	$0.0	($23.0)
Internal Bilateral	$418.1	$419.0	$0.9	($0.0)	$13.4	$13.4	$0.0	($0.0)	$0.0	($0.0)
Up to Congestion	$0.0	$0.0	($57.0)	($57.0)	$0.0	$0.0	($143.2)	($143.2)	$0.0	($200.2)
Wheel In	$0.0	$63.2	$21.2	($42.0)	$0.0	($2.2)	($1.7)	$0.5	$0.0	($41.6)
Wheel Out	$63.2	$0.0	$0.0	$63.2	($2.2)	$0.0	$0.0	($2.2)	$0.0	$61.1
Total	$595.5	($1,671.2)	($35.4)	$2,231.3	$52.7	$218.1	($133.6)	($299.1)	$0.0	$1,932.2

Table 11-12 Total PJM congestion costs by transaction type by market: 2014 to 2015 change (Dollars (Millions))

	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	$1.5	$0.0	$0.0	$1.5	($39.8)	$0.0	$0.0	($39.8)	$0.0	($38.3)
Demand	($20.7)	$0.0	$0.0	($20.7)	($73.2)	$0.0	$0.0	($73.2)	$0.0	($93.9)
Demand Response	$0.9	$0.0	$0.0	$0.9	($0.8)	$0.0	$0.0	($0.8)	$0.0	$0.1
Explicit Congestion Only	$0.0	$0.0	$1.7	$1.7	$0.0	$0.0	($0.3)	($0.3)	$0.0	$1.4
Export	$43.4	$0.0	$1.5	$44.9	$39.8	$0.0	($4.4)	$35.4	$0.0	$80.3
Generation	$0.0	$664.0	$0.0	($664.0)	$0.0	($182.7)	$0.0	$182.7	$0.0	($481.3)
Grandfathered Overuse	$0.0	$0.0	$8.9	$8.9	$0.0	$0.0	($0.4)	($0.4)	$0.0	$8.6
Import	$0.0	$9.7	($7.2)	($16.9)	$0.0	$53.2	($2.4)	($55.7)	$0.0	($72.5)
INC	$0.0	$36.9	$0.0	($36.9)	$0.0	($40.8)	$0.0	$40.8	$0.0	$3.9
Internal Bilateral	$31.3	$30.5	($0.8)	$0.0	$20.3	$20.3	$0.0	($0.0)	$0.0	($0.0)
Up to Congestion	$0.0	$0.0	$82.0	$82.0	$0.0	$0.0	($37.7)	($37.7)	$0.0	$44.3
Wheel In	$0.0	($37.6)	($0.5)	$37.1	$0.0	$1.7	$1.1	($0.6)	$0.0	$36.5
Wheel Out	($37.6)	$0.0	$0.0	($37.6)	$1.7	$0.0	$0.0	$1.7	$0.0	($35.9)
Total	$18.8	$703.5	$85.6	($599.1)	($52.1)	($148.3)	($44.0)	$52.2	$0.0	($546.9)

Monthly Congestion

Table 11-13 shows that monthly total congestion costs ranged from $58.4 million to $429.8 million in 2015. Table 11-13 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 11-13 Monthly PJM congestion costs by market (Dollars (Millions)): 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	$114.0	($7.5)	($0.0)	$106.6
Jul	$118.1	($14.0)	$0.0	$104.1	$97.4	($8.5)	($0.0)	$89.0
Aug	$68.9	$0.0	$0.0	$68.9	$64.2	($5.8)	$0.0	$58.4
Sep	$85.8	$4.4	$0.0	$90.1	$92.3	($15.3)	($0.0)	$77.0
Oct	$87.1	($14.3)	($0.0)	$72.8	$103.2	($16.8)	($0.0)	$86.4
Nov	$105.3	($16.3)	$0.0	$89.0	$102.8	($10.8)	$0.0	$92.0
Dec	$74.3	($9.3)	($0.0)	$65.0	$79.1	($15.2)	$0.0	$63.9
Total	$2,231.3	($299.1)	$0.0	$1,932.2	$1,632.1	($246.9)	$0.0	$1,385.3

Figure 11-1 shows PJM monthly total congestion cost for 2009 through 2015.

Figure 11-1 PJM monthly total congestion cost (Dollars (Millions)): 2009 through 2015

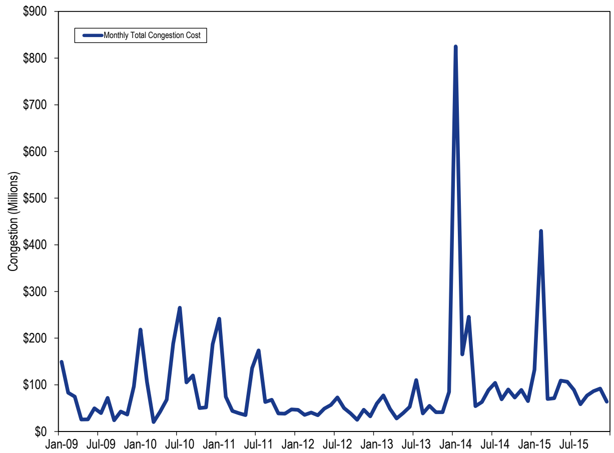


Table 11-14 Monthly PJM congestion costs by virtual transaction type and by market (Dollars (Millions)): 2015

	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)	($5.0)
May	$5.1	($3.7)	$5.9	$7.3	($4.8)	($2.1)	($21.7)	($28.6)	($21.3)
Jun	$9.0	($3.2)	$6.6	$12.4	($9.5)	$0.2	($6.9)	($16.2)	($3.8)
Jul	$7.0	($3.0)	$4.7	$8.7	($7.5)	$3.5	($12.3)	($16.4)	($7.7)
Aug	$4.2	($1.8)	$2.8	$5.2	($4.4)	$0.5	($6.6)	($10.5)	($5.3)
Sep	$4.3	$0.1	$4.6	$9.1	($6.4)	($4.1)	($10.5)	($21.0)	($11.9)
Oct	$6.7	($1.7)	$9.6	$14.6	($6.8)	($0.5)	($14.0)	($21.3)	($6.7)
Nov	$5.9	($3.3)	$7.7	$10.4	($5.0)	$2.1	($7.5)	($10.4)	($0.1)
Dec	$6.7	($1.9)	$6.2	$11.0	($7.0)	$0.9	($11.9)	($18.0)	($6.9)
Total	$81.4	($24.2)	$25.0	$82.2	($97.6)	$5.1	($180.8)	($273.3)	($191.1)

Table 11-14 shows the monthly total congestion costs for each virtual transaction type in 2015 and Table 11-15 shows the monthly total congestion costs for each virtual transaction type in 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 11-14 and Table 11-15 shows that UTCs were paid both day-ahead congestion credits and balancing congestion credits in 2014 and in 2015 UTCs paid day-ahead congestion costs and were paid balancing congestion credits. Total day-ahead congestion payments to UTCs decreased by $82.0 million from 2014 to 2015, from $57.0 million in 2014 to -$25.0 million in 2015. Over the same period balancing congestion payments to UTCs increased from $143.2 million in 2014 to $180.8 million in 2015. Overall, total congestion payments to UTC decreased by 22.2 percent between 2014 and 2015. UTCs were paid $200.2 million in congestion in 2014 and $155.9 million in 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.[18]

18 See 18 CFR § 385.213 (2014).

Table 11-15 Monthly PJM congestion costs by virtual transaction type and by market (Dollars (Millions)): 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)
Jul	$5.2	($0.1)	$13.4	$18.5	($4.3)	($1.2)	($13.7)	($19.2)	($0.7)
Aug	$1.4	($1.2)	$4.4	$4.6	($0.3)	$0.7	($1.1)	($0.7)	$3.9
Sep	$2.5	($2.6)	($1.1)	($1.2)	($0.6)	$1.0	$0.7	$1.0	($0.1)
Oct	$2.0	($6.2)	($0.1)	($4.3)	($1.5)	$5.3	($9.5)	($5.7)	($10.0)
Nov	$2.1	($5.3)	$1.0	($2.3)	($6.2)	$1.8	($10.8)	($15.1)	($17.4)
Dec	$1.9	($2.5)	$2.5	$1.9	$0.2	$1.3	($6.7)	($5.2)	($3.3)
Total	$79.9	$12.7	($57.0)	$35.6	($57.8)	($35.7)	($143.2)	($236.6)	($201.0)

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 2015, there were 184,713 day-ahead, congestion-event hours compared to 363,463 day-ahead congestion-event hours in 2014. In 2015, there were 28,524 real-time, congestion-event hours compared to 28,802 real-time, congestion-event hours in 2014.

During 2015, there were 14,968 real-time congestion-event hours, 8.1 percent of day-ahead energy congestion-event hours, when the same facilities also constrained in the Real-Time Energy Market. During 2015, there were 14,961 day-ahead congestion-event hours, 52.5 percent of real-time congestion-event hours, when the same facilities were also constrained in the Day-Ahead Energy Market.

The Conastone – Northwest Line was the largest contributor to total congestion costs in 2015. With $108.5 million in total congestion costs, it accounted for 7.9 percent of the total PJM congestion costs in 2015. The top five constraints in terms of congestion costs contributed $472.6 million, or 34.1 percent, of the total PJM congestion costs in 2015. The top five constraints were the 5004/5005 Interface, the Bedington - Black Oak Interface, the Bagley – Graceton Line, the Conastone – Northwest Line and the Cherry Valley Flowgate.

Congestion by Facility Type and Voltage

In 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 decreased on flowgate and interface facilities.

Day-ahead congestion costs decreased on all types of facilities except transmission lines in 2015 compared to 2014. Balancing congestion costs increased on all types of facilities except transmission lines in 2015 compared to 2014.

Table 11-16 provides congestion-event hour subtotals and congestion cost subtotals comparing 2015 results by facility type: line, transformer, interface, flowgate and unclassified facilities.[19,20] Table 11-17 presents this information for 2014.

19 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.

20 The term flowgate refers to MISO reciprocal coordinated flowgates and NYISO M2M flowgates.

Table 11-16 Congestion summary (By facility type): 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	$25.2	($276.6)	($22.9)	$278.9	$1.7	$2.7	($25.1)	($26.1)	$252.8	26,167	5,394
Interface	$74.8	($316.9)	($30.1)	$361.6	$10.7	$28.8	$2.9	($15.1)	$346.5	9,208	2,052
Line	$397.9	($234.2)	$96.9	$729.0	($17.1)	$24.1	($145.6)	($186.8)	$542.2	107,542	17,449
Other	($0.2)	($1.2)	$0.3	$1.2	$0.1	$0.1	($0.1)	($0.1)	$1.2	1,976	38
Transformer	$116.6	($137.4)	$5.8	$259.8	$4.9	$13.4	($20.6)	($29.0)	$230.7	39,820	3,591
Unclassified	$0.0	($1.4)	$0.3	$1.6	$0.3	$0.9	$10.8	$10.3	$11.9	NA	NA
Total	$614.2	($967.6)	$50.3	$1,632.1	$0.6	$69.8	($177.6)	($246.9)	$1,385.3	184,713	28,524

Table 11-17 Congestion summary (By facility type): 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	($100.8)	($423.8)	($16.8)	$306.2	$2.8	$13.7	($37.9)	($48.7)	$257.4	35,828	5,909
Interface	$367.4	($630.9)	($105.2)	$893.1	$62.7	$145.7	$16.6	($66.5)	$826.6	19,248	5,511
Line	$215.7	($470.6)	$39.9	$726.3	($25.8)	$41.9	($59.1)	($126.8)	$599.5	189,019	14,693
Other	$0.0	($2.5)	$1.0	$3.6	$0.0	$0.0	($0.0)	$0.0	$3.6	7,003	1
Transformer	$111.2	($131.4)	$32.3	$275.0	$5.3	$15.3	($62.2)	($72.2)	$202.8	112,365	2,688
Unclassified	$2.0	($11.8)	$13.4	$27.3	$7.6	$1.6	$9.0	$15.1	$42.4	NA	NA
Total	$595.5	($1,671.2)	($35.4)	$2,231.3	$52.7	$218.1	($133.6)	($299.1)	$1,932.2	363,463	28,802

Table 11-18 and Table 11-19 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 11-18. In 2015, there were 184,713 congestion-event hours in the Day-Ahead Energy Market. Among those day-ahead congestion-event hours, only 14,968 (8.1 percent) were also constrained in the Real-Time Energy Market. In 2014, among the 363,463 day-ahead congestion-event hours, only 15,933 (4.4 percent) were binding in the Real-Time Energy Market.[21]

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 11-19. In 2015, there were 28,524 congestion-event hours in the Real-Time Energy Market. Among these real-time congestion-event hours, 14,961 (52.5 percent) were also constrained in the Day-Ahead Energy Market. In 2014, among the 28,802 real-time congestion-event hours, 16,399 (56.9 percent) were also in the Day-Ahead Energy Market.

Table 11-18 Congestion event hours (Day-Ahead against Real-Time): 2014 and 2015

	Congestion Event Hours					
	2014			2015		
Type	Day-Ahead	Corresponding Real-Time	Percent	Day-Ahead	Corresponding Real-Time	Percent
Flowgate	35,828	3,265	9.1%	26,167	2,504	9.6%
Interface	19,248	3,982	20.7%	9,208	1,503	16.3%
Line	189,019	7,562	4.0%	107,542	9,706	9.0%
Other	7,003	0	0.0%	1,976	0	0.0%
Transformer	112,365	1,124	1.0%	39,820	1,255	3.2%
Total	363,463	15,933	4.4%	184,713	14,968	8.1%

21 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 11-19 Congestion event hours (Real-Time against Day-Ahead): 2014 and 2015

	Congestion Event Hours					
	2014			2015		
Type	Real-Time	Corresponding Day-Ahead	Percent	Real-Time	Corresponding Day-Ahead	Percent
Flowgate	5,909	3,395	57.5%	5,394	2,518	46.7%
Interface	5,511	4,349	78.9%	2,052	1,539	75.0%
Line	14,693	7,575	51.6%	17,449	9,705	55.6%
Other	1	0	0.0%	38	0	0.0%
Transformer	2,688	1,080	40.2%	3,591	1,199	33.4%
Total	28,802	16,399	56.9%	28,524	14,961	52.5%

Table 11-20 shows congestion costs by facility voltage class for 2015. Congestion costs in 2015 decreased for facilities rated at 765kV, 500 kV, 345 kV, 161 kV and 69 kV compared to 2014 (Table 11-21).

Table 11-20 Congestion summary (By facility voltage): 2015

	Congestion Costs (Millions)										
	Day-Ahead				Balancing					Congestion 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	$19.2	($56.5)	($4.2)	$71.5	$3.4	$2.3	($1.7)	($0.5)	$71.0	2,816	144
500	$85.4	($327.5)	($28.3)	$384.6	$13.2	$28.8	($1.3)	($16.9)	$367.8	10,615	1,180
460	($0.0)	($3.6)	$0.3	$4.0	$0.0	$0.0	$0.0	$0.0	$4.0	1,360	0
345	($12.4)	($174.0)	$15.7	$177.4	$7.6	$7.4	($26.5)	($26.3)	$151.1	31,125	2,694
230	$362.1	($30.3)	$30.0	$422.4	($4.0)	($3.6)	($53.7)	($54.1)	$368.3	34,830	8,484
161	($19.5)	($55.9)	($7.8)	$28.5	($1.0)	$1.9	($2.9)	($5.7)	$22.8	4,279	1,533
138	$109.7	($290.4)	$36.7	$436.8	($10.0)	$35.0	($96.5)	($141.5)	$295.4	71,226	10,656
115	$26.2	($22.8)	$7.4	$56.4	$0.5	$0.5	($4.7)	($4.7)	$51.6	13,587	1,930
69	$43.3	($5.3)	$0.1	$48.6	($9.5)	($3.2)	($1.2)	($7.5)	$41.2	13,793	1,853
34	$0.1	$0.0	$0.2	$0.3	($0.0)	$0.0	$0.0	$0.0	$0.3	1,026	50
13	$0.0	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	55	0
12	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	1	0
Unclassified	$0.0	($1.4)	$0.3	$1.6	$0.3	$0.9	$10.8	$10.3	$11.9	NA	NA
Total	$614.2	($967.6)	$50.3	$1,632.1	$0.6	$69.8	($177.6)	($246.9)	$1,385.3	184,713	28,524

Table 11-21 Congestion summary (By facility voltage): 2014

	Congestion Costs (Millions)										
	Day-Ahead				Balancing					Congestion 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	$24.5	($53.9)	$3.7	$82.2	$1.6	$0.4	($4.7)	($3.4)	$78.8	12,662	657
500	$372.8	($639.6)	($98.6)	$913.8	$75.0	$161.8	$7.6	($79.2)	$834.6	21,954	2,467
460	($0.0)	($0.3)	$0.1	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	218	0
345	($74.3)	($370.2)	$2.7	$298.6	$4.1	$17.7	($31.6)	($45.2)	$253.4	69,866	3,133
230	$129.2	($242.8)	($19.6)	$352.4	$3.4	($0.2)	($1.9)	$1.7	$354.1	55,335	8,293
161	($28.5)	($62.9)	($2.5)	$31.9	($1.9)	$0.6	($1.6)	($4.1)	$27.8	7,042	1,178
138	$90.9	($284.9)	$59.5	$435.3	($7.4)	$43.1	($106.0)	($156.6)	$278.8	153,597	9,662
115	$3.3	($23.1)	$4.6	$30.9	($6.1)	$2.7	($3.4)	($12.2)	$18.8	19,474	1,299
69	$75.3	$18.3	$1.3	$58.2	($23.7)	($9.6)	($1.0)	($15.2)	$43.1	19,352	2,113
34	$0.0	($0.0)	$0.1	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	3,917	0
26	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	31	0
13	($0.0)	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	5	0
12	$0.0	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	10	0
Unclassified	$2.0	($11.8)	$13.4	$27.3	$7.6	$1.6	$9.0	$15.1	$42.4	NA	NA
Total	$595.5	($1,671.2)	($35.4)	$2,231.3	$52.7	$218.1	($133.6)	($299.1)	$1,932.2	363,463	28,802

Constraint Duration

Table 11-22 lists the constraints in 2014 and 2015 that were most frequently binding and Table 11-23 shows the constraints which experienced the largest change in congestion-event hours from 2014 to 2015.

Table 11-22 Top 25 constraints with frequent occurrence: 2014 and 2015

			Congestion 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	Bagley - Graceton	Line	4,584	3,544	(1,040)	1,884	1,973	89	52%	40%	(12%)	22%	22%	1%
2	Oak Grove - Galesburg	Flowgate	6,905	3,356	(3,549)	1,059	1,306	247	79%	38%	(41%)	12%	15%	3%
3	Bunsonville - Eugene	Flowgate	2,244	3,762	1,518	675	748	73	26%	43%	17%	8%	9%	1%
4	Conastone - Northwest	Line	103	2,536	2,433	108	1,734	1,626	1%	29%	28%	1%	20%	19%
5	Maywood - Saddlebrook	Line	1,511	3,456	1,945	186	509	323	17%	39%	22%	2%	6%	4%
6	Tidd	Transformer	833	3,803	2,970	7	92	85	10%	43%	34%	0%	1%	1%
7	Bergen - New Milford	Line	4,745	2,970	(1,775)	331	795	464	54%	34%	(20%)	4%	9%	5%
8	Braidwood	Transformer	7,742	3,727	(4,015)	0	0	0	88%	42%	(46%)	0%	0%	0%
9	East Danville - Banister	Line	272	3,465	3,193	6	126	120	3%	39%	36%	0%	1%	1%
10	Monroe - Vineland	Line	1,348	3,121	1,773	24	197	173	15%	36%	20%	0%	2%	2%
11	Bedington - Black Oak	Interface	2,796	2,933	137	323	344	21	32%	33%	1%	4%	4%	0%
12	Easton	Transformer	1,758	3,099	1,341	0	0	0	20%	35%	15%	0%	0%	0%
13	Sayreville - Sayreville	Line	2,869	3,077	208	0	0	0	33%	35%	2%	0%	0%	0%
14	East Bend	Transformer	5,082	2,808	(2,274)	0	0	0	58%	32%	(26%)	0%	0%	0%
15	SENECA	Interface	3,562	938	(2,624)	3,227	1,182	(2,045)	41%	11%	(30%)	37%	13%	(23%)
16	Michigan City - Laporte	Flowgate	3,111	1,879	(1,232)	0	0	0	36%	21%	(14%)	0%	0%	0%
17	Tanners Creek	Transformer	8,096	1,838	(6,258)	0	0	0	92%	21%	(71%)	0%	0%	0%
18	Burnham - Munster	Flowgate	341	1,748	1,407	0	0	0	4%	20%	16%	0%	0%	0%
19	Miami Fort - Willey	Line	79	1,585	1,506	32	112	80	1%	18%	17%	0%	1%	1%
20	Cherry Valley	Transformer	2,762	789	(1,973)	324	885	561	32%	9%	(23%)	4%	10%	6%
21	49 Street - Hoboken	Line	394	1,643	1,249	0	0	0	4%	19%	14%	0%	0%	0%
22	Breed - Wheatland	Flowgate	3,758	1,358	(2,400)	602	149	(453)	43%	15%	(27%)	7%	2%	(5%)
23	Braidwood - East Frankfort	Line	1,245	1,449	204	25	58	33	14%	16%	2%	0%	1%	0%
24	Elwood - Elwood	Other	2,160	1,464	(696)	0	0	0	25%	17%	(8%)	0%	0%	0%
25	Bergen - Leonia	Line	2,128	1,456	(672)	0	0	0	24%	17%	(8%)	0%	0%	0%

Table 11-23 Top 25 constraints with largest year-to-year change in occurrence: 2014 and 2015

			Congestion 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	Miami Fort	Transformer	8,820	815	(8,005)	23	3	(20)	101%	9%	(91%)	0%	0%	(0%)
2	Tanners Creek	Transformer	8,096	1,838	(6,258)	0	0	0	92%	21%	(71%)	0%	0%	0%
3	Clinch River	Transformer	6,618	478	(6,140)	0	0	0	76%	5%	(70%)	0%	0%	0%
4	Kendall Co. Energy Ctr.	Transformer	5,488	121	(5,367)	0	0	0	63%	1%	(61%)	0%	0%	0%
5	Monticello - East Winamac	Flowgate	3,511	0	(3,511)	1,440	0	(1,440)	40%	0%	(40%)	16%	0%	(16%)
6	AP South	Interface	5,090	1,285	(3,805)	981	42	(939)	58%	15%	(43%)	11%	0%	(11%)
7	SENECA	Interface	3,562	938	(2,624)	3,227	1,182	(2,045)	41%	11%	(30%)	37%	13%	(23%)
8	Huntington Junction - Huntington	Line	4,508	26	(4,482)	0	0	0	51%	0%	(51%)	0%	0%	0%
9	Burlington - Croydon	Line	4,971	880	(4,091)	544	214	(330)	57%	10%	(47%)	6%	2%	(4%)
10	Wolf Creek	Transformer	5,102	710	(4,392)	131	171	40	58%	8%	(50%)	1%	2%	0%
11	Sunbury	Transformer	4,344	29	(4,315)	0	0	0	50%	0%	(49%)	0%	0%	0%
12	Conastone - Northwest	Line	103	2,536	2,433	108	1,734	1,626	1%	29%	28%	1%	20%	19%
13	Braidwood	Transformer	7,742	3,727	(4,015)	0	0	0	88%	42%	(46%)	0%	0%	0%
14	Nelson - Cordova	Line	4,107	414	(3,693)	279	69	(210)	47%	5%	(42%)	3%	1%	(2%)
15	Sporn	Transformer	3,560	36	(3,524)	0	0	0	41%	0%	(40%)	0%	0%	0%
16	East Danville - Banister	Line	272	3,465	3,193	6	126	120	3%	39%	36%	0%	1%	1%
17	Oak Grove - Galesburg	Flowgate	6,905	3,356	(3,549)	1,059	1,306	247	79%	38%	(41%)	12%	15%	3%
18	Mardela - Vienna	Line	4,627	1,365	(3,262)	76	86	10	53%	16%	(37%)	1%	1%	0%
19	Fort Robinson - Wolf Hills	Line	3,185	0	(3,185)	0	0	0	36%	0%	(36%)	0%	0%	0%
20	Keeney	Transformer	3,099	9	(3,090)	58	0	(58)	35%	0%	(35%)	1%	0%	(1%)
21	Tidd	Transformer	833	3,803	2,970	7	92	85	10%	43%	34%	0%	1%	1%
22	Gould Street - Westport	Line	3,867	789	(3,078)	0	23	23	44%	9%	(35%)	0%	0%	0%
23	Beckjord	Transformer	3,040	145	(2,895)	0	0	0	35%	2%	(33%)	0%	0%	0%
24	Benton Harbor - Palisades	Flowgate	3,025	283	(2,742)	137	0	(137)	35%	3%	(31%)	2%	0%	(2%)
25	Breed - Wheatland	Flowgate	3,758	1,358	(2,400)	602	149	(453)	43%	15%	(27%)	7%	2%	(5%)

Constraint Costs

Table 11-24 and Table 11-25 present the top constraints affecting congestion costs by facility for the periods 2015 and 2014.

Table 11-24 Top 25 constraints affecting PJM congestion costs (By facility): 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
1	Conastone - Northwest	Line	BGE	$100.9	($2.4)	$1.6	$105.0	($1.6)	($8.1)	($2.7)	$3.8	$108.8	7.9%
2	Bagley - Graceton	Line	BGE	$99.5	$5.6	$5.0	$98.9	($0.2)	($12.4)	($3.2)	$9.0	$107.9	7.8%
3	5004/5005 Interface	Interface	500	($23.0)	($134.8)	($9.2)	$102.6	$7.0	$22.5	$1.9	($13.6)	$89.0	6.4%
4	Bedington - Black Oak	Interface	500	$46.1	($45.2)	($7.2)	$84.1	$2.4	$2.2	$3.2	$3.5	$87.6	6.3%
5	Cherry Valley	Flowgate	MISO	($9.1)	($82.1)	$6.7	$79.6	$0.0	$0.0	$0.0	$0.0	$79.6	5.7%
6	AP South	Interface	500	$38.1	($22.8)	($5.5)	$55.4	$0.3	$0.2	$0.6	$0.7	$56.2	4.1%
7	AEP - DOM	Interface	500	$28.1	($28.0)	($1.1)	$55.0	$0.9	$1.6	($1.9)	($2.6)	$52.4	3.8%
8	Joshua Falls	Transformer	AEP	$9.7	($35.9)	($4.7)	$40.9	$0.7	($0.1)	$2.3	$3.1	$44.0	3.2%
9	Bergen - New Milford	Line	PSEG	$25.2	$18.4	$17.9	$24.7	($7.6)	$9.3	($51.2)	($68.1)	($43.5)	(3.1%)
10	Person - Halifax	Flowgate	MISO	$79.7	$29.2	($10.4)	$40.1	$0.0	($0.0)	($0.1)	($0.1)	$40.0	2.9%
11	Maywood - Saddlebrook	Line	PSEG	$8.9	$3.9	$7.5	$12.5	($4.7)	$9.0	($22.2)	($36.0)	($23.4)	(1.7%)
12	East	Interface	500	($13.0)	($37.6)	($2.1)	$22.4	($0.1)	$0.3	$0.5	$0.1	$22.6	1.6%
13	Easton	Transformer	DPL	$29.0	$6.6	($0.5)	$21.9	$0.0	$0.0	$0.0	$0.0	$21.9	1.6%
14	Glenarm - Windy Edge	Line	BGE	$3.3	($13.0)	$1.0	$17.3	$1.9	($1.9)	($0.7)	$3.2	$20.5	1.5%
15	Oak Grove - Galesburg	Flowgate	MISO	($16.1)	($44.8)	($6.3)	$22.4	$0.2	$1.1	($1.9)	($2.8)	$19.7	1.4%
16	Mahans Lane - Tidd	Line	AEP	$7.7	($13.3)	($1.6)	$19.4	$0.4	$1.1	$0.9	$0.2	$19.6	1.4%
17	East Danville - Banister	Line	AEP	$8.1	($7.6)	$2.0	$17.7	$0.5	($1.5)	($0.6)	$1.4	$19.1	1.4%
18	49th Street - Hoboken	Line	PSEG	$0.0	$0.0	$0.0	$0.0	($3.0)	$2.1	($13.7)	($18.8)	($18.8)	(1.4%)
19	BCPEP	Interface	Pepco	$15.3	($3.0)	$0.1	$18.4	$0.0	$0.0	$0.0	$0.0	$18.4	1.3%
20	Braidwood - East Frankfort	Line	ComEd	($2.3)	($21.0)	$0.6	$19.4	$0.3	$0.4	($1.2)	($1.3)	$18.1	1.3%
21	Valley	Transformer	Dominion	$17.4	($0.2)	$0.0	$17.7	$0.0	$0.0	$0.0	$0.0	$17.7	1.3%
22	Cloverdale	Transformer	AEP	$6.6	($9.8)	($1.4)	$15.0	$0.0	$0.0	$0.0	$0.0	$15.0	1.1%
23	Breed - Wheatland	Flowgate	MISO	($1.7)	($15.5)	$0.6	$14.4	$0.1	($0.6)	($0.7)	($0.0)	$14.4	1.0%
24	Miami Fort - Willey	Line	DEOK	($0.8)	($12.4)	$1.2	$12.8	$1.2	$0.7	($0.3)	$0.2	$13.0	0.9%
25	Central	Interface	500	($15.5)	($32.7)	($3.9)	$13.3	$0.1	$1.0	$0.3	($0.7)	$12.6	0.9%

Table 11-25 Top 25 constraints affecting PJM congestion costs (By facility): 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
1	AP South	Interface	500	$329.7	($201.4)	($11.2)	$520.0	$31.5	$73.5	$8.9	($33.1)	$486.8	25.2%
2	West	Interface	500	($21.3)	($297.0)	($79.1)	$196.5	$17.7	$49.7	$17.0	($15.0)	$181.6	9.4%
3	Bagley - Graceton	Line	BGE	$98.5	($9.5)	($1.7)	$106.3	$5.7	($4.0)	$4.5	$14.2	$120.5	6.2%
4	Bedington - Black Oak	Interface	500	$42.8	($43.9)	($0.2)	$86.5	$3.9	$3.4	($2.3)	($1.9)	$84.6	4.4%
5	Breed - Wheatland	Flowgate	MISO	($17.7)	($100.2)	($9.3)	$73.2	$2.4	$1.1	$5.6	$6.9	$80.1	4.1%
6	Benton Harbor - Palisades	Flowgate	MISO	($12.5)	($79.3)	($8.0)	$58.8	($0.2)	$0.7	($1.0)	($1.8)	$57.0	2.9%
7	Cloverdale	Transformer	AEP	$23.3	($27.3)	$0.2	$50.7	$0.0	$0.0	$0.0	$0.0	$50.7	2.6%
8	BCPEP	Interface	Pepco	$15.6	($15.2)	($1.6)	$29.3	($1.6)	($14.2)	$1.5	$14.1	$43.4	2.2%
9	Unclassified	Unclassified	Unclassified	$2.0	($11.8)	$13.4	$27.3	$7.6	$1.6	$9.0	$15.1	$42.4	2.2%
10	Monticello - East Winamac	Flowgate	MISO	($3.8)	($46.7)	$1.6	$44.6	$2.6	$4.3	($10.8)	($12.5)	$32.1	1.7%
11	Oak Grove - Galesburg	Flowgate	MISO	($28.4)	($62.2)	($2.3)	$31.5	($0.4)	$0.5	($0.3)	($1.3)	$30.3	1.6%
12	Cherry Valley	Transformer	ComEd	$21.9	($20.4)	$5.2	$47.5	($5.1)	$1.1	($11.3)	($17.5)	$30.0	1.6%
13	Cook - Palisades	Flowgate	MISO	($12.6)	($55.3)	($5.3)	$37.4	($1.5)	$1.6	($6.2)	($9.3)	$28.1	1.5%
14	Readington - Roseland	Line	PSEG	($8.9)	($46.1)	($12.2)	$25.1	$0.9	$5.4	$5.8	$1.3	$26.4	1.4%
15	Cloverdale	Transformer	AEP	$23.1	($4.8)	($2.3)	$25.7	$0.0	$0.0	$0.0	$0.0	$25.7	1.3%
16	Wolf Creek	Transformer	AEP	$4.6	$1.3	$4.7	$8.0	$3.6	$5.6	($29.3)	($31.3)	($23.3)	(1.2%)
17	Brambleton - Loudoun	Line	Dominion	($11.2)	($35.1)	($1.3)	$22.6	$0.6	$0.0	$0.1	$0.6	$23.2	1.2%
18	SENECA	Interface	PENELEC	$5.6	$9.9	($6.5)	($10.9)	($3.0)	$1.2	($6.1)	($10.4)	($21.3)	(1.1%)
19	Wescosville	Transformer	PPL	$17.6	($0.8)	$2.7	$21.1	($0.0)	$0.0	$0.0	($0.0)	$21.1	1.1%
20	East	Interface	500	($9.8)	($34.2)	($3.4)	$21.0	$0.3	$0.7	$0.5	$0.1	$21.1	1.1%
21	Nelson - Cordova	Line	ComEd	($24.7)	($47.1)	$4.2	$26.6	($0.7)	$1.1	($4.3)	($6.0)	$20.5	1.1%
22	Bridgewater - Middlesex	Line	PSEG	$0.2	($22.2)	($3.0)	$19.4	($1.5)	$0.1	$1.4	($0.2)	$19.2	1.0%
23	5004/5005 Interface	Interface	500	($0.7)	($23.6)	($3.3)	$19.5	$8.1	$17.5	$7.3	($2.1)	$17.4	0.9%
24	Atlantic - Larrabee	Line	JCPL	$2.0	($14.8)	($0.7)	$16.1	$0.0	$1.3	$1.2	($0.1)	$16.0	0.8%
25	Amos	Transformer	AEP	$1.6	($12.8)	($0.2)	$14.2	$1.2	($1.6)	($1.2)	$1.6	$15.8	0.8%

Figure 11-2 shows the locations of the top 10 constraints by PJM total congestion costs in2015. Figure 11-3 shows the locations of the top 10 constraints by PJM day-ahead congestion costs in 2015. Figure 11-4 shows the locations of the top 10 constraints by PJM balancing congestion costs in 2015.

Figure 11-2 Location of the top 10 constraints by PJM total congestion costs: 2015

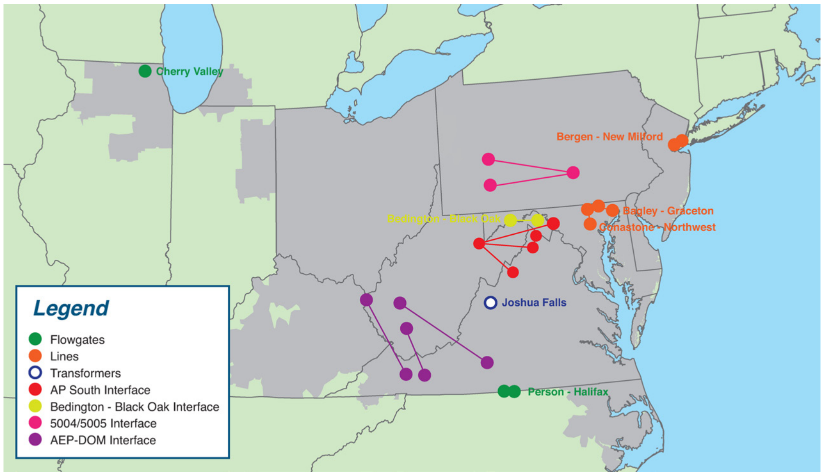


Figure 11-3 Location of the top 10 constraints by PJM day-ahead congestion costs: 2015

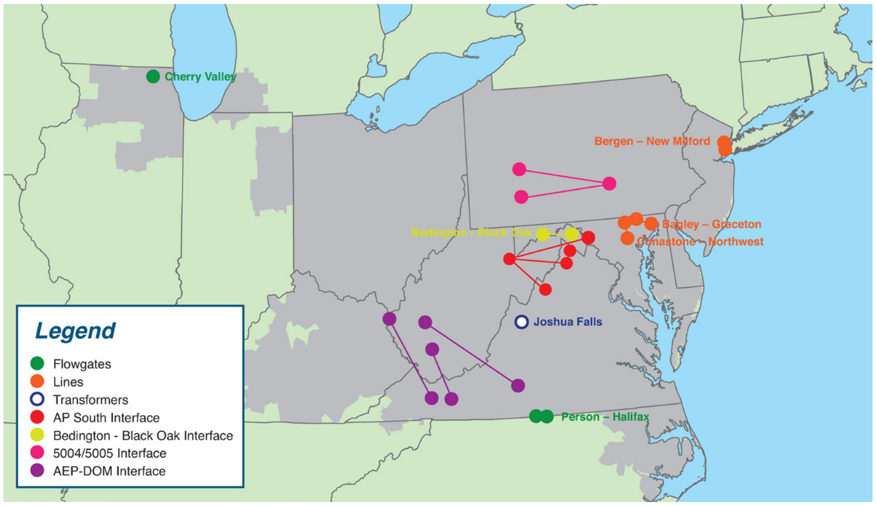
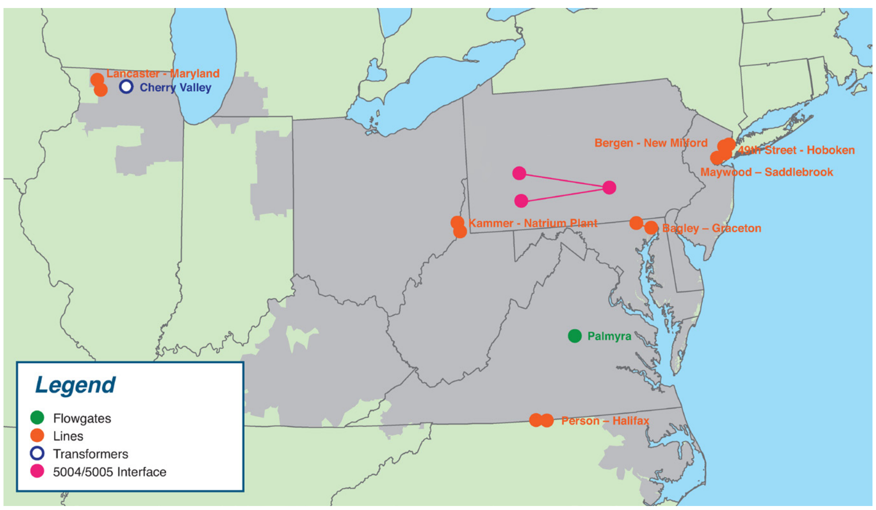


Figure 11-4 Location of the top 10 constraints by PJM balancing congestion costs: 2015



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.[22] A flowgate is a facility or group of facilities that may act as constraint points on the regional system.[23] PJM models these coordinated flowgates and controls for them in its security-constrained, economic dispatch.

As of December 31, 2015, PJM had 130 flowgates eligible for M2M (Market to Market) coordination and MISO had 207 flowgates eligible for M2M coordination.

22 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://www.pjm.com/documents/agreements.aspx>

23 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.," (December 11, 2008), Section 2.2.24 <http://www.pjm.com/documents/agreements.aspx>

Table 11-26 and Table 11-27 show the MISO flowgates which PJM and/or MISO took dispatch action to control during 2015 and 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 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 11-26 Top 20 congestion cost impacts from MISO flowgates affecting PJM dispatch (By facility): 2015

		Congestion Costs (Millions)									Congestion Event Hours	
		Day-Ahead				Balancing						
No.	Constraint	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day-Ahead	Real-Time
1	Cherry Valley	($9.1)	($82.1)	$6.7	$79.6	$0.0	$0.0	$0.0	$0.0	$79.6	1,348	0
2	Person - Halifax	$79.7	$29.2	($10.4)	$40.1	$0.0	($0.0)	($0.1)	($0.1)	$40.0	1,412	6
3	Oak Grove - Galesburg	($16.1)	($44.8)	($6.3)	$22.4	$0.2	$1.1	($1.9)	($2.8)	$19.7	3,356	1,306
4	Breed - Wheatland	($1.7)	($15.5)	$0.6	$14.4	$0.1	($0.6)	($0.7)	($0.0)	$14.4	1,358	149
5	Burnham - Munster	($0.0)	($10.7)	$1.1	$11.8	$0.0	$0.0	$0.0	$0.0	$11.8	1,748	0
6	Rising	$0.5	($11.8)	($6.6)	$5.7	$0.4	$0.0	$3.4	$3.7	$9.4	699	459
7	Bunsonville - Eugene	($3.1)	($17.8)	($7.6)	$7.2	$0.3	($0.2)	$1.5	$1.9	$9.1	3,762	748
8	Nelson	($2.9)	($11.3)	$0.8	$9.1	$0.0	$0.0	$0.0	$0.0	$9.1	708	0
9	Dixon - McGirr Rd	($3.1)	($11.0)	($0.0)	$7.9	$0.0	$0.0	$0.0	$0.0	$7.9	1,040	0
10	Michigan City - Laporte	$1.0	($6.9)	($0.4)	$7.5	$0.0	$0.0	$0.0	$0.0	$7.5	1,879	0
11	Monroe - Bayshore	($3.8)	($12.9)	($2.5)	$6.6	($0.1)	($0.8)	($0.1)	$0.5	$7.1	572	215
12	Crete - St Johns Tap	($0.2)	($5.7)	$1.0	$6.5	$0.0	$0.0	$0.0	$0.0	$6.5	724	0
13	Braidwood - East Frankfurt	($0.1)	($5.1)	($0.0)	$5.0	$0.0	$0.0	$0.0	$0.0	$5.0	54	0
14	Byron - Cherry Valley	($0.5)	($4.8)	$0.5	$4.9	$0.0	$0.0	$0.0	$0.0	$4.9	233	0
15	Mercer IP - Galesburg	($3.7)	($10.9)	($1.6)	$5.6	($0.0)	$0.5	($0.6)	($1.1)	$4.5	816	206
16	Marysville - Tangy	($0.4)	($5.1)	($0.2)	$4.5	$0.0	$0.0	$0.0	$0.0	$4.5	118	0
17	Cherry Valley - Silver Lake	($1.0)	($4.9)	$0.1	$4.1	$0.0	$0.0	$0.0	$0.0	$4.1	224	0
18	Benton Harbor - Palisades	($0.1)	($3.8)	($0.5)	$3.3	$0.0	$0.0	$0.0	$0.0	$3.3	283	0
19	Maryland	($2.3)	($4.6)	$0.8	$3.1	$0.0	$0.0	$0.0	$0.0	$3.1	434	0
20	Klondcin - Purdue	$0.0	($0.1)	$0.0	$0.1	$0.0	$0.4	($2.5)	($2.9)	($2.8)	40	53

Table 11-27 Top 20 congestion cost impacts from MISO flowgates affecting PJM dispatch (By facility): 2014

		Congestion Costs (Millions)									Congestion Event Hours	
		Day-Ahead				Balancing						
No.	Constraint	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day-Ahead	Real-Time
1	Breed - Wheatland	($17.7)	($100.2)	($9.3)	$73.2	$2.4	$1.1	$5.6	$6.9	$80.1	3,758	602
2	Benton Harbor - Palisades	($12.5)	($79.3)	($8.0)	$58.8	($0.2)	$0.7	($1.0)	($1.8)	$57.0	3,025	137
3	Monticello - East Winamac	($3.8)	($46.7)	$1.6	$44.6	$2.6	$4.3	($10.8)	($12.5)	$32.1	3,511	1,440
4	Oak Grove - Galesburg	($28.4)	($62.2)	($2.3)	$31.5	($0.4)	$0.5	($0.3)	($1.3)	$30.3	6,905	1,059
5	Cook - Palisades	($12.6)	($55.3)	($5.3)	$37.4	($1.5)	$1.6	($6.2)	($9.3)	$28.1	2,316	308
6	Michigan City - Laporte	($4.8)	($17.2)	$1.9	$14.4	$0.0	$0.0	$0.0	$0.0	$14.4	3,111	0
7	Rising	($5.1)	($3.8)	$1.4	$0.2	($3.9)	$1.2	($9.3)	($14.3)	($14.1)	386	115
8	Wake - Carso	$0.0	$0.0	$0.0	$0.0	$4.2	$2.7	($10.7)	($9.3)	($9.3)	0	115
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	Bunsonville - Eugene	($4.4)	($8.6)	($0.1)	$4.1	($0.1)	($0.2)	($0.9)	($0.7)	$3.4	2,244	675
12	Rantoul - Rantoul Jct	($2.7)	($5.5)	$0.3	$3.0	$0.0	$0.0	$0.0	$0.0	$3.0	1,088	0
13	Batesville - Hubble	($1.7)	($5.6)	($0.9)	$2.9	($0.0)	($0.0)	$0.1	$0.1	$3.0	438	16
14	Todd Hunter	($0.7)	($3.0)	$0.7	$2.9	$0.0	$0.0	$0.0	$0.0	$2.9	867	0
15	Byron - Cherry Valley	($0.6)	($3.4)	$0.1	$2.9	$0.0	$0.0	$0.0	$0.0	$2.9	42	0
16	Beaver Channel - Albany	$0.0	$0.0	$0.0	$0.0	($1.4)	$0.0	($1.0)	($2.5)	($2.5)	0	73
17	Paddock - Townline	$0.1	($2.4)	($0.3)	$2.2	$0.0	$0.0	$0.1	$0.1	$2.3	670	38
18	Edwards - Kewanee	($1.7)	($3.9)	$0.1	$2.3	$0.0	$0.0	$0.0	$0.0	$2.3	1,864	0
19	Nelson	($2.7)	($5.1)	($0.4)	$2.0	$0.0	$0.0	$0.0	$0.0	$2.0	169	19
20	Pana North	$0.1	($0.2)	$0.1	$0.4	$0.0	$0.3	($2.0)	($2.3)	($1.9)	162	275

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.[24] 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.[25]

Table 11-28 shows the NYISO flowgates which PJM and/or NYISO took dispatch action to control during 2015, and which had the greatest congestion cost impact on PJM.

Table 11-28 Top two congestion cost impacts from NYISO flowgates affecting PJM dispatch (By facility): 2015

				Congestion Costs (Millions)										
				Day-Ahead				Balancing					Congestion 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	$0.4	$1.1	($0.0)	($0.7)	($0.7)	0	419
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 11-29 Top two congestion cost impacts from NYISO flowgates affecting PJM dispatch (By facility): 2014

				Congestion Costs (Millions)										
				Day-Ahead				Balancing					Congestion 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	143
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 11-30 and Table 11-31 show the 500 kV constraints affecting congestion costs in PJM for 2015 and 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 11-30 Regional constraints summary (By facility): 2015

				Congestion Costs (Millions)										
				Day-Ahead				Balancing					Congestion 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	($23.0)	($134.8)	($9.2)	$102.6	$7.0	$22.5	$1.9	($13.6)	$89.0	678	321
2	Bedington - Black Oak	Interface	500	$46.1	($45.2)	($7.2)	$84.1	$2.4	$2.2	$3.2	$3.5	$87.6	2,933	344
3	AP South	Interface	500	$38.1	($22.8)	($5.5)	$55.4	$0.3	$0.2	$0.6	$0.7	$56.2	1,285	42
4	AEP - DOM	Interface	500	$28.1	($28.0)	($1.1)	$55.0	$0.9	$1.6	($1.9)	($2.6)	$52.4	1,328	44
5	East	Interface	500	($13.0)	($37.6)	($2.1)	$22.4	($0.1)	$0.3	$0.5	$0.1	$22.6	540	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	($1.8)	($15.6)	($0.9)	$12.9	$0.2	$1.0	$0.1	($0.6)	$12.3	319	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	$1.0	$0.9	$0.7	$0.0	$0.2	$1.2	87	29

24 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/documents/agreements.aspx>.

25 See "Joint Operating Agreement Among and Between the New York Independent System Operator Inc. and PJM Interconnection, L.L.C.," (January 17, 2013) Section 35.23 <http://www.pjm.com/documents/agreements.aspx>.

Table 11-31 Regional constraints summary (By facility): 2014

				Congestion Costs (Millions)										
				Day-Ahead				Balancing					Congestion 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	$329.7	($201.4)	($11.2)	$520.0	$31.5	$73.5	$8.9	($33.1)	$486.8	5,090	981
2	West	Interface	500	($21.3)	($297.0)	($79.1)	$196.5	$17.7	$49.7	$17.0	($15.0)	$181.6	1,534	415
3	Bedington - Black Oak	Interface	500	$42.8	($43.9)	($0.2)	$86.5	$3.9	$3.4	($2.3)	($1.9)	$84.6	2,796	323
4	East	Interface	500	($9.8)	($34.2)	($3.4)	$21.0	$0.3	$0.7	$0.5	$0.1	$21.1	1,734	17
5	5004/5005 Interface	Interface	500	($0.7)	($23.6)	($3.3)	$19.5	$8.1	$17.5	$7.3	($2.1)	$17.4	554	336
6	AEP - DOM	Interface	500	$10.7	($11.4)	$3.9	$26.0	$5.3	$13.2	($9.6)	($17.5)	$8.5	2,511	66
7	Central	Interface	500	($5.2)	($13.9)	($3.8)	$4.8	$0.2	$0.5	$0.0	($0.3)	$4.6	334	10
8	Juniata	Transformer	500	$0.1	($0.2)	$0.1	$0.5	$0.1	($0.0)	($0.1)	$0.0	$0.5	253	9
9	Branchburg - Elroy	Line	500	($0.0)	($0.2)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	43	0
10	Nagel - Phipps Bend	Line	500	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	53	0

Congestion Costs by Physical and Financial Participants

In order to evaluate the recipients and payers of congestion, the MMU categorized all participants in PJM as either physical or financial. Physical entities include utilities and customers which primarily take physical positions in PJM markets. Financial entities include banks and hedge funds which primarily take financial positions in PJM markets. International market participants that primarily take financial positions in PJM markets are generally considered to be financial entities even if they are utilities in their own countries.

In 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 2015, the total explicit cost was -$127.3 million (indicating net credits to participants), of which -$155.9 million (122.4 percent) was credited to UTCs. In 2014, the total explicit cost was -$169.0 million, of which -$200.2 million (118.5 percent) was credited to UTCs. In 2015, financial entities received $133.1 million in net congestion credits, a decrease of $93.6 million or 41.3 percent compared to 2014. In 2015, physical entities paid $1,518.3 million in congestion charges, a decrease of $640.6 million or 29.7 percent compared to 2014.

Table 11-32 Congestion cost by type of participant: 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	$82.3	$40.5	($2.7)	$39.0	($49.3)	($7.9)	($130.7)	($172.1)	$0.0	($133.1)
Physical	$531.9	($1,008.2)	$53.0	$1,593.1	$49.8	$77.7	($46.9)	($74.8)	$0.0	$1,518.3
Total	$614.2	($967.6)	$50.3	$1,632.1	$0.6	$69.8	($177.6)	($246.9)	$0.0	$1,385.3

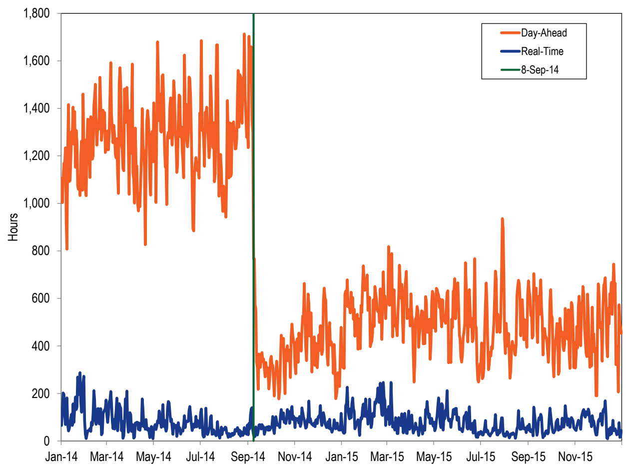
Table 11-33 Congestion cost by type of participant: 2014

	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	$63.8	$75.7	($104.7)	($116.6)	($40.4)	($8.1)	($77.8)	($110.1)	$0.0	($226.7)
Physical	$531.6	($1,746.9)	$69.3	$2,347.9	$93.1	$226.2	($55.8)	($189.0)	$0.0	$2,158.9
Total	$595.5	($1,671.2)	($35.4)	$2,231.3	$52.7	$218.1	($133.6)	($299.1)	$0.0	$1,932.2

Congestion-Event Summary before and after September 8, 2014

The day-ahead congestion event hours decreased significantly after September 8, 2014, when UTC activity declined significantly. The reduction in UTC activity was a result of FERC's UTC uplift refund notice, effective September 8, 2014.[26] Figure 11-5 shows the daily day-ahead and real-time congestion event hours for 2014 through 2015.

Figure 11-5 Daily congestion event hours: 2014 through 2015



Marginal Losses

Marginal Loss Accounting

Marginal losses occur in the Day-Ahead and Real-Time Energy Markets. The loss cost is based on the applicable day-ahead and real-time marginal loss component of LMP (MLMP). 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.[27] 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 participants based on real-time load (excluding losses) ratio share.[28] 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.

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.

26 See 18 CFR § 385.213 (2014).

27 OA. Schedule 1 (PJM Interchange Energy Market) §3.7

28 *Id.*

The total 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 allocated to PJM market participants based on real-time load plus export ratio share as marginal loss credits.[29]

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.

- **Day-Ahead Load Loss Payments.** Day-ahead load loss payments are calculated for all cleared demand, decrement bids and day-ahead energy market sale transactions. Day-ahead, load loss payments are calculated using MW and the load bus loss MLMP, the decrement bid MLMP or the MLMP at the source of the sale transaction.
- **Day-Ahead Generation Loss Credits.** Day-ahead generation loss credits are calculated for all cleared generation and increment offers and day-ahead energy market purchase transactions. Day-ahead, generation loss credits are calculated using MW and the generator bus MLMP, the increment offer MLMP or the MLMP at the sink of the purchase transaction.
- **Balancing Load Loss Payments.** Balancing load loss payments are calculated for all deviations between a PJM member's real-time load and energy sale transactions and their day-ahead cleared demand, decrement bids and energy sale transactions. Balancing, load loss payments are calculated using MW deviations and the real-time MLMP for each bus where a deviation exists.
- **Balancing Generation Loss Credits.** Balancing generation loss credits are calculated for all deviations between a PJM member's real-time generation and energy purchase transactions and the day-ahead cleared generation, increment offers and energy purchase transactions. Balancing, generation loss credits are calculated using MW deviations and the real-time MLMP for each bus where a deviation exists.
- **Explicit Loss Costs.** Explicit loss costs are the net loss costs associated with point to point energy transactions. These costs equal the product of the transacted MW and MLMP differences between sources (origins) and sinks (destinations) in the Day-Ahead Energy Market. Balancing energy market explicit loss costs equal the product of the differences between the real-time and day-ahead transacted MW and the differences between the real-time MLMP at the transactions' sources and sinks.
- **Inadvertent Loss Charges.** Inadvertent loss charges are the net loss charges resulting from the differences between the net actual energy flow and the net scheduled energy flow into or out of the PJM control area each hour. This inadvertent interchange of energy may be positive or negative, where positive interchange typically results in a charge while negative interchange typically results in a credit. Inadvertent loss charges are common costs, not directly attributable to specific participants, that are distributed on a load ratio basis.[30]

The total marginal loss cost in PJM for 2015 was $968.7 million, which was comprised of load loss payments of -$37.1 million, generation loss credits of -$1,021.0 million, explicit loss costs of -$20.5 million and inadvertent loss charges of $0.0 million. Monthly marginal loss costs in 2015 ranged from $44.6 million

29 See PJM. "Manual 28: Operating Agreement Accounting," Revision 72 (December 17, 2015), p.65.

30 OA. Schedule 1 (PJM Interchange Energy Market) §3.7.

in December to $220.3 million in February. Total loss surplus decreased in 2015 by $148.2 million or 30.7 percent from 2014, from $482.1 million to $333.9 million.

Total Marginal Loss Costs

Table 11-34 shows the total marginal loss costs as a component of total energy related costs for 2009 through 2015.

Table 11-34 Total component costs (Dollars (Millions)): 2009 through 2015[31]

	Loss Costs	Percent Change	Total PJM Billing	Percent of PJM Billing
2009	$1,268	NA	$26,550	4.8%
2010	$1,635	29.0%	$34,771	4.7%
2011	$1,380	(15.6%)	$35,887	3.8%
2012	$982	(28.8%)	$29,181	3.4%
2013	$1,035	5.5%	$33,862	3.1%
2014	$1,466	41.6%	$50,030	2.9%
2015	$969	(33.9%)	$42,630	2.3%

Table 11-35 shows PJM total marginal loss costs by accounting category for 2009 through 2015. Table 11-36 shows PJM total marginal loss costs by accounting category by market for 2009 through 2015.

Table 11-35 Total PJM marginal loss costs by accounting category (Dollars (Millions)): 2009 through 2015

	Marginal Loss Costs (Millions)				
	Load Payments	Generation Credits	Explicit Costs	Inadvertent Charges	Total
2009	($78.5)	($1,314.3)	$32.0	($0.0)	$1,267.7
2010	($122.3)	($1,707.0)	$50.2	($0.0)	$1,634.8
2011	($174.0)	($1,551.9)	$1.6	$0.0	$1,379.5
2012	($11.1)	($1,036.8)	($44.0)	$0.0	$981.7
2013	($4.1)	($1,083.3)	($43.9)	($0.0)	$1,035.3
2014	($59.2)	($1,581.3)	($56.0)	$0.0	$1,466.1
2015	($31.7)	($1,021.0)	($20.5)	$0.0	$968.7

Table 11-36 Total PJM marginal loss costs by accounting category by market (Dollars (Millions)): 2009 through 2015

	Marginal Loss Costs (Millions)									
	Day-Ahead				Balancing					
	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
2009	($84.7)	($1,311.7)	$65.4	$1,292.3	$6.2	($2.7)	($33.5)	($24.6)	($0.0)	$1,267.7
2010	($146.3)	($1,716.1)	$95.8	$1,665.6	$23.9	$9.1	($45.6)	($30.8)	($0.0)	$1,634.8
2011	($215.4)	($1,592.1)	$53.8	$1,430.5	$41.4	$40.2	($52.2)	($51.0)	$0.0	$1,379.5
2012	($43.0)	($1,060.3)	($13.4)	$1,003.8	$32.0	$23.4	($30.6)	($22.1)	$0.0	$981.7
2013	($37.1)	($1,112.4)	$62.4	$1,137.8	$33.0	$29.1	($106.4)	($102.5)	($0.0)	$1,035.3
2014	($113.9)	($1,618.8)	$66.6	$1,571.4	$54.7	$37.5	($122.5)	($105.3)	$0.0	$1,466.1
2015	($53.4)	($1,032.2)	$33.8	$1,012.6	$21.7	$11.3	($54.3)	($43.9)	$0.0	$968.7

Table 11-37 and Table 11-38 show the total loss costs for each transaction type in 2015 and 2014. In 2015, generation paid 97.1 percent of total loss cost and the loss cost paid by generation was $940.7 million. In 2014, generation paid 98.2 percent of total loss cost and the loss cost paid by generation was $1,439.1 million.

31 The loss costs include net inadvertent charges.

Table 11-37 Total PJM loss costs by transaction type by market (Dollars (Millions)): 2015

	Loss 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	($1.3)	$0.0	$0.0	($1.3)	($4.0)	$0.0	$0.0	($4.0)	$0.0	($5.3)
Demand	($10.2)	$0.0	$0.0	($10.2)	$22.2	$0.0	$0.0	$22.2	$0.0	$12.0
Demand Response	($0.0)	$0.0	$0.0	($0.0)	$0.1	$0.0	$0.0	$0.1	$0.0	$0.0
Export	($17.8)	$0.0	$0.4	($17.4)	($2.5)	$0.0	$1.6	($1.0)	$0.0	($18.3)
Generation	$0.0	($980.0)	$0.0	$980.0	$0.0	$39.3	$0.0	($39.3)	$0.0	$940.7
Grandfathered Overuse	$0.0	$0.0	($1.5)	($1.5)	$0.0	$0.0	$0.0	$0.0	$0.0	($1.5)
Import	$0.0	($14.2)	$3.8	$18.0	$0.0	($48.2)	$1.6	$49.7	$0.0	$67.8
INC	$0.0	($13.9)	$0.0	$13.9	$0.0	$14.2	$0.0	($14.2)	$0.0	($0.2)
Internal Bilateral	($24.1)	($24.1)	$0.0	$0.0	$6.0	$6.0	$0.0	($0.0)	$0.0	($0.0)
Up to Congestion	$0.0	$0.0	$29.1	$29.1	$0.0	$0.0	($57.3)	($57.3)	$0.0	($28.2)
Wheel In	$0.0	$0.0	$1.9	$1.9	$0.0	$0.0	($0.1)	($0.1)	$0.0	$1.8
Total	($53.4)	($1,032.2)	$33.8	$1,012.6	$21.7	$11.3	($54.3)	($43.9)	$0.0	$968.7

Table 11-38 Total PJM loss costs by transaction type by market (Dollars (Millions)): 2014

	Loss 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	($4.3)	$0.0	$0.0	($4.3)	$3.4	$0.0	$0.0	$3.4	$0.0	($0.9)
Demand	($10.3)	$0.0	$0.0	($10.3)	$72.1	$0.0	$0.0	$72.1	$0.0	$61.8
Demand Response	($0.2)	$0.0	$0.0	($0.2)	$0.2	$0.0	$0.0	$0.2	$0.0	($0.0)
Export	($26.7)	$0.0	$0.2	($26.5)	($20.9)	$0.0	$2.4	($18.5)	$0.0	($44.9)
Generation	$0.0	($1,515.2)	$0.0	$1,515.2	$0.0	$76.1	$0.0	($76.1)	$0.0	$1,439.1
Grandfathered Overuse	$0.0	$0.0	($2.3)	($2.3)	$0.0	$0.0	$0.0	$0.0	$0.0	($2.3)
Import	$0.0	($10.8)	$15.6	$26.4	$0.0	($63.9)	$3.8	$67.8	$0.0	$94.2
INC	$0.0	($20.5)	$0.0	$20.5	$0.0	$25.4	$0.0	($25.4)	$0.0	($4.9)
Internal Bilateral	($72.4)	($72.3)	$0.1	($0.0)	($0.1)	($0.1)	$0.0	($0.0)	$0.0	($0.0)
Up to Congestion	$0.0	$0.0	$49.7	$49.7	$0.0	$0.0	($128.6)	($128.6)	$0.0	($79.0)
Wheel In	$0.0	$0.0	$3.3	$3.3	$0.0	$0.0	($0.2)	($0.2)	$0.0	$3.1
Total	($113.9)	($1,618.8)	$66.6	$1,571.4	$54.7	$37.5	($122.5)	($105.3)	$0.0	$1,466.1

Monthly Marginal Loss Costs

Table 11-39 shows a monthly summary of marginal loss costs by market type for 2014 and 2015. Total marginal loss costs decreased were higher in 2014 as a result of high load and outages caused by cold weather in the winter of 2014.

Table 11-39 Monthly marginal loss costs by market (Millions): 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
Jul	$102.1	($9.6)	$0.0	$92.5	$89.3	($5.7)	$0.0	$83.6
Aug	$80.5	($5.3)	$0.0	$75.2	$77.3	($4.4)	$0.0	$72.9
Sep	$70.3	($1.1)	$0.0	$69.2	$68.8	($3.8)	($0.0)	$65.0
Oct	$64.5	($0.1)	$0.0	$64.3	$53.8	($4.3)	($0.0)	$49.5
Nov	$82.9	$0.4	($0.0)	$83.3	$48.5	($3.6)	$0.0	$44.9
Dec	$76.2	($0.8)	($0.0)	$75.4	$49.6	($5.0)	($0.0)	$44.6
Total	$1,571.4	($105.3)	$0.0	$1,466.1	$1,012.6	($43.9)	$0.0	$968.7

Figure 11-6 shows PJM monthly marginal loss costs for 2009 through 2015.

Figure 11-6 PJM monthly marginal loss costs (Dollars (Millions)): 2009 through 2015

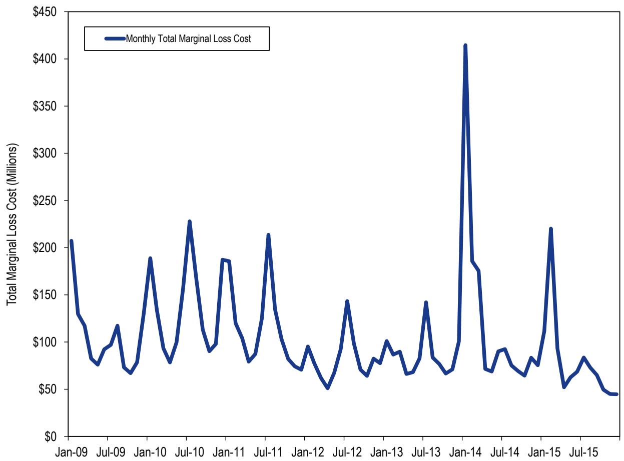


Table 11-40 and Table 11-41 show the monthly total loss costs for each virtual transaction type in 2014 and 2015. Virtual transaction loss costs, when positive, measure the total loss cost to the virtual transaction and when negative, measure the total loss credit to the virtual transaction. In 2015, DECs were paid $1.3 million in loss credits in the day-ahead market, were paid $4.0 million in congestion credits in the balancing energy market and received $5.3 million in net payment for loss. In 2015, INCs paid $13.9 million in loss credits in the day-ahead market, were paid $14.2 million in congestion cost in the balancing energy market and received $0.2 million in net payment for loss. In 2015, up to congestion paid $29.1 million in loss cost in the day-ahead market, were paid $57.3 million in loss credits in the balancing energy market and received $28.2 million in net payment for loss.

Table 11-40 Monthly PJM loss costs by virtual transaction type and by market (Dollars (Millions)): 2015

	Loss Costs (Millions)								
	Day-Ahead				Balancing				
	DEC	INC	Up to Congestion	Virtual Total	DEC	INC	Up to Congestion	Virtual Total	Virtual Grand Total
Jan	$0.2	$0.8	$2.9	$3.8	($1.1)	($0.7)	($4.9)	($6.7)	($2.9)
Feb	($0.6)	$1.8	($0.4)	$0.7	($0.8)	($2.0)	($3.4)	($6.2)	($5.5)
Mar	$0.5	$1.3	$3.5	$5.2	($1.1)	($2.3)	($6.0)	($9.4)	($4.2)
Apr	($0.3)	$0.9	$1.2	$1.7	($0.5)	($0.6)	($3.6)	($4.7)	($2.9)
May	($1.9)	$2.3	$1.2	$1.7	$0.4	($1.7)	($6.0)	($7.3)	($5.7)
Jun	($0.6)	$1.7	$4.3	$5.4	$0.2	($1.4)	($5.6)	($6.7)	($1.3)
Jul	$0.2	$1.1	$4.0	$5.3	($0.3)	($1.0)	($6.1)	($7.3)	($2.0)
Aug	$0.3	$0.9	$1.4	$2.6	($0.2)	($1.0)	($3.9)	($5.1)	($2.5)
Sep	$0.1	$1.0	$2.6	$3.7	($0.1)	($1.2)	($4.6)	($5.9)	($2.2)
Oct	$0.6	$0.5	$2.9	$4.0	($0.4)	($0.6)	($4.1)	($5.2)	($1.1)
Nov	($0.1)	$1.0	$2.4	$3.3	$0.2	($1.1)	($3.8)	($4.7)	($1.4)
Dec	$0.3	$0.7	$3.2	$4.3	($0.3)	($0.8)	($5.3)	($6.3)	($2.0)
Total	($1.3)	$13.9	$29.1	$41.8	($4.0)	($14.2)	($57.3)	($75.5)	($33.8)

Table 11-41 Monthly PJM loss costs by virtual transaction type and by market (Dollars (Millions)): 2014

	Loss Costs (Millions)								
	Day-Ahead				Balancing				
	DEC	INC	Up to Congestion	Virtual Total	DEC	INC	Up to Congestion	Virtual Total	Virtual Grand Total
Jan	$5.6	$5.5	$1.8	$12.9	($4.3)	($8.2)	($19.7)	($32.3)	($19.4)
Feb	$0.0	$2.5	$7.5	$10.0	($0.8)	($3.4)	($15.9)	($20.1)	($10.1)
Mar	$1.2	$2.8	$12.9	$16.9	($0.5)	($3.8)	($23.3)	($27.6)	($10.6)
Apr	($1.1)	$0.9	$4.4	$4.2	$1.5	($0.8)	($11.9)	($11.2)	($7.0)
May	($1.6)	$1.6	$4.6	$4.5	$1.8	($1.6)	($12.8)	($12.6)	($8.1)
Jun	($1.0)	$1.3	$7.9	$8.2	$1.3	($1.7)	($13.8)	($14.3)	($6.1)
Jul	($0.5)	$1.2	$6.8	$7.5	$0.3	($1.5)	($12.1)	($13.2)	($5.8)
Aug	($1.2)	$1.1	$1.4	$1.3	$0.7	($0.9)	($7.5)	($7.7)	($6.3)
Sep	($1.0)	$0.8	$0.4	$0.2	$0.6	($0.9)	($3.7)	($4.0)	($3.8)
Oct	($1.8)	$0.8	$0.6	($0.5)	$1.6	($0.9)	($2.2)	($1.5)	($2.0)
Nov	($1.5)	$1.2	$1.0	$0.7	$0.9	($1.3)	($2.7)	($3.1)	($2.4)
Dec	($1.3)	$0.6	$0.5	($0.2)	$0.3	($0.4)	($3.0)	($3.1)	($3.3)
Total	($4.3)	$20.5	$49.7	$65.8	$3.4	($25.4)	($128.6)	($150.6)	($84.8)

Marginal Loss Costs and Loss Credits

Total 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 11-42 shows the total energy costs, the total marginal loss costs collected, the net residual market adjustments and total marginal loss credits redistributed for 2009 through 2015. The total marginal loss credits decreased $145.8 million in 2015 from 2014.

Table 11-42 Marginal loss credits (Dollars (Millions)): 2009 through 2015[32]

	Loss Credit Accounting (Millions)			
	Total Energy Charges	Total Marginal Loss Charges	Adjustments	Total Loss Surplus
2009	($628.8)	$1,267.7	$0.8	$639.7
2010	($797.9)	$1,634.8	$0.0	$836.9
2011	($793.8)	$1,379.5	$0.9	$586.7
2012	($593.0)	$981.7	($2.0)	$386.7
2013	($687.6)	$1,035.3	($2.9)	$344.8
2014	($977.7)	$1,466.1	($6.3)	$482.1
2015	($627.4)	$968.7	($5.0)	$336.3

32 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.

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 or total loss costs, are equal to the load energy payments minus generation energy credits, plus explicit energy costs, incurred in both the Day-Ahead Energy Market and the balancing energy market, plus net inadvertent energy charges. Total energy costs can by more accurately thought of as net energy costs.

Total Energy Costs

The total energy cost for 2015 was -$627.4 million, which was comprised of load energy payments of $40,601.8 million, generation energy credits of $41,231.9 million, explicit energy costs of $0.0 million and inadvertent energy charges of $2.7 million. The monthly energy costs for 2015 ranged from -$141.5 million in February to -$28.9 million in December.

Table 11-43 shows total energy component costs and total PJM billing, for 2009 through 2015. The total energy component costs are net energy costs.

Table 11-43 Total PJM costs by energy component (Dollars (Millions)): 2009 through 2015[33]

	Energy Costs	Percent Change	Total PJM Billing	Percent of PJM Billing
2009	($629)	NA	$26,550	(2.4%)
2010	($798)	26.9%	$34,771	(2.3%)
2011	($794)	(0.5%)	$35,887	(2.2%)
2012	($593)	(25.3%)	$29,181	(2.0%)
2013	($688)	15.9%	$33,862	(2.0%)
2014	($978)	42.2%	$50,030	(2.0%)
2015	($627)	(35.8%)	$42,630	(1.5%)

Energy costs for 2009 through 2015 are shown in Table 11-44 and Table 11-45. Table 11-44 shows PJM energy costs by accounting category for 2009 through 2015 and Table 11-45 shows PJM energy costs by market category for 2009 through 2015.

Table 11-44 Total PJM energy costs by accounting category (Dollars (Millions)): 2009 through 2015

	Energy Costs (Millions)				
	Load Payments	Generation Credits	Explicit Costs	Inadvertent Charges	Total
2009	$42,535.2	$43,165.7	$0.0	$1.7	($628.8)
2010	$53,101.5	$53,886.9	$0.0	($12.6)	($797.9)
2011	$47,658.9	$48,481.0	$0.0	$28.3	($793.8)
2012	$37,471.3	$38,073.5	$0.0	$9.1	($593.0)
2013	$42,774.3	$43,454.6	$0.0	($7.4)	($687.6)
2014	$60,258.5	$61,232.0	$0.0	($4.2)	($977.7)
2015	$40,601.8	$41,231.9	$0.0	$2.7	($627.4)

33 The energy costs include net inadvertent charges.

Table 11-45 Total PJM energy costs by market category (Dollars (Millions)): 2009 through 2015

	Energy Costs (Millions)									
	Day-Ahead				Balancing					
	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
2009	$42,683.8	$43,351.2	$0.0	($667.4)	($148.5)	($185.5)	$0.0	$36.9	$1.7	($628.8)
2010	$53,164.9	$53,979.1	$0.0	($814.1)	($63.4)	($92.2)	$0.0	$28.8	($12.6)	($797.9)
2011	$48,144.9	$48,880.0	$0.0	($735.2)	($485.9)	($399.1)	$0.0	($86.9)	$28.3	($793.8)
2012	$37,641.2	$38,251.1	$0.0	($609.9)	($169.9)	($177.6)	$0.0	$7.7	$9.1	($593.0)
2013	$42,795.2	$43,628.9	$0.0	($833.7)	($20.9)	($174.4)	$0.0	$153.5	($7.4)	($687.6)
2014	$60,325.2	$61,668.9	$0.0	($1,343.7)	($66.7)	($436.9)	$0.0	$370.2	($4.2)	($977.7)
2015	$40,837.8	$41,595.7	$0.0	($757.9)	($236.0)	($363.8)	$0.0	$127.8	$2.7	($627.4)

Table 11-46 and Table 11-47 show the total energy costs for each virtual transaction type in 2015 and 2014. In 2015, generation were paid $28,339.7 million and demand paid $28,497.4 million in net energy payment. In 2014, generation were paid $42,531.8 million and demand paid $42,003.1 million in net energy payment.

Table 11-46 Total PJM energy costs by transaction type by market (Dollars (Millions)): 2015

	Energy Costs (Millions)								
	Day-Ahead				Balancing				
Transaction Type	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total
DEC	$1,303.1	$0.0	$0.0	$1,303.1	($1,297.8)	$0.0	$0.0	($1,297.8)	$5.3
Demand	$28,243.8	$0.0	$0.0	$28,243.8	$253.5	$0.0	$0.0	$253.5	$28,497.4
Demand Response	($1.9)	$0.0	$0.0	($1.9)	$1.8	$0.0	$0.0	$1.8	($0.1)
Export	$708.1	$0.0	$0.0	$708.1	$182.0	$0.0	$0.0	$182.0	$890.1
Generation	$0.0	$29,150.1	$0.0	($29,150.1)	$0.0	($810.4)	$0.0	$810.4	($28,339.7)
Import	$0.0	$451.9	$0.0	($451.9)	$0.0	$1,194.6	$0.0	($1,194.6)	($1,646.6)
INC	$0.0	$1,409.0	$0.0	($1,409.0)	$0.0	($1,372.5)	$0.0	$1,372.5	($36.5)
Internal Bilateral	$10,584.7	$10,584.7	$0.0	($0.0)	$624.5	$624.5	$0.0	$0.0	($0.0)
Total	$40,837.8	$41,595.7	$0.0	($757.9)	($236.0)	($363.8)	$0.0	$127.8	($630.1)

Table 11-47 Total PJM energy costs by transaction type by market (Dollars (Millions)): 2014

	Energy Costs (Millions)								
	Day-Ahead				Balancing				
Transaction Type	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total
DEC	$2,898.7	$0.0	$0.0	$2,898.7	($2,881.0)	$0.0	$0.0	($2,881.0)	$17.7
Demand	$40,504.8	$0.0	$0.0	$40,504.8	$1,498.3	$0.0	$0.0	$1,498.3	$42,003.1
Demand Response	($5.8)	$0.0	$0.0	($5.8)	$5.1	$0.0	$0.0	$5.1	($0.8)
Export	$1,188.3	$0.0	$0.0	$1,188.3	$619.2	$0.0	$0.0	$619.2	$1,807.5
Generation	$0.0	$43,777.0	$0.0	($43,777.0)	$0.0	($1,245.2)	$0.0	$1,245.2	($42,531.8)
Import	$0.0	$635.1	$0.0	($635.1)	$0.0	$1,593.7	$0.0	($1,593.7)	($2,228.8)
INC	$0.0	$1,517.1	$0.0	($1,517.1)	$0.0	($1,476.4)	$0.0	$1,476.4	($40.8)
Internal Bilateral	$15,739.6	$15,739.6	$0.0	($0.0)	$691.0	$691.0	$0.0	($0.0)	($0.0)
Total	$60,325.5	$61,668.9	$0.0	($1,343.4)	($67.4)	($436.9)	$0.0	$369.5	($973.9)

Monthly Energy Costs

Table 11-48 shows a monthly summary of energy costs by market type for 2014 and 2015. Marginal total energy costs in 2015 decreased from 2014. Monthly total energy costs in 2015 ranged from -$141.5 million in February to -$28.9 million in December.

Table 11-48 Monthly energy costs by market type (Dollars (Millions)): 2014 and 2015

	Energy Costs (Millions)							
	2014				2015			
	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)
Jul	($91.1)	$28.9	$0.7	($61.5)	($64.7)	$12.5	$0.1	($52.0)
Aug	($79.2)	$28.2	$0.5	($50.6)	($55.5)	$9.6	$0.1	($45.8)
Sep	($55.8)	$10.5	$0.7	($44.6)	($49.9)	$8.9	($0.0)	($41.1)
Oct	($47.5)	$8.3	$0.1	($39.1)	($41.8)	$9.1	($0.1)	($32.8)
Nov	($63.4)	$8.6	($0.4)	($55.2)	($37.0)	$7.7	$0.1	($29.1)
Dec	($58.3)	$9.0	($0.3)	($49.6)	($40.1)	$11.2	($0.0)	($28.9)
Total	($1,343.7)	$370.2	($4.2)	($977.7)	($757.9)	$127.8	$2.7	($627.4)

Figure 11-7 shows PJM monthly energy costs for 2009 through 2015.

Figure 11-7 PJM monthly energy costs (Millions): 2009 through 2015

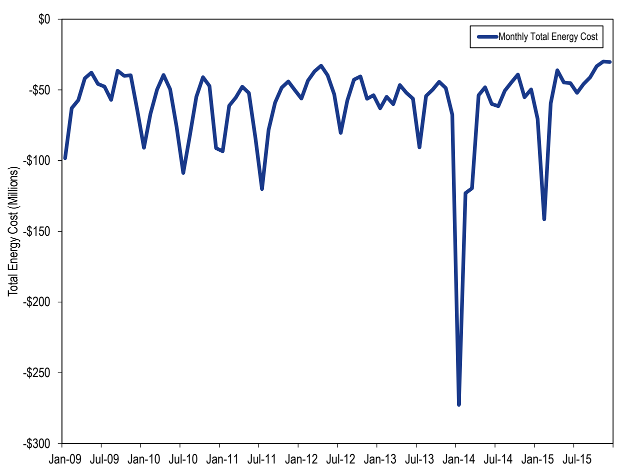


Table 11-49 and Table 11-50 show the monthly total energy costs for each virtual transaction type in 2015 and 2014. In 2015, DECs paid $1,303.1 million in energy credits in the day-ahead market, were paid $1,297.8 million in energy credits in the balancing energy market and paid $5.3 million in net payment for energy. In 2015, INCs were paid $1,409.0 million in energy credits in the day-ahead market, paid $1,372.5 million in energy cost in the balancing market and received $36.5 million in net payment for energy. In 2014, DECs paid $2,898.7 million in energy credits in the day-ahead market, were paid $2,881.0 million in energy credits in the balancing energy market and paid $17.7 million in net payment for energy. In 2014, INCs were paid $1,517.1 million in energy credits in the day-ahead market, paid $1,476.4 million in energy cost in the balancing energy market and received $40.8 million in net payment for energy.

Table 11-49 Monthly PJM energy costs by virtual transaction type and by market (Dollars (Millions)): 2015

	Energy Costs (Millions)						
	Day-Ahead			Balancing			
	DEC	INC	Virtual Total	DEC	INC	Virtual Total	Virtual Grand Total
Jan	$152.0	($122.5)	$29.5	($152.0)	$120.6	($31.3)	($1.8)
Feb	$224.2	($243.8)	($19.5)	($217.0)	$223.6	$6.6	($13.0)
Mar	$126.3	($140.1)	($13.8)	($137.0)	$148.6	$11.6	($2.2)
Apr	$78.8	($98.9)	($20.1)	($78.3)	$96.3	$18.0	($2.1)
May	$114.4	($128.4)	($14.0)	($108.5)	$119.8	$11.2	($2.8)
Jun	$98.2	($99.5)	($1.3)	($97.7)	$97.7	($0.0)	($1.4)
Jul	$88.8	($100.4)	($11.6)	($86.8)	$97.2	$10.4	($1.2)
Aug	$79.8	($95.8)	($16.0)	($76.7)	$92.2	$15.4	($0.6)
Sep	$99.1	($97.1)	$2.0	($107.4)	$102.0	($5.3)	($3.3)
Oct	$90.7	($98.1)	($7.4)	($85.6)	$92.7	$7.1	($0.3)
Nov	$74.2	($94.5)	($20.3)	($72.8)	$91.9	$19.2	($1.1)
Dec	$76.5	($89.9)	($13.4)	($77.9)	$89.9	$12.0	($1.4)
Total	$1,303.1	($1,409.0)	($105.9)	($1,297.8)	$1,372.5	$74.7	($31.1)

Table 11-50 Monthly PJM energy costs by virtual transaction type and by market (Dollars (Millions)): 2014

	Energy Costs (Millions)						
	Day-Ahead			Balancing			
	DEC	INC	Virtual Total	DEC	INC	Virtual Total	Virtual Grand Total
Jan	$568.1	($309.6)	$258.5	($525.2)	$271.0	($254.1)	$4.3
Feb	$288.0	($148.4)	$139.6	($283.6)	$144.8	($138.8)	$0.8
Mar	$331.5	($147.0)	$184.5	($364.2)	$159.1	($205.1)	($20.6)
Apr	$172.1	($86.0)	$86.1	($161.7)	$81.0	($80.6)	$5.5
May	$196.8	($126.8)	$70.0	($204.2)	$128.3	($75.9)	($5.9)
Jun	$204.3	($102.4)	$102.0	($211.8)	$104.7	($107.1)	($5.1)
Jul	$212.7	($109.3)	$103.4	($209.9)	$107.1	($102.9)	$0.5
Aug	$173.0	($88.8)	$84.1	($169.1)	$86.1	($83.1)	$1.1
Sep	$179.4	($85.3)	$94.2	($184.7)	$86.6	($98.1)	($4.0)
Oct	$182.0	($91.9)	$90.1	($189.2)	$94.6	($94.6)	($4.5)
Nov	$209.3	($122.9)	$86.4	($197.5)	$115.6	($81.8)	$4.5
Dec	$181.4	($98.7)	$82.7	($179.9)	$97.5	($82.4)	$0.2
Total	$2,898.7	($1,517.1)	$1,381.5	($2,881.0)	$1,476.4	($1,404.6)	($23.1)

Generation and Transmission Planning

Overview

Planned Generation and Retirements

- **Planned Generation.** As of December 31, 2015, 85,323.1 MW of capacity were in generation request queues for construction through 2024, compared to an average installed capacity of 187,744.2 MW as of December 31, 2015. Of the capacity in queues, 6,246.5 MW, or 7.3 percent, are uprates and the rest are new generation. Wind projects account for 15,698.8 MW of nameplate capacity or 18.4 percent of the capacity in the queues. Combined-cycle projects account for 56,827.9 MW of capacity or 66.6 percent of the capacity in the queues.

- **Generation Retirements.** As shown in Table 12-6, 27,689.0 MW have been, or are planned to be, retired between 2011 and 2020. Of that, 3,912.3 MW are planned to retire after 2015. In 2015, 9,859.7 MW were retired, of which 7,661.8 MW were coal units. The coal unit retirements were a result of low gas prices and the EPA's Mercury and Air Toxics Standards (MATS) for some units.

- **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 2,007.0 MW of coal fired steam capacity are currently in the queue, 60,717.7 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, 2,275 projects, representing 327,280.0 MW, have completed the queue process since its inception. Of those, 605 projects, 41,021.9 MW, went into service. Of the projects that entered the queue process, 87.5 percent of the MW withdrew prior to completion. Such projects may create barriers to entry for projects that would otherwise be completed by taking up queue positions, increasing interconnection costs and creating uncertainty.

- Feasibility, impact and facilities studies may be delayed for reasons including disputes with developers, circuit and network issues and retooling as a result of projects being withdrawn. The Earlier Queue Submittal Task Force (EQSTF) was established in August 2015 to address delays.[2]

- As defined in the tariff, a transmission owner (TO) is an "entity that owns, leases or otherwise has a possessory interest in facilities used for the transmission of electric energy in interstate commerce under the tariff."[3] 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 and when the transmission owner evaluates the interconnection requirements of new generation which is part of the same company as the transmission owner. There is also a potential conflict of interest when the transmission owner evaluates the interconnection requirements of a merchant transmission developer which is a competitor of the transmission owner.

1 See PJM, OATT Parts IV & VI.

2 See Earlier Queue Submittal Task Force at <http://www.pjm.com/committees-and-groups/task-forces/eqstf.aspx>

3 See PJM, OATT, Part I, § 1 "Definitions"

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 and operational performance under a range of anticipated system conditions, and the elimination of potential planning criteria violations in this area. On July 30, 2015, the PJM Board of Managers accepted PJM's recommendation to assign the project to LS Power, a merchant developer, PSEG, and PHI with a total cost estimate between $263M and $283M.[4,5]
- On October 25, 2012, Schedule 12 of the tariff and Schedule 6 of the OA were changed to address FERC Order No. 1000 reforms to the cost allocation requirements for local and regional transmission planning projects that were formerly defined in Order No. 890. The new approach was applied for the first time to the 2013 RTEP. Since then, some developers have raised concern with the cost allocations using the new solution based dfax method.

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 may have substantial impacts on energy and capacity markets. There is currently only one backbone project under development, 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 outage requests according to rules in PJM's Manual 3 to decide if the outage is on time, late, or past its deadline and whether or not they will allow the outage.[6]
- There were 19,593 transmission outage requests submitted for 2015. Of the requested outages, 79.2 percent were planned for five days or shorter and 4.9 percent were planned for longer than 30 days. Of the requested outages, 49.1 percent were late according to the rules in PJM's Manual 3.
- There were 19,614 transmission outage requests submitted for 2014. Of the requested outages, 79.8 percent were planned for five days or shorter and 5.4 percent were planned for longer than 30 days. Of the requested outages, 48.7 percent were late according to the rules in PJM's Manual 3.

Recommendations

The MMU recommends improvements to the planning process.

- The MMU recommends that PJM continue to incorporate the principle that the goal of transmission planning should be the incorporation of transmission investment decisions into market driven processes as much as possible. (Priority: Low. First reported 2001. Status: Not adopted.)
- 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 rules be implemented to require that project cost caps on new transmission projects be part of the evaluation of competing projects. (Priority: Low. New recommendation. Status: Not adopted.)

4 See "Artificial Island Recommendations," presented at the TEAC meeting on April 28, 2015 at <http://www.pjm.com/~/media/committees-groups/committees/teac/20150428-ai/20150428-artificial-island-recommendations.ashx>

5 See letter from Terry Boston concerning the Artificial Island Project at <http://www.pjm.com/~/media/documents/reports/board-statement-on-artificial-island-project.ashx>

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

- The MMU recommends that barriers to entry be addressed in a timely manner in order to help ensure that the capacity market will result in the entry of new capacity to meet the needs of PJM market participants and reflect the uncertainty and resultant risks in the cost of new entry used to establish the capacity market demand curve in RPM. (Priority: Low. First reported 2012. 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.[7] (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: Partially 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 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 RTEP. (Priority: Medium. First reported 2014. Status: Not adopted.)
- 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. First reported Q2, 2015. Status: Not adopted.)
- The MMU recommends consideration of changing the minimum distribution factor in the allocation from .01 to .00 and adding a threshold minimum impact on the load on the line. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that PJM reevaluate all transmission outage tickets as on time or late 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.)
- The MMU recommends that PJM draft a clear definition of the congestion analysis required for transmission outage requests to include in Manual 3 after appropriate review. (Priority: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM modify the rules to reduce or eliminate the approval of late outage requests submitted or rescheduled after the FTR auction bidding opening date. (Priority: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM not permit transmission owners to divide long duration outages into smaller segments to avoid complying with the requirements for long duration outages. (Priority: Low. New Recommendation. Status: Not adopted.)

7 See "Comments of the Independent Market Monitor for PJM," Docket No. ER12-1177-000, <http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Comments_ER12-1177-000_20120312.pdf>.

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 FERC 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 a 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 RTEP should build upon FERC 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 the RTEP process and be made available to all providers on equal terms.

There are currently no market incentives for transmission owners to submit and complete transmission outages in a timely and efficient manner. Requiring transmission owners to pay does not create an effective incentive when those payments are passed through to transmission customers. 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

Expected net revenues provide incentives to build new generation to serve PJM markets. 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 December 31, 2015, 85,323.1 MW of capacity were in generation request queues for construction through 2024, compared to an average installed capacity of 187,744.2 MW as of December 31, 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 2015, 3,808.4 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 2015

Year	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	3,808.4

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 AB2 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.[8] 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.[9]

Table 12-2 shows MW in queues by expected completion date and MW changes in the queues between December 31, 2014 and December 31, 2015, for ongoing projects, i.e. projects with the status active, under construction or suspended.[10] Projects that are already in service are not included here. The total MW in queues increased by 17,214.7 MW, or 25.3 percent, from 68,108.4 MW at the end of 2014. The change was the result of 36,808.3 MW in new projects entering the queue, 14,751.6 MW in projects withdrawing, and 3,899.3 MW going into service. The remaining difference is the result of projects adjusting their expected MW.[11]

Table 12-2 Queue comparison by expected completion year (MW): December 31, 2014 vs. December 31, 2015[12]

			Annual Change	
Year	As of 12/31/2014	As of 12/31/2015	MW	Percent
2014	4,604.5	0.0	(4,604.5)	NA
2015	13,992.5	9,641.9	(4,350.6)	(45.1%)
2016	16,974.2	15,085.7	(1,888.5)	(12.5%)
2017	14,075.1	12,442.3	(1,632.8)	(13.1%)
2018	12,587.0	13,403.6	816.6	6.1%
2019	3,051.0	21,461.3	18,410.3	85.8%
2020	1,152.0	11,444.3	10,292.3	89.9%
2021	78.2	0.0	(78.2)	NA
2022	0.0	250.0	250.0	100.0%
2024	1,594.0	1,594.0	0.0	0.0%
Total	68,108.4	85,323.1	17,214.7	25.3%

Table 12-3 shows the yearly project status changes in more detail and how scheduled queue capacity has changed between December 31, 2014, and December 31, 2015. For example, 36,808.3 MW entered the queue in 2015, 30,806.2 MW of which are currently active and 5,823.2 MW of which were withdrawn before the year ended. Of the total 41,729.0 MW marked as active at the beginning of the year, 8,005.7 MW were withdrawn, 19,783.8 MW started construction, and 602.1 MW went into service by the end of the year. The Under Construction column shows that 927.6 MW came out of suspension and 11,645.5 MW began construction in

8 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>.

9 PJM does not track the duration of suspensions or PJM termination of projects.

10 Expected completion dates are entered when the project enters the queue. Actual completion dates are generally different than expected completion dates.

11 PJM put a new planning system database into production in late 2015. There are some minor differences in reported data between this report and 2014 as a result.

12 Wind and solar capacity in Table 12-2 through Table 12-5 have not been adjusted to reflect derating.

2015, in addition to the 15,690.1 MW of capacity that maintained the status under construction from the previous year.

Table 12-3 Change in project status (MW): December 31, 2014 vs. December 31, 2015

		Status at 12/31/2015				
Status at 12/31/2014	Total at 12/31/2014	Active	Suspended	Under Construction	In Service	Withdrawn
(Entered in 2015)		30,806.2	0.0	10.9	168.0	5,823.2
Active	41,729.0	19,783.8	33.9	11,645.5	602.1	8,005.7
Suspended	4,751.8	200.0	3,020.2	927.6	0.0	544.0
Under Construction	21,627.6	628.0	1,644.9	15,690.1	3,129.2	378.8
In Service	38,341.7	932.1	0.0	0.0	37,122.7	0.0
Withdrawn	274,630.6	0.0	0.0	0.0	0.0	271,506.4
Total at 12/31/2015		52,350.1	4,698.9	28,274.1	41,021.9	286,258.0

Table 12-4 Capacity in PJM queues (MW): At December 31, 2015[13]

Queue	Active	In-Service	Under Construction	Suspended	Withdrawn	Total
A Expired 31-Jan-98	0.0	8,103.0	0.0	0.0	17,252.0	25,355.0
B Expired 31-Jan-99	0.0	4,645.5	0.0	0.0	14,620.7	19,266.2
C Expired 31-Jul-99	0.0	531.0	0.0	0.0	3,470.3	4,001.3
D Expired 31-Jan-00	0.0	850.6	0.0	0.0	7,182.0	8,032.6
E Expired 31-Jul-00	0.0	795.2	0.0	0.0	8,021.8	8,817.0
F Expired 31-Jan-01	0.0	52.0	0.0	0.0	3,092.5	3,144.5
G Expired 31-Jul-01	0.0	1,189.6	0.0	0.0	17,961.8	19,151.4
H Expired 31-Jan-02	0.0	702.5	0.0	0.0	8,421.9	9,124.4
I Expired 31-Jul-02	0.0	103.0	0.0	0.0	3,728.4	3,831.4
J Expired 31-Jan-03	0.0	40.0	0.0	0.0	846.0	886.0
K Expired 31-Jul-03	0.0	98.9	0.0	0.0	485.2	584.1
L Expired 31-Jan-04	0.0	256.5	0.0	0.0	4,033.7	4,290.2
M Expired 31-Jul-04	186.0	318.8	150.0	0.0	3,555.6	4,210.4
N Expired 31-Jan-05	0.0	2,398.8	38.0	0.0	8,090.3	10,527.0
O Expired 31-Jul-05	0.0	1,668.2	437.0	0.0	5,466.8	7,572.0
P Expired 31-Jan-06	190.5	3,064.7	62.5	210.0	5,110.5	8,638.2
Q Expired 31-Jul-06	0.0	3,147.9	1,594.0	0.0	9,791.7	14,533.6
R Expired 31-Jan-07	160.0	1,886.4	488.3	800.0	19,420.6	22,755.3
S Expired 31-Jul-07	256.0	3,512.7	246.9	120.0	12,396.5	16,532.0
T Expired 31-Jan-08	550.0	1,779.0	2,168.0	300.0	22,738.3	27,535.3
U Expired 31-Jan-09	668.0	837.3	681.9	320.0	30,829.6	33,336.8
V Expired 31-Jan-10	1,483.7	1,824.1	919.1	550.0	12,036.4	16,813.3
W Expired 31-Jan-11	1,323.0	1,918.6	1,359.7	1,410.0	18,066.0	24,077.3
X Expired 31-Jan-12	2,944.0	436.9	8,962.7	366.8	17,634.0	30,344.5
Y Expired 30-Apr-13	1,705.1	533.8	4,579.6	592.5	18,354.7	25,765.5
Z Expired 30-Apr-14	4,081.3	293.7	4,393.5	22.4	5,652.8	14,443.7
AA1 Expired 31-Oct-14	7,651.3	33.4	2,182.1	7.3	2,128.3	12,002.4
AA2 Expired 30-Apr-15	11,874.6	0.0	7.5	0.0	4,195.8	16,077.9
AB1 Expired 31-Oct-15	18,802.9	0.0	3.4	0.0	1,673.9	20,480.2
AB2 Through 31-Dec-15	473.7	0.0	0.0	0.0	0.0	473.7
Total	52,350.1	41,021.9	28,274.1	4,698.9	286,258.0	412,129.4

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 December 31, 2015, there are 85,323.1 MW of capacity in queues that are not yet in service, of which 5.5 percent are suspended, 33.1 percent are under construction and 61.4 percent have not begun construction.

13 Projects listed as partially in-service are counted as in-service for the purposes of this analysis.

Distribution of Units in the Queues

Table 12-5 shows the projects under construction, suspended, or active, by unit type, and control zone.[14] As of December 31, 2015, 85,323.1 MW of capacity were in generation request queues for construction through 2024, compared to 79,603.8 MW at September 30, 2015.[15] Table 12-5 also shows the planned retirements for each zone.

Table 12-5 Queue capacity by LDA, control zone and fuel (MW): At December 31, 2015[16]

LDA	Zone	BioMass	CC	CT	Diesel	Fuel Cell	Hydro	Nuclear	Solar	Steam	Storage	Wind	Total Queue Capacity	Planned Retirements
EMAAC	AECO	0.0	1,746.0	239.5	0.0	1.5	0.0	0.0	60.2	0.0	21.0	373.0	2,441.2	8.0
	DPL	0.0	742.0	7.0	2.0	0.0	0.0	0.0	405.1	0.0	20.0	749.6	1,925.7	34.0
	JCPL	0.0	3,376.2	0.0	0.6	0.0	0.0	0.0	482.6	0.0	180.0	0.0	4,039.4	614.5
	PECO	0.0	3,626.0	0.0	8.6	0.0	0.0	50.0	0.0	0.0	40.8	0.0	3,725.4	50.8
	PSEG	0.0	1,727.0	671.0	10.6	0.0	0.0	0.0	119.6	24.0	2.0	0.0	2,554.2	611.0
	RECO	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
	EMAAC Total	0.0	11,217.2	917.5	21.8	1.5	0.0	50.0	1,067.5	24.0	263.8	1,122.6	14,685.9	1,318.3
SWMAAC	BGE	0.0	0.0	256.0	30.3	0.0	0.4	0.0	23.1	132.0	20.1	0.0	461.9	209.0
	Pepco	0.0	2,642.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,642.6	1,204.0
	SWMAAC Total	0.0	2,642.6	256.0	30.3	0.0	0.4	0.0	23.1	132.0	20.1	0.0	3,104.5	1,413.0
WMAAC	Met-Ed	0.0	2,311.5	34.1	0.0	0.0	0.0	0.0	3.0	0.0	0.0	0.0	2,348.6	0.0
	PENELEC	0.0	3,664.5	1,420.8	181.7	0.0	40.0	0.0	13.5	0.0	40.0	493.3	5,853.8	0.0
	PPL	16.0	7,195.0	19.9	24.9	0.0	0.0	0.0	16.0	0.0	30.0	466.5	7,768.3	0.0
	WMAAC Total	16.0	13,171.0	1,474.8	206.6	0.0	40.0	0.0	32.5	0.0	70.0	959.8	15,970.7	0.0
Non-MAAC	AEP	0.0	7,234.0	142.0	13.0	0.0	134.0	102.0	119.2	211.0	114.0	6,602.0	14,671.2	0.0
	AP	0.0	4,335.4	0.0	132.8	0.0	0.0	0.0	354.8	1,726.5	73.0	1,251.8	7,874.3	0.0
	ATSI	0.0	5,947.0	0.0	65.3	0.0	0.0	0.0	0.0	0.0	32.5	518.0	6,562.8	94.0
	ComEd	0.0	4,949.3	590.0	58.7	0.0	22.7	80.0	0.0	27.0	111.1	3,472.5	9,311.3	510.0
	DAY	1.9	0.0	0.0	0.0	0.0	0.0	0.0	25.9	12.0	20.0	300.0	359.8	0.0
	DEOK	0.0	513.0	0.0	6.4	0.0	112.0	0.0	125.0	50.0	10.0	0.0	816.4	0.0
	DLCO	0.0	205.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20.0	0.0	225.0	0.0
	Dominion	62.5	5,463.4	60.0	14.0	0.0	0.0	1,594.0	1,891.3	0.0	34.0	1,472.1	10,591.3	325.0
	EKPC	0.0	1,150.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,150.0	149.0
	Non-MAAC Total	64.4	29,797.1	792.0	290.2	0.0	268.7	1,776.0	2,516.2	2,026.5	414.6	13,616.4	51,562.1	1,078.0
Total		80.4	56,827.9	3,440.3	548.9	1.5	309.1	1,826.0	3,639.3	2,182.5	768.5	15,698.8	85,323.1	3,809.3

A significant shift in the distribution of unit types within the PJM footprint continues to develop as natural gas fired units enter the queue and steam units retire. While 60,717.7 MW of gas fired capacity are in the queue, there are only 2,007.0 MW of coal fired steam capacity in the queue. The only new coal project currently in the queue is the new Hatfield unit, with 1,710 MW of capacity. This project, which entered the queue in October 2014 and is already under construction, is intended to replace three coal units retired in October 2013 at the same location. With respect to retirements, 2,467.0 MW of coal fired steam capacity and 282.8 MW of natural gas capacity are slated for deactivation between now and 2020. 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.

14 Unit types designated as reciprocating engines are classified as diesel.

15 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 15,698.8 MW of wind resources and 3,639.3 MW of solar resources, the 85,323.1 MW currently active in the queue would be reduced to 69,408.8 MW.

16 This data includes only projects with a status of active, under-construction, or suspended.

Planned Retirements

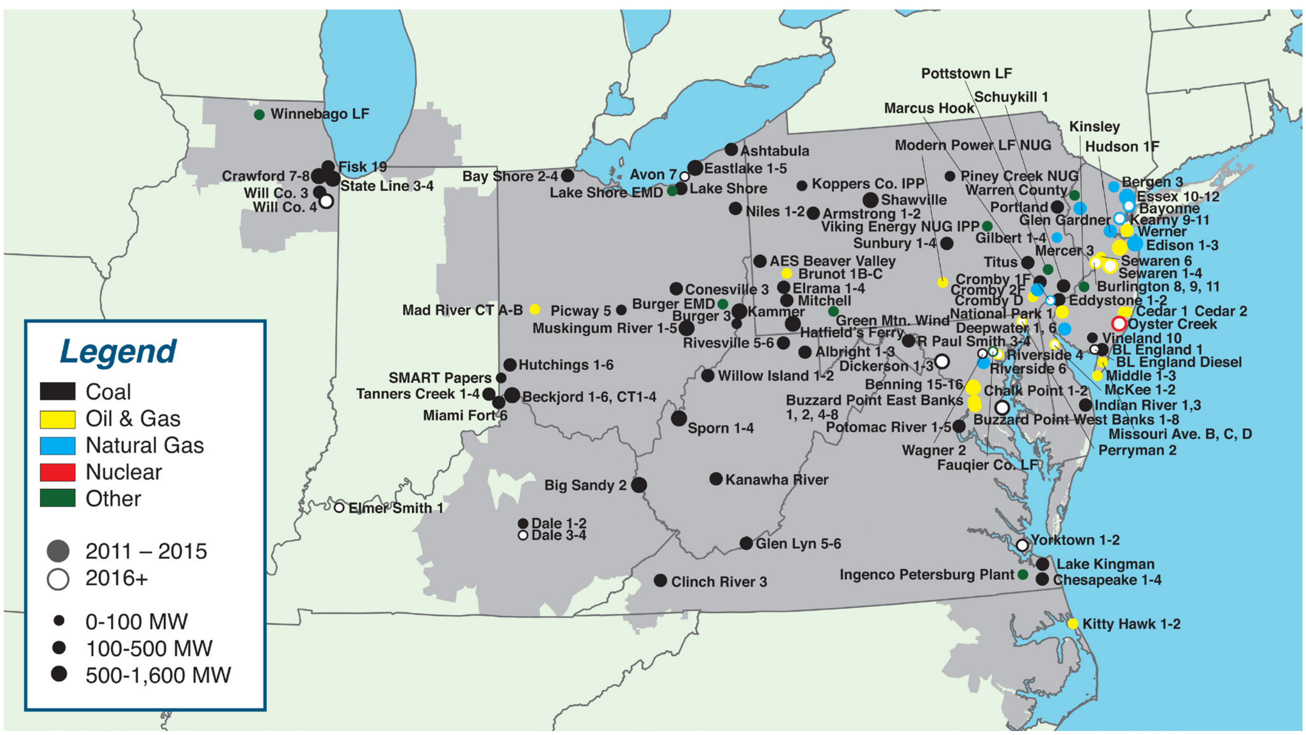
As shown in Table 12-6, 27,689.0 MW have been, or are planned to be, retired between 2011 and 2020.[17] Of that, 3,912.3 MW are planned to retire after 2015. In 2015, 9,859.7 MW were retired, of which 7,661.8 MW were coal units. The coal unit retirements were a result of low gas prices and the EPA's Mercury and Air Toxics Standards (MATS) for some units.

Table 12-6 Summary of PJM unit retirements by fuel (MW): 2011 through 2020

	Coal	Diesel	Heavy Oil	Kerosene	Landfill Gas	Light Oil	Natural Gas	Nuclear	Wind	Wood Waste	Total
Retirements 2011	543.0	0.0	0.0	0.0	0.0	63.7	522.5	0.0	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	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	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	0.0	2,970.3
Retirements 2015	7,661.8	10.3	0.0	644.2	2.0	212.0	1,319.0	0.0	10.4	0.0	9,859.7
Planned Retirements Post-2015	2,467.0	59.0	108.0	0.0	2.0	0.0	661.8	614.5	0.0	0.0	3,912.3
Total	21,596.6	122.2	274.0	828.2	23.1	1,148.7	3,047.3	614.5	10.4	24.0	27,689.0

A map of the retirements between 2011 and 2020 is shown in Figure 12-1.

Figure 12-1 Map of PJM unit retirements: 2011 through 2020



17 See PJM "Generator Deactivation Summary Sheets," at <http://www.pjm.com/planning/generation-deactivation/gd-summaries.aspx> (February 23, 2016).

The list of pending retirements is shown in Table 12-7.

Table 12-7 Planned retirement of PJM units: as of December 31, 2015

Unit	Zone	ICAP (MW)	Fuel	Unit Type	Projected Deactivation Date
Perryman 2	BGE	51.0	Diesel	Combustion Turbine	01-Jan-16
Fauquier County Landfill	Dominion	2.0	Diesel	Diesel	29-Feb-16
Yorktown 1-2	Dominion	323.0	Coal	Steam	31-Mar-16
Dale 3-4	EKPC	149.0	Coal	Steam	16-Apr-16
Avon Lake 7	ATSI	94.0	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
Will County 4	ComEd	510.0	Coal	Steam	31-May-18
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
Elmer Smith U1	External	52.0	Coal	Steam	01-Jun-19
Oyster Creek	JCPL	614.5	Nuclear	Nuclear	31-Dec-19
Wagner 2	BGE	135.0	Coal	Steam	01-Jun-20
Total		3,912.3			

Table 12-8 shows the capacity, average size, and average age of units retiring in PJM, from 2011 through 2020, while Table 12-9 shows these retirements by state. The majority, 78.0 percent, of all MW retiring during this period are coal steam units. These units have an average age of 56.0 years and an average size of 166.1 MW. Half of them, 50.5 percent, are located in either Ohio or Pennsylvania. Retirements have generally consisted of smaller subcritical coal steam units and those without adequate environmental controls to remain viable beyond 2015.

Table 12-8 Retirements by fuel type: 2011 through 2020

	Number of Units	Avg. Size (MW)	Avg. Age at Retirement (Years)	Total MW	Percent
Coal	130	166.1	56.0	21,596.6	78.0%
Diesel	7	17.5	42.7	122.2	0.4%
Heavy Oil	4	68.5	57.5	274.0	1.0%
Kerosene	20	41.4	45.5	828.2	3.0%
Landfill Gas	6	3.9	15.8	23.1	0.1%
Light Oil	15	76.6	43.8	1,148.7	4.1%
Natural Gas	51	59.8	46.3	3,047.3	11.0%
Nuclear	1	614.5	50.0	614.5	2.2%
Wind	1	10.4	15.0	10.4	0.0%
Wood Waste	2	12.0	23.5	24.0	0.1%
Total	237	116.8	50.4	27,689.0	100.0%

Table 12-9 Retirements (MW) by fuel type and state: 2011 through 2020

State	Coal	Diesel	Heavy Oil	Kerosene	Landfill Gas	Light Oil	Natural Gas	Nuclear	Wind	Wood Waste	Total
DC	0.0	0.0	0.0	0.0	0.0	788.0	0.0	0.0	0.0	0.0	788.0
DE	254.0	0.0	34.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	288.0
IL	2,134.0	0.0	0.0	0.0	6.4	0.0	0.0	0.0	0.0	0.0	2,140.4
IN	982.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	982.0
KY	1,047.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,047.0
MD	1,454.0	51.0	74.0	0.0	0.0	0.0	115.0	0.0	0.0	0.0	1,694.0
NC	0.0	0.0	0.0	0.0	0.0	31.0	0.0	0.0	0.0	0.0	31.0
NJ	136.0	8.0	0.0	828.2	4.7	212.0	2,680.5	614.5	0.0	0.0	4,483.9
OH	5,752.6	60.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5,812.9
PA	5,145.0	0.0	166.0	0.0	10.0	117.7	251.8	0.0	10.4	24.0	5,724.9
VA	2,051.0	2.9	0.0	0.0	2.0	0.0	0.0	0.0	0.0	0.0	2,055.9
WV	2,641.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,641.0
Total	21,596.6	122.2	274.0	828.2	23.1	1,148.7	3,047.3	614.5	10.4	24.0	27,689.0

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
AES Corporation	AES Beaver Valley	124.0	Coal	DLCO	28	01-Sep-15
First Energy	Burger EMD	6.3	Diesel	ATSI	43	18-Sep-15
NextEra Energy, Inc.	Arnold (Green Mountain) Wind Farm	10.4	Wind	PENELEC	15	05-Nov-15
Waste Management	Pottstown LF (Moser)	2.0	Landfill Gas	PECO	24	07-Dec-15
Total		9,859.7				

Generation Mix

As of December 31, 2015, PJM had an installed capacity of 187,744.2 MW (Table 12-11). This measure differs from capacity market installed capacity because it includes energy-only units, excludes all external units, and uses nameplate values for solar and wind resources.

Table 12-11 Existing PJM capacity: At December 31, 2015 (By zone and unit type (MW))[18]

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	2,103.2	32,807.2
AP	1,129.0	1,214.9	47.9	0.0	129.2	0.0	36.1	5,409.0	27.4	1,088.5	9,082.0
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	76.0	2,431.9	28,640.4
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	10.0	0.0	4,441.2
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	134.7	7,890.0	0.0	0.0	24,717.5
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
JCPL	2,682.5	763.1	19.9	0.0	400.0	614.5	104.3	10.0	0.0	0.0	4,594.3
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	52.2	0.0	512.8	0.0	0.0	6,793.5	0.0	930.9	8,696.9
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	3,846.3	1,132.0	11.1	0.0	5.0	3,493.0	134.0	2,050.1	2.0	0.0	10,673.5
RECO	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	31,932.0	28,865.9	824.1	30.0	8,152.1	33,732.1	482.9	76,763.0	180.4	6,781.7	187,744.2

Figure 12-2 and Table 12-12 show the age of PJM generators by unit type. Units older than 40 years comprise 66,781.6 MW, or 35.6 percent, of the total capacity of 187,744.2 MW.

Table 12-12 PJM capacity (MW) by age (years): At December 31, 2015

Age (years)	CC	CT	Diesel	Fuel Cell	Hydroelectric	Nuclear	Solar	Steam	Storage	Wind	Total
Less than 20	27,263.5	21,457.0	563.4	30.0	232.8	0.0	482.9	4,601.9	180.4	6,781.7	61,593.6
20 to 40	4,226.5	2,913.9	88.8	0.0	3,557.2	22,893.9	0.0	25,688.7	0.0	0.0	59,369.0
40 to 60	442.0	4,495.0	169.9	0.0	3,010.0	10,838.2	0.0	44,835.9	0.0	0.0	63,791.0
More than 60	0.0	0.0	2.0	0.0	1,352.1	0.0	0.0	1,636.5	0.0	0.0	2,990.6
Total	31,932.0	28,865.9	824.1	30.0	8,152.1	33,732.1	482.9	76,763.0	180.4	6,781.7	187,744.2

Figure 12-2 PJM capacity (MW) by age (years): At December 31, 2015

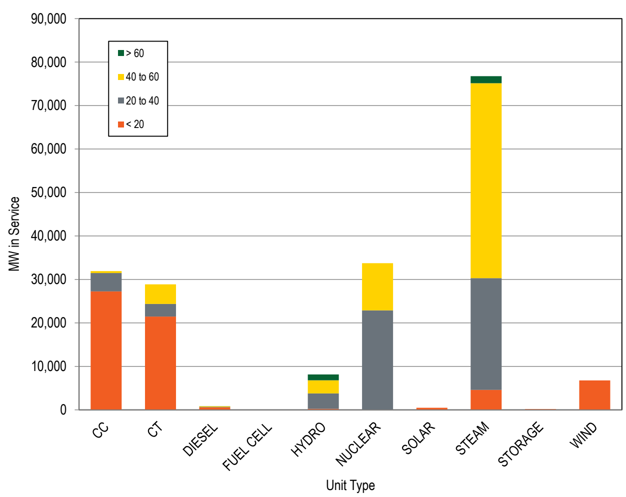


Table 12-13 shows the effect that expected retirements and new generation in the queues would have on the existing generation mix five years from now. The planned additions reflect the historical rates of completion, as shown in

18 The capacity described in this section refers to all nameplate installed capacity in PJM, regardless of whether the capacity entered the RPM auction. This table previously included external units.

Table 12-16. While there are currently 85,323.1 MW in the queue, historical patterns indicate that we can expect 36,713.3 MW to go into service, based on current status in the queue process. Even though 66,781.6 MW of the total capacity are more than 40 years old, only 3,912.3 MW of these 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 in SWMAAC is currently 63.0 percent steam, which will be reduced to 46.2 percent by 2020 as a result of the addition of an expected 2,047.0 MW of planned CC capacity. The percentage of CC capacity would increase from 2.2 percent to 19.7 percent of capacity in SWMAAC in 2020. CC and CT generators would comprise 38.2 percent of SWMAAC capacity in 2020. In PJM as a whole, the percentage of capacity from renewables increases from 8.3 percent to 11.7 percent by 2020.

Table 12-13 Expected capacity (MW) in five years: as of December 31, 2015[19]

LDA	Unit Type	Current Generator Capacity	Percent of Area Total	Planned Additions	Planned Retirements	Estimated Capacity in 5 Years	Percent of Area Total
EMAAC	Combined Cycle	12,138.2	35.9%	3,923.7	0.0	16,061.9	42.2%
	Combustion Turbine	5,059.2	14.9%	277.3	0.0	5,336.5	14.0%
	Diesel	152.6	0.5%	11.9	8.0	156.5	0.4%
	Fuel Cell	30.0	0.1%	0.2	0.0	30.2	0.1%
	Hydroelectric	2,047.0	6.0%	0.0	0.0	2,047.0	5.4%
	Nuclear	8,654.3	25.6%	30.7	614.5	8,070.5	21.2%
	Solar	287.0	0.8%	656.2	0.0	943.2	2.5%
	Steam	5,475.1	16.2%	16.9	695.8	4,796.2	12.6%
	Storage	3.0	0.0%	67.4	0.0	70.4	0.2%
	Wind	7.5	0.0%	563.6	0.0	571.1	1.5%
	Total	33,853.9	100.0%	5,547.9	1,318.3	38,083.5	100.0%
SWMAAC	Combined Cycle	230.0	2.2%	2,047.0	0.0	2,277.0	19.7%
	Combustion Turbine	1,931.7	18.3%	205.9	0.0	2,137.6	18.5%
	Diesel	28.3	0.3%	24.4	0.0	52.7	0.5%
	Hydroelectric	0.0	0.0%	0.3	0.0	0.3	0.0%
	Nuclear	1,716.0	16.3%	0.0	0.0	1,716.0	14.9%
	Solar	0.0	0.0%	18.5	0.0	18.5	0.2%
	Steam	6,644.6	63.0%	106.1	1,413.0	5,337.7	46.2%
	Storage	0.0	0.0%	2.6	0.0	2.6	0.0%
	Total	10,550.6	100.0%	2,404.7	1,413.0	11,542.4	100.0%
WMAAC	Biomass	0.0	0.0%	12.9	0.0	12.9	0.0%
	Combined Cycle	3,918.9	16.7%	5,493.1	0.0	9,412.0	31.6%
	Combustion Turbine	1,430.2	6.1%	264.5	0.0	1,694.7	5.7%
	Diesel	149.1	0.6%	43.9	0.0	193.0	0.6%
	Hydroelectric	1,238.4	5.3%	28.1	0.0	1,266.5	4.2%
	Nuclear	3,325.0	14.2%	0.0	0.0	3,325.0	11.2%
	Solar	15.0	0.1%	26.1	0.0	41.1	0.1%
	Steam	12,163.4	52.0%	0.0	0.0	12,163.4	40.8%
	Storage	20.0	0.1%	17.5	0.0	37.5	0.1%
	Wind	1,150.6	4.9%	505.2	0.0	1,655.8	5.6%
	Total	23,410.6	100.0%	6,391.3	0.0	29,801.8	100.0%
RTO	Biomass	0.0	0.0%	51.8	0.0	51.8	0.0%
	Combined Cycle	15,644.9	13.0%	12,073.5	0.0	27,718.4	19.6%
	Combustion Turbine	20,444.8	17.0%	302.9	0.0	20,747.7	14.7%
	Diesel	494.1	0.4%	130.1	2.0	622.2	0.4%
	Hydroelectric	4,866.7	4.1%	193.4	0.0	5,060.1	3.6%
	Nuclear	20,036.8	16.7%	83.3	0.0	20,120.1	14.3%
	Solar	181.0	0.0	767.1	0.0	948.1	0.7%
	Steam	52,479.9	43.8%	1,522.1	1,128.0	52,874.0	37.5%
	Storage	157.4	0.1%	111.6	0.0	269.0	0.2%
	Wind	5,623.6	4.7%	7,133.7	0.0	12,757.3	9.0%
	Total	119,929.2	100.0%	22,369.5	1,130.0	141,168.6	100.0%
Total		187,744.2		36,713.3	3,861.3	220,596.3	

19 Percentages shown in Table 12-13 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.[20] 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 due to these and other process improvements, the study backlog has been significantly reduced.[21] The Earlier Queue Submittal Task Force (EQSTF) was established in August 2015, to further address the issue.[22]

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.

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.[23] The impact and facilities studies are performed using the full amount of planned generation in the queues. The actual withdrawal rates are shown in Table 12-15 and Table 12-16.

Table 12-15 shows the milestone status when projects were withdrawn, for all withdrawn projects. Of the projects withdrawn, 47.5 percent were withdrawn before the system 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.[24,25] Withdrawing at or beyond this point is uncommon; only 221 projects, or 13.2 percent, of all projects withdrawn were withdrawn after reaching this milestone.

Table 12-15 Last milestone completed at time of withdrawal: January 1, 1997 through December 31, 2015

Milestone Completed	Projects Withdrawn	Percent
Never Started	173	10.4%
Feasibility Study	620	37.1%
System Impact Study	548	32.8%
Facilities Study	108	6.5%
Interconnection Service Agreement (ISA)	37	2.2%
Wholesale Market Participation Agreement (WMPA)	128	7.7%
Construction Service Agreement (CSA) or beyond	56	3.4%
Total	1,670	100.0%

Table 12-16 shows, by MW, the rate at which projects drop out of the queue as they move through the process, as well as the rate at which projects eventually go into service. Out of 327,280.0 nameplate MW that entered the queue, 41,021.9, 12.5 percent, went into service, while the remaining 286,258.0 MW withdrew at some point. Of the withdrawals, 39.6 percent happened after the feasibility study was completed.

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

20 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>.

21 See presentation by Dave Egan to the Planning Committee PJM, at <http://www.pjm.com/~/media/committees-groups/committees/pc/20150611/20150611-item-09-queue-status-update.ashx>

22 See Earlier Queue Submittal Task Force at <http://www.pjm.com/committees-and-groups/task-forces/eqstf.aspx>

23 See PJM Manual 14B. "PJM Region Transmission Planning Process," Revision 30 (February 26, 2015), p.70.

24 "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.

25 See PJM. "Manual 14C: Generation and Transmission Interconnection Facility Construction," Revision 08 (December 20, 2012), p.22.

Table 12-16 Completed (withdrawn or in service) queue MW: January 1, 1997 through December 31, 2015

Milestone Completed	MW in Queue	Percent of Total in Queue	MW Withdrawn	Percent of Total Withdrawn	Percent that Go In Service
Enter Queue	327,280.0	100.0%	27,566.5	9.6%	12.5%
Feasibility Study	299,713.5	91.6%	145,294.4	50.8%	13.7%
System Impact Study	154,419.1	47.2%	94,994.6	33.2%	26.6%
Facilities Study	59,424.6	18.2%	1,000.1	0.3%	69.0%
ISA/WMPA	58,424.5	17.9%	7,408.2	2.6%	70.2%
Construction	51,016.3	15.6%	9,994.4	3.5%	80.4%
In-Service	41,021.9	12.5%	0.0	0.0%	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 933 days, or 2.6 years, between entering a queue and going into service. Nuclear and wind projects tend to take longer to go into service averaging 1,468 and 1,474 days. The average time to go into service for all other fuel types is 703 days. For withdrawn projects, there is an average time of 667 days between entering a queue and withdrawing.

Table 12-17 Average project queue times (days): At December 31, 2015

Status	Average (Days)	Standard Deviation	Minimum	Maximum
Active	1,004	751	21	4,179
In-Service	933	688	1	4,024
Suspended	2,160	830	545	4,149
Under Construction	1,653	991	116	6,380
Withdrawn	667	667	7	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 658 projects in the queue as of December 31, 2015, 96 had a completed feasibility study and 227 were under construction.

Table 12-18 PJM generation planning summary: At December 31, 2015

Milestone Completed	Number of Projects	Percent of Total Projects	Average Days	Maximum Days
Not Started	138	21.0%	714	1,828
Feasibility Study	96	14.6%	764	2,555
Impact Study	89	13.5%	1,274	3,745
Facilities Study	15	2.3%	1,585	3,279
Interconnection Service Agreement (ISA)	24	3.6%	1,502	3,653
Wholesale Market Participation Agreement (WMPA)	3	0.5%	1,067	2,167
Construction Service Agreement (CSA)	11	1.7%	2,663	4,179
Under Construction	227	34.5%	1,653	6,380
Suspended	55	8.4%	2,160	4,149
Total	658	100.0%		

The time it takes to complete a study depends on the backlog and the number of projects in the queue, but not on the size of the project. Table 12-19 shows the number of projects that entered the queue by year. The last two years show an increase in queue entries, primarily by renewable projects (solar, hydro, storage, biomass, wind). Of the 495 projects entered in 2014 and 2015, 314, 63.4 percent, were renewable.

Table 12-19 Number of projects entered in the queue as of December 31, 2015

	Fuel Group			
Year Entered	Nuclear	Renewable	Traditional	Grand Total
1997	2	1	10	13
1998	0	0	18	18
1999	1	5	83	89
2000	2	3	75	80
2001	4	6	81	91
2002	3	14	32	49
2003	1	34	17	52
2004	4	17	32	53
2005	3	77	52	132
2006	9	77	71	157
2007	9	68	142	219
2008	3	114	99	216
2009	10	113	50	173
2010	5	381	55	441
2011	6	264	78	348
2012	2	73	80	155
2013	1	78	72	151
2014	0	122	68	190
2015	0	192	113	305
Grand Total	65	1,639	1,228	2,932

Even though renewable projects comprise the majority of projects entered in the queue, as well as what is currently active in the queue, renewable projects only account for 24.0 percent of the nameplate MW currently active in the queue (Table 12-20).

Table 12-20 Queue details by fuel group: At December 31, 2015

Fuel Group	Number of Projects	Percent of Projects	MW	Percent MW
Nuclear	10	1.5%	1,826.0	2.1%
Renewable	405	61.6%	20,496.0	24.0%
Traditional	243	36.9%	63,001.1	73.8%
Total	658	100.0%	85,323.1	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.[26] The coordination begins with PJM identifying transmission issues resulting from the generation projects. The TOs perform the studies and provide the mitigation requirements. 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) and any other affected TOs are 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.[27]

Of 658 active projects analyzed, the developer and TO are part of the same company for 52 of the projects, or 11,478.2 MW of a total 85,323.1 MW, or 13.5 percent. 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 12-21 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 nine related projects which account for 5,902.1 MW, 55.7 percent of the total MW currently in the queue in the Dominion Zone. Of that, 4,296.1 MW (72.8 percent) are natural gas projects, 1,594.0 MW are nuclear, and 12 MW are wind. Renewable projects comprise 3,461.9 MW, 73.8 percent, of unrelated projects in the queue in the Dominion Zone. In contrast, the AEP Zone has 12 related projects, but they account for only 2.5 percent of its total MW currently in the queue.

Table 12-21 Summary of project developer relationship to TO parent company

	Number of Projects			Total MW		
Parent Company	Related	Unrelated	Percent Related	Related	Unrelated	Percent Related
AEP	12	82	12.8%	370.2	14,301.0	2.5%
AES	3	5	37.5%	34.5	325.3	9.6%
DLCO	0	2	0.0%	0.0	225.0	0.0%
Dominion	9	65	12.2%	5,902.1	4,689.2	55.7%
Duke	1	6	14.3%	50.0	766.4	6.1%
Exelon	15	96	13.5%	2,646.0	10,852.6	19.6%
First Energy	1	210	0.5%	1,710.0	24,968.8	6.4%
Pepco	0	85	0.0%	0.0	7,009.5	0.0%
PPL	0	30	0.0%	0.0	7,768.3	0.0%
PSEG	11	24	31.4%	765.4	1,788.8	30.0%
EKPC	0	1	0.0%	0.0	1,150.0	0.0%
Total	52	606	7.9%	11,478.2	73,844.9	13.5%

These projects are shown by fuel type in Table 12-22. Natural gas generators comprise 66.4 percent of the total related MW in this table. Developers of coal and nuclear projects are almost entirely related to the TO, with 93.6 percent and 100.0 percent of MW. Developers are related to the TO for 12.6 percent of the natural gas project MW in the queue, 8.1 percent of the storage project MW, and 11.0 percent of the hydro project MW. All other fuel types projects have no more than 1.0 percent of MW in development related to the TO.

26 See PJM, OATT, Part VI, § 210

27 See PJM. "Manual 14A: "Generation and Transmission Interconnection Process," Revision 17, (January 22, 2015),<http://www.pjm.com/documents/manuals.aspx>

Table 12-22 Developer-transmission owner relationship by fuel type

				MW by Fuel Type											
Parent Company	Transmission Owner	Related to Developer	Number of Projects	Biomass	Coal	Diesel	Hydro	Landfill Gas	Natural Gas	Nuclear	Oil	Solar	Storage	Wind	Total MW
AEP	AEP	Related	12	0.0	83.0	0.0	34.0	0.0	137.0	102.0	0.0	12.2	2.0	0.0	370.2
		Unrelated	82	0.0	128.0	0.0	100.0	13.0	7,239.0	0.0	0.0	107.0	112.0	6,602.0	14,301.0
AES	DAY	Related	3	0.0	12.0	0.0	0.0	0.0	0.0	0.0	0.0	2.5	20.0	0.0	34.5
		Unrelated	5	1.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	23.4	0.0	300.0	325.3
DLCO	DLCO	Unrelated	2	0.0	0.0	0.0	0.0	0.0	205.0	0.0	0.0	0.0	20.0	0.0	225.0
Dominion	Dominion	Related	9	0.0	0.0	0.0	0.0	0.0	4,296.1	1,594.0	0.0	0.0	0.0	12.0	5,902.1
		Unrelated	65	62.5	0.0	0.0	0.0	14.0	1,227.3	0.0	0.0	1,891.3	34.0	1,460.1	4,689.2
Duke	DEOK	Related	1	0.0	50.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	50.0
		Unrelated	6	0.0	0.0	0.0	112.0	6.4	513.0	0.0	0.0	125.0	10.0	0.0	766.4
Exelon	BGE	Related	2	0.0	0.0	0.0	0.0	0.0	256.0	0.0	0.0	20.0	0.0	0.0	276.0
		Unrelated	28	0.0	0.0	25.0	0.4	4.0	1.3	0.0	132.0	3.1	20.1	0.0	185.9
	ComEd	Related	4	0.0	0.0	0.0	0.0	0.0	0.0	80.0	0.0	0.0	0.0	0.0	80.0
		Unrelated	55	0.0	0.0	0.0	22.7	46.1	5,578.9	0.0	0.0	0.0	111.1	3,472.5	9,231.3
	PECO	Related	9	0.0	0.0	0.0	0.0	0.0	2,200.0	50.0	0.0	0.0	40.0	0.0	2,290.0
		Unrelated	13	0.0	0.0	6.1	0.0	2.0	1,426.5	0.0	0.0	0.0	0.8	0.0	1,435.4
First Energy	APS	Related	1	0.0	1,710.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,710.0
		Unrelated	71	0.0	0.0	0.0	0.0	15.2	4,469.5	0.0	0.0	354.8	73.0	1,251.8	6,164.3
	ATSI	Unrelated	19	0.0	0.0	0.0	0.0	5.6	6,006.7	0.0	0.0	0.0	32.5	518.0	6,562.8
	JCPL	Unrelated	76	0.0	0.0	0.0	0.0	0.0	3,376.8	0.0	0.0	482.6	180.0	0.0	4,039.4
	Met-Ed	Unrelated	5	0.0	0.0	0.0	0.0	0.0	2,345.6	0.0	0.0	3.0	0.0	0.0	2,348.6
	PENELEC	Unrelated	39	0.0	0.0	0.0	40.0	0.0	5,267.0	0.0	0.0	13.5	40.0	493.3	5,853.8
Pepco	AECO	Unrelated	25	0.0	0.0	0.0	0.0	0.0	1,987.0	0.0	0.0	60.2	21.0	373.0	2,441.2
	DPL	Unrelated	52	0.0	0.0	0.0	0.0	2.0	749.0	0.0	0.0	405.1	20.0	749.6	1,925.7
	Pepco	Unrelated	8	0.0	0.0	0.0	0.0	0.0	2,642.6	0.0	0.0	0.0	0.0	0.0	2,642.6
PPL	PPL	Unrelated	30	16.0	0.0	0.0	0.0	5.0	7,234.8	0.0	0.0	16.0	30.0	466.5	7,768.3
PSEG	PSEG	Related	11	0.0	24.0	0.0	0.0	0.0	738.0	0.0	0.0	3.4	0.0	0.0	765.4
		Unrelated	24	0.0	0.0	0.0	0.0	0.0	1,670.6	0.0	0.0	116.2	2.0	0.0	1,788.8
EKPC	EKPC	Unrelated	1	0.0	0.0	0.0	0.0	0.0	1,150.0	0.0	0.0	0.0	0.0	0.0	1,150.0
Total		Related	52	0.0	1,879.0	0.0	34.0	0.0	7,627.1	1,826.0	0.0	38.1	62.0	12.0	11,478.2
		Unrelated	606	80.4	128.0	31.1	275.1	113.3	53,090.6	0.0	132.0	3,601.2	706.5	15,686.8	73,844.9

Regional Transmission Expansion Plan (RTEP)

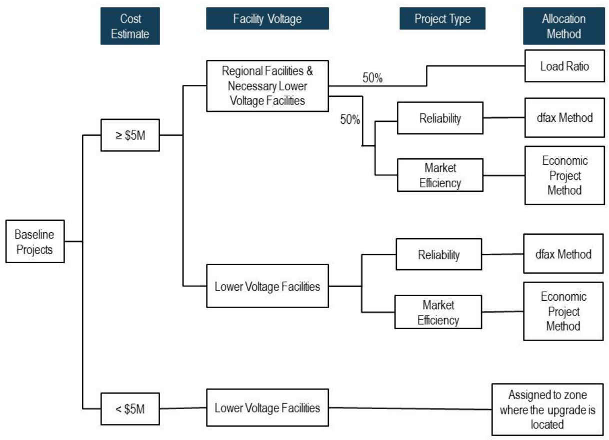
PJM's Transmission Expansion Advisory Committee (TEAC), made up of PJM staff, is responsible for the Regional Transmission Expansion Plan (RTEP).[28] Transmission upgrades can be divided into three categories: network, supplemental, and baseline. Network upgrades are initiated by generation queue projects 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 market efficiency and reliability criteria violations not addressed in other ways. Per FERC Order 1000, 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. All approved baseline projects are added to the RTEP via amendments to the tariff. Retired generators are included in this analysis for one year after their retirement to reflect the ownership of CIRs.

RTEP Cost Allocation

The costs of RTEP baseline projects are allocated to all transmission owners, based on the size of the project, the facility voltage, and whether the project addresses a reliability issue or market efficiency. In addition, the allocation methods attempt to distribute the costs proportionally with respect to who will benefit from the upgrade. The allocation rules are summarized in Figure 12-3.

28 See PJM. "Manual 14B: PJM Region Transmission Planning Process," Revision 30 (February 26, 2015), Section 2, p.14.

Figure 12-3 RTEP cost allocation rules



For reliability projects, upgrade costs are allocated based on distribution factors (dfax). The distribution factors used in the current allocation method are a measure of the use of the transmission upgrade by zonal loads and by merchant transmission facilities, based on power flow analysis. Under this allocation method (solutions based method), a zone with a distribution factor less than 0.01 is not allocated any costs regardless of its load on the line.[29] This approach to cost allocation replaced the earlier method which was based on distribution factors as a measure of contributions to the reasons for the transmission upgrade.[30]

In 2015, the Board approved four separate amendments to the RTEP. The first was a result of a proposal window opened in 2014 to address reliability criteria violations including baseline N-1 voltage, N-1-1 voltage, light load reliability criteria (thermal & voltage), and local TO criteria. The second included the Artificial Island projects and some adjustments to existing upgrade projects.[31] The last two were to address the two RTEP proposal windows opened in 2015, one for baseline N-1, generation deliverability and common mode outage, N-1-1, and load deliverability and the other for light load analysis and 2020 TO criteria.[32,33] Table 12-23 shows a summary of the all of the new baseline upgrade costs in 2015 for each TO, as well as how those costs were allocated.[34]

Table 12-23 2015 Board approved new baseline upgrades by transmission owner and allocations

	Baseline Upgrades ($ million)					
Transmission Owner	17-Feb-15	29-Jul-15	15-Oct-15	15-Dec-15	Total Approved Upgrades	Total Allocated Costs
AECO	0.0	0.0	0.0	0.0	0.0	3.5
AEP	262.7	29.2	93.1	0.0	385.0	513.0
AP	61.2	12.2	0.1	0.0	73.5	35.1
ATSI	0.0	16.7	0.0	0.0	16.7	33.6
BGE	0.0	0.0	0.0	0.0	0.0	12.6
ComEd	0.7	24.7	15.0	0.0	40.4	48.6
ConEd	0.0	0.0	0.0	0.0	0.0	1.1
DAY	0.0	0.0	0.0	0.0	0.0	4.7
DEOK	0.0	6.8	0.0	0.0	6.8	14.5
DLCO	0.0	12.9	0.0	0.0	12.9	5.7
Dominion	213.0	468.6	287.4	0.0	969.0	857.9
DPL	0.0	2.4	0.0	2.5	4.9	255.4
ECP	0.0	0.0	0.0	0.0	0.0	0.5
EKPC	2.1	2.7	0.5	0.0	5.2	9.7
HTP	0.0	0.0	0.0	0.0	0.0	0.5
JCPL	19.0	1.5	6.5	1.0	28.0	34.5
Met-Ed	1.0	13.9	0.4	0.0	15.2	13.7
Neptune	0.0	0.0	0.0	0.0	0.0	1.0
NTD	0.0	0.0	0.0	129.6	129.6	0.0
PECO	1.5	9.7	0.3	0.0	11.5	13.4
PENELEC	5.8	24.1	0.0	0.0	29.8	34.0
Pepco	0.0	0.0	0.0	0.0	0.0	38.6
PPL	0.8	4.2	0.0	0.0	5.0	15.2
PSEG	15.6	4.5	157.7	142.4	320.2	165.9
RECO	0.0	0.0	0.0	0.0	0.0	0.5
TranSource	59.5	0.0	0.0	0.0	59.5	0.0
Total	642.8	634.0	561.0	275.5	2,113.3	2,113.3

Cost Allocation Issues

The RTEP Baseline Upgrade filings, ER14-972-000 on January 10, 2014, and ER14-1485-000 on March 13, 2014, represented the first time the new allocation rules were used. They resulted in approximately $1.5 billion in additional baseline transmission enhancements and expansions. PJM approved additional RTEP upgrades (Docket Nos. ER15-2562 and ER15-2563) on July 29, 2015.

29 OATT, Schedule 12(b)(iii). (p.595).

30 See *PJM Interconnection, L.L.C.*, 142 FERC ¶ 61,214 (2013).

31 Artificial Island is an area in the PSEG Zone in southern New Jersey that includes nuclear units at Salem and at Hope Creek. The projects, assigned to TO PSEG, TO PHI, and merchant TO LS Power will address stability issues, operational performance under a range of anticipated system conditions, and the elimination of potential planning criteria violations.

32 See "PJM RTEP – 2015 RTEP Proposal Window #1 Problem Statement & Requirements Document," June 19, 2015 at <http://www.pjm.com/~/media/planning/rtep-dev/expan-plan-process/ferc-order-1000/rtep-proposal-windows/2015-rtep-window-1-problem-statement-and-requirements.ashx>.

33 See "PJM RTEP – 2015 RTEP Proposal Window #1 Problem Statement & Requirements Document," August 5, 2015 at <http://www.pjm.com/~/media/planning/rtep-dev/expan-plan-process/ferc-order-1000/rtep-proposal-windows/2015-rtep-window-2-problem-statement-and-requirements-document.ashx>.

34 The totals will not match the corresponding whitepapers published by PJM because cost estimates are adjusted frequently and these data show the most accurate current estimates.

In response to complaints about the cost allocations in these filings, on November 24, 2015, FERC accepted, and immediately suspended for five months, both of the July 29, 2015 filings. FERC concluded that "the proposed Tariff amendments have not been shown to be just and reasonable."[35]

FERC ordered a technical conference, which took place on January 12, 2016, to address the complaints in proceedings EL15-18-000 (ConEd), EL15-67-000 (Linden), and EL15-95-000 (Artificial Island). FERC identified two main discussion points: Whether there is "a definable category of reliability projects within PJM for which the solution-based dfax cost allocation method may not be just and reasonable" and whether there is "an alternative just and reasonable ex ante cost allocation method that could be established for any such category of projects."[36]

The issues identified in the complaints and at the technical conference include: whether the solutions based allocation method is appropriate for upgrades not related to transmission overload issues; whether the solutions based allocation method correctly identifies all the beneficiaries of the upgrades; whether it is reasonable to allocate a level of costs to a merchant transmission project that could force bankruptcy; and whether the significant shifts in allocation that result from use of the .01 distribution factor cutoff are appropriate.

The MMU recognizes that the allocation issues are difficult. Nonetheless the allocation methods affect the efficiency of the markets and the incentives for merchant transmission owners to compete to build new transmission. It appears that use of the arbitrary .01 distribution factor cutoff can result in large shifts in cost allocation. It also appears that the if the intent of the use of the .01 cutoff is to help eliminate small, arbitrary cost allocations to geographically distant areas, another approach would be to add a threshold for a minimum usage impact on the line. The MMU recommends consideration of changing the minimum distribution factor in the allocation from .01 to .00 and adding a threshold minimum impact on the load on the line.

35 153 FERC ¶ 61,245 (November 24, 2015).

36 "Supplemental Notice of Technical Conference re PJM Interconnection, L.L.C et al under ER15-2562 et al.," Docket No. E15-95-000 (December 30, 2015).

TranSource

TranSource LLC filed a complaint against PJM on June 23, 2015, amended February 10, 2016, seeking work papers explaining how PJM performed System Impact Studies (SIS) for three TranSource transmission projects.[37] TranSource complains, in addition, that PJM "fail[ed] to provide TranSource with open access on a nondiscriminatory basis to the PJM transmission planning process and to Auction Revenue Rights (ARR) associated with transmission upgrades" and "violated its requirement to provide TranSource with a transparent, replicable process for evaluating transmission upgrade requests."[38] PJM responded that it has provided all work papers relevant to the SIS and objects to the complaint on procedural grounds.[39] On September 24, 2015, the Commission issued an order establishing hearing and settlement judge procedures.[40] The MMU is participating in this process.

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. Designated backbone projects in 2015 included Mount Storm-Doubs, Jacks Mountain, Susquehanna-Roseland, and Surry Skiffes Creek 500kV. Figure 12-4 shows the location of these four projects. Surry Skiffes Creek 500kV is the only remaining active backbone project.

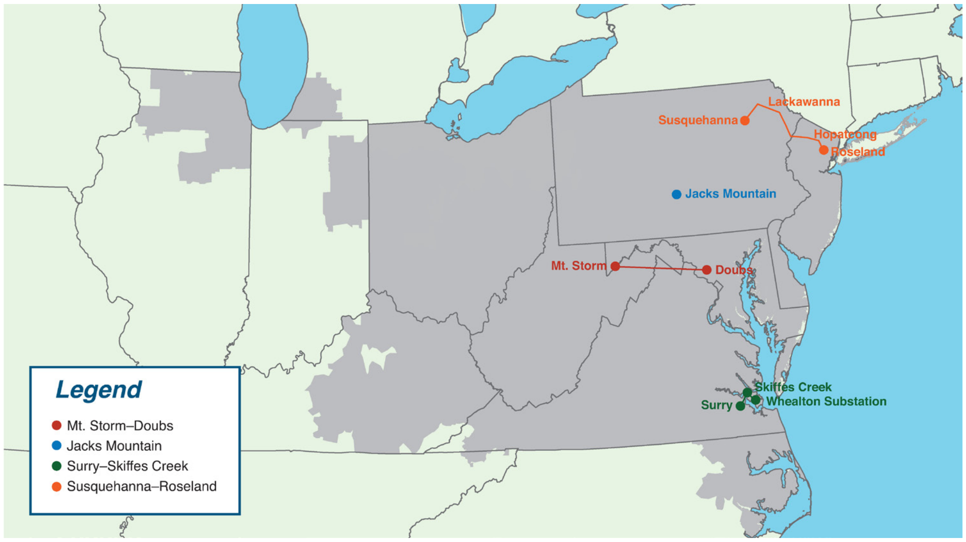
37 TranSource Complaint, Amended and Restated Complaint and Request for Fast Track Processing of TranSource, LLC, FERC Docket No. EL15-79-000.

38 *Id.* at 1–2.

39 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).

40 152 FERC ¶ 61,229.

Figure 12-4 PJM Backbone Projects



Two of these projects, Mount Storm-Doubs and Susquehanna-Roseland, were completed in 2015 and are currently in service. The Jacks Mountain backbone project has been cancelled. It was initiated to resolve voltage problems for load deliverability starting June 1, 2017.

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. The initial project includes 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.[41] On April 30, 2015, Dominion filed a petition for rehearing, which was rejected, and the case was remanded to the State Corporation Commission (SCC). The SCC issued an order on June 5, 2015, stressing the need for this project to be completed, extending the completion date to December 31, 2015.[42] The SCC issued another order on December 4, 2015, temporarily suspending this updated completion date, pending the Army Corps of Engineers' (ACE) issuance of a construction permit.[43] The ACE is currently studying the effects of the project as currently proposed, as well as an alternative approach. The JCC Board will vote on the final action in January, 2016 or later, at which point an energization date can be established.[44]

Transmission Facility Outages

Scheduling Transmission Facility Outage Requests

A transmission facility is designated as reportable by PJM 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.[45] 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.[46]

41 BASF Corporation v SCC, et al., Record No. 141009 et al.

42 See Commonwealth of Virginia State Corporation Commission Order in Case No. PUE-2012-00029, June 5, 2015 at <https://www.dom.com/library/domcom/pdfs/electric-transmission/surry-skiffes-creek/scc-order-060515.pdf>.

43 See Commonwealth of Virginia State Corporation Commission Order in Case No. PUE-2012-00029, December 4, 2015 at <https://www.dom.com/library/domcom/pdfs/electric-transmission/surry-skiffes-creek/due-date-order-120415.pdf?la=en>.

44 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>.

45 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. See PJM. "Manual 3A: Energy Management System (EMS) Model Updates and Quality Assurance (QA), Revision 10 (June 25, 2015).

46 See PJM. "Manual 3: Transmission Operations," Revision 48 (December 1, 2015), p.57.

Transmission outages have significant impacts on PJM markets. There are impacts on FTR auctions, on congestion, and on expected market outcomes in the day-ahead and real-time markets. It is important for the efficient functioning of the markets that there be clear, enforceable rules governing transmission outages.

Transmission 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.[47] Table 12-24 shows that 79.2 percent of the requested outages were planned for less than or equal to five days and 4.9 percent of requested outages were planned for greater than 30 days in 2015. All of the outage data in this section are for outages scheduled to occur in 2014 and 2015, regardless of when they were initially submitted.[48]

Table 12-24 Transmission facility outage request summary by planned duration: 2014 and 2015

	2014		2015	
Planned Duration (Days)	Outage Requests	Percent	Outage Requests	Percent
<=5	15,645	79.8%	15,521	79.2%
>5 & <=30	2,917	14.9%	3,117	15.9%
>30	1,052	5.4%	953	4.9%
Total	19,614	100.0%	19,591	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.[49]

The purpose of the rules defined in Table 12-25 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 about market conditions on which to base their FTR bids and so that PJM can accurately model market conditions.[50]

47 See PJM. "Manual 3: Transmission Operations," Revision 48 (December 1, 2015), p.58.

48 The hotline tickets, EMS tripping tickets or test outage tickets were excluded. We only included all the transmission outage tickets submitted by PJM internal companies which are currently active.

49 See PJM. "Manual 3: Transmission Operations," Revision 48 (December 1, 2015), p.58 and p.59.

50 See "Report of PJM Interconnection, L.L.C. on Transmission Oversight Procedures," Docket No. EL01-122-000 (November 2, 2001).

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 1) February 1st, 2) the 1st of the month six months prior to the starting month of the outage	On Time
	After or on the earlier of 1) February 1st, 2) 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 2015, 49.1 percent of outage requests received were late.

Table 12-26 Transmission facility outage request summary by received status: 2014 and 2015

	2014				2015			
Planned Duration (Days)	On Time	Late	Total	Percent Late	On Time	Late	Total	Percent Late
<=5	8,124	7,521	15,645	48.1%	8,075	7,446	15,521	48.0%
>5 & <=30	1,482	1,435	2,917	49.2%	1,527	1,590	3,117	51.0%
>30	449	603	1,052	57.3%	377	576	953	60.4%
Total	10,055	9,559	19,614	48.7%	9,979	9,612	19,591	49.1%

Once received, PJM processes outage requests in priority order: emergency transmission outage request; transmission outage requests submitted on time; and transmission outage request submitted late. PJM retains the right to deny all transmission outage requests that are submitted past the relevant deadline unless the request is an emergency.[51]

Outages with emergency status will be approved even if submitted past the relevant deadline after PJM determines that the outage does not result in Emergency Procedures. PJM cancels or withholds approval of any outage that results in Emergency Procedures.[52] Table 12-27 is a summary of outage requests by emergency status. Of all outage requests scheduled to occur in 2015,

51 PJM. "Manual 3: Transmission Operations," Revision 48 (December 1, 2015), p. 69.

52 PJM. "Manual 3: Transmission Operations," Revision 48 (December 1, 2015), p. 67 and p.68.

13.3 percent were for emergency outages. Of all outage requests scheduled to occur in 2014, 14.1 percent were for emergency outages.

Table 12-27 Transmission facility outage request summary by emergency: 2014 and 2015

	2014				2015			
Planned Duration (Days)	Emergency	Non Emergency	Total	Percent Emergency	Emergency	Non Emergency	Total	Percent Emergency
<=5	2,249	13,396	15,645	14.4%	2,103	13,418	15,521	13.5%
>5 & <=30	370	2,547	2,917	12.7%	402	2,715	3,117	12.9%
>30	143	909	1,052	13.6%	99	854	953	10.4%
Total	2,762	16,852	19,614	14.1%	2,604	16,987	19,591	13.3%

PJM will approve all transmission outage requests that are submitted on time and do not jeopardize the reliability of the PJM system. PJM will approve all transmission outage requests that are submitted late and do not cause congestion on the PJM system and do not jeopardize the reliability of the PJM system.

Table 12-28 Transmission facility outage request summary by congestion: 2014 and 2015

	2014				2015			
Planned Duration (Days)	Congestion Expected	No Congestion Expected	Total	Percent Congestion Expected	Congestion Expected	No Congestion Expected	Total	Percent Congestion Expected
<=5	1,492	14,153	15,645	9.5%	1,428	14,093	15,521	9.2%
>5 & <=30	307	2,610	2,917	10.5%	360	2,757	3,117	11.5%
>30	113	939	1,052	10.7%	101	852	953	10.6%
Total	1,912	17,702	19,614	9.7%	1,889	17,702	19,591	9.6%

Table 12-29 Transmission facility outage requests that by received status, congestion and emergency: 2014 and 2015

		2014				2015			
Submission Status		Congestion Expected	No Congestion Expected	Total	Percent Congestion	Congestion Expected	No Congestion Expected	Total	Percent Congestion
Late	Emergency	97	2,650	2,747	3.5%	113	2,474	2,587	4.4%
	Non Emergency	374	6,438	6,812	5.5%	342	6,683	7,025	4.9%
On Time	Emergency	1	14	15	6.7%	3	14	17	17.6%
	Non Emergency	1,440	8,600	10,040	14.3%	1,431	8,531	9,962	14.4%
Total		1,912	17,702	19,614	9.7%	1,889	17,702	19,591	9.6%

After PJM determines that a late request may cause congestion, PJM informs the Transmission Owner of solutions available to eliminate the congestion. For example, if a generator planned or maintenance outage request is contributing to the congestion, PJM can request that the Generation Owner defer the outage. If no solutions are available, PJM may require the Transmission Owner to reschedule or cancel the outage. Table 12-28 is a summary of outage requests by congestion status. Of all outage requests submitted in 2015, 9.6 percent were expected to cause congestion. Of all the outage requests that were expected to cause congestion, 4.1 percent (78 out of 1,889) were denied by PJM in 2015 (Table 12-30).

Table 12-29 shows the outage requests summary by received status, congestion status and emergency status. In 2015, 73.1 percent of late requests were non-emergency outages while 4.9 percent of late non-emergency outage requests were expected to cause congestion in 2015.

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.[53] 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 72.8 (249 out of 342) percent of late, non-emergency, outage requests which were expected to cause congestion were approved and completed and 4.1 percent (78 out of 1,889) of the outage requests which were expected to cause congestion were denied in 2015.

53 See PJM. "Outage Information," <http://www.pjm.com/markets-and-operations/etools/oasis/system-information/outage-info.aspx> (November 1, 2015).

Table 12-30 Transmission facility outage requests that might cause congestion status summary: 2014 and 2015

Submission Status		2014 Cancelled	2014 Complete	2014 In Process	2014 Denied	2014 Congestion Expected	2014 Percent Complete	2015 Cancelled	2015 Complete	2015 In Process	2015 Denied	2015 Congestion Expected	2015 Percent Complete
Late	Emergency	4	92	1	0	97	94.8%	12	100	0	1	113	88.5%
	Non Emergency	77	257	1	39	374	68.7%	65	249	2	26	342	72.8%
On Time	Emergency	1	0	0	0	1	0.0%	0	3	0	0	3	100.0%
	Non Emergency	322	1,038	2	78	1,440	72.1%	384	994	2	51	1,431	69.5%
Total		404	1,387	4	117	1,912	72.5%	461	1,346	4	78	1,889	71.3%

There are clear rules defined for assigning on time or late status for submitted outage requests in both the PJM Tariff and PJM Manuals.[54] However, the on time or late status only affects the priority that PJM assigns for processing the outage request. Many (72.8 percent) non-emergency, expected to cause congestion, late transmission outages were approved and completed. The expected impact on congestion is the basis for PJM's treatment of late outage requests. But there is no rule or clear definition of this congestion analysis in the PJM Manuals. The MMU recommends that PJM draft a clear definition of the congestion analysis required for transmission outage requests to include in Manual 3 after appropriate review.

Rescheduling Transmission Facility Outage Requests

Table 12-31 Rescheduled and cancelled transmission outage request summary: 2014 and 2015

Days	2014 Outage Requests	2014 Approved and Rescheduled	2014 Percent Approved and Rescheduled	2014 Approved and Cancelled	2014 Percent Approved and Cancelled	2015 Outage Requests	2015 Approved and Rescheduled	2015 Percent Approved and Rescheduled	2015 Approved and Cancelled	2015 Percent Approved and Cancelled
<=5	15,645	1,913	12.2%	2,127	13.6%	15,523	1,788	11.5%	2,028	13.1%
>5 & <=30	2,917	1,435	49.2%	197	6.8%	3,117	1,472	47.2%	203	6.5%
>30	1,052	648	61.6%	51	4.8%	953	544	57.1%	63	6.6%
Total	19,614	3,996	20.4%	2,375	12.1%	19,593	3,804	19.4%	2,294	11.7%

A TO can reschedule or cancel an outage after initial submission. Table 12-31 is a summary of all the outage requests planned for 2014 and 2015 which were approved and then cancelled or rescheduled by TOs at least once. If an outage request was submitted, approved and subsequently rescheduled at least once, the outage request will be counted as Approved and Rescheduled. If an outage request was submitted, approved and subsequently cancelled at least once, the outage request will be counted as Approved and Cancelled. In 2015, 19.4 percent of transmission outage requests were approved by PJM and then rescheduled by the TOs, and 11.7 percent of the transmission outages were approved by PJM and subsequently cancelled by the TOs.

If a requested outage is determined to be late and TO reschedules the outage, the outage will be revaluated by PJM again as on time or late.

A transmission outage ticket with a 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.[55] This rule allows a TO to reschedule within the same month with very little notice.

54 OATT Attachment K Appendix § 1.9.2 (Outage Scheduling).

55 PJM. "Manual 3: Transmission Operations," Revision 48 (December 1, 2015), p. 63.

A transmission outage ticket with a duration exceeding five days with an on time status can retain its on time status if the outage is rescheduled to a future month, and the revision is submitted by the first of the month prior to the revised month in which the outage will occur.[56] This rescheduling rule is much less strict than the rule that applies to the first submission of outage requests with similar duration. When first submitted, the outage request with a duration exceeding five days needs to be submitted before the first of the month six months prior to the month in which the outage was expected to occur.

The MMU recommends that PJM reevaluate all transmission outage tickets as on time or late as if they were new requests when an outage is rescheduled and apply the standard rules for late submissions to any such outages.

Long Duration Transmission Facility Outage Requests

PJM rules (Table 12-25) define a transmission outage request as on time or late based on the planned outage duration and the time of submission. The rule has stricter submission requirements for transmission outage requests planned for longer than 30 days. In order to avoid the stricter submission requirement, some transmission owners divided the duration of outage requests longer than 30 days into shorter segments for the same equipment and submitted one request for each segment. The MMU recommends that PJM not permit transmission owners to divide long duration outages into smaller segments to avoid complying with the requirements for long duration outages. Table 12-32 shows that there were 11,274 transmission equipment planned outages in 2015, of which 855 were planned outages longer than 30 days, and of which 188 or 1.7 percent were scheduled longer than 30 days if the duration of the outages were combined for the same equipment. The duration of those outages could potentially be longer than 30 days, however were divided into shorter periods by transmission owners.

Table 12-32 Transmission outage summary: 2014 and 2015

		2014		2015	
Duration	Divided into Shorter Periods	Number of Outages	Percent	Number of Outages	Percent
> 30 Days	No	923	8.3%	855	7.6%
	Yes	193	1.7%	188	1.7%
<= 30 Days		10,047	90.0%	10,231	90.7%
Total		11,163	100.0%	11,274	100.0%

Table 12-33 shows the details of potentially long duration (> 30 days) outages when combining the duration of the outages for the same equipment. The actual duration of scheduled outages would be longer than 30 days if the duration of the outages were combined for the same equipment within a period of days. In 2015, there would have been five outages with a combined duration longer than 30 days that were instead scheduled to occur as shorter outages within a period of less than or equal to 31 days. In 2015, there would have been 150 outages with a combined duration longer than 30 days that were instead scheduled to occur as shorter outages within a period of more than 92 days.

Table 12-33 Summary of potentially long duration (> 30 days) outages: 2014 and 2015

	2014		2015	
Days	Number of Outages	Percent	Number of Outages	Percent
<=31	5	2.6%	5	2.7%
>31 & <=62	21	10.9%	13	6.9%
>62 and <=92	20	10.4%	20	10.6%
>=92	147	76.2%	150	79.8%
Total	193	100.0%	188	100.0%

Transmission Facility Outage Analysis for the FTR Market

Transmission facility outages affect the price and quantity outcomes of FTR auctions. The purpose of the rules is to ensure 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. Table 12-37 shows that 637 outage requests with a duration of two weeks or longer but shorter than two months were late, and only four of them were denied by

56 PJM. "Manual 3: Transmission Operations," Revision 48 (December 1, 2015), p. 64.

PJM. Table 12-37 also shows that 189 outage requests with a duration of two months or longer were late and none of them were denied by PJM in the 2015 to 2016 planning year.

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 durations 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.[57]

Table 12-34 shows that 88.3 percent of the outage requests for outages expected to occur during the planning period 2015 to 2016 had a planned duration of less than two weeks and that 44.7 (6,800 out of 15,225) percent of all outage requests for the planning period were submitted late according to outage submission rules.

Table 12-35 shows outage requests summary by emergency status. Of all outage requests for outages expected to occur in the 2015 to 2016 planning year and submitted late, 74.1 percent were for non-emergency outages.

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 12-36 shows a summary of requests by expected congestion and received status. Overall, 4.7 percent of all outage requests for outages expected to occur in the 2015 to 2016 planning year and submitted late were requests that were expected to cause congestion.

Table 12-34 Transmission facility outage requests by received status: Planning periods 2014 to 2015 and 2015 to 2016

	2014/2015				2015/2016			
Planned Duration	On Time	Late	Total	Percent	On Time	Late	Total	Percent
<2 weeks	9,307	8,383	17,690	88.7%	7,476	5,974	13,450	88.3%
>=2 weeks & <2 months	844	896	1,740	8.7%	807	637	1,444	9.5%
>=2 months	201	316	517	2.6%	142	189	331	2.2%
Total	10,352	9,595	19,947	100.0%	8,425	6,800	15,225	100.0%

Table 12-35 Transmission facility outage requests by received status and emergency: Planning periods 2014 to 2015 and 2015 to 2016

		2014/2015				2015/2016			
	Planned Duration	Emergency	Non Emergency	Total	Percent Non Emergency	Emergency	Non Emergency	Total	Percent Non Emergency
On Time	<2 weeks	13	9,294	9,307	99.9%	16	7,460	7,476	99.8%
	>=2 weeks & <2 months	0	844	844	100.0%	2	805	807	99.8%
	>=2 months	0	201	201	100.0%	0	142	142	100.0%
	Total	13	10,339	10,352	99.9%	18	8,407	8,425	99.8%
Late	<2 weeks	2,370	6,013	8,383	71.7%	1,623	4,351	5,974	72.8%
	>=2 weeks & <2 months	169	727	896	81.1%	107	530	637	83.2%
	>=2 months	64	252	316	79.7%	31	158	189	83.6%
	Total	2,603	6,992	9,595	72.9%	1,761	5,039	6,800	74.1%

57 PJM Financial Transmission Rights, "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> (April 1, 2015).

Table 12-36 Transmission facility outage requests by submission status and congestion: Planning periods 2014 to 2015 and 2015 to 2016

		2014/2015				2015/2016			
	Planned Duration	Congestion Expected	No Congestion Expected	Total	Percent Congestion Expected	Congestion Expected	No Congestion Expected	Total	Percent Congestion Expected
On Time	<2 weeks	1,340	7,967	9,307	14.4%	933	6,543	7,476	12.5%
	>=2 weeks & <2 months	168	676	844	19.9%	160	647	807	19.8%
	>=2 months	38	163	201	18.9%	33	109	142	23.2%
	Total	1,546	8,806	10,352	14.9%	1,126	7,299	8,425	13.4%
Late	<2 weeks	447	7,936	8,383	5.3%	280	5,694	5,974	4.7%
	>=2 weeks & <2 months	45	851	896	5.0%	34	603	637	5.3%
	>=2 months	9	307	316	2.8%	8	181	189	4.2%
	Total	501	9,094	9,595	5.2%	322	6,478	6,800	4.7%

Table 12-37 shows that 67.0 percent of late outage requests with a duration of two weeks or longer but shorter than two months were completed, 0.6 percent were denied by PJM and 5.5 percent of late outage requests with a duration of two weeks or longer but shorter than two months were approved or active in the 2015 to 2016 planning year. The table also shows that 56.6 percent of late outage requests with duration of two months or longer were completed, none of them were denied, and 25.9 percent were approved and active in the 2015 to 2016 planning year.

Table 12-38 shows that there were 637 outage requests with a duration of two weeks or longer but shorter than two months submitted late, of which 32 were non-emergency and expected to cause congestion in the 2015 to 2016 planning year. Of the 32 such requests, 24 were approved. For the outages planned for two months or longer, there were 331 total outages, of which 189 requests were late. Of the late requests, seven outages that were non-emergency and expected to cause congestion were all approved.

Table 12-37 Transmission facility outage requests by received status and processed status: Planning periods 2014 to 2015 and 2015 to 2016

		2014/2015				2015/2016			
Planned Duration	Processed Status	On Time	Percent	Late	Percent	On Time	Percent	Late	Percent
<2 weeks	In Progress	21	0.2%	149	1.8%	2,180	29.2%	418	7.0%
	Denied	106	1.1%	98	1.2%	55	0.7%	44	0.7%
	Approved	0	0.0%	0	0.0%	7	0.1%	26	0.4%
	Cancelled by Company	2,762	29.7%	1,205	14.4%	1,707	22.8%	715	12.0%
	Revised	0	0.0%	0	0.0%	33	0.4%	2	0.0%
	Active	0	0.0%	0	0.0%	32	0.4%	43	0.7%
	Completed	6,418	69.0%	6,931	82.7%	3,462	46.3%	4,726	79.1%
Total Submission		9,307	100.0%	8,383	100.0%	7,476	100.0%	5,974	100.0%
>=2 weeks & <2 months	In Progress	1	0.1%	9	1.0%	259	32.1%	105	16.5%
	Denied	0	0.0%	4	0.4%	0	0.0%	4	0.6%
	Approved	0	0.0%	0	0.0%	0	0.0%	1	0.2%
	Cancelled by Company	199	23.6%	106	11.8%	183	22.7%	63	9.9%
	Revised	0	0.0%	0	0.0%	8	1.0%	3	0.5%
	Active	0	0.0%	0	0.0%	22	2.7%	34	5.3%
	Completed	644	76.3%	777	86.7%	335	41.5%	427	67.0%
Total Submission		844	100.0%	896	100.0%	807	100.0%	637	100.0%
>=2 months	In Progress	0	0.0%	7	2.2%	20	14.1%	19	10.1%
	Denied	0	0.0%	0	0.0%	0	0.0%	0	0.0%
	Approved	0	0.0%	0	0.0%	1	0.7%	0	0.0%
	Cancelled by Company	42	20.9%	31	9.8%	30	21.1%	14	7.4%
	Revised	0	0.0%	0	0.0%	1	0.7%	0	0.0%
	Active	1	0.5%	2	0.6%	24	16.9%	49	25.9%
	Completed	158	78.6%	276	87.3%	66	46.5%	107	56.6%
Total Submission		201	100.0%	316	100.0%	142	100.0%	189	100.0%

Table 12-38 Transmission facility outage requests by received status, processed status, emergency and congestion: Planning periods 2014 to 2015 and 2015 to 2016

		2014/2015						2015/2016					
		On Time			Late			On Time			Late		
Planned Duration	Processed Status	Non Emergency and Congestion Expected	Total	Percent	Non Emergency and Congestion Expected	Total	Percent	Non Emergency and Congestion Expected	Total	Percent	Non Emergency and Congestion Expected	Total	Percent
<2 weeks	In Progress	2	21	9.5%	3	149	2.0%	200	2,180	9.2%	16	418	3.8%
	Denied	70	106	66.0%	39	98	39.8%	24	55	43.6%	13	44	29.5%
	Approved	0	0	0.0%	0	0	0.0%	2	7	28.6%	2	26	7.7%
	Cancelled by Company	363	2,762	13.1%	75	1,205	6.2%	214	1,707	12.5%	42	715	5.9%
	Revised	0	0	0.0%	0	0	0.0%	3	33	9.1%	0	2	0.0%
	Active	0	0	0.0%	0	0	0.0%	5	32	15.6%	1	43	2.3%
	Completed	904	6,418	14.1%	224	6,931	3.2%	482	3,462	13.9%	135	4,726	2.9%
Total Submission		1,339	9,307	14.4%	341	8,383	4.1%	930	7,476	12.4%	209	5,974	3.5%
>=2 weeks & <2 months	In Progress	1	1	100.0%	0	9	0.0%	54	259	20.8%	5	105	4.8%
	Denied	0	0	0.0%	2	4	50.0%	0	0	0.0%	0	4	0.0%
	Approved	0	0	0.0%	0	0	0.0%	0	0	0.0%	1	1	100.0%
	Cancelled by Company	31	199	15.6%	6	106	5.7%	20	183	10.9%	3	63	4.8%
	Revised	0	0	0.0%	0	0	0.0%	2	8	25.0%	0	3	0.0%
	Active	0	0	0.0%	0	0	0.0%	6	22	27.3%	1	34	2.9%
	Completed	136	644	21.1%	33	777	4.2%	78	335	23.3%	22	427	5.2%
Total Submission		168	844	19.9%	41	896	4.6%	160	807	19.8%	32	637	5.0%
>=2 months	In Progress	0	0	0.0%	0	7	0.0%	5	20	25.0%	0	19	0.0%
	Denied	0	0	0.0%	0	0	0.0%	0	0	0.0%	0	0	0.0%
	Approved	0	0	0.0%	0	0	0.0%	1	1	100.0%	0	0	0.0%
	Cancelled by Company	3	42	7.1%	1	31	3.2%	2	30	6.7%	0	14	0.0%
	Revised	0	0	0.0%	0	0	0.0%	0	1	0.0%	0	0	0.0%
	Active	0	1	0.0%	0	2	0.0%	5	24	20.8%	2	49	4.1%
	Completed	35	158	22.2%	8	276	2.9%	20	66	30.3%	5	107	4.7%
Total Submission		38	201	18.9%	9	316	2.8%	33	142	23.2%	7	189	3.7%

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 12-39 shows that 88.9 percent of outage requests labelled on time according to rules were submitted or rescheduled after the annual FTR bidding opening date in the 2015 to 2016 planning year.

Table 12-39 Transmission facility outage requests by received status and bidding opening date: Planning periods 2014 to 2015 and 2015 to 2016

	2014/2015						2015/2016					
	On Time			Late			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	Before Bidding Opening Date	After Bidding Opening Date	Percent After	Before Bidding Opening Date	After Bidding Opening Date	Percent After
<2 weeks	566	8,741	93.9%	13	8,370	99.8%	665	6,811	91.1%	10	5,964	99.8%
>=2 weeks & <2 months	173	671	79.5%	14	882	98.4%	226	581	72.0%	14	623	97.8%
>=2 months	45	156	77.6%	2	314	99.4%	40	102	71.8%	6	183	96.8%
Total	784	9,568	92.4%	29	9,566	99.7%	931	7,494	88.9%	30	6,770	90.0%

Table 12-40 shows that 77.5 percent of late outage requests which were submitted or rescheduled after the Annual FTR Auction bidding opening date were approved and complete in the 2015 to 2016 planning.

Table 12-40 Late transmission facility outage requests that are submitted after annual bidding opening date: Planning periods 2014 to 2015 and 2015 to 2016

	2014/2015			2015/2016		
Planned Duration	Completed Outages	Total	Percent	Completed Outages	Total	Percent
<2 weeks	6,926	8,370	82.7%	4,720	5,964	79.1%
>=2 weeks & <2 months	772	882	87.5%	420	623	67.4%
>=2 months	275	314	87.6%	106	183	57.9%
Total	7,973	9,566	83.3%	5,246	6,770	77.5%

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 since the rule has no direct connection to the annual FTR auction opening date. The MMU recommends that PJM modify the rules to reduce or eliminate the approval of late outage requests submitted or rescheduled after the FTR Auction bidding opening date.

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.

PJM maintains the history of outage requests including all the processed status changes and all the starting or ending date changes. Any such status change is defined as an instance. For example, if an outage request were submitted, received, approved and completed, the four occurrences, termed instances, of the outage request will be stored in the database. If an outage request is revised, that is an instance. There may be more than one instance for each outage request due to the change of the processed status. In the day-ahead market transmission outage analysis, all instances of the outages planned to occur in 2014 and 2015 are included. In the day-ahead market transmission analysis, all submissions or changes of outage requests at or after 12:00 pm on the day before the planned starting date until the hour beginning 23:00 pm on the planned starting date will be defined as late for day-ahead market.

Table 12-41 shows that in 2015 13.0 percent of non-emergency outage request instances were submitted late for the day-ahead market and PJM expected them to cause congestion.

Table 12-41 Transmission facility outage request instance summary by congestion and emergency: 2014 and 2015

		2014				2015			
For Day-ahead Market	Submission Status	Congestion Expected	No Congestion Expected	Total	Percent Congestion	Congestion Expected	No Congestion Expected	Total	Percent Congestion
Late	Emergency	271	4,217	4,488	6.0%	299	3,757	4,056	7.4%
	Non Emergency	2,752	16,266	19,018	14.5%	2,383	15,925	18,308	13.0%
On Time	Emergency	779	15,624	16,403	4.7%	686	11,241	11,927	5.8%
	Non Emergency	14,929	92,753	107,682	13.9%	15,035	91,526	106,561	14.1%
	Total	18,731	128,860	147,591	12.7%	18,403	122,449	140,852	13.1%

Table 12-42 shows that there were 22,364 late outage request instances which were submitted in 2015, of which 3,232 (14.0 percent) had the status submitted, cancelled by company or revised and 192 (0.9 percent) non-emergency instances had the status submitted, cancelled by company or revised and were expected to cause congestion. The top five zones accounted for 57.4 percent of all outages that were late for the day-ahead market in 2015. These zones were: AEP, ATSI, GPU, Dominion and ComEd.

Table 12-42 Late transmission facility outage request instance status summary by congestion and emergency: 2014 and 2015

	2014			2015		
Processed Status	Non Emergency and Congestion Expected	Total	Percent	Non Emergency and Congestion Expected	Total	Percent
Submitted	73	1,859	3.9%	65	1,776	3.7%
Cancelled by Company	84	861	9.8%	80	876	9.1%
Revised	45	524	8.6%	47	480	9.8%
Other	2,550	20,262	12.6%	2,191	19,232	11.4%
Total	2,752	23,506	11.7%	2,383	22,364	10.7%

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) were introduced to permit 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 congestion 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] Congestion is defined to be load payments in excess of generation revenues. Congestion 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, or an equivalent mechanism, to pay back to load the difference between the total load payments and the total generation revenues. 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 ensure that all congestion revenues are returned to load. Congestion revenues are defined to be equal to the sum of day ahead and balancing congestion. FTRs are one way to do that.

Effective June 1, 2003, PJM replaced the direct allocation of FTRs to load with an allocation of Auction Revenue Rights (ARRs). The load still owns the rights to congestion collected under this system, but the ARR construct allows load to either claim the FTRs directly (through a process called self scheduling), or to sell the rights in the FTR auction in exchange for a revenue stream based on the prices of the FTRs. Under the ARR construct, all of the FTR auction revenues should belong to the load and all of the congestion revenues should belong to those that purchase or self schedule the FTRs.

The current ARR/FTR design does not serve as an efficient way to ensure that load receives all the congestion revenues or has the ability to receive the auction revenues associated with all the potential congestion revenues. Total ARR and self scheduled FTR revenue offset only 63.8 percent of total congestion costs including congestion in the Day-Ahead Energy Market and the balancing energy market for the 2014 to 2015 planning period. One of the reasons for this inefficiency is the link, established by PJM member companies in their initial FTR filings, between congestion revenues and specific generation to load transmission paths. The original filings, made before PJM members had any experience with LMP markets, retained the view of congestion rooted in physical transmission rights. In an effort to protect themselves, the PJM utilities linked the payment of FTRs to specific, physical contract paths from specific generating units to specific load zones. That linkage was inconsistent with the appropriate functioning of FTRs in an LMP system. The ARR allocation in 2015 continued to be based on those original physical generation to load paths, an illustration of the inadequacy of that approach and a source of the issues with the FTR model in 2015.

If the original PJM FTR design had simply been designed to return congestion revenues to load, many of the subsequent issues with the FTR design would have been avoided. Now is a good time to address the issues of the FTR design and to return the design to its original purpose. This would eliminate much of the complexity associated with ARRs and FTRs and eliminate unnecessary controversy about the appropriate recipients of congestion revenues.

1 *See* 81 FERC ¶ 61,257, at 62,241 (1997).
2 *See Id.* at 62, 259–62,260 & n. 123.

The *2015 State of the Market Report for PJM* focuses on the Monthly Balance of Planning Period FTR Auctions for the 2014 to 2015 and 2015 to 2016 planning periods, covering January 1, 2015, through December 31, 2015, and summarizes the Annual FTR Auction results for the 2015 to 2016 planning period.

Table 13-1 The FTR Auction Markets results were competitive

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

- 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 flawed because there are significant flaws with the basic ARR/FTR design which need to be addressed. The market design is not an efficient way to ensure that congestion revenues are returned to load.

Overview

Auction Revenue Rights

Market Structure

- **ARR Allocations.** PJM's actions to address prior low levels of FTR 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 2015 to 2016 planning period, PJM allocated a total of 26,845.4 MW of residual ARRs, up from 22,737.4 MW in the first seven months of the 2014 to 2015 planning period, with a total target allocation of $7.5 million for the 2015 to 2016 planning period, down from $9.0 million for the first seven months of the 2014 to 2015 planning period. Total Residual ARR allocations for the 2013 to 2014 planning period were 15,417.5 MW for $4.7 million. This large increase in residual ARR allocations over the 2013 to 2014 planning period was primarily a result of PJM's significant reductions in Annual ARR Stage 1B allocations. The outages were only assumed in order to reduce the initial allocation. As a result, there were more available ARRs during the year which were distributed as residual ARRs.
- **ARR Reassignment for Retail Load Switching.** There were 53,343 MW of ARRs associated with $503,400 of revenue that were reassigned in the 2014 to 2015 planning period. There were 43,089 MW of ARRs associated with $504,600 of revenue that were reassigned for the first seven months of the 2015 to 2016 planning period.

Market Performance

- **Revenue Adequacy.** For the 2015 to 2016 planning period, the ARR target allocations, which are based on the nodal price differences from the Annual FTR Auction, were $928.8 million, while PJM collected $962.0 million from the combined Long Term, Annual and Monthly Balance of Planning Period

FTR Auctions, making ARRs revenue adequate. For the 2014 to 2015 planning period, the ARR target allocations were $735.3 million while PJM collected $767.9 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. For the 2015 to 2016 planning period ARR dollars per MW increased 15.6 percent relative to the 2013 to 2014 planning period.

- **ARRs as an Offset to Congestion.** ARRs did not serve as an effective way to return congestion revenues to load. Total ARR and self scheduled FTR revenue offset only 63.8 percent of total congestion costs including congestion in the Day-Ahead Energy Market and the balancing energy market for the 2014 to 2015 planning period. In the first seven months of the 2015 to 2016 planning period, total ARR and self scheduled FTR revenues offset 85.8 percent of total congestion costs.

Financial Transmission Rights

Market Structure

- **Supply.** The principal binding constraints limiting the supply of FTRs in the 2016 to 2019 Long Term FTR Auction include the Kenney – Stockton line in DPL and the Glenview – Kleeman line in DEOK. The principal binding constraints limiting the supply of FTRs in the Annual FTR Auction for the 2015 to 2016 planning period include the Bush – Lafayette flowgate in MISO and the Oakgrove – Galesburg flowgate in MISO.

  Market participants can sell FTRs. In the 2016 to 2019 Long Term FTR Auction, total participant FTR sell offers were 327,980 MW, up from 240,748 in the 2015 to 2018 Long Term FTR Auction. In the 2015 to 2016 Annual FTR Auction, total participant sell offers were 378,744 MW, up from 271,368 MW in the 2014 to 2015 Annual FTR Auction. In the Monthly Balance of Planning Period FTR Auctions for the 2015 to 2016 planning period, total participant FTR sell offers were 3,495,474 MW, up from 2,424,369 MW for the same period during the 2014 to 2015 planning period.

- **Demand.** In the 2016 to 2019 Long Term FTR Auction, total FTR buy bids were 2,459,946 MW, down 21.3 percent from 3,124,613 MW the previous planning period. There were 2,461,662 MW of buy and self-scheduled bids in the 2015 to 2016 Annual FTR Auction, down 24.7 percent from 3,270,311 MW the previous planning period. The total FTR buy bids from the Monthly Balance of Planning Period FTR Auctions for the 2015 to 2016 planning period decreased 11.5 percent from 17,863,834 MW for the same time period of the prior planning period, to 15,813,526 MW.

- **Patterns of Ownership.** For the 2016 to 2019 Long Term FTR Auction, financial entities purchased 70.1 percent of prevailing flow FTRs and 78.5 percent of counter flow FTRs. For the 2015 to 2016 Annual FTR Auction, financial participants purchased 56.3 percent of all prevailing flow FTRs and 75.0 percent of all counter flow FTRs. For the Monthly Balance of Planning Period Auctions, financial entities purchased 74.9 percent of prevailing flow and 76.8 percent of counter flow FTRs for January through December of 2015. Financial entities owned 65.9 percent of all prevailing and counter flow FTRs, including 60.6 percent of all prevailing flow FTRs and 79.6 percent of all counter flow FTRs during the period from January through December 2015.

Market Behavior

- **FTR Forfeitures.** Total forfeitures for the 2015 to 2016 planning period were $0.2 million for Increment Offers, Decrement Bids and UTC Transactions.

- **Credit Issues.** There were three collateral defaults and seven payment defaults for 2015. Two collateral defaults totaled $710,300 and seven payment defaults totaled $1,726,641 for Intergrid Mideast Group, LLC. There was one other collateral default for the first nine months of 2015 for $35,000, which was promptly cured. There were no additional defaults in the last quarter of 2015.

  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 has liquidated all of Intergrid's FTR positions in accordance with Section

7.3.9 of the Operating Agreement.[3] 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 is $279,414. PJM has notified its Members that the Intergrid default will not result in any default allocation assessments in accordance with Section 15.2.2 of the Operating Agreement.[4]

Market Performance

- **Volume.** The 2016 to 2019 Long Term FTR Auction cleared 277,397 MW (11.3 percent) of demand of FTR buy bids, down 0.2 percent from 277,865 MW (8.9 percent) in the 2015 to 2018 Long Term FTR Auction. The Long Term FTR Auction also cleared 61,210 MW (18.7 percent) of FTR sell offers, compared to 34,629 (14.4 percent), a 76.8 percent increase.

  In the Annual FTR Auction for the 2015 to 2016 planning period 378,328 MW (15.4 percent) of buy and self-schedule bids cleared, up 3.4 percent from 365,843 MW (10.4 percent) for the previous planning period. In the 2015 to 2016 planning period Monthly Balance of Planning Period FTR Auctions 1,466,985 MW (9.3 percent) of FTR buy bids and 803,463 MW (23.0 percent) of FTR sell offers cleared.

- **Price.** The weighted-average buy-bid FTR price in the 2016 to 2019 Long Term FTR Auction was $0.05 per MW, up from $0.04 per MW for the 2015 to 2018 planning period. The weighted-average buy-bid FTR price in the Annual FTR Auction for the 2015 to 2016 planning period 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 2015 to 2016 planning period was $0.25, up from $0.16 per MW for the same period in the 2014 to 2015 planning period.

- **Revenue.** The 2016 to 2019 Long Term FTR Auction generated $23.2 million of net revenue for all FTRs, up from $9.0 million for the 2015 to 2018 Long Term FTR Auction. The 2015 to 2016 Annual FTR Auction generated $936.3 million in net revenue, up from $748.6 million for the 2014 to 2015 Annual FTR Auction. The Monthly Balance of Planning Period FTR Auctions generated $25.8 million in net revenue for all FTRs for the 2015 to 2016 planning period, up from $12.5 million for the same time period in the 2014 to 2015 planning period.

- **Revenue Adequacy.** FTRs were paid at 100 percent of the target allocation level for the 2015 to 2016 planning period. This high level of revenue adequacy was primarily a result of actions taken by PJM to reduce the level of available ARRs and FTRs. 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.

- **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 $453.5 million in profits for physical entities, of which $325.9 million was from self-scheduled FTRs, and $182.3 million for financial entities.

Markets Timeline

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

Recommendations

- The MMU recommends that the ARR/FTR design be modified to ensure that all congestion revenues are returned to load. (Priority: High. New recommendation. Status: Not adopted.)

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.

- The MMU recommends that all FTR auction revenue be distributed to ARR holders. (Priority: High. New recommendation. Status: Not adopted.)
- The MMU recommends that historical generation to load paths be eliminated as a basis for allocating ARRs. (Priority: High. New recommendation. Status: Not adopted.)
- The MMU recommends that counter flow FTRs be eliminated. (Priority: High. New recommendation. Status: Not adopted.)
- The MMU recommends that FTR auction revenues not be used to buy counter flow FTRs with the purpose of improving FTR payout ratios.[5] (Priority: High. New recommendation. Status: Not adopted.)
- The MMU recommends that PJM report correct monthly payout ratios to reduce understatement of payout ratios on a monthly basis. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM eliminate portfolio netting to eliminate cross subsidies among FTR marketplace participants. (Priority: High. First reported 2012. Status: Not adopted. Pending before FERC.)
- 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 2012. 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 the basis for the Stage 1A assignments be reviewed and made explicit, that the role of out of date generation to load paths be reviewed and that the building of the transmission capability required to provide all defined Stage 1A allocations be reviewed. (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 examine the mechanism by which self scheduled FTRs are allocated when load switching among LSEs occurs throughout the planning period. (Priority: Low. First reported 2011. Status: Not adopted.)

Conclusion

The annual ARR allocation should be designed to return congestion revenues to firm transmission service customers, without requiring contract path physical transmission rights that are difficult or impossible to define and enforce in LMP markets. The fixed charges paid for firm transmission services result in the transmission system which provides physically firm transmission service which results in load paying congestion revenues.

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 fact 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 congestion revenues in an LMP market. In other words, load payments in excess

5 See PJM. "Manual 6: Financial Transmission Rights" Revision 16 (June 1, 2014), p. 56.

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, which equals total congestion revenues.

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.

As a result of the creation of ARRs and other changes to the design, the current ARR/FTR design does not serve as an efficient way to ensure that load receives all the congestion revenues or has the ability to receive the auction revenues associated with all the potential congestion revenues. Total ARR and self scheduled FTR revenue offset only 63.8 percent of total congestion costs including congestion in the Day-Ahead Energy Market and the balancing energy market for the 2014 to 2015 planning period.

For these reasons, load should never be required to subsidize payments to FTR holders, regardless of the reason. Such subsidies have been suggested repeatedly.[6] 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 and that congestion is defined, in an accounting sense, to equal the sum of 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 and result in profits to FTR holders.

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 even when defined correctly. Load does have those rights based on load's payment for the transmission system and load's payment of total congestion.

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 balancing congestion which is the other part of total congestion. 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 in recent years, 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 markets. Such differences are not an indication that FTR holders are under paid.

The difference between the congestion payout using total congestion and the congestion payout using only day-ahead congestion illustrates the issue. For 2015, total day-ahead congestion was $1,632.1 million while total day-ahead plus balancing congestion was $1,385.3 million, compared to target allocations of $1,231.3 million in the same time period.

PJM used a more conservative approach to modeling the transmission capability for the 2014 to 2015 planning period. PJM simply assumed higher outage levels and included additional constraints, both of which reduced system capability in the FTR auction model. The result was a significant reduction in Stage 1B and Stage 2 ARR allocations, 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

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

bid prices, increased clearing prices and reduced clearing quantities.

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. In the 2014 to 2015 and 2015 to 2016 planning periods, due to reduced ARR allocations, FTR volume decreased relative to the 2013 to 2014 planning period. The reduction in ARR allocations and resulting FTR volume caused, by definition, an improvement in revenue adequacy, and also resulted in an increase in the prices of FTRs. Increased FTR prices resulted in increased ARR target allocations, because ARR target allocations are based on the Annual FTR Auction nodal prices.

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. The origin and basis for the requirement to assign Stage 1A ARRs needs further investigation. The issues associated with over allocation appear to be based on the use of out of date generation to load ARR paths and on whether PJM has appropriately built transmission to meet the requirement.

The MMU recommends that the basis for the Stage 1A assignments be reviewed and made explicit, that the role of out of date generation to load paths be reviewed and that the building of the transmission capability required to provide all defined Stage 1A allocations be reviewed. The implementation of the MMU's recommendation to return all congestion revenues to load would also significantly affect this issue.

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.

For the 2014 to 2015 and 2015 to 2016 planning periods FTRs have been revenue adequate. This is not because the underlying problems have been fixed. Revenue adequacy has been accomplished by limiting the amount of available ARRs and FTRs by arbitrarily decreasing the ARR allocations for Stage 1B and Stage 2 which also results in a redistribution of ARRs based on differences in allocations between Stage 1A and Stage 1B ARRs.

Auction Revenue Rights

ARRs are the financial instruments through which the proceeds from FTR Auctions are allocated to load based on load's payment for the transmission system and for load's payment of congestion. ARR values are based on nodal price differences between the ARR source and sink points.[7] 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.

The goal of the ARR/FTR design should be to provide an efficient mechanism to ensure that load receives all the congestion revenues, or has the ability to receive the auction revenues associated with all the potential

7 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.

congestion revenues, all auction proceeds should be allocated to the ARR holders. The MMU recommends that all FTR auction proceeds to allocated to ARR holders.

When a new control zone is integrated into PJM, firm transmission customers in that control zone may choose to receive either an FTR allocation or an ARR allocation before the start of the Annual FTR Auction for two consecutive planning periods following their integration date. After the transition period, such participants receive ARRs from the annual allocation process and are not eligible for directly allocated FTRs. Network service users and firm transmission customers cannot choose to receive both an FTR allocation and an ARR allocation. This selection applies to the participant's entire portfolio of ARRs that sink into the new control zone. During this transitional period, the directly allocated FTRs are reallocated, as load shifts between LSEs within the transmission zone.

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.[8] 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 present, 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 13-3.

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.[9] 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 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.[10] While transmission upgrades are being implemented, Stage 1A ARRs, and therefore FTRs, are overallocated which can lead to revenue inadequacy.

8 PJM. "Manual 6: Financial Transmission Rights," Revision 16 (June 1, 2014), 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>.

9 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.

10 See PJM. "Manual 6: Financial Transmission Rights" Revision 16 (June 1, 2014), p. 22.

- **Stage 1B.** ARRs unallocated in Stage 1A are available in the Stage 1B allocation for the following planning period. Network transmission service customers can obtain ARRs, up to their share of the zonal peak load, based on generation resources that historically have served load in each control zone and up to 100 percent of their transmission responsibility for nonzone network load. Firm, point-to-point transmission service customers can obtain ARRs based on the MW of long-term, firm, point-to-point service provided between the receipt and delivery points for the historical reference year. These long-term point-to-point service agreements must also remain in effect for the planning period covered by the allocation.
- **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.[11] 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.[12]

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.[13] 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).[14]

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.

Table 13-3 shows the top 10 principal binding transmission constraints that limited the 2015 to 2016 ARR Stage 1A allocation. PJM was required to increase

11 See PJM. "Manual 6: Financial Transmission Rights," Revision 16 (June 1, 2014), pp. 21.

12 *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.

13 PJM. "Manual 6: Financial Transmission Rights," Revision 16 (June 1, 2014), pp. 55-56.

14 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. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>

capability limits for several facilities in order to make the ARR allocation feasible.[15]

Table 13-3 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
Nelson - Electric Junction	Flowgate	MISO
Cherry Valley - Silverlake	Flowgate	MISO
Pana North	Flowgate	MISO
Nelson - Cordova	Line	ComEd
Pana North	Flowgate	MISO
Cherry Valley	Transformer	ComEd
Pontiac Midpoint - Wilton Ctr.	Flowgate	ComEd

FTR Revenue Adequacy and Stage 1B/Stage 2 ARR Allocations

For the entire 2014 to 2015 and 2015 to 2016 planning periods, FTR 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.

Figure 13-1 Historic Stage 1B and Stage 2 ARR Allocations from the 2011 to 2012 through 2015 to 2016 planning period

15 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.

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 arbitrary 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.

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 has 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 13-1 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. Total Stage 1B and Stage 2 ARR allocations increased in the 2015 to 2016 planning year over the 2014-2015 planning year allocations, from 4,605.6 MW to 6,996.1 MW. But the ARR allocations for the 2015-2016 planning year were still 79.7 percent below 2013 to 2014 planning year volumes of 34,444.0 MW. The dollars per ARR MW for the first seven months of the 2014 to 2015 and 2015 to 2016 planning periods were up 68.5 percent and 15.6 percent relative to the 2013 to 2014 planning period while congestion was up by only 33.6 percent and 25.8 percent relative to the first seven months of the 2013 to 2014 planning period.

Table 13-4 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 arbitrary increase in modeled outages 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 13-4 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

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.[16] ARR reassignment occurs daily only if the LSE losing load has ARRs with a net positive economic value to that control zone. An LSE gaining load in the same control zone is allocated a proportional share of positively valued ARRs within the control zone based on the shifted load. ARRs are reassigned to the nearest 0.001 MW and any MW of load may be reassigned multiple times over a planning period. Residual ARRs are also subject to the rules of ARR reassignment. This practice supports competition by ensuring that the offset to congestion follows load, thereby removing a barrier to competition among LSEs and, by ensuring that only ARRs with a positive value are reassigned, preventing an LSE from assigning poor ARR choices to other LSEs. However, when ARRs are 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 53,343 MW of ARRs associated with $503,400 of revenue that were reassigned in the 2014 to 2015 planning period. There were 43,089 MW of ARRs associated with $504,600 of revenue that were reassigned for the 2015 to 2016 planning period.

16 See PJM. "Manual 6: Financial Transmission Rights," Revision 16 (June 1, 2014), p. 28.

Table 13-5 summarizes ARR MW and associated revenue automatically reassigned for network load in each control zone where changes occurred between June 2014 and December 2015.

Table 13-5 ARRs and ARR revenue automatically reassigned for network load changes by control zone: June 1, 2014, through December 31, 2015

	ARRs Reassigned (MW-day)		ARR Revenue Reassigned [Dollars (Thousands) per MW-day]	
Control Zone	2014/2015 (12 months)	2015/2016 (7 months)*	2014/2015 (12 months)	2015/2016 (7 months)*
AECO	539	462	$3.1	$3.5
AEP	2,453	6,657	$37.5	$66.9
AP	2,351	1,709	$50.9	$40.9
ATSI	8,627	4,625	$70.8	$42.3
BGE	3,264	2,557	$52.7	$81.1
ComEd	6,720	3,478	$94.9	$87.2
DAY	794	417	$1.1	$0.8
DEOK	6,490	5,821	$13.8	$27.9
DLCO	5,891	4,245	$10.9	$9.0
DPL	1,853	1,289	$30.5	$45.7
Dominion	20	20	$0.3	$0.3
EKPC	0	0	$0.0	$0.0
JCPL	1,354	1,138	$9.5	$8.8
Met-Ed	1,018	858	$11.2	$7.4
PECO	2,949	3,554	$27.1	$19.3
PENELEC	1,019	906	$15.4	$15.8
PPL	3,953	2,578	$20.6	$14.0
PSEG	1,510	1,059	$36.8	$25.4
Pepco	2,486	1,676	$16.3	$8.3
RECO	49	42	$0.0	$0.0
Total	53,343	43,089	$503.4	$504.6

* Through 31-December-2015

Incremental ARRs (IARRs) for RTEP Upgrades

Table 13-6 lists the incremental ARR allocation volume for the planning periods from the 2008 to 2009 planning period through the 2015 to 2016 planning period.

Table 13-6 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 13-7 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 13-7 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 13-8 shows the Residual ARRs automatically allocated to eligible participants, along with the target allocations from the effective month. In the first seven months of the 2015 to 2016 planning period planning period, PJM allocated a total of 19,409.44 MW of residual ARRs, up from 15,096.9 MW for the first seven months of the 2014 to 2015 planning period. Residual ARRs had a total target allocation of $5.9 million for the first seven months of the 2015 to 2016 planning period, down from $6.6 million for the first seven months of the 2014 to 2015 planning period consistent with a decrease in Monthly Balance of Planning Period Auction prices from the previous year. 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 13-8 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
Jul-15	4,859.7	3,047.7	62.7%	$1,563,502
Aug-15	4,142.6	2,932.5	70.8%	$1,071,790
Sep-15	3,393.8	2,850.9	84.0%	$973,555
Oct-15	3,690.4	2,553.8	69.2%	$651,586
Nov-15	8,784.6	3,643.7	41.5%	$562,507
Dec-15	4,152.6	2,604.9	62.7%	$650,267
Total	58,610.4	26,845.4	45.8%	$7,458,577

Market Performance

Volume

Table 13-9 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 13-9 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.[17]

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.

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.[18]

Figure 13-2 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.

Figure 13-2 Stage 1A Infeasibility Funding Impact

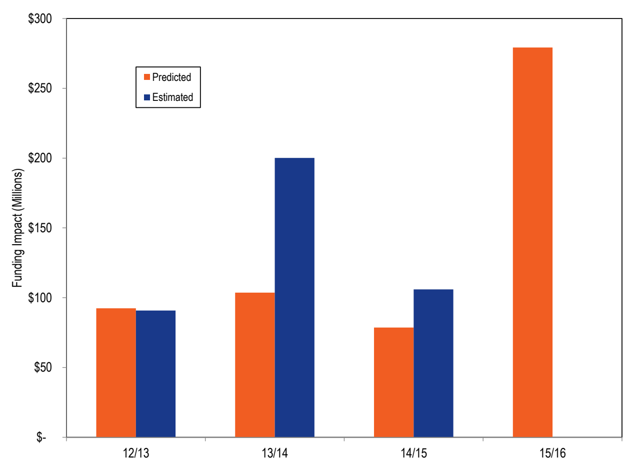
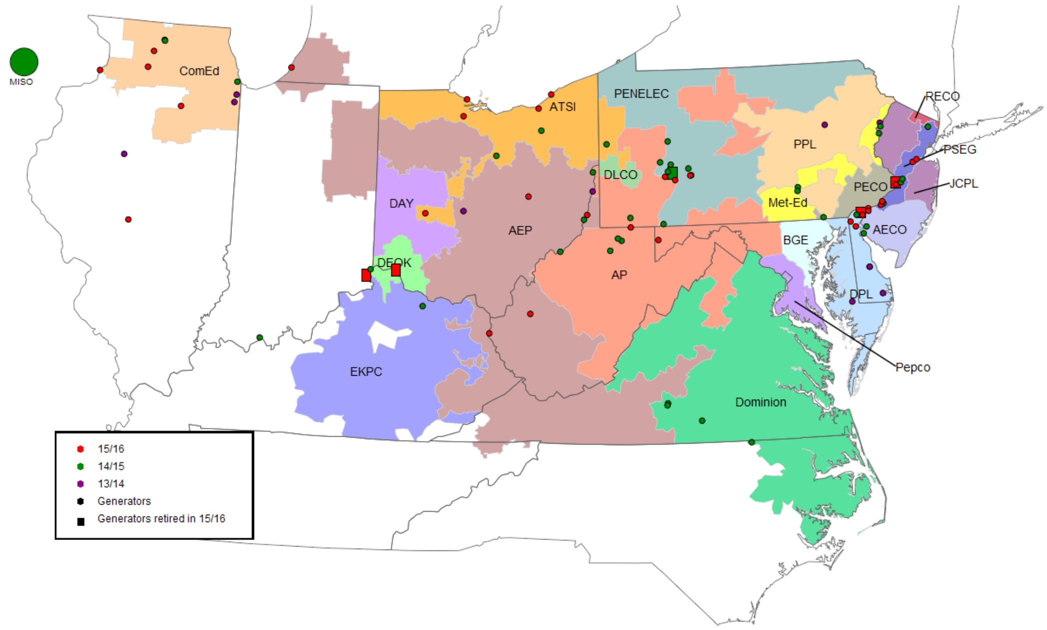


Figure 13-3 shows a map of over allocated ARR source points in Stage 1A, regardless of reason, for the 2013 to 2014 through 2015 to 2016 planning period. The year indicated for each source point is the latest year that source was announced as over allocated in the Stage 1A process. Generators retired as of the 2015 to 2016 planning period are indicated by a square marker to show Stage 1A source points that are no longer in service for the most recent Stage 1A allocation period.

17 PJM. "Manual 6: Financial Transmission Rights," Revision 16 (June 1, 2014), p22.

18 *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 13-3 Overallocated Stage 1A ARR source points



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 13-10 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 2014 to 2015 planning period and the 2015 to 2016 planning periods. As seen here, due to decreased FTR volume leading to increased FTR nodal prices, auction revenue increased 24.5 percent while projected ARR target allocations increased 26.1 percent from the previous planning period.

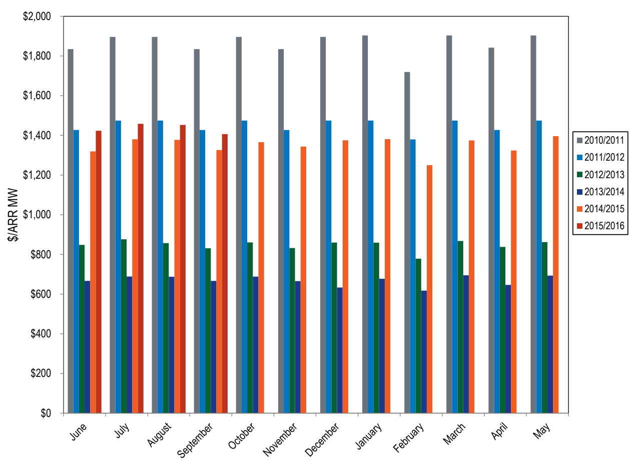
Table 13-10 Projected ARR revenue adequacy (Dollars (Millions)): Planning periods 2014 to 2015 and 2015 to 2016

	2014/ 2015	2015/ 2016
Total FTR auction net revenue	$767.9	$962.0
Annual FTR Auction net revenue	$748.6	$936.3
Monthly Balance of Planning Period FTR Auction net revenue*	$19.3	$25.8
ARR target allocations	$735.3	$928.8
ARR credits	$735.3	$928.8
Surplus auction revenue	$32.6	$33.2
ARR payout ratio	100%	100%
FTR payout ratio*	100%	100%

* Shows twelve months for 2014/2015 and seven months for 2015/2016.

Figure 13-4 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 resulted 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. For the first seven months of the 2015 to 2016 planning period, the dollars per MW of ARR allocation was $7,739.36.

Figure 13-4 Dollars per ARR MW paid to ARR holders: Planning periods 2010 to 2011 through 2015 to 2016



Excess ARR Revenue

Figure 13-5 shows the monthly excess ARR revenue from the 2011 to 2012 through 2015 to 2016 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. Stage 1A ARRs may be over allocated in the initial Stage 1A process, which requires that facility limits are increased above their actual capability. These increased facility limits must be carried over into the FTR auctions, which results in an over selling of FTR MW. Beginning with the 2014 to 2015 planning period, market rules allow PJM to decrease prevailing flow target allocations 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 FTR auction revenue is allocated pro rata to FTR holders at the end of the planning period, instead of being distributed to ARR holders.

Figure 13-5 Monthly excess ARR revenue: Planning periods 2011 to 2012 through 2015 to 2016

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 target allocation 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 target allocation 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.

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.[19] 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 may be included in the model, while known outages of five days or more may be 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.[20] The full list of outages selected is publicly posted, but the process by which these outages are selected is not fully explained and PJM exercises significant discretion in selecting outages to accomplish FTR revenue adequacy.

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.

Long Term FTR Auctions

PJM conducts a Long Term FTR Auction for the next three consecutive planning periods. The capacity offered for sale in Long Term FTR Auctions is the residual system capability assuming that all ARRs allocated in the prior annual ARR allocation process are self scheduled as FTRs. These ARRs are modeled as fixed injections and withdrawals in the Long Term FTR Auction. Future transmission upgrades are not included in the model. The 2009 to 2012 and 2010 to 2013 Long Term FTR Auctions consisted of two rounds.[21] The 2011 to 2014 and 2012 to 2015 Long Term FTR Auctions consisted of three rounds. FTRs purchased in prior rounds may be offered for sale in subsequent rounds. FTRs obtained

19 See PJM. "Manual 6: Financial Transmission Rights," Revision 16 (June 1, 2014), p. 38.

20 See PJM. "Manual 6: Financial Transmission Rights," Revision 16 (June 1, 2014), p. 55.

21 FERC approved, on December 7, 2009, the addition of a third round to the Long Term FTR Auction. FERC letter order accepting PJM Interconnection, L.L.C.'s revisions to Long-Term Financial Transmission Rights Auctions to its Amended and Restated Operating Agreement and Open Access Transmission Tariff, Docket No. ER10-82-000 (December 7, 2009).

in the Long Term Auctions may have terms of any one year or a single term of all three years. FTR products available in the Long Term Auction include 24-hour, on peak and off peak FTR obligations. FTR option products are not available in Long Term FTR Auctions.

- **Round 1.** The first round is conducted in the June prior to the start of the term covered by the Long Term FTR Auction. Market participants make offers for FTRs between any source and sink.
- **Round 2.** The second round is conducted approximately three months after the first round and follows the same rules as Round 1.
- **Round 3.** The third round is conducted approximately six months after the first round and follows the same rules as Round 1.

Table 13-11 and Table 13-12 show the top 10 binding constraints for the 2016 to 2018 Long Term FTR Auction and the 2015 to 2016 Annual FTR Auction based on the marginal value of on peak hours. The severity ranking is based on the marginal value of the constraint in the simultaneous feasibility test.

Table 13-11 Top 10 principal binding transmission constraints limiting the Long Term FTR Auction: Planning periods 2016 to 2019

			Severity Ranking by Auction Round		
Constraint	Type	Control Zone	1	2	3
Kenney - Stockton	Line	DPL	NA	NA	1
Glenview - Kleeman	Line	DEOK	NA	NA	2
Garner D. P.	Transformer	Dominion	791	706	3
Cornell - Cornell Tap	Line	DEOK	NA	1	5
New Hope - Ocean Pines	Line	DPL	NA	2	22
St. Johns	Transformer	Dominion	NA	NA	4
Erie South - French Road	Line	Penelec	9	5	6
Grovewood - Grovewood Tap	Line	ATSI	NA	NA	7
Montgomery - Rochelle	Line	DEOK	NA	3	NA
Fremont - West Fremont	Line	AEP	16	4	12

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 13-12 shows the top 10 binding constraints for the 2015 to 2016 Annual FTR Auction based on the marginal value of on peak hours.

Table 13-12 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.[22]

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 Monthly Balance of Planning Period FTR Auctions for the 2014 to 2015 planning period and the first four months of the 2015 to 2016 planning period were 25,346,227 MW and 7,840,917 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 13-13 presents the 2016 to 2019 Long Term FTR Auction market cleared FTRs by trade type, organization type and FTR direction. The results show that financial entities purchased 70.1 percent of prevailing flow buy bid FTRs and 78.5 percent of counter flow buy bid FTRs with the result that financial entities purchased 73.8 percent of all Long Term FTR Auction cleared buy bids for the 2016 to 2019 Long Term FTR Auction.

Table 13-13 Long Term FTR Auction patterns of ownership by FTR direction: Planning periods 2016 to 2019

		FTR Direction		
Trade Type	Organization Type	Prevailing Flow	Counter Flow	All
Buy Bids	Physical	29.9%	21.5%	26.2%
	Financial	70.1%	78.5%	73.8%
	Total	100.0%	100.0%	100.0%
Sell Offers	Physical	29.2%	24.3%	27.5%
	Financial	70.8%	75.7%	72.5%
	Total	100.0%	100.0%	100.0%

Table 13-14 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.

Table 13-14 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 13-15 presents the Monthly Balance of Planning Period FTR Auction cleared FTRs for 2015 by trade type, organization type and FTR direction. Financial entities purchased 74.9 percent of prevailing flow FTRs, down

22 See PJM. "Manual 6: Financial Transmission Rights," Revision 16 (June 1, 2014), p. 39.

5.2 percent, and 76.8 percent of counter flow FTRs, down 11.0 percent, for the year, with the result that financial entities purchased 75.7 percent, down 7.3 percent, of all prevailing and counter flow FTR buy bids in the Monthly Balance of Planning Period FTR Auction cleared FTRs for 2015.

Table 13-15 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	25.1%	23.2%	24.3%
	Financial	74.9%	76.8%	75.7%
	Total	100.0%	100.0%	100.0%
Sell Offers	Physical	33.8%	34.7%	34.1%
	Financial	66.2%	65.3%	65.9%
	Total	100.0%	100.0%	100.0%

Table 13-16 presents the average daily net position ownership for all FTRs for 2015, by FTR direction.

Table 13-16 Daily FTR net position ownership by FTR direction: 2015

	FTR Direction		
Organization Type	Prevailing Flow	Counter Flow	All
Physical	39.4%	20.4%	32.1%
Financial	60.6%	79.6%	67.9%
Total	100.0%	100.0%	100.0%

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.[23]

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.[24]

In the 2016 to 2019 Long Term FTR Auction 120,650 MW (23.2 percent of demand; 43.5 percent of total FTR volume) of counter flow FTR buy bids cleared, an increase from 104,812 MW and 37.7 percent of total FTR volume. In the same auction, prevailing flow FTR buy bids cleared 156,746 MW (8.1 percent of demand; 56.5 percent of total FTR volume) a decrease from 173,054 MW and 62.3 percent of total FTR volume. In the 2016 to 2019 Long Term FTR Auction, there were 22,060 MW (13.5 percent) of counter flow sell offers and 39,151 MW (23.8 percent) of prevailing flow sell offers cleared.

23 See PJM. "Manual 6: Financial Transmission Rights," Revision 16 (June 1, 2014) p. 56.

24 See PJM. "Manual 6: Financial Transmission Rights," Revision 16 (June 1, 2014) p. 56.

Table 13-17 Long Term FTR Auction market volume: Planning period 2016 to 2019

Trade Type	FTR Direction	Period Type	Bid and Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
Buy bids	Counter Flow	Year 1	69,294	203,576	44,632	21.9%	158,944	78.1%
		Year 2	60,191	167,272	37,036	22.1%	130,236	77.9%
		Year 3	56,893	146,128	37,819	25.9%	108,309	74.1%
		Year All	481	2,849	1,162	40.8%	1,687	59.2%
		Total	186,859	519,826	120,650	23.2%	399,176	76.8%
	Prevailing Flow	Year 1	163,197	708,948	60,879	8.6%	648,069	91.4%
		Year 2	142,419	583,929	47,617	8.2%	536,313	91.8%
		Year 3	144,512	609,599	47,743	7.8%	561,856	92.2%
		Year All	6,237	37,643	507	1.3%	37,135	98.7%
		Total	456,365	1,940,120	156,746	8.1%	1,783,373	91.9%
	Total		643,224	2,459,946	277,397	11.3%	2,182,549	88.7%
Sell offers	Counter Flow	Year 1	36,047	101,383	15,139	14.9%	86,243	85.1%
		Year 2	19,076	52,779	6,339	12.0%	46,440	88.0%
		Year 3	4,649	9,646	581	6.0%	9,064	94.0%
		Year All	NA	NA	NA	NA	NA	NA
		Total	59,772	163,807	22,060	13.5%	141,747	86.5%
	Prevailing Flow	Year 1	39,472	102,176	26,278	25.7%	75,898	74.3%
		Year 2	22,689	49,719	11,330	22.8%	38,389	77.2%
		Year 3	6,510	12,278	1,542	12.6%	10,736	87.4%
		Year All	NA	NA	NA	NA	NA	NA
		Total	68,671	164,173	39,151	23.8%	125,022	76.2%
	Total		128,443	327,980	61,210	18.7%	266,770	81.3%

Table 13-18 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.

Table 13-18 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

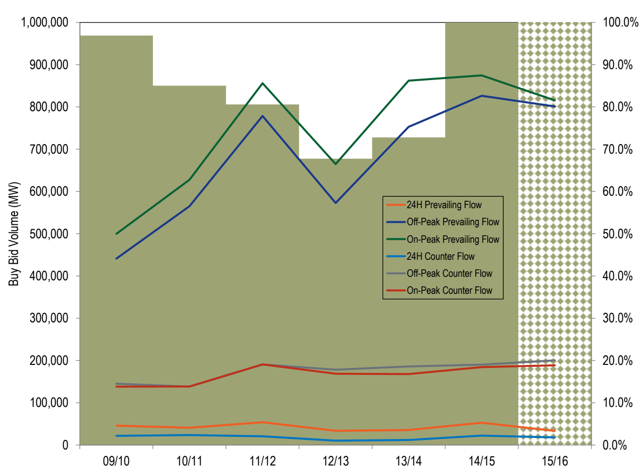


Figure 13-7 shows the cleared volumes of the Annual FTR Auctions from planning period 2009 to 2010 through the 2015 to 2016 planning period and the associated planning period payout ratios, represented by the background bars. The payout ratio for the current planning period is shown as dotted background 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

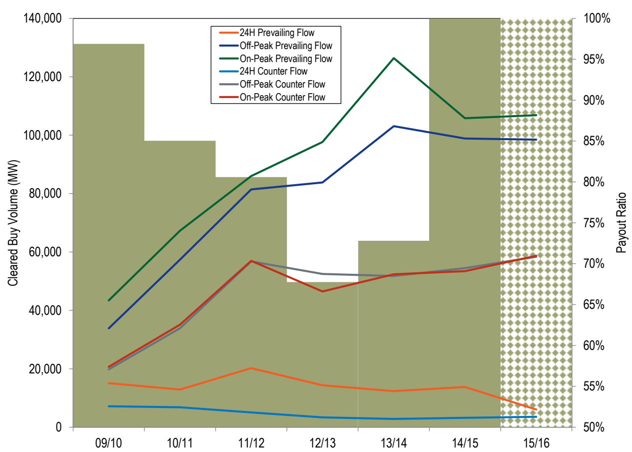


Table 13-19 shows the proportion of ARRs self-scheduled as FTRs for the last six planning periods. The maximum possible level of self-scheduled FTRs includes all ARRs, including RTEP ARRs. Eligible participants self-scheduled 23,699 MW (30.4 percent) of ARRs as FTRs for the 2015 to 2016 planning period, 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 13-19 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 13-20 provides the Monthly Balance of Planning Period FTR Auction market volume for the entire 2014 to 2015 planning period and the first seven months of the 2015 to 2016 planning period. There were 13,392,911 MW of FTR obligation buy bids and 3,163,460 MW of FTR obligation sell offers for all bidding periods in the first seven months of the 2015 to 2016 planning period. The monthly balance of planning period auction cleared 1,408,108 MW (10.5 percent) of FTR obligation buy bids and 714,041 MW (22.6 percent) of FTR obligation sell offers.

There were 2,420,615 MW of FTR option buy bids and 332,014 MW of FTR option sell offers for all bidding periods in the Monthly Balance of Planning Period FTR Auctions for the first seven months of the 2015 to 2016 planning period. The monthly auctions cleared 58,877 (2.4 percent) of FTR option buy bids, and 89,422 MW (26.9 percent) of FTR option sell offers.

Table 13-20 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%
Jul-15	Obligations	Buy bids	427,398	1,909,109	208,278	10.9%	1,700,831	89.1%
		Sell offers	185,213	575,921	111,179	19.3%	464,742	80.7%
	Options	Buy bids	16,004	432,537	9,019	2.1%	423,517	97.9%
		Sell offers	14,202	52,274	15,790	30.2%	36,483	69.8%
Aug-15	Obligations	Buy bids	379,565	1,624,183	174,941	10.8%	1,449,242	89.2%
		Sell offers	147,217	405,601	92,842	22.9%	312,759	77.1%
	Options	Buy bids	14,473	421,949	8,971	2.1%	412,978	97.9%
		Sell offers	12,307	46,856	12,875	27.5%	33,981	72.5%
Sep-15	Obligations	Buy bids	416,971	2,241,148	249,881	11.1%	1,991,267	88.9%
		Sell offers	146,522	420,845	86,461	20.5%	334,385	79.5%
	Options	Buy bids	12,489	387,724	9,252	2.4%	378,472	97.6%
		Sell offers	11,516	48,013	12,315	25.6%	35,698	74.4%
Oct-15	Obligations	Buy bids	333,888	1,416,533	179,387	12.7%	1,237,146	87.3%
		Sell offers	160,065	465,514	104,934	22.5%	360,581	77.5%
	Options	Buy bids	13,032	287,985	7,718	2.7%	280,267	97.3%
		Sell offers	9,167	42,569	10,572	24.8%	31,997	75.2%
Nov-15	Obligations	Buy bids	388,822	2,208,150	207,167	9.4%	2,000,983	90.6%
		Sell offers	147,105	382,018	111,712	29.2%	270,306	70.8%
	Options	Buy bids	13,314	274,669	7,677	2.8%	266,992	97.2%
		Sell offers	8,310	40,607	10,822	26.7%	29,785	73.3%
Dec-15	Obligations	Buy bids	368,842	1,976,377	201,097	10.2%	1,775,280	89.8%
		Sell offers	146,219	359,859	104,188	29.0%	255,671	71.0%
	Options	Buy bids	10,814	262,952	8,240	3.1%	254,711	96.9%
		Sell offers	9,662	44,596	11,876	26.6%	32,720	73.4%
2014/2015*	Obligations	Buy bids	333,888	21,777,160	179,387	0.8%	21,597,773	99.2%
		Sell offers	160,065	3,357,375	104,934	3.1%	3,252,441	96.9%
	Options	Buy bids	13,032	3,569,067	7,718	0.2%	3,561,348	99.8%
		Sell offers	9,167	225,710	10,572	4.7%	215,138	95.3%
2015/2016**	Obligations	Buy bids	2,700,252	13,392,911	1,408,108	10.5%	11,984,803	89.5%
		Sell offers	1,112,482	3,163,460	714,041	22.6%	2,449,419	77.4%
	Options	Buy bids	92,555	2,420,615	58,877	2.4%	2,361,738	97.6%
		Sell offers	76,205	332,014	89,422	26.9%	242,593	73.1%

* Shows twelve months for 2014/2015; ** Shows seven months ended December 31 for 2015/2016

Table 13-21 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 180,531.0 MW. The average monthly cleared volume for 2014 was 224,036.6 MW.

Table 13-21 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	128,762	286,539	295,518	273,146	2,370,211
	Cleared	81,472	22,796	20,096	8,887	22,091	23,222	16,792	195,356
Jul-15	Bid	904,856	349,043	208,322		291,464	304,176	283,784	2,341,645
	Cleared	94,500	29,493	14,536		26,019	28,501	24,249	217,298
Aug-15	Bid	691,897	309,793	197,303		253,731	304,429	288,979	2,046,131
	Cleared	80,734	22,612	16,510		16,943	25,396	21,717	183,912
Sep-15	Bid	1,153,687	364,094	306,346		138,961	343,682	322,103	2,628,872
	Cleared	132,952	37,968	24,533		11,011	23,214	29,455	259,133
Oct-15	Bid	672,814	306,427	221,964			261,395	241,919	1,704,518
	Cleared	94,781	30,910	13,282			23,195	24,938	187,105
Nov-15	Bid	1,343,152	329,830	307,998			205,138	296,701	2,482,819
	Cleared	108,573	32,856	26,531			14,028	32,857	214,844
Dec-15	Bid	1,241,897	307,725	249,625			138,292	301,790	2,239,329
	Cleared	124,375	26,497	17,112			10,766	30,587	209,337

Figure 13-8 Cleared auction volume (MW) as a percent of total FTR cleared volume by calendar month: June 2004 through December 2015

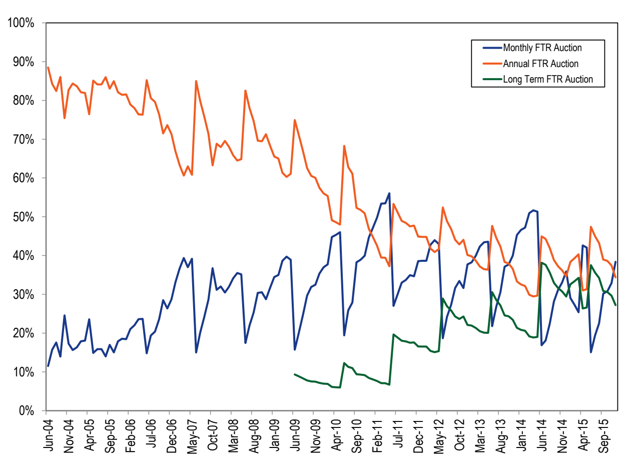


Figure 13-8 shows cleared auction volumes as a percent of the total FTR cleared volume by calendar months for June 2004 through December 2015, by type of auction. FTR volumes are included in the calendar month they are effective, with Long Term and Annual FTR auction volume spread equally to each month 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.

Table 13-22 provides the secondary bilateral FTR market volume for the entire 2014 to 2015 and 2015 to 2016 planning periods.

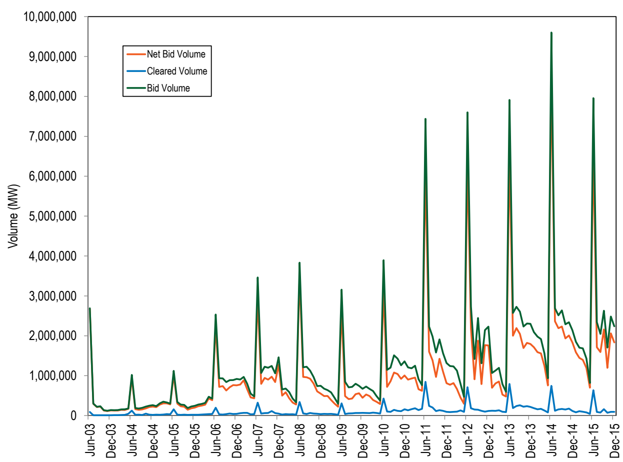
Table 13-22 Secondary bilateral FTR market volume: Planning periods 2014 to 2015 and 2015 to 2016[25]

Planning Period	Type	Class Type	Volume (MW)
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
2015/2016	Obligation	24-Hour	636
		On Peak	20,338
		Off Peak	17,842
		Total	38,816
	Option	24-Hour	0
		On Peak	2,523
		Off Peak	2,169
		Total	4,691

25 The 2013 to 2014 planning period covers bilateral FTRs that are effective for any time between June 1, 2013 through June 1, 2014, which originally had been purchased in a Long Term FTR Auction, Annual FTR Auction or Monthly Balance of Planning Period FTR Auction.

Figure 13-9 shows the FTR bid, cleared and net bid volume from June 2003 through December 2015 for Long Term, Annual and Monthly Balance of Planning Period Auctions.[26] 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 December 2015



Price

Table 13-23 shows the cleared, weighted-average prices by trade type, FTR direction, period type and class type for the 2016 to 2019 Long Term FTR Auction. Only FTR obligation products are available in the Long Term FTR Auctions. In this auction, weighted-average buy bid counter flow and prevailing flow FTR prices were -$0.36 and $0.28, compared to -$0.23 and $0.21 from the 2014 to 2017 Long Term FTR Auction. Weighted-average sell bid counter flow and prevailing flow FTR prices were -$0.33 and $0.45, compared to -$0.42 for counter flow FTRs and up from $0.27 for prevailing flow FTRs.

Table 13-23 Long Term FTR Auction weighted-average cleared prices (Dollars per MW): Planning periods 2016 to 2019

			Class Type			
Trade Type	FTR Direction	Period Type	24-Hour	On Peak	Off Peak	All
Buy bids	Counter Flow	Year 1	($1.02)	($0.40)	($0.59)	($0.53)
		Year 2	($0.76)	($0.39)	($0.58)	($0.50)
		Year 3	($0.45)	($0.31)	($0.51)	($0.40)
		Year All	NA	($0.05)	($0.11)	($0.07)
		Total	($0.80)	($0.36)	($0.55)	($0.47)
	Prevailing Flow	Year 1	$0.64	$0.44	$0.63	$0.54
		Year 2	$0.59	$0.37	$0.56	$0.46
		Year 3	$0.52	$0.27	$0.43	$0.35
		Year All	NA	$0.00	$0.30	$0.13
		Total	$0.56	$0.36	$0.55	$0.45
	Total		($0.09)	$0.04	$0.07	$0.05
Sell offers	Counter Flow	Year 1	($1.57)	($0.32)	($0.51)	($0.41)
		Year 2	NA	($0.23)	($0.38)	($0.30)
		Year 3	NA	($0.16)	($0.29)	($0.21)
		Year All	NA	NA	NA	NA
		Total	($1.55)	($0.29)	($0.47)	($0.37)
	Prevailing Flow	Year 1	$1.02	$0.36	$0.58	$0.46
		Year 2	$1.14	$0.25	$0.48	$0.35
		Year 3	NA	$0.26	$0.53	$0.38
		Year All	NA	NA	NA	NA
		Total	$1.04	$0.32	$0.55	$0.43
	Total		($0.04)	$0.10	$0.19	$0.14

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.

26 The data for this table are available in *2014 State of the Market Report for PJM*, Volume 2, Appendix H.

Figure 13-10 Annual FTR Auction volume-weighted average buy bid price: Planning period 2009 to 2010 through 2015 to 2016

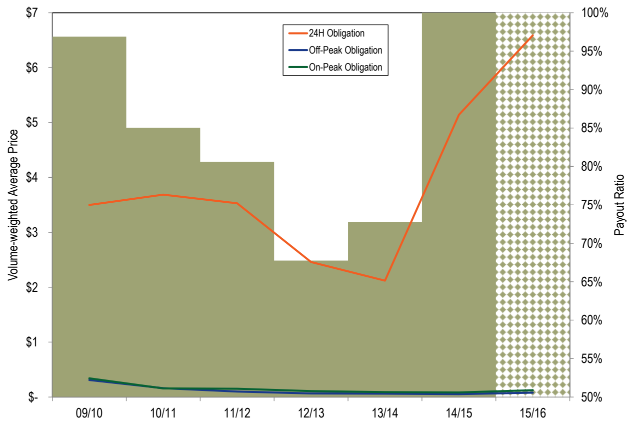


Table 13-24 shows the weighted-average cleared buy-bid prices by trade type, FTR product, FTR direction and class type for the Annual FTR Auction for the 2015 to 2016 planning period. The weighted-average cleared buy bid price in the 2015 to 2016 Annual FTR Auction was $0.31 per MW, up from $0.29 per MW in the 2014 to 2015 planning period.

Table 13-24 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 13-25 shows the weighted-average cleared buy-bid price in the Monthly Balance of Planning Period FTR Auctions by bidding period for January 2015 through December 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.

The cleared weighted-average price paid in the Monthly Balance of Planning Period FTR Auctions for January through December 2015 was $0.24 per MW, up from $0.16 per MW in the same time last year, a 50.0 percent increase in FTR prices. The cleared weighted-average price for the current planning period was $0.25, up 56.2 percent from $0.16 for the same time period during the previous planning period.

Table 13-25 Monthly Balance of Planning Period FTR Auction cleared, weighted-average, buy-bid price per period (Dollars per MW): January through December 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
Jul-15	$0.25	$0.33	$0.02		$0.31	$0.39	$0.20	$0.28
Aug-15	$0.21	$0.21	$0.24		$0.06	$0.47	$0.24	$0.26
Sep-15	$0.08	$0.13	$0.08		$0.32	$0.42	$0.15	$0.18
Oct-15	$0.19	$0.20	($0.05)			$0.47	$0.16	$0.24
Nov-15	$0.17	$0.20	$0.34			$0.39	$0.17	$0.21
Dec-15	$0.16	$0.23	$0.33			$0.23	$0.16	$0.18

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.

The fact that FTRs have been consistently profitable regardless of the payout ratio raises questions about the design of the process. If FTRs are profitable why do participants not bid FTR prices up to the point where profits approach zero?

Table 13-26 FTR profits by organization type and FTR direction: 2015

Organization Type	FTR Direction: Prevailing Flow	Self Scheduled Prevailing Flow	Counter Flow	Self Scheduled Counter Flow	All
Physical	$153,200,377	$324,887,334	($25,582,647)	$1,042,334	$453,547,398
Financial	$147,619,734	NA	$34,662,401	NA	$182,282,134
Total	$300,820,110	$324,887,334	$9,079,754	$1,042,334	$635,829,532

Table 13-26 lists FTR profits by organization type and FTR direction for the period from January through December 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 $453.5 million in profits for physical entities, of which $325.9 million was from self-scheduled FTRs, and $182.3 million for financial entities. Counter flow FTR profits for financial participants increased greatly in the fourth quarter, from $1.3 million at the end of the September to $34.7 million at the end December. In 2014, FTRs were more profitable, with an overall profit of $1,417.6 million. The large profit last year was mainly due to January 2014, which experienced unusually high congestion.

Table 13-27 lists the monthly FTR profits in 2015 by organization type.

Table 13-27 Monthly FTR profits by organization type: 2015

Month	Organization Type: 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
Jul	($1,273,858)	$16,657,006	($3,054,368)	$12,328,779
Aug	($7,223,862)	$12,479,243	($12,355,914)	($7,100,534)
Sep	$8,763,025	$16,495,114	($1,942,823)	$23,315,316
Oct	$11,147,268	$18,948,791	($3,208,916)	$26,887,143
Nov	$18,125,472	$20,090,351	$926,228	$39,142,051
Dec	($10,999,614)	$12,175,007	$9,803,392	$10,978,784
Total	$128,796,027	$325,923,265	$181,118,455	$635,837,747

Revenue

Long Term FTR Auction Revenue

Table 13-28 shows the Long Term FTR Auction revenue data by trade type, FTR direction, period type and class type. The 2016 to 2019 Long Term FTR Auction netted $23.2 million in revenue, $6.4 million more than the previous Long Term FTR Auction. Buyers paid $60.4 million and sellers received $37.1 million, up $33.2 million and $26.7 million over the previous Long Term FTR Auction. In general, revenue increased substantially over the previous Long Term FTR Auction, with counter flow buy bid revenue increasing 198.7 percent and prevailing flow buy bid revenue increasing 169.8 percent.

Table 13-28 Long Term FTR Auction Revenue: Planning periods 2016 to 2019

			Class Type			
Trade Type	FTR Direction	Period Type	24-Hour	On Peak	Off Peak	All
Buy bids	Counter Flow	Year 1	($17,524,187)	($51,369,274)	($40,309,389)	($109,202,849)
		Year 2	($8,298,786)	($42,364,684)	($32,890,794)	($83,554,264)
		Year 3	($3,506,308)	($35,282,333)	($29,002,985)	($67,791,626)
		Year All	($2)	($624,031)	($478,803)	($1,102,835)
		Total	($29,329,283)	($129,640,322)	($102,681,970)	($261,651,575)
	Prevailing Flow	Year 1	$8,227,038	$77,647,069	$60,254,171	$146,128,278
		Year 2	$7,639,963	$52,624,403	$39,843,317	$100,107,683
		Year 3	$6,187,338	$38,876,904	$29,771,775	$74,836,017
		Year All	$57,704	$877,122	$12,452	$947,278
		Total	$22,112,044	$170,025,498	$129,881,715	$322,019,256
	Total		($7,217,239)	$40,385,176	$27,199,744	$60,367,681
Sell offers	Counter Flow	Year 1	($521,181)	($14,981,202)	($11,736,474)	($27,238,857)
		Year 2	($85)	($4,755,532)	($3,573,202)	($8,328,818)
		Year 3	0	($305,404)	($238,399)	($543,803)
		Year All	NA	NA	NA	NA
		Total	($521,266)	($20,042,138)	($15,548,074)	($36,111,478)
	Prevailing Flow	Year 1	$406,667	$30,277,463	$22,341,053	$53,025,184
		Year 2	$81,595	$10,556,020	$6,982,324	$17,619,939
		Year 3	0	$1,630,664	$961,927	$2,592,591
		Year All	NA	NA	NA	NA
		Total	$488,262	$42,464,148	$30,285,304	$73,237,714
	Total		($33,004)	$22,422,010	$14,737,230	$37,126,236
Total			($7,184,236)	$17,963,167	$12,462,515	$23,241,446

Annual FTR Auction Revenue

Table 13-29 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 13-29 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 13-30 shows Monthly Balance of Planning Period FTR Auction revenue by trade type, type and class type for January through December 2015. The Monthly Balance of Planning Period FTR Auctions for the 2015 to 2016 planning period netted $25.8 million in revenue, with buyers paying $209.4 million and sellers receiving $183.7 million for the first seven months 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 13-30 Monthly Balance of Planning Period FTR Auction revenue: 2015

Monthly Auction	Type	Trade Type	Class 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
Jul-15	Obligations	Buy bids	$1,633,632	$22,311,865	$12,897,614	$36,843,111
		Sell offers	($412,532)	$17,080,478	$10,400,325	$27,068,271
	Options	Buy bids	$506	$1,302,588	$1,094,866	$2,397,960
		Sell offers	$83,391	$4,106,104	$2,423,493	$6,612,988
Aug-15	Obligations	Buy bids	$80,255	$14,604,065	$12,805,600	$27,489,920
		Sell offers	($3,479,752)	$11,900,107	$11,647,533	$20,067,888
	Options	Buy bids	$1,872	$1,208,914	$809,947	$2,020,733
		Sell offers	$57,496	$3,545,631	$2,492,184	$6,095,311
Sep-15	Obligations	Buy bids	$1,630,612	$12,189,005	$10,198,226	$24,017,843
		Sell offers	$358,566	$8,995,434	$8,449,341	$17,803,342
	Options	Buy bids	$495	$1,222,013	$831,324	$2,053,832
		Sell offers	$26,129	$2,705,884	$2,197,030	$4,929,043
Oct-15	Obligations	Buy bids	$1,903,005	$12,642,794	$8,345,348	$22,891,147
		Sell offers	$561,997	$10,797,329	$7,260,665	$18,619,990
	Options	Buy bids	$0	$1,554,390	$729,719	$2,284,108
		Sell offers	$13,688	$2,540,958	$1,557,775	$4,112,421
Nov-15	Obligations	Buy bids	$1,213,851	$11,643,030	$7,713,134	$20,570,016
		Sell offers	$206,940	$9,891,738	$6,548,379	$16,647,057
	Options	Buy bids	$0	$2,385,279	$1,549,702	$3,934,981
		Sell offers	$13,833	$2,746,512	$2,166,151	$4,926,496
Dec-15	Obligations	Buy bids	$808,713	$10,694,821	$6,415,188	$17,918,722
		Sell offers	$255,028	$7,855,695	$4,575,367	$12,686,091
	Options	Buy bids	$2,278	$1,275,897	$845,480	$2,123,655
		Sell offers	$6,506	$2,643,983	$1,852,588	$4,503,077
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	$8,244,313	$109,905,072	$74,210,353	$192,359,738
		Sell offers	($1,657,264)	$85,000,154	$61,210,868	$144,553,757
	Options	Buy bids	$5,151	$10,349,983	$6,710,402	$17,065,536
		Sell offers	$208,210	$23,107,523	$15,784,216	$39,099,948
	Net Total		$9,698,519	$12,147,378	$3,925,672	$25,771,569

* Shows Twelve Months; ** Shows seven months

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 2015 to 2016 planning period. Figure 13-11 shows the ten largest positive and negative FTR target allocations, summed by sink, for the 2015 to 2016 planning period. The top 10 sinks that produced financial benefit accounted for 48.7 percent of total positive target allocations during the 2015 to 2016 planning period with the Northern Illinois Hub accounting for 12.5 percent of all positive target allocations. The top 10 sinks that created liability accounted for 23.7 percent of total negative target allocations with the Western Hub accounting for 4.6 percent of all negative target allocations.

Figure 13-11 Ten largest positive and negative FTR target allocations summed by sink: 2015 to 2016 planning period

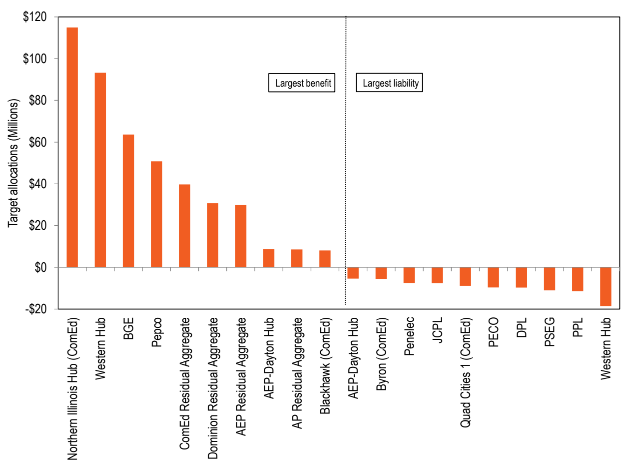
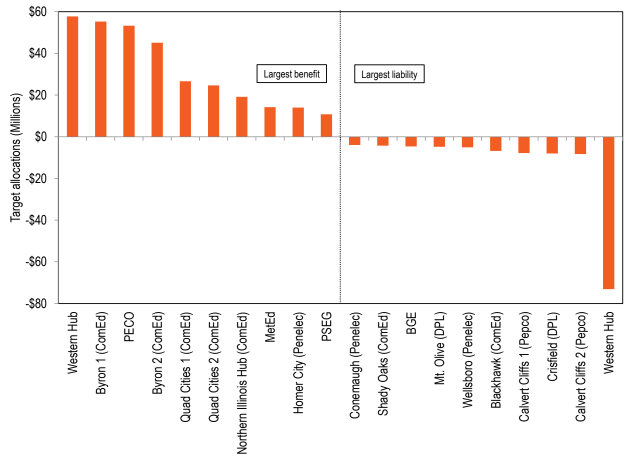


Figure 13-12 shows the ten largest positive and negative FTR target allocations, summed by source, for the 2015 to 2016 planning period. The top 10 sources with a positive target allocation accounted for 34.8 percent of total positive target allocations with the Western Hub accounting for 6.3 percent of total positive target allocations. The top 10 sources with a negative target allocation accounted for 31.6 percent of all negative target allocations, with the Western Hub accounting for 18.2 percent.

Figure 13-12 Ten largest positive and negative FTR target allocations summed by source: 2015 to 2016 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.[27] 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 net positively valued FTRs. If PJM allocated FTRs equal to the transmission capability into constrained areas, FTR payouts would equal the sum of congestion.

27 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."

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. For example, 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.[28] 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 13-31 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.[29]

Market to market operations resulted in NYISO, MISO and PJM redispatching units to control congestion on flowgates located in the other's area and in the exchange of payments for this redispatch. The Firm Flow Entitlement (FFE) represents the amount of historic flow that each RTO had created on each reciprocally coordinated flowgate (RCF) used in the market to market settlement process. The FFE establishes the amount of market flow that each RTO is permitted to create on the RCF before incurring redispatch costs during the market to market process. If the non-monitoring RTO's real-time market flow is greater than their FFE plus the approved MW adjustment from day-ahead coordination, then the non-monitoring RTO will pay the monitoring RTO based on the difference between their market flow and their FFE. If the non-monitoring RTO's real-time market flow is less than their FFE plus the approved MW adjustment from day-ahead coordination, then the monitoring RTO will pay the non-monitoring RTO for congestion relief provided by the non-monitoring RTO based on the difference between the non-monitoring RTO's market flow and their FFE.

For the 2014 to 2015 planning period, PJM paid MISO and NYISO a combined $33.2 million for redispatch on the designated M2M flowgates, and for the 2015 to 2016 planning period PJM paid MISO and NYISO a combined $16.7 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 and 2015 to 2016 planning periods. 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

28 When hourly congestion revenues are negative, it is defined as a net negative congestion hour.

29 See "Joint Operating Agreement between the Midwest Independent System Operator, Inc. and PJM Interconnection, L.L.C." (December 11, 2008), Section 6.1 <http://pjm.com/media/documents/merged-tariffs/miso-joa.pdf>. (Accessed February 23, 2016)

2015 planning period, and $572.8 million during the 2015 to 2016 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 2015 to 2016 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 and top source with the largest negative FTR target allocation was the Western Hub.

Table 13-31 Total annual PJM FTR revenue detail (Dollars (Millions)): Planning periods 2014 to 2015 and 2015 to 2016

Accounting Element	2014/2015	2015/2016
ARR information		
ARR target allocations	$765.9	$564.2
FTR auction revenue	$794.9	$575.3
ARR excess	$29.0	$11.2
FTR targets		
Positive target allocations	$1,551.6	$636.0
Negative target allocations	($293.7)	($116.4)
FTR target allocations	$1,257.8	$519.6
Adjustments:		
Adjustments to FTR target allocations	($3.5)	($0.2)
Total FTR targets	$1,254.4	$519.5
FTR revenues		
ARR excess	$29.0	$11.2
Congestion		
Net Negative Congestion (enter as negative)	($69.6)	($13.2)
Hourly congestion revenue	$1,463.8	$588.0
Midwest ISO M2M (credit to PJM minus credit to Midwest ISO)	($33.2)	($16.7)
Adjustments:		
Excess revenues carried forward into future months	$63.7	$3.5
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	$115.1	$49.9
Net Negative Congestion charged to DA Operating Reserves	$0.0	$0.0
Total FTR congestion credits	$1,457.1	$572.8
Total congestion credits on bill (includes CEPSW and end-of-year distribution)	$1,457.1	$572.8
Remaining deficiency	($115.1)	($49.9)

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. For the 2015 to 2016 planning period, Stage 1B and Stage 2 ARR allocations were reduced 76.9 percent and 82.0 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 13-31 and the dollars per MW increase in Figure 13-4.

Table 13-31 presents the PJM FTR revenue detail for the 2014 to 2015 planning period and the 2015 to 2016 planning period.

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 13-32 shows the monthly unallocated congestion charges made to day-ahead operating reserves for the 2012 to 2013 planning period through the 2015 to 2016 planning period. Months with no unallocated congestion are excluded from the table.[30]

Table 13-32 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 13-33 lists the FTR revenues, target allocations, credits, payout ratios, congestion credit deficiencies and excess congestion charges by month. At the end of the 12-month planning period, excess congestion charges are used to offset any monthly congestion credit deficiencies.

The total row in Table 13-33 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. March 2015, had a revenue shortfall of $38.7 million, but was fully funded using excess revenue from previous months.

30 See the *2014 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.

Table 13-33 Monthly FTR accounting summary (Dollars (Millions)): Planning period 2014 to 2015 and 2015 to 2016

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%	$20.2
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%	($6.7)
Nov-14	$106.4	$106.4	83.3%	$106.4	100.0%	($17.7)
Dec-14	$65.4	$58.2	100.0%	$58.2	100.0%	$8.7
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%	($38.7)
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%	$139.6
Jun-15	$103.8	$83.8	100.0%	$103.8	100.0%	$20.0
Jul-15	$88.0	$67.5	100.0%	$88.0	100.0%	$20.5
Aug-15	$57.3	$47.6	100.0%	$57.3	100.0%	$9.7
Sep-15	$77.5	$76.6	100.0%	$77.5	100.0%	$0.9
Oct-15	$84.8	$82.6	100.0%	$82.6	100.0%	$2.2
Nov-15	$91.9	$92.3	99.5%	$92.3	100.0%	($0.4)
Dec-15	$66.1	$69.1	95.6%	$69.1	100.0%	($3.0)
Summary for Planning Period 2015 to 2016						
Total	$569.3	$519.4		$570.6	100.0%	$49.9

Figure 13-13 shows the original PJM reported FTR payout ratio by month, excluding excess revenue distribution, for January 2004 through December 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 December 2015

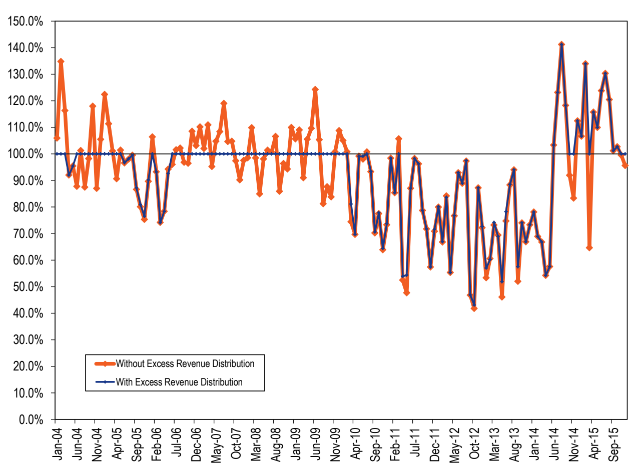


Table 13-34 shows the FTR payout ratio by planning period from the 2003 to 2004 planning period forward. Planning period 2013 to 2014 includes the additional revenue from unallocated congestion charges from Balancing Operating Reserves. For the 2014 to 2015 planning period, there was excess congestion 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 13-34 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 13-35 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 13-35 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 13-36 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.[31] 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 13-36 shows the PJM reported and actual monthly payout ratios for 2015. 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 the first four months 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 or be distributed prorata at the end of the planning period.

Table 13-36 PJM Reported and Actual Monthly Payout Ratios: Planning period 2015 to 2016

	Reported Monthly Payout Ratio	Actual Monthly Payout Ratio
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%
Jun-15	100.0%	100.0%
Jul-15	100.0%	100.0%
Aug-15	100.0%	100.0%
Sep-15	100.0%	100.0%
Oct-15	100.0%	100.0%
Nov-15	100.0%	100.0%
Dec-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. Elimination of portfolio netting would correctly account for negative target allocations as a source of revenue to pay positive

31 See PJM. "Manual 28: Operating Agreement Accounting," Revision 72 (December 17, 2015), p. 57-58.

target allocations. It would also apply the payout ratio directly to a participant's positive target allocations before subtracting negative target allocations, rather than applying the payout ratio to a participant's net portfolio. Applying the payout ratio to a participant's net portfolio results in unequal payout ratios depending on a participant's portfolio construction.

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 13-37 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. In this example, there was $45 in congestion revenue collected, which results in a payout ratio of 39.1 percent for positive target allocations when ignoring any contribution by negative or net negative target allocations. With portfolio netting, the total revenue available to pay positive target allocations is $50, which is the $45 in congestion collected plus the $5 generated by the net negative target allocation of Participant 4, which results in a payout ratio of 41.7 percent for net positive target allocations. Without portfolio netting there is $110 in total revenue available, which is the $45 in congestion collected plus the $65 in negative target allocations from all participants, which results in a payout ratio of 61.1 percent for positive target allocations.

The positive and negative TA columns show the total positive and negative target allocations, calculated separately, for each organization. The percent negative target allocations is the share of the portfolio which is negative target allocation FTRs. The net target allocation is the net of the positive and negative target allocations for the given hour. The FTR netting payout column shows what a participant would see on their bill, including payout ratio adjustments, under the current method. The per FTR payout column shows what a participant would see on their bill, including payout ratio adjustments, if FTR target allocations were done correctly. In this example, the actual monthly payout ratio is 41.7 percent. If portfolio netting were eliminated, the actual monthly payout ratio would rise to 61.1 percent.

This table shows the effects of a per FTR target allocation calculation on individual participants. The total payout does not change, but the allocation across individual participants does.

The largest change in payout is for participants 1 and 2. Participant 1, who has a large proportion of FTRs with negative target allocations, receives less payment. Participant 2, who has no negative target allocations, receives more payment.

Table 13-37 Example of FTR payouts from portfolio netting and without portfolio netting

Participant	Positive Target Allocation	Negative Target Allocation	Percent Negative Target Allocation	Net TA	FTR Netting Payout (Current)	No Netting Payout (Proposed)	Percent Change
1	$60.00	($40.00)	66.7%	$20.00	$8.33	($3.33)	(140.0%)
2	$30.00	$0.00	0.0%	$30.00	$12.50	$18.33	46.7%
3	$90.00	($20.00)	22.2%	$70.00	$29.17	$35.00	20.0%
4	$0.00	($5.00)	100.0%	($5.00)	($5.00)	($5.00)	0.0%
Total	$180.00	($65.00)	-	$115.00	$45.00	$45.00	-

Table 13-38 Monthly positive and negative target allocations and payout ratios with and without hourly netting: Planning period 2014 to 2015 and 2015 to 2016

	Net Positive Target Allocations	Net Negative Target Allocations	Per FTR Positive Target Allocations	Per FTR Negative Target Allocations	Total Congestion Revenue	Reported Payout Ratio (Current)	No Netting Payout Ratio (Proposed)
Jan-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)	$112,208,980	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%
Jun-15	$101,492,683	($17,638,087)	$222,590,294	($139,100,325)	$103,801,957	100.0%	100.0%
Jul-15	$84,827,111	($17,321,775)	$200,161,717	($132,638,752)	$87,968,263	100.0%	100.0%
Aug-15	$58,681,563	($11,121,312)	$137,089,167	($89,562,397)	$57,290,482	100.0%	100.0%
Sep-15	$92,594,711	($15,996,098)	$231,109,085	($154,468,134)	$77,511,284	100.0%	100.0%
Oct-15	$98,581,703	($16,026,518)	$243,208,767	($160,641,784)	$84,759,219	100.0%	100.0%
Nov-15	$109,318,449	($17,000,203)	$263,233,848	($170,879,749)	$92,318,246	100.0%	100.0%
Dec-15	$90,426,000	($21,292,916)	$247,346,193	($178,213,108)	$69,082,410	100.0%	100.0%
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%
2015/2016 Total	$635,922,219	($116,396,908)	$1,544,739,071	($1,025,504,249)	$572,731,862	100.0%	100.0%

Table 13-38 shows the total value for the 2014 to 2015 and 2015 to 2016 planning periods of FTRs with positive and negative target allocations. The Net Positive Target Allocation column shows the value of all portfolios with an hourly net positive value after negative target allocation FTRs are netted against positive target allocation FTRs. The Net Negative Target Allocation column shows the value of all portfolios with an hourly net negative value after negative target allocation FTRs are netted against positive target allocation FTRs. The Per FTR Positive Allocation column shows the total value of the hourly positive target allocation FTRs without netting. The Per Negative Allocation column shows the total value of the hourly negative target allocation FTRs without netting.

The Reported Payout Ratio column is the monthly payout ratio as currently reported by PJM, calculated as total revenue divided by the sum of the net positive and net negative target allocations. The No Netting FTR Payout Ratio column is the payout ratio that participants with positive target allocations would receive if FTR payouts were calculated without portfolio netting, calculated by dividing the total revenue minus the per FTR negative target allocation by the per FTR positive target allocations. The total revenue available to fund the holders of positive target allocation FTRs is calculated by adding any negative target allocations to the congestion credits for that month.

If netting within portfolios were eliminated and the payout ratio were calculated correctly, the payout ratio for the 2013 to 2014 planning period would have been 87.5 percent instead of the reported 72.8. For the 2014 to 2015 and 2015 to 2016 planning periods there was no revenue inadequacy, so eliminating portfolio netting would have no effect. March 2015 experienced revenue inadequacy, but excess revenue was distributed from previous months to ensure full funding. For months with no revenue inadequacies there is no change in payout ratio.

Portfolio Dependent Payout Ratio

Under the current portfolio netting rules, negative target allocations are first netted against positive, and then the payout ratio is applied. This results in two significant problems with the current method. First is that a participant can shield itself from both monthly revenue inadequacy and the end of planning period uplift charge by shrinking the size of their positive target allocations. This is advantageous because the participant can still be profiting from their negative target allocations if they are paid to take counter flow positions and pay back less than they received. Additionally, it results in positive target allocations receiving different payout ratios depending on the composition of the portfolio they are in. All positive target allocation FTR should be treated equally, regardless of the portfolio they are in, and this can only be accomplished by eliminating portfolio netting. Not treating all FTRs equally results in participants with more negative target allocations receiving a subsidy by reducing the effective payout ratio to participants with fewer negative target allocations. The reduced payouts to participants with fewer negative target allocations subsidize increased payout ratios to participants with larger negative target allocations, and is an unbalanced distribution of available congestion revenue collected.

Table 13-39 demonstrates the impact on the payout ratio to positive target allocation FTRs with and without portfolio netting. In the example the total congestion collected is $4,750 and the total net target allocation is $9,500, resulting in a reported payout ratio of 50.0 percent. With portfolio netting, the net target allocation is simply multiplied by the payout ratio to calculate the congestion revenue a participant receives. For Participant 1, this is $250 multiplied by 0.5 for a total revenue received of $125. The revenue to positive TA column is an indication of how much revenue the positive target allocations, which are the only part of a portfolio receiving available revenue, of a participant need to be paid in order to reach the congestion revenue received. For participant 1, they are effectively being paid $875 of their $1,000 so that the congestion revenue received can be $125. Another way to state this is the participant is effectively paying themselves their negative target allocations first, and then receiving revenue based on their net target allocation. The result of this is that Participant 1's positive target allocations are effectively granted a payout ratio of 87.5 percent simply because they hold negative target allocations, while Participant 3, who holds no negative target allocations, is only paid at a 50.0 percent payout ratio.

Without portfolio netting all participants are paid at the same effective payout ratio for their positive target allocations. Counting negative target allocations as a source of revenue raises the payout ratio to 54.5 percent. Without portfolio netting, the payout ratio is first applied to positive target allocations, then the participant's negative target allocations are added. The result of this calculation is that each participant is paid an equal 54.5 percent regardless of their portfolio's negative target allocations. In this example Participant 1 pays ends up paying $204.55 into the congestion pot, in net, while Participant 3 is paid 54.5 percent of the positive target allocations, resulting in a payment of $4,745.45. Eliminating portfolio netting is the only way to treat positive target allocations equally across all portfolios, and eliminates the subsidy positive target allocations holders are paying to negative target allocation holders.

Table 13-39 Change in positive target allocation payout ratio given portfolio construction

Congestion = $4,750 Net TA = $9,500					With Netting			Without Netting		
Participant	Positive Target Allocations	Negative Target Allocations	Net Target Allocations	Reported Payout Ratio	Congestion Revenue Received	Revenue to Positive TA	Calculated Positive TA Payout Ratio	Congestion Revenue Received	Revenue to Positive TA	Calculated Positive TA Payout Ratio
1	$1,000.00	($750.00)	$250.00	50.0%	$125.00	$875.00	87.5%	($204.55)	$545.45	54.5%
2	$750.00	($200.00)	$550.00	50.0%	$275.00	$475.00	63.3%	$209.09	$409.09	54.5%
3	$8,700.00	$0.00	$8,700.00	50.0%	$4,350.00	$4,350.00	50.0%	$4,745.45	$4,745.45	54.5%
Total	$10,450.00	($950.00)	$9,500.00	-	$4,750.00	$5,700.00	-	$4,750.00	$5,700.00	-

Mathematically Equivalent FTRs

A single FTR can be broken into multiple FTRs. The newly formed set of multiple FTRs can have the same net target allocation as long as the start and end points of the constituent end points are, in net, the same as the original. Opponents of the elimination of FTR netting have claimed that without netting this would no longer be true. However, this assertion does not account for revenues from negative target allocation FTR paths in the mathematically equivalent set of FTRs. Appropriately including these revenues results in mathematical equivalence between the single FTR and that same FTR broken into a constituent set of FTRs with the same start and end point.

Table 13-41 shows the effects on a participant with and without portfolio netting under three distinct scenarios. Table 13-40 provides the day-ahead CLMP values for each node used in the example. In this example, a participant can either buy an FTR position directly from A to B or can break it into individual pieces with the net effect of an FTR from A to B with a net target allocation of $5. In this example, there was $3.60 in congestion collected, due to a payout ratio of 72.0 percent and a total payout in each of the three scenarios of $3.60. This payout amount is simply the payout ratio of 72.0 percent multiplied by the net target allocations of $5 in each scenario.

With the elimination of netting, if the additional revenue created by considering positive and negative target allocations separately is disregarded, it appears as if the payout for the same net FTR is drastically different depending on the composition of the FTR. The results of this mistake are payouts of $3.60, -$0.60 and -$25.80 for the same net FTR in each distinct scenario. However, if the negative target allocations are properly accounted for as a source of revenue when considering congestion collected, the total revenue available increases thereby increasing the payout ratio for each scenario's positive target allocations. The total revenue available is the $3.60 in congestion collected plus the negative target allocations, resulting in revenue available to pay positive target allocations of $3.60, $18.60 and $108.60 with payout ratios to positive target allocations of 72.0 percent (unchanged due to no negative target allocations), 93.0 percent and 98.7 percent. Multiplying these correct payout ratios by the scenario's positive target allocations, and then adding the scenario's negative target allocations results in a net payout of $3.60 for each scenario.

The results of this example demonstrate the mathematical fact that no matter how an FTR path is constructed, as a single FTR or a mathematically equivalent set of FTRs, the total payment the FTR path will be the same. Attempts to disprove this ignore the revenues from the constituent FTR counter flow positions and the resulting change in payout ratio that is experienced by positive target allocations. A net FTR may be constructed in any manner and the resultant total payout will be equivalent with and without portfolio netting.

Table 13-40 Nodal day-ahead CLMPs

Node	DA CLMP
A	$20
B	$25
C	$40
D	$100
E	$10

Table 13-41 Mathematically equivalent FTR payments with and without portfolio netting

FTR Path(s)	Positive TA	Negative TA	Net TA	Available Revenue Netting	Netting Revenue Received	No Netting Revenue Received (Incorrect)	Available Revenue No Netting	Payout Ratio No Netting	Correct No Netting Revenue Received
A-B	$5.00	$0.00	$5.00	$3.60	$3.60	$3.60	$3.60	72.0%	$3.60
A-C, C-B	$20.00	-$15.00	$5.00	$3.60	$3.60	-$0.60	$18.60	93.0%	$3.60
A-C, C-E, E-D, D-B	$110.00	-$105.00	$5.00	$3.60	$3.60	-$25.80	$108.60	98.7%	$3.60

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 13-42 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 13-42 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 revenue inadequacy	($10.00)	$10.00
Profit after revenue inadequacy	($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 13-43 shows the monthly positive, negative and total target allocations.[32] Table 13-43 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 or 2015 to 2016 planning periods.

32 Reported payout ratio may differ between Table 13-38 and Table 13-43 due to rounding differences when netting target allocations and considering each FTR individually.

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 March during the 2014 to 2015 planning period and November and December for the 2015 to 2016 planning period that was not revenue adequate. The result of this would be $1.1 million in additional revenue generated for the first seven months of the 2015 to 2016 planning period.

The result of removing portfolio netting and applying a payout ratio to counter flow FTRs would increase the calculated payout ratio for the 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 FTR surplus and the collected Day-Ahead, Balancing and Total congestion: January 2005 through December 2015

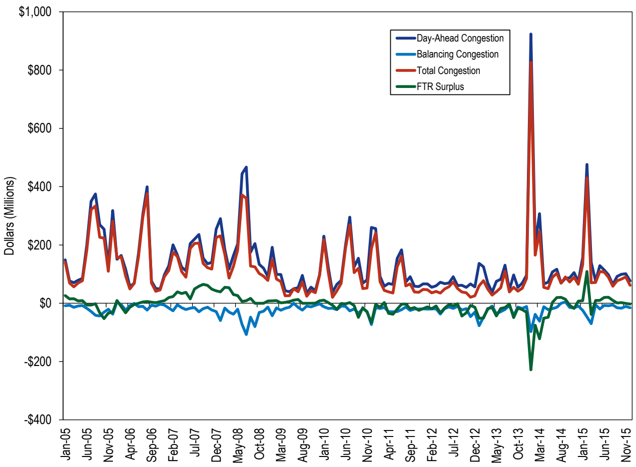


Table 13-43 Counter flow FTR payout ratio adjustment impacts: Planning period 2014 to 2015 and 2015 to 2016

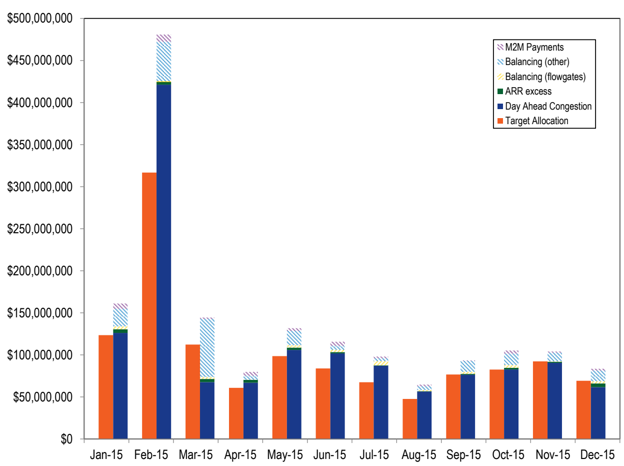
	Positive Target Allocations	Negative Target Allocations	Total Target Allocations	Total Congestion Revenue	Reported Payout Ratio*	Total Revenue Available	Adjusted Prevailing Flow Payout Ratio	Adjusted Counter Flow Payout Ratio	Adjusted Counter Flow Revenue Available	Additional Revenue Generated
Jan-15	410,273,039.40	(283,654,557.66)	$126,618,482	$131,999,162	100.0%	$415,653,720	100.0%	100.0%	$415,653,720	$0
Feb-15	1,037,653,444.39	(719,673,940.00)	$317,979,504	$425,826,022	100.0%	$1,145,499,962	100.0%	100.0%	$1,145,499,962	$0
Mar-15	414,369,579.96	(300,458,779.30)	$113,910,801	$112,294,395	98.6%	$412,753,174	100.0%	100.0%	$413,256,180	$503,006
Apr-15	272,864,686.11	(211,944,616.99)	$60,920,069	$70,299,122	100.0%	$282,243,739	100.0%	100.0%	$282,243,739	$0
May-15	392,526,758.17	(293,928,391.90)	$98,598,366	$108,377,660	100.0%	$402,306,052	100.0%	100.0%	$402,306,052	$0
Jun-15	222,590,293.62	(139,100,324.66)	$83,489,969	$103,747,323	100.0%	$242,847,647	100.0%	100.0%	$242,847,647	$0
Jul-15	200,161,717.10	(132,638,752.10)	$67,522,965	$87,968,263	100.0%	$220,607,015	100.0%	100.0%	$220,607,015	$0
Aug-15	137,089,167.17	(89,562,397.25)	$47,526,770	$57,290,482	100.0%	$146,852,879	100.0%	100.0%	$146,852,879	$0
Sep-15	231,109,085.00	(154,468,134.20)	$76,640,951	$77,511,284	100.0%	$231,979,418	100.0%	100.0%	$231,979,418	$0
Oct-15	243,208,767.05	(160,641,783.85)	$82,566,983	$84,759,219	100.0%	$245,401,003	100.0%	100.0%	$245,401,003	$0
Nov-15	263,233,848.17	(170,879,749.04)	$92,354,099	$91,923,077	99.5%	$262,802,827	100.0%	100.0%	$262,939,878	$137,051
Dec-15	247,346,192.69	(178,213,108.16)	$69,133,085	$66,093,057	95.6%	$244,306,166	100.0%	100.0%	$245,277,728	$971,563
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%	100.0%	$4,407,511,707	$503,006
Total 2015/2016	1,544,739,070.80	(1,025,504,249.26)	$519,234,822	$569,292,705	100.0%	$1,594,796,954	100.0%	100.0%	$1,595,905,568	$1,108,614

* Reported payout ratios may vary due to rounding differences when netting

Figure 13-14 shows the FTR surplus, collected day-ahead, balancing and total congestion payments from January 2005 through December 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 13-15 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



ARRs as a Congestion Offset for Load

Load pays for the transmission system and contributes all congestion revenues. FTRs and later ARRs were intended to return congestion revenues to load. With the implementation of the current FTR/ARR design, other participants are allowed to receive a portion of the congestion revenues.

Table 13-44 compares the revenue received by ARR holders and total congestion for the 2013 to 2014, 2014 to 2015 and the first seven months of the 2015 to 2016 planning period. This compares the total offset provided to all ARR holders including all ARRs converted to self scheduled FTRs to the total congestion revenues. 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 represent the total self scheduled FTR target allocations for FTRs held by ARR holders, adjusted by the FTR payout ratio. ARR holders that elect to self schedule into FTRs are paid the daily ARR credits for the ARR, and then pay the daily auction price of the self scheduled FTRs, netting the cost of the FTRs to zero. This is accounted for in the ARR credits column by subtracting the cost of the FTR from the ARR credits.

The total ARR/FTR offset is the sum of the ARR and self scheduled FTR credits. The congestion column shows the total amount of congestion collected in the Day-Ahead Energy Market and the balancing energy market. The percent offset is the percent of total, system wide, congestion offset by ARR and self scheduled FTR credits that ARR holders receive.

Table 13-44 shows the offset provided by ARRs and self scheduled FTRs for the entire 2013 to 2014, 2014 to 2015 planning period and the first seven months of the 2015 to 2016 planning period. ARR and FTR revenues offset 42.4 percent of Day-Ahead Energy Market and the balancing energy market for the 2013 to 2014 planning period and 63.8 percent for the 2014 to 2015 planning period. For the first seven months of the 2015 to 2016 planning period ARRs and self scheduled FTRs offset 85.8 percent of total congestion costs.

This demonstrates the inadequacies of the current ARR/FTR design. The goal of the design should be to return 100 percent of the congestion revenues to the load. But the actual results fall well short of that goal.

Table 13-44 ARR and FTR total congestion offset (in millions) for ARR holders: Planning periods 2014 to 2015 and 2015 to 2016[33]

Planning Period	ARR Credits	FTR Credits	Total Congestion	Total ARR/ FTR Offset	Percent Offset
2013/2014	$337.7	$414.9	$1,777.1	$752.6	42.4%
2014/2015	$482.4	$404.4	$1,390.9	$886.8	63.8%
2015/2016*	$372.3	$128.0	$573.0	$500.3	87.3%

*Shows seven months through December 31, 2015

33 FTR Credits does not include any end of planning period excess or shortfall distribution.

Credit Issues

There were two collateral defaults and seven payment defaults for the first nine months of 2015 for Intergrid Mideast Group, LLC. The two collateral defaults totaled $710,300 and the seven payment defaults totaled $1,726,641. There was one other collateral default for the first nine months of 2015 for $35,000, which was promptly cured. There were no additional defaults in the last quarter of 2015.

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 has liquidated all of Intergrid's FTR positions in accordance with Section 7.3.9 of the Operating Agreement.[34] 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 is $279,414. PJM has notified its Members that the Intergrid default will not result in any default allocation assessments in accordance with Section 15.2.2 of the Operating Agreement.[35]

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 13-16 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 13-16, the INC has a dfax of 0.25 and the maximum withdrawal dfax on the constraint is -0.5. The difference between the two dfax values 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 dfax values is 0.75 (-0.25 minus 0.5). The absolute value is also 0.75.

Figure 13-16 Illustration of INC/DEC FTR forfeiture rule

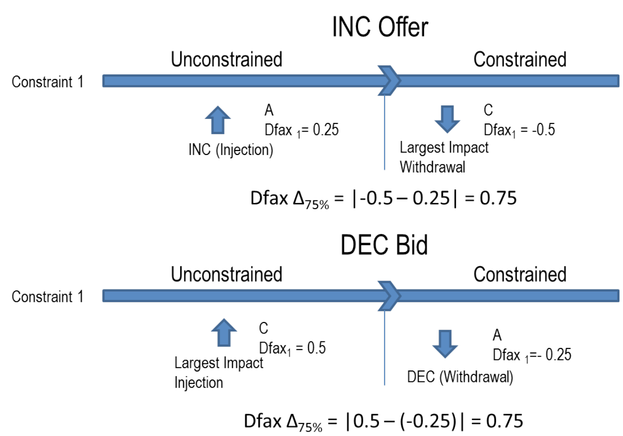


Figure 13-17 shows the FTR forfeiture values for both physical and financial participants for each month of June 2010 through December 2015. Currently, counter flow FTRs are not subject to forfeiture regardless of INC or DEC positions. Total forfeitures for the 2015 to 2016 planning period were $0.17 million (0.03 percent of total FTR target allocations).

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

Figure 13-17 Monthly FTR forfeitures for physical and financial participants: June 2010 through December 2015

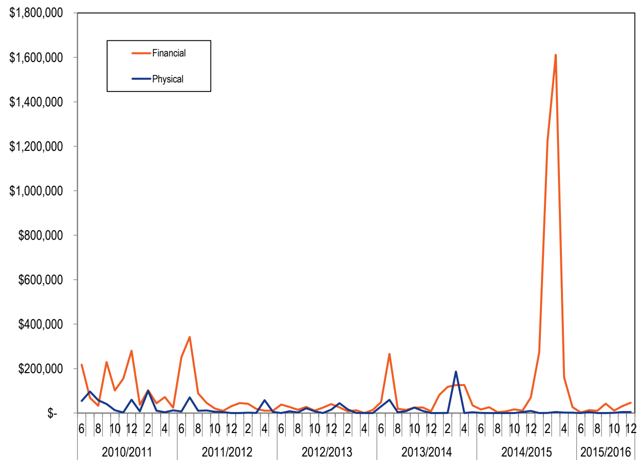


Figure 13-18 FTR forfeitures for INCs/DECs and INCs/DECs/UTCs for both the PJM and MMU methods: January 2013 through December 2015

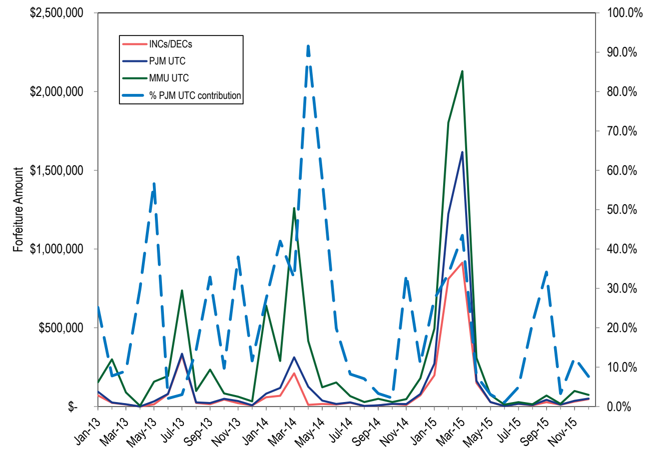


Figure 13-18 shows the FTR forfeitures on just INCs and DECs, FTR forfeitures on INCs, DECs and UTCs using the method proposed by PJM and FTR forfeitures on INCs, DECs and UTCs using the method proposed by the MMU from January 2013 through December 2015. The method proposed by PJM for calculating forfeitures 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.

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 13-19 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 13-19 Illustration of UTC FTR forfeiture rule

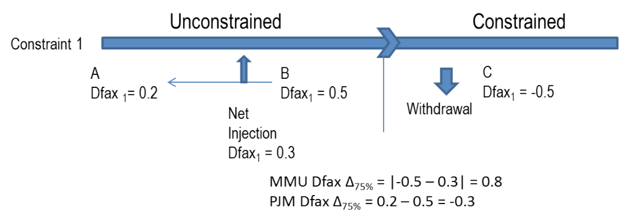
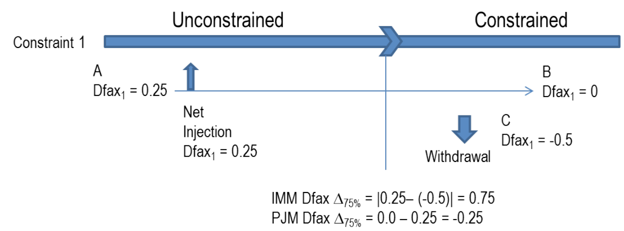


Figure 13-20 demonstrates where the assumption of contract path for UTCs in PJM's method does not hold with actual system conditions when either the source or sink of the UTC does not have any impact on the constraint being considered. In this case, the UTC is effectively an INC or a DEC relative to 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 13-20, 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 13-20 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.