Q1

State of the Market Report for PJM

Monitoring Analytics, LLC

Independent
Market Monitor
for PJM

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Preface

The PJM Market Monitoring Plan provides:

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

Accordingly, Monitoring Analytics, LLC, which serves as the Market Monitoring Unit (MMU) for PJM Interconnection, L.L.C. (PJM),[2] and is also known as the Independent Market Monitor for PJM (IMM), submits this *2017 Quarterly State of the Market Report for PJM: January through March*.[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.
3 All references to this report should refer to the source as Monitoring Analytics, LLC, and should include the complete name of the report: *2017 Quarterly State of the Market Report for PJM: January through March*.

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Introduction

2017 Q1 in Review

The results of the energy market, the results of the capacity market and the results of the regulation market were competitive in the first three months of 2017. The goal of competition is to provide customers wholesale power at the lowest possible price, but no lower. The PJM markets work. The PJM markets bring customers the benefits of competition. But the PJM markets, and wholesale power markets in the U.S., face new challenges that potentially threaten the viability of competitive markets.

Particularly in times of stress on markets and when some flaws in markets are revealed, nonmarket 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, batteries, demand side 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. Proposals for fuel diversity are generally proposals to subsidize an existing, uneconomic technology. Subsidies are tempting because they maintain existing resources and provide increased revenues to asset owners in uncertain markets. Cost of service regulation is tempting because cost of service regulation incorporates integrated resource planning and because guaranteed rates of return and fixed prices may look attractive to asset owners in uncertain markets.

It is essential that any approach to the PJM markets and the PJM Capacity Market incorporate a consistent view of how the preferred market design is expected to work to provide competitive results in a sustainable market design over the long run. A sustainable market design means a market design that results in appropriate incentives to retire units and to invest in new units over time such that reliability is ensured as a result of the functioning of the market. There are at least two broad paradigms that could result in such an outcome. The market paradigm includes a full set of markets, most importantly the energy market and capacity market, which together ensure that there are adequate revenues to incent new generation when it is needed and to incent retirement of units when appropriate. This approach will result in long term reliability at the lowest possible cost.

The quasi-market paradigm includes an energy market based on LMP but addresses the need for investment incentives via the long-term contract model or the cost of service model. In the quasi-market paradigm, competition to build capacity is limited and does not include the entire PJM footprint. In the quasi-market paradigm, customers absorb the risks associated with investment in and ownership of generation assets through guaranteed payments under either guaranteed long term contracts or the cost of service approach. In the quasi-market paradigm there is no market clearing pricing to incent investment in existing units or new units. In the quasi-market paradigm there is no incentive for entities without cost of service treatment to enter and thus competition is effectively eliminated.

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, those entities 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.

The issue of external subsidies emerged more fully in 2016. These subsidies are not directly part of the PJM market design but nonetheless threaten the foundations of the PJM capacity market as well as the competitiveness of PJM markets overall.

The Ohio subsidy proceedings and the Illinois ZEC subsidy proceeding all originated from the fact that competitive markets result in the exit of uneconomic and uncompetitive generating units. Regardless of the specific rationales offered by unit owners, the proposed solution for all such generating units has been to provide out of market subsidies in order to retain such units. These subsidies are not accurately characterized as state subsidies. These subsidies were all requested by the owners of specific uneconomic generating units in order to improve the profitability of those specific units. These subsidies were not requested to accomplish broader social goals. Broader social goals can all be met with market based mechanisms available to all market participants on a competitive basis and without discrimination.

The proposed subsidy solutions in all cases ignore the opportunity cost of subsidizing uneconomic units, which is the displacement of resources and technologies that would otherwise be economic. A decision to subsidize uneconomic units that are a significant source of energy and capacity has direct and significant impacts on other sources of energy; the opportunity costs of subsidies are substantial. Such subsidies suppress energy and capacity market prices and therefore suppress incentives for investments in new, higher efficiency thermal plants but also suppress investment incentives for the next generation of energy supply technologies and energy efficiency technologies. These impacts are long lasting but difficult to quantify precisely.

Subsidies are contagious. Competition in the markets could be replaced by competition to receive subsidies. PJM markets have no protection against this emergent threat. Accurate signals for entry and exit are necessary for well functioning and competitive markets. Competitive investors rely on accurate signals to make decisions. Similar threats to competitive markets are being discussed by unit owners in other states and the potentially precedential nature of these actions enhances the urgency of creating an effective rule to maintain competitive markets by modifying market rules to address these subsidies. Fortunately, this can be accomplished quickly by expanding the coverage of an existing rule that already reflects stakeholder compromises.

The current proposals for subsidies demonstrate that the markets need protection against subsidized, noncompetitive offers from existing as well as new resources. The current minimum offer price rule (MOPR) only addresses subsidies for new entry. The MOPR should be expanded to address subsidies for existing units, and this should be done expeditiously. This issue will not become moot unless and until the MOPR is reformed. Action is needed to correct the MOPR immediately. An existing unit MOPR is the best means to defend the PJM markets from the threat posed by subsidies intended to forestall retirement of financially distressed assets. The role of subsidies to renewables should also be clearly defined and incorporated in this rule.

A MOPR for existing units should incorporate the key elements of the current MOPR which applies only to new gas-fired CT and CC units. This design would limit the impact of subsidies on markets while ensuring that existing forms of market participation by vertically integrated, cost of service companies could continue. An existing unit MOPR is a much better way to maintain PJM markets than the PJM proposal to incorporate public policy based subsidies that could result in the capacity market becoming a residual market. The PJM capacity market and PJM markets overall cannot function as markets if the capacity market is a residual market. The current design requires all capacity resources to offer and all load to buy capacity, except those companies that elect the FRR option and keep load and generation out of the capacity market.

While an existing unit MOPR would protect markets in the short run, the underlying issues that have resulted in the pressure on markets should also be examined. Unit owners are seeking subsidies because gas prices are low resulting in low energy market margins and because flaws in the PJM capacity design have led to very substantial price suppression over the past 10 years.

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 nonmarket 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 and have had substantial impacts. Capacity prices that were suppressed substantially below the level consistent with supply and demand fundamentals affected some participants' long term decisions and led some market participants to seek subsidies. PJM has addressed the fundamental issues of the capacity market design in its Capacity Performance design, including price formation, product definition and performance incentives. But there are significant ongoing efforts to undo some of the key elements of the Capacity Performance design including performance incentives and product definition.

Within the market paradigm, the temptation to modify other elements of the PJM energy and capacity market design in order to address asserted issues related to the level of prices or the shape of the supply curve should also be resisted. One of the lessons of the history of PJM capacity market design is that design changes based on short term, non-market considerations can have long term, significant, negative unintended consequences. The basic logic of LMP should not be modified in order to increase prices or revenues. The shape of the supply curve does not affect the basic logic of LMP and it should not be modified in order to meet a goal not related to the logic of LMP. The capacity market design should not be modified in order to introduce elements of integrated resource planning to favor specific technologies. Improvements to market design should be made when consistent with the basic market design, including better pricing when transmission constraints are violated and better and more locational scarcity pricing.

To the extent that there are shared broader goals related to PJM markets, they should also be addressed. If society determines that carbon is a pollutant with a negative value, a market approach to carbon is preferred to a technology or unit specific subsidy approach. Implementation of a carbon price is a market approach which would let market participants respond in efficient and innovative ways to the price signal rather than relying on planners to identify specific technologies or resources to be subsidized. If a shared goal is increased renewables in addition to their carbon attributes, a common approach to RECs would be a market based solution. Fuel diversity has also been mentioned as an issue. Current fuel diversity is higher than ever in PJM. If there is an issue, the real issue is fuel security and not fuel diversity. Significant reliance on specific fuels, including nuclear, coal and gas means that markets are at risk from a significant disruption in any one fuel. If fuel security for gas is a concern, a number of issues should be considered including the reliability of the pipelines, the compatibility of the gas pipeline regulated business model with long term guaranteed contracts and the merchant generator market business model, the degree to which electric generators have truly firm gas service and the need for a gas RTO to help ensure reliability.

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. 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.

A primary market power mitigation rule in PJM is the three pivotal supplier (TPS) test. The 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.

The price of energy must reflect supply and demand fundamentals. The inclusion of gas costs and other fuel costs in energy market offers must be based on market prices. The fuel cost policy for every unit documents the process by which a unit owner calculates the fuel cost component of its cost-based offers. Fuel cost policies must be algorithmic, verifiable and systematic to ensure that only market-based short run marginal costs are included in fuel costs, especially when markets are stressed. FERC's order on hourly offers means that generators have the ability to appropriately reflect gas cost changes in energy offers during the operating day in order to permit the energy market to reflect the current cost of gas. But offer changes should be based only on algorithmic and verifiable changes in gas cost and therefore not permit the exercise of market power.

The application of market power mitigation rules in the Day-Ahead Energy Market and the Real-Time Energy Market helps ensure competitive market outcomes even in the presence of structural market power. But the efficacy of market power mitigation rules depends on the definition of a competitive offer. A competitive offer is equal to short run marginal costs. The enforcement of market power mitigation rules is undermined if the definition of a competitive offer is not correct. The significance of competition metrics like markup is also undermined if the definition of a competitive offer is not correct. The definition of a competitive offer, as currently interpreted by PJM, is not correct. Some unit owners include costs that are not short run marginal costs in offers, including long term maintenance costs. This issue can be resolved by simple changes to the PJM Market Rules to incorporate a clear and accurate definition of short run marginal costs. PJM Manual 15 should be replaced with a straightforward description of the components of cost offers based on short run marginal costs and the correct calculation of cost offers.

The overall energy market results in 2016 and the first three months of 2017 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 is not always the case during high demand hours. This is evidence of generally competitive behavior, although the behavior of some participants during high demand periods raises concerns about economic withholding. The performance of the PJM markets under high load conditions has raised a number of concerns related to aggregate market power, or the ability to increase markups substantially in tight market conditions, related to the uncertainties about the pricing and availability of natural gas, and related to the role of demand response and interchange transactions.

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. PJM real-time energy market prices increased in the first three months of 2017 compared to the first three months of 2016. The load-weighted average real-time LMP was 13.0 percent higher in the first three months of 2017 than in the first three months of 2016, $30.28 per MWh versus $26.80 per MWh. Energy prices were higher primarily as a result of higher fuel prices.

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 increased from 4.2 percent of the real-time load-weighted average LMP in the first three months of 2016 to 12.6 percent in the first three months of 2017. 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 for high demand periods 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 generation owners who routinely include high markups in price-based offers on some units. These markups do not affect prices under normal conditions but may affect prices during high demand conditions.

Net revenue is a key measure of overall market performance as well as a measure of the incentive to invest in new generation to serve PJM markets. Energy net revenues are significantly affected by energy prices and fuel prices. Energy prices and fuel prices were higher in the first three months of 2017 than in the first three months of 2016. Natural gas prices increased more than LMP and new CTs and new CCs ran with lower margins as a result. Coal prices increased by less than LMP and new coal plants ran for more hours in the first three months of 2017 than in the first three months of 2016 and with higher margins. In the first three months of 2017, average energy market net revenues decreased by 66 percent for a new CT and 29 percent for a new CC. Average energy market net revenues increased by 17 percent for a new coal plant, 17 percent for a new nuclear plant, and 16 percent for a new wind installation, as compared to the first three months of 2016.

Load pays for the transmission system and contributes 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 ensure that load receives the rights to congestion revenues, without requiring contract path physical transmission rights that are impossible to define correctly and enforce in nodal, network 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 that load receives the auction revenues associated with all the potential congestion revenues.

The goal of the design should be to assign the rights to 100 percent of the congestion revenues to load. But the actual results fall well short of that goal. The current allocation of congestion revenue resulted in a total shortfall of $1,731.7 million when comparing the revenues to ARR holders to congestion, a 72.4 percent congestion offset, over the last six planning periods. Total ARR and self scheduled FTR revenues offset only 44.7 percent of congestion costs in the 13/14 planning period, 63.8 percent in the 14/15 planning period and 86.5 percent in the 15/16 planning period. For the first 10 months of the 16/17 planning period ARRs and self scheduled FTR revenues offset 92.4 percent of total congestion costs.

On September 15, 2016, FERC issued an order that moved the market design substantially further from the goal of returning congestion revenues to load. The order shifted costs to load and shifted revenues to FTR holders. The order assigned the costs of balancing congestion to load, assigned excess auction revenues to FTR holders and assigned all day-ahead congestion revenues in excess of target allocations to FTR holders. If the new rules had been in place beginning with the 11/12 planning period and the ARR/FTR allocations had remained the same, ARR holders would have received $1,010.3 million less in congestion offsets for the 11/12 through the 16/17 planning periods. The total overpayment to FTR holders for the 11/12 through 16/17 planning period would have been $923.5 million.

The FTR/ARR design should be significantly modified in order to return the design to its original purpose and function, which was to return congestion revenues to 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: January through March, 2016 and 2017[1 2]

	Jan - Mar, 2016	Jan - Mar, 2017	Percent Change
Load	192,935 GWh	189,213 GWh	(1.9%)
Generation	195,329 GWh	200,971 GWh	2.9%
Net Actual Interchange	6,564 GWh	3,661 GWh	(44%)
Losses	3,879 GWh	3,889 GWh	0.3%
Regulation Requirement*	613 MW	657 MW	7.2%
RTO Primary Reserve Requirement	2,175 MW	2,175 MW	0.0%
Total Billing	$9.50 Billion	$9.71 Billion	2.2%
Peak	Jan 19, 2016 7:00	Jan 9, 2017 7:00	
Peak Load	129,876 MW	127,543 MW	(1.8%)
Installed Capacity	As of 3/31/2016	As of 3/31/2017	
Installed Capacity	178,492 MW	183,594 MW	2.9%

* This is an hourly average stated in effective MW.

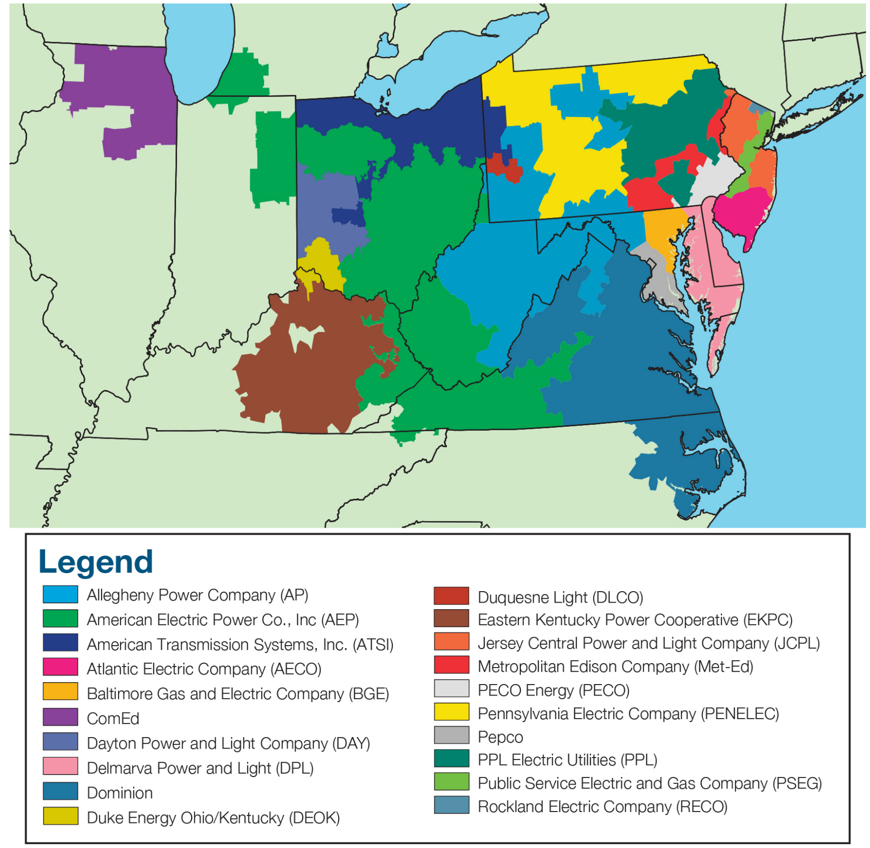
PJM Market Background

The PJM Interconnection, L.L.C. (PJM) operates a centrally dispatched, competitive wholesale electric power market that, as of March 31, 2017, had installed generating capacity of 183,594 megawatts (MW) and 987 members including market buyers, sellers and traders of electricity in a region including more than 65 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).[3 4 5]

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 Positive net interchange values represent imports and negative net interchange values represent exports. Imports and exports are reported in Section 9, "Interchange Transactions."
3 See PJM's "Member List," which can be accessed at: <http://pjm.com/about-pjm/member-services/member-list.aspx>.
4 See PJM's "Who We Are," which can be accessed at: <http://pjm.com/about-pjm/who-we-are.aspx>.
5 See the *2016 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography" for maps showing the PJM footprint and its evolution prior to 2017.

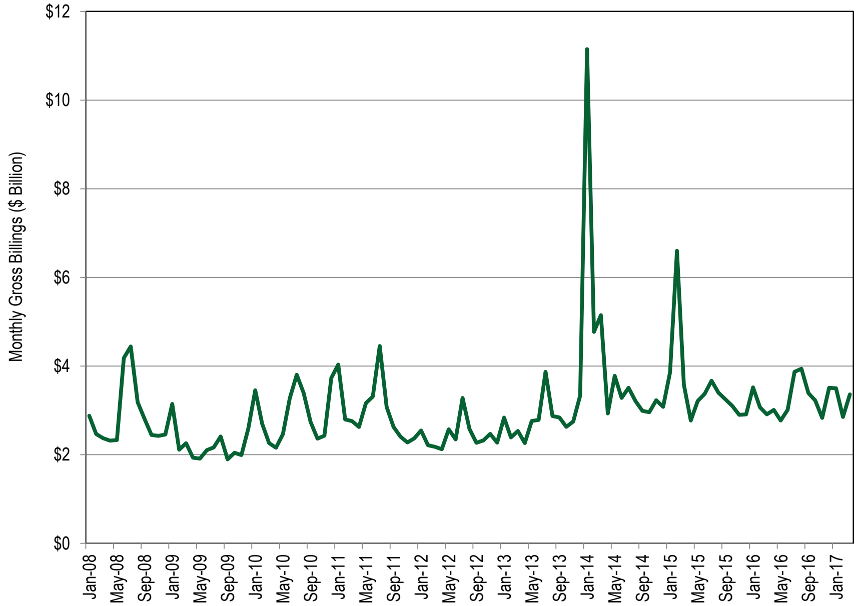
Figure 1-1 PJM's footprint and its 20 control zones



In the first three months of 2017, PJM had total billings of $9.71 billion, an increase of 2.2 percent from $9.50 billion in the first three months of 2016 (Figure 1-2).[6]

6 Monthly and year to date billing values are provided by PJM.

Figure 1-2 PJM reported monthly billings ($ Billion): 2008 through March, 2017



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 Market, 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.[7 8] 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 the first three months of 2017, including market structure, participant behavior and market performance. This report was prepared by and represents the analysis of the Independent Market Monitor for PJM, also referred to as the Market Monitoring Unit or MMU.

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

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

Market structure refers to the ownership structure of the market. The three pivotal supplier (TPS) test is the most relevant measure of market structure because it accounts for both the ownership of assets and the relationship between the pattern of ownership among multiple entities and the market demand using actual market conditions with both temporal and geographic granularity. Market shares and the related Herfindahl-Hirschman Index (HHI) are also measures of market structure.

7 See also the *2016 State of the Market Report for PJM*, Volume II, Appendix B, "PJM Market Milestones."

8 Analysis of 2017 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 2017, see *2016 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography."

Participant behavior refers to the actions of individual market participants, also sometimes referred to as participant conduct.

Market performance refers to the outcome of the market. Market performance reflects the behavior of market participants within a market structure, mediated by market design.

Market design means the rules under which the entire relevant market operates, including the software that implements the market rules. Market rules include the definition of the product, the definition of short run marginal cost, rules governing offer behavior, market power mitigation rules, and the definition of demand. Market design is characterized as effective, mixed or flawed. An effective market design provides incentives for competitive behavior and permits competitive outcomes. A mixed market design has significant issues that constrain the potential for competitive behavior to result in competitive market outcomes, and does not have adequate rules to mitigate market power or incent competitive behavior. A flawed market design produces inefficient outcomes which cannot be corrected by competitive behavior.

The MMU concludes for the first three months of 2017:

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. The hourly HHI (Herfindahl-Hirschman Index) results indicate that by the FERC standards, the PJM Energy Market in the first three months of 2017 was unconcentrated. Average HHI was 980 with a minimum of 882 and a maximum of 1126 in the first three months of 2017. The fact that the average HHI is in the unconcentrated range and the maximum hourly HHI is in the moderately concentrated range does not mean that the aggregate market was competitive in all hours. It is possible to have pivotal suppliers in the aggregate market even when the HHI level is not in the highly concentrated range. It is possible to have an exercise of market power even when the HHI level is not in the highly concentrated range. The PJM Energy Market peaking segment of supply was 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 because unit owners can exercise market power even when mitigated.
- 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 in most cases although issues with the implementation of market power mitigation and development of cost-based offers remain. 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.[9] 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.[10] 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 even when market power mitigation rules are applied. 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 issues related to the level of variable operating and maintenance expense 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 and there are pivotal suppliers in the aggregate market. Aggregate market power needs to be addressed. Now that generators will be allowed to modify offers hourly, market design must reflect appropriate incentives for competitive behavior, the application of local market power mitigation needs to be fixed, the definition of a competitive offer needs to be fixed, and aggregate market power mitigation rules need to be developed. The importance of these issues is amplified by the new rules permitting cost-based offers in excess of $1,000 per MWh

9 OATT Attachment M (PJM Market Monitoring Plan).

10 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.[11]
- 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.[12]
- 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

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

12 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.

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 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.
- 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 nonsynchronized reserve market clears with a nonzero price.

Table 1-5 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 6.9 percent of all cleared hours in the first three months of 2017.
- 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. Offers above $0.00 set the clearing price in 496 hours (22.8 percent).
- Market design was evaluated as mixed because the DASR product does not include performance obligations, and 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 1-6 The Regulation Market results were competitive

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

- The regulation market structure was evaluated as not competitive for the first three months of 2017 because the PJM Regulation Market failed the three pivotal supplier (TPS) test in 92.1 percent of the hours in the first three months of 2017.
- Participant behavior in the PJM Regulation Market was evaluated as competitive for the first three months of 2017 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 noncompetitive behavior.
- Market performance was evaluated as competitive, despite significant issues with the market design.
- Market design was evaluated as flawed. 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. The

result is significantly flawed market signals to existing and prospective suppliers of regulation.

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. But it is not clear, in a competitive market, why FTR purchases by financial entities remain persistently profitable.
- Market design was evaluated as flawed because there are significant flaws with the basic ARR/FTR design. The market design is not an efficient way to ensure that all congestion revenues are returned to load.

Role of MMU

The FERC assigns three core functions to MMUs: reporting, monitoring and market design.[13] These functions are interrelated and overlap. The PJM Market Monitoring Plan establishes these functions, providing that the MMU is responsible for monitoring: compliance with the PJM Market Rules; actual or potential design flaws in the PJM Market Rules; structural problems in the PJM Markets that may inhibit a robust and competitive market; the actual or potential exercise of market power or violation of the market rules by a Market Participant; PJM's implementation of the PJM Market Rules or operation of the PJM Markets; and such matters as are necessary to prepare reports.[14]

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.

The MMU presents reports directly to PJM stakeholders, PJM staff, FERC staff, state commission staff, state commissions, other regulatory agencies and the general public. Report presentations provide an opportunity for interested parties to ask questions, discuss issues, and provide feedback to the MMU.

Monitoring

To perform its monitoring function, the MMU screens and monitors the conduct of Market Participants under the MMU's broad purview to monitor, investigate, evaluate and report on the PJM Markets.[15] The MMU has direct, confidential access to the FERC.[16] The MMU may also refer matters to the attention of state commissions.[17]

The MMU monitors market behavior for violations of FERC Market Rules and PJM Market Rules, including the actual or potential exercise of market power.[18] The MMU will investigate and refer "Market Violations," which refers

13 18 CFR § 35.28(g)(3)(ii); see also *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, FERC Stats. & Regs. ¶31,281 (2008) ("Order No. 719"), *order on reh'g*, Order No. 719-A, FERC Stats. & Regs. ¶31,292 (2009), *reh'g denied*, Order No. 719-B, 129 FERC ¶ 61,252 (2009).

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

15 OATT Attachment M § IV.

16 OATT Attachment M § IV.K.3.

17 OATT Attachment M § IV.H.

18 OATT § I.1 ("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

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…"[19 20 21] The MMU also monitors PJM for compliance with the rules, in addition to market participants.[22]

An important component of the monitoring function is the review of inputs to mitigation. The actual or potential exercise of market power is addressed in part through ex ante mitigation rules incorporated in PJM's market clearing software for the energy market, the capacity market and the regulation market. If a market participant fails the TPS test in any of these markets its offer is set to the lower of its price-based or cost-based offer. This prevents the exercise of market power and ensures competitive pricing, provided that the cost-based offer accurately reflects short run marginal cost.

If the cost-based offer does not accurately reflect short run marginal cost, the automated market power mitigation process does not ensure competitive pricing in PJM markets. The MMU evaluates the fuel cost policy for every unit as well as the other inputs to cost-based offers. PJM Manual 15 does not clearly or accurately describe the short run marginal cost of generation. Manual 15 should be replaced with a straightforward description of the components of cost offers based on short run marginal costs and the correct calculation of cost offers. 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]

The MMU also monitors transmission planning, interconnections and rules for vertical market power issues, and with the introduction of competitive

establish… "PJM Market Rules" mean the rules, standards, procedures, and practices of the PJM Markets set forth in the PJM Tariff, the PJM Operating Agreement, the PJM Reliability Assurance Agreement, the PJM Consolidated Transmission Owners Agreement, the PJM Manuals, the PJM Regional Practices Document, the PJM-Midwest Independent Transmission System Operator Joint Operating Agreement or any other document setting forth market rules.")

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

20 OATT § I.1.

21 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.

22 OATT Attachment M § IV.C.

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.

transmission development policy in Order No. 1000, horizontal market power issues.[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 and Modified 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 *2017 Quarterly State of the Market Report for PJM: January through March*, the MMU includes one new recommendation and two modified recommendations.[40]

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.
40 New or modified recommendations include all MMU recommendations that were reported for the first time, or substantially modified, in this *2017 Quarterly State of the Market Report for PJM: January through March.*

New and Modified Recommendations from Section 5, Capacity Market

- The MMU recommends that PJM reduce the number of incremental auctions to a single incremental auction held three months prior to the start of the delivery year and reevaluate the triggers for holding conditional incremental auctions. (Priority: Medium. First reported 2013. Modified Q1 2017. Status: Not adopted.)
- The MMU recommends that PJM release capacity in the incremental auction only in cases where the combination of quantities released and associated prices would increase the welfare of capacity market resource owners and load, including consideration of both capacity and energy market benefits in the determination of release quantities and prices. (Priority: Medium. New Recommendation. Status: Not adopted.)

Modified Recommendation from Section 10, Ancillary Service Markets

- The MMU recommends that PJM modify the DASR Market to ensure that all resources cleared incur a real-time performance obligation. (Priority: Low. First reported 2013. Modified 2017. 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 shows the average price, by component, for the first three months of 2016 and 2017.

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 95.9 percent of the total price per MWh in the first three months of 2017.

Each of the components is defined in PJM's Open Access Transmission Tariff (OATT) and PJM Operating Agreement and each is collected through PJM's billing system.

Components of Total Price

- The Energy component is the real time load weighted average PJM locational marginal price (LMP).
- The Capacity component is the average price per MWh of Reliability Pricing Model (RPM) payments.
- The Transmission Service Charges component is the average price per MWh of network integration charges, and firm and nonfirm 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 (AC^2) and OATT Schedule 9 funding of FERC, OPSI and the MMU.
- The Transmission Enhancement Cost Recovery component is the average cost per MWh of PJM billed (and not otherwise collected through utility rates) costs for transmission upgrades and projects, including annual recovery for the TrAIL and PATH projects.[45]
- The 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]
- 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]

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.
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.

- The nonsynchronized 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: January 1 through March 31, 2016 and 2017[58]

Category	Jan-Mar 2016 $/MWh	Jan-Mar 2016 Percent of Total	Jan-Mar 2017 $/MWh	Jan-Mar 2017 Percent of Total	Percent Change Totals
Load Weighted Energy	$26.80	55.2%	$30.28	59.6%	13.0%
Capacity	$12.27	25.3%	$10.08	19.9%	(17.9%)
Transmission Service Charges	$7.57	15.6%	$8.33	16.4%	10.0%
Transmission Enhancement Cost Recovery	$0.54	1.1%	$0.61	1.2%	14.2%
PJM Administrative Fees	$0.45	0.9%	$0.50	1.0%	11.6%
Reactive	$0.38	0.8%	$0.46	0.9%	21.2%
Regulation	$0.11	0.2%	$0.11	0.2%	(0.1%)
Energy Uplift (Operating Reserves)	$0.20	0.4%	$0.10	0.2%	(48.4%)
Transmission Owner (Schedule 1A)	$0.09	0.2%	$0.10	0.2%	7.1%
Black Start	$0.08	0.2%	$0.09	0.2%	14.2%
Synchronized Reserves	$0.04	0.1%	$0.06	0.1%	37.7%
NERC/RFC	$0.03	0.1%	$0.03	0.1%	1.8%
Load Response	$0.01	0.0%	$0.01	0.0%	(33.3%)
Non-Synchronized Reserves	$0.01	0.0%	$0.01	0.0%	(58.9%)
RTO Startup and Expansion	$0.00	0.0%	$0.00	0.0%	3.3%
Day Ahead Scheduling Reserve (DASR)	$0.00	0.0%	$0.00	0.0%	(84.1%)
Transmission Facility Charges	$0.00	0.0%	$0.00	0.0%	(100.0%)
Capacity (FRR)	$0.00	0.0%	$0.00	0.0%	0.0%
Emergency Load Response	$0.00	0.0%	$0.00	0.0%	0.0%
Emergency Energy	$0.00	0.0%	$0.00	0.0%	0.0%
Total Price	$48.59	100.0%	$50.76	100.0%	4.5%

Table 1-9 shows the average price, by component of the total wholesale power price per MWh, for calendar years 1999 through 2016.

56 OA Schedule 1 § 3.2.3A.001.
57 OA Schedule 1 § 3.2.6.
58 Note: The totals in this table include after the fact billing adjustments and may not match totals presented in past reports.

Table 1-9 Total price per MWh by category: Calendar Years 1999 through 2016[59]

Category	1999 $/MWh	2000 $/MWh	2001 $/MWh	2002 $/MWh	2003 $/MWh	2004 $/MWh	2005 $/MWh	2006 $/MWh	2007 $/MWh	2008 $/MWh	2009 $/MWh	2010 $/MWh	2011 $/MWh	2012 $/MWh	2013 $/MWh	2014 $/MWh	2015 $/MWh	2016 $/MWh
Load Weighted Energy	$34.07	$30.72	$36.65	$31.60	$41.23	$44.34	$63.46	$53.35	$61.66	$71.13	$39.05	$48.35	$45.94	$35.23	$38.66	$53.14	$36.16	$29.23
Capacity	$0.14	$0.25	$0.27	$0.12	$0.08	$0.09	$0.03	$0.03	$3.53	$7.80	$10.78	$12.15	$9.71	$6.05	$7.13	$9.01	$11.12	$10.96
Transmission Service Charges	$3.41	$4.03	$3.48	$3.39	$3.57	$3.28	$2.71	$3.18	$3.45	$3.68	$4.03	$4.04	$4.49	$4.90	$5.21	$5.96	$7.09	$7.81
Transmission Enhancement Cost Recovery	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.01	$0.06	$0.11	$0.20	$0.27	$0.34	$0.36	$0.41	$0.51	$0.52
PJM Administrative Fees	$0.23	$0.26	$0.71	$0.86	$1.05	$0.93	$0.72	$0.74	$0.72	$0.39	$0.31	$0.36	$0.38	$0.44	$0.42	$0.44	$0.44	$0.45
Reactive	$0.26	$0.29	$0.22	$0.20	$0.24	$0.26	$0.26	$0.29	$0.29	$0.34	$0.36	$0.45	$0.41	$0.46	$0.76	$0.40	$0.37	$0.39
Energy Uplift (Operating Reserves)	$0.52	$0.93	$1.27	$0.72	$0.89	$0.95	$1.07	$0.47	$0.65	$0.64	$0.48	$0.80	$0.78	$0.74	$0.61	$1.15	$0.38	$0.17
Regulation	$0.15	$0.39	$0.53	$0.42	$0.50	$0.51	$0.80	$0.53	$0.63	$0.70	$0.34	$0.36	$0.32	$0.26	$0.25	$0.33	$0.23	$0.11
Transmission Owner (Schedule 1A)	$0.07	$0.09	$0.08	$0.07	$0.07	$0.10	$0.09	$0.09	$0.09	$0.09	$0.09	$0.09	$0.09	$0.08	$0.08	$0.09	$0.09	$0.09
Black Start	$0.00	$0.00	$0.00	$0.00	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.04	$0.14	$0.08	$0.08	$0.09
Day Ahead Scheduling Reserve (DASR)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.01	$0.00	$0.01	$0.05	$0.05	$0.06	$0.05	$0.10	$0.07
Synchronized Reserves	$0.00	$0.00	$0.00	$0.01	$0.15	$0.13	$0.11	$0.08	$0.06	$0.08	$0.05	$0.07	$0.09	$0.04	$0.04	$0.12	$0.11	$0.05
NERC/RFC	$0.00	-$0.00	$0.01	$0.01	$0.01	$0.01	$0.01	-$0.00	$0.01	$0.01	$0.02	$0.02	$0.02	$0.02	$0.02	$0.03	$0.03	$0.03
Load Response	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.03	$0.06	$0.05	$0.01	$0.01	$0.01	$0.02	$0.01	$0.03	$0.02	$0.01
Non-Synchronized Reserves	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.02	$0.02	$0.01
RTO Startup and Expansion	$0.00	$0.00	$0.00	$0.00	$0.00	$0.06	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.00
Transmission Facility Charges	$0.01	$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Capacity (FRR)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.53	$0.52	$0.11	$0.20	$0.13	$0.00
Emergency Load Response	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.02	$0.02	$0.01	$0.06	$0.06	$0.00	$0.00
Emergency Energy	$0.07	$0.02	$0.00	$0.00	$0.02	$0.00	$0.02	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.01	$0.00	$0.00
Total Price	$38.92	$36.98	$43.22	$37.39	$47.83	$50.66	$69.30	$58.82	$71.19	$85.00	$55.66	$66.93	$63.21	$49.22	$53.93	$71.50	$56.88	$50.00

Table 1-10 shows the percent of average price, by component of the wholesale power price per MWh, for calendar years 1999 through 2016.

59 Note: The totals in this table include after the fact billing adjustments and may not match totals presented in past reports.

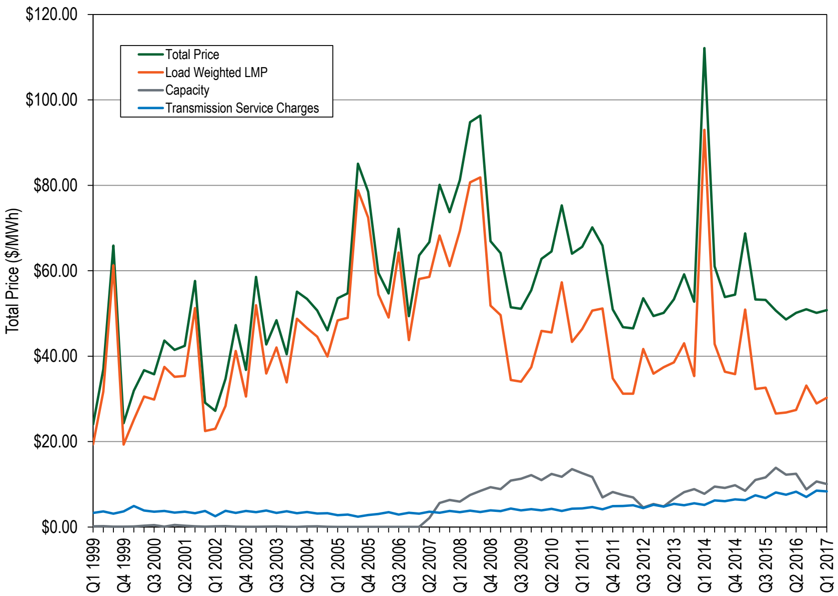
Table 1-10 Percent of total price per MWh by category: Calendar Years 1999 through 2016[60]

Category	Percent of Total Charges 1999	Percent of Total Charges 2000	Percent of Total Charges 2001	Percent of Total Charges 2002	Percent of Total Charges 2003	Percent of Total Charges 2004	Percent of Total Charges 2005	Percent of Total Charges 2006	Percent of Total Charges 2007	Percent of Total Charges 2008	Percent of Total Charges 2009	Percent of Total Charges 2010	Percent of Total Charges 2011	Percent of Total Charges 2012	Percent of Total Charges 2013	Percent of Total Charges 2014	Percent of Total Charges 2015	Percent of Total Charges 2016
Load Weighted Energy	87.5%	83.1%	84.8%	84.5%	86.2%	87.5%	91.6%	90.7%	86.6%	83.7%	70.2%	72.2%	72.7%	71.6%	71.7%	74.3%	63.6%	58.5%
Capacity	0.4%	0.7%	0.6%	0.3%	0.2%	0.2%	0.0%	0.0%	5.0%	9.2%	19.4%	18.2%	15.4%	12.3%	13.2%	12.6%	19.6%	21.9%
Transmission Service Charges	8.8%	10.9%	8.0%	9.1%	7.5%	6.5%	3.9%	5.4%	4.8%	4.3%	7.2%	6.0%	7.1%	9.9%	9.7%	8.3%	12.5%	15.6%
Transmission Enhancement Cost Recovery	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.2%	0.3%	0.4%	0.7%	0.7%	0.6%	0.9%	1.0%
PJM Administrative Fees	0.6%	0.7%	1.7%	2.3%	2.2%	1.8%	1.0%	1.3%	1.0%	0.5%	0.6%	0.5%	0.6%	0.9%	0.8%	0.6%	0.8%	0.9%
Reactive	0.7%	0.8%	0.5%	0.5%	0.5%	0.5%	0.4%	0.5%	0.4%	0.4%	0.7%	0.7%	0.6%	0.9%	1.4%	0.6%	0.7%	0.8%
Energy Uplift (Operating Reserves)	1.3%	2.5%	2.9%	1.9%	1.9%	1.9%	1.5%	0.8%	0.9%	0.8%	0.9%	1.2%	1.2%	1.5%	1.1%	1.6%	0.7%	0.3%
Regulation	0.4%	1.1%	1.2%	1.1%	1.1%	1.0%	1.1%	0.9%	0.9%	0.8%	0.6%	0.5%	0.5%	0.5%	0.5%	0.5%	0.4%	0.2%
Transmission Owner (Schedule 1A)	0.2%	0.2%	0.2%	0.2%	0.1%	0.2%	0.1%	0.1%	0.1%	0.1%	0.2%	0.1%	0.1%	0.2%	0.2%	0.1%	0.2%	0.2%
Black Start	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%	0.1%	0.3%	0.1%	0.1%	0.2%
Day Ahead Scheduling Reserve (DASR)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.1%	0.1%	0.2%	0.1%
Synchronized Reserves	0.0%	0.0%	0.0%	0.0%	0.3%	0.3%	0.2%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.2%	0.2%	0.1%
NERC/RFC	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%	0.0%	0.0%	0.0%	0.1%	0.1%
Load Response	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Non-Synchronized Reserves	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%	0.0%	0.0%	0.0%	0.0%	0.0%
RTO Startup and Expansion	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Transmission Facility Charges	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%	0.0%	0.0%	0.0%	0.0%	0.0%
Capacity (FRR)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.8%	1.1%	0.2%	0.3%	0.2%	0.0%
Emergency Load Response	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%	0.0%	0.1%	0.1%	0.0%	0.0%
Emergency Energy	0.2%	0.1%	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%	0.0%	0.0%	0.0%
Total Price	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	99.9%	100.0%	100.0%	100.0%	100.0%	100.0%

Figure 1-3 shows the contributions of load-weighted energy, capacity and transmission service charges to the total price of wholesale power for each quarter since 1999.

60 Note: The totals in this table include after the fact billing adjustments and may not match totals presented in past reports.

Figure 1-3 Top three components of quarterly total price ($/MWh): January 1, 1999 through March 31, 2017[61]



Section Overviews

Overview: Section 3, "Energy Market"

Market Structure

- **Supply.** Supply includes physical generation and imports and virtual transactions. The maximum of average offered real-time generation decreased by 2,613 MW, or 1.5 percent, from 173,439 MW in the first three months of 2016 to 170,827 MW in the first three months of 2017. In the first three months 2017, 1,317.7 MW of new capacity resources were added. In the first three months 2017, 209.0 MW were retired.

PJM average real-time cleared generation in the first three months of 2017 increased by 2,604 MW, or 2.9 percent, from the first three months of 2016, from 88,470 MW to 91,074 MW.

PJM average day-ahead cleared supply in the first three months of 2017, including INCs and up to congestion transactions, increased by 5.6 percent from the first three months of 2016, from 133,263 MW to 140,756 MW, primarily as a result of an increase in UTC volumes.

- **Market Concentration.** The PJM Energy Market was unconcentrated overall with moderate concentration in the baseload and intermediate segments, and high concentration in the peaking segment.
- **Generation Fuel Mix.** In the first three months of 2017, coal units provided 33.3 percent, nuclear units 35.8 percent and natural gas units 24.4 percent of total generation. Compared to the first three months of 2016, generation from coal units increased 7.0 percent, generation from natural gas units increased 1.3 percent and generation from nuclear units increased 0.5 percent.
- **Fuel Diversity.** In the first three months of 2017, the fuel diversity of energy generation, measured by the fuel diversity index for energy (FDIe), increased 0.2 percent over the first three months of 2016.
- **Marginal Resources.** In the PJM Real-Time Energy Market, in the first three months of 2017, coal units were 34.2 percent of marginal resources and natural gas units were 51.0 percent of marginal resources. In the first three months of 2016, coal units were 45.9 percent and natural gas units were 42.0 percent of the marginal resources.

In the PJM Day-Ahead Energy Market, in the first three months of 2017, up to congestion transactions were 83.7 percent of marginal resources, INCs were 4.6 percent of marginal resources, DECs were 7.6 percent of marginal resources, and generation resources were 4.1 percent of marginal resources. In the first three months of 2016, up to congestion transactions were 83.2 percent of marginal resources, INCs were 4.0 percent of marginal resources, DECs were 6.9 percent of marginal resources, and generation resources were 5.9 percent of marginal resources.

61 Note: The totals presented in this figure include after the fact billing adjustments and may not match totals presented in past reports.

- **Demand.** Demand includes physical load and exports and virtual transactions. The PJM accounting peak load during the first three months 2017 was 127,543 MW in the HE 0700 on January 09, 2017, which was 2,333 MW, 1.8 percent, lower than the PJM peak load for the first three months 2016, which was 129,876 MW in the HE 0700 on January 19, 2016.

  PJM average real-time load in the first three months of 2017 decreased from 2016, from 89,322 MW to 87,598 MW. PJM average day-ahead demand in the first three months of 2017, including DECs and up to congestion transactions, increased by 3.9 percent in the first three months of 2016, from 130,534 MW to 135,560 MW.

- **Supply and Demand: Load and Spot Market.** Companies that serve load in PJM can do so using a combination of self-supply, bilateral market purchases and spot market purchases. For the first three months of 2017, 17.9 percent of real-time load was supplied by bilateral contracts, 20.9 percent by spot market purchases and 61.1 percent by self-supply. Compared with the first three months of 2016, reliance on bilateral contracts increased by 5.1 percentage points, reliance on spot market purchases decreased by 3.0 percentage points and reliance on self-supply decreased by 2.1 percentage points.

- **Supply and Demand: Scarcity.** There were no shortage pricing events in the first three months of 2017.

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 when the rules are designed and implemented properly. 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 decreased from 0.1 percent in the first three months of 2016 to 0 percent in the first three months of 2017. In the Real-Time Energy Market, for units committed to provide energy for local constraint relief, offer-capped unit hours decreased from 0.4 percent in the first three months of 2016 to 0.2 percent in the first three months of 2017.

  In the first three months of 2017, nine control zones experienced congestion resulting from one or more constraints binding for 25 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 increased from 0.1 percent in the first three months of 2016 to 0.2 percent in the first three months of 2017. In the Real-Time Energy Market, for units committed for reliability reasons, offer-capped unit hours increased from 0.1 percent in the first three months of 2016to 0.2 percent in the first three months of 2017.

- **Markup Index.** The markup index is a summary measure of participant offer behavior for individual marginal units. In the first three months of 2017, in the PJM Real-Time Energy Market, 91.4 percent of marginal units had offer prices less than $50 per MWh. The average dollar markups of units with offer prices less than $25 was negative when using unadjusted cost offers. The average dollar markups of units with offer prices between $25 and $50 was positive when using unadjusted cost offers. Negative markup means the unit is offering to run at a price less than its cost-based offer, demonstrating a revealed short run marginal cost that is less than the allowable cost-based offer under the PJM Market Rules. Some marginal units did have substantial markups. Using the unadjusted cost offers, the highest markup for any marginal unit in the first three months of 2017 was $235.44 while the highest markup in the first three months of 2016 was $219.30.

In the PJM Day-Ahead Energy Market, when using unadjusted cost offers, In the first three months of 2017, 89.3 percent of marginal generating units had offer prices less than $50 per MWh and the average dollar markup was positive, and the 1.1 percent of marginal generating units had offers in the $75 to $100 per MWh range and the average dollar markup was positive.

- **Markup.** The markup frequency distributions show that a significant proportion of units make price-based offers less than the cost-based offers permitted under the PJM market rules. This behavior means that competitive price-based offers reveal actual unit marginal costs and that PJM market rules permit the inclusion of costs in cost-based offers that are not short run marginal costs.

  The markup behavior shown in the markup frequency distributions also shows that a substantial number of units were offered with high markups, consistent with the exercise of market power.

- **Frequently Mitigated Units (FMU) and Associated Units (AU).** A new FMU rule became effective November 1, 2014, limiting the availability of FMU adders to units with net revenues less than unit going forward costs. The 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 since December 2014.

- **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. In the first three months of 2017, the average hourly increment offers submitted MW increased by 40.3 percent from 7,425 MW in the first three months of 2016 to 10,419 MW in the first three months of 2017, and cleared MW increased by 30.4 percent from 4,691 MW in the first three months of 2016 to 6,115 MW in the first three months of 2017. In the first three months of 2017, the average hourly decrement bids submitted MW increased by 22.5 percent from 7,901 MW in the first three months of 2016 to 9,676 MW in the first three months of 2017, and cleared MW increased by 4.5 percent from 4,661 MW in the first three months of 2016 to 4,869 MW in the first three months of 2017. In the first three months of 2017, the average hourly up to congestion submitted MW increased by 30.1 percent from 145,311 MW in the first three months of 2016 to 188,905 MW in the first three months of 2017, and cleared MW increased by 15.8 percent from 36,711 MW in the first three months of 2016 to 42,516 MW in the first three months of 2017.

- **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 the first three months of 2017, 57.1 percent were offered as available for economic dispatch, 3.6 percent were offered as emergency dispatch, 20.3 percent were offered as self scheduled, and 19.0 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, emissions related expenses, markup and local price differences caused by congestion. PJM also may administratively set prices with the creation of closed loop interfaces related to demand side resources or reactive power, the application of transmission penalty factors, or the application of price setting logic.

  PJM real-time energy market prices increased in the first three months of 2017 compared to the first three months of 2016. The load-weighted average real-time LMP was 13.0 percent higher in the first three months of 2017 than in first three months of 2016, $30.28 per MWh versus $26.80 per MWh.

PJM day-ahead energy market prices increased in the first three months of 2017 compared to the first three months of 2016. The load-weighted average day-ahead LMP was 8.8 percent higher in the first three months of 2017 than in the first three months of 2016, $30.40 per MWh versus $27.94 per MWh.

- **Components of LMP.** In the PJM Real-Time Energy Market, in 2016, 40.3 percent of the load-weighted LMP was the result of coal costs, 32.4 percent was the result of gas costs and 2.09 percent was the result of the cost of emission allowances.

  In the PJM Day-Ahead Energy Market in the first three months of 2017, 21.0 percent of the load-weighted LMP was the result of the cost of coal, 24.7 percent was the result of DECs, 21.1 percent was the result of the cost of gas, 19.5 percent was the result of INCs, and 3.4 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 the first three months of 2017, the adjusted markup component of LMP was $3.81 per MWh or 12.6 percent of the PJM real-time, load-weighted average LMP. January had the highest adjusted peak markup component, $5.88 per MWh, or 17.13 percent of the real-time peak hour load-weighted average LMP. Using the unadjusted cost offers, the highest markup of a marginal unit in the first three months of 2017 was $235.44 per MWh. There were 12 hours in the first three months of 2017 where the positive markup contribution to the PJM system wide, load-weighted, average LMP exceeded $42.99 per MWh.

  In the PJM Day-Ahead Energy Market, INCs, DECs and UTCs have zero markups. In the first three months of 2017, the adjusted markup component of LMP resulting from generation resources was $1.56 per MWh or 5.1 percent of the PJM day-ahead load-weighted average LMP. March had the highest adjusted markup component, $1.99 per MWh or 5.1 percent of the day-ahead load-weighted average LMP.

  Participant behavior was evaluated as competitive because the analysis of markup shows that marginal units generally make offers at, or close to, their marginal costs in both the Day-Ahead and Real-Time Energy Markets, although the behavior of some participants 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 -$1.30 per MWh in the first three months of 2016 and -$0.20 per MWh in the first three months of 2017. The difference between average day-ahead and real-time prices, by itself, is not a measure of the competitiveness or effectiveness of the Day-Ahead Energy Market.

Scarcity

- There were no shortage pricing events in the first three months of 2017.

Section 3 Recommendations

- The MMU recommends that the market rules should explicitly require that offers into the Day-Ahead Energy Market be competitive, where competitive is defined to be the short run marginal cost of the units. The short run marginal cost should reflect opportunity cost when and where appropriate. (Priority: Medium. First reported 2009. Status: Not adopted.)
- The MMU recommends that PJM require every market participant to make available at least one cost schedule with the same fuel type and parameters as that of their offered price schedule. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM require that the level of incremental costs includable in cost offers not exceed the unit's short run marginal cost. (Priority: Medium. First reported 2016. Status: Not adopted.)

- The MMU recommends that PJM require that all fuel cost policies be algorithmic, verifiable, and systematic. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that Manual 15 be replaced with a straightforward description of the components of cost offers based on short run marginal costs and the correct calculation of cost offers. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends removal of all use of the FERC System of Accounts in the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends the removal of all use of cyclic starting and peaking factors from the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends the removal of all labor costs from the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends changing the definition of the start heat input for combined cycles to include only the amount of fuel used from firing each combustion turbine in the combined cycle to the breaker close of each combustion turbine. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends the removal of nuclear fuel and nonfuel operations and maintenance costs that are not short run marginal costs from the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends revising the pumped hydro fuel cost calculation to include day-ahead and real-time power purchases. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends revisions to the calculation of energy market opportunity costs to incorporate all time based offer parameters and all limitations that impact the opportunity cost of generating unit output. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends removing the catastrophic designation for force majeure fuel supply limitations in Schedule 2. (Priority: Medium. First reported 2016. Status: Not adopted.)
- 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 the full MWh range of 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. First reported 2015. 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. First reported 2015. 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 and that this standard be applied to all technologies on a uniform basis. (Priority: Medium. First reported 2015. 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 nonperformance charges and the amount of uplift payments to those generators should reflect the flexibility goals of the capacity performance construct. (Priority: Medium. First reported 2015. Status: Not adopted.)

- 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 retain other existing rules that limit incentives to exercise market power. (Priority: High. First reported 1999. Status: Partially adopted, 1999.)
- The MMU recommends that PJM not allow nuclear generators which do not respond to prices or which only respond to manual instructions from the dispatcher to set the LMPs in the real-time market. (Priority: Low. First reported 2016. Status: Not adopted.)
- The MMU recommends that PJM document 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 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; the allowed duration of the violation; the use of constraint relaxation logic; and when the transmission penalty factors will be used to set the shadow price. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that the definition of maximum emergency status in the tariff apply at all times rather than just during maximum emergency events.[62] (Priority: Medium. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM 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.[63] There is currently no PJM documentation in the tariff or manuals explaining how hubs are created and how their definitions are changed.[64] (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that during hours when a generation bus shows a net withdrawal, the energy withdrawal be treated as load, not negative generation, for purposes of calculating load and load-weighted LMP. The MMU 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 remove nonspecific 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 2015. Status: Partially 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 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.)

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

63 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.

64 The general definition of a hub can be found in the PJM.com Glossary <http://www.pjm.com/Glossary.aspx>.

- 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: Partially adopted, 2014.)
- The MMU recommends that PJM require all generating units to identify the fuel type associated with each of their offered schedules. (Priority: Low. First reported 2014. Status: Adopted in full, 2014.)

Section 3 Conclusion

The MMU analyzed key elements of PJM energy market structure, participant conduct and market performance in the first three months of 2017, 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 cleared generation increased by 2,604 MW, 2.9 percent, and peak load decreased by 2,333 MW, 1.8 percent, in the first three months of 2017 compared to the first three months of 2016. Market concentration levels remained in the unconcentrated range on average although there is high concentration in the peaking segment 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 and the extent of pivotal suppliers, 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. Low average aggregate concentration does not mean that market power cannot be exercised. It is possible that market power can be exercised at times when individual suppliers or small groups of suppliers are pivotal even when the HHI level does not indicate that the market is highly concentrated. High markups for some units demonstrate the potential to exercise market power during high demand conditions.

Prices are a key outcome of markets. Prices vary across hours, days and years for multiple reasons. Price is an indicator of the level of competition in a market although individual prices are not always easy to interpret. In a competitive market, prices are directly related to the marginal cost of the most expensive unit required to serve load in each hour. The pattern of prices within days and across months and years illustrates how prices are directly related to supply and demand conditions and thus also illustrates the potential significance of the impact of the price elasticity of demand on prices. Energy market results in the first three months of 2017 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.[65] This is a flexible, targeted real-time measure of market structure which replaced the offer capping of all units required to relieve a constraint. A generation owner or group of generation owners is pivotal for a local market if the output of the owners' generation facilities is required in order to relieve a transmission constraint. When a generation owner or group of owners is pivotal, it has the ability to increase the market price above the competitive level. The three pivotal supplier test explicitly incorporates the impact of excess supply and implicitly accounts for the impact of the price elasticity of demand in the market power tests. The result of the introduction of the three pivotal supplier test was to limit offer capping to times when the local market structure was noncompetitive and specific

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

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 market power 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.

Another issue with the application of market power mitigation in the Day-Ahead Energy Market and the Real-Time Energy Market when market sellers fail the TPS test is related to the definition of a competitive offer. A competitive offer is equal to short run marginal costs. The enforcement of market power mitigation rules is undermined if the definition of a competitive offer is not correct. The significance of competition metrics like markup is also undermined if the definition of a competitive offer is not correct. The definition of a competitive offer, as interpreted by PJM, is not currently correct. Some unit owners include costs that are not short run marginal costs in offers, including maintenance costs. This issue can be resolved by simple changes to the PJM Market Rules to incorporate a clear and accurate definition of short run marginal costs.

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 in 2014, 2015 or 2016. This is evidence of generally competitive behavior and competitive market outcomes, although the behavior of some participants during the high demand periods 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 the first three months of 2017.

Overview: Section 4, "Energy Uplift"

Energy Uplift Results

- **Energy Uplift Charges.** Total energy uplift charges decreased by $13.9 million, or 35.2 percent, in the first three months of 2017 compared to the first three months of 2016, from $39.5 million to $25.6 million.
- **Energy Uplift Charges Categories.** The decrease of $13.9 million in the first three months of 2017 is comprised of a $16.1 million decrease in day-ahead operating reserve charges, a $3.5 million decrease in balancing operating reserve charges and a $5.6 million increase in reactive services charges.
- **Average Effective Operating Reserve Rates in the Eastern Region.** Day-ahead load paid $0.025 per MWh, real-time load paid $0.028 per MWh, a DEC paid $0.227 per MWh and an INC and any load, generation or interchange transaction deviation paid $0.202 per MWh.
- **Average Effective Operating Reserve Rates in the Western Region.** Day-ahead load paid $0.025 per MWh, real-time load paid $0.024 per MWh, a DEC paid $0.218 per MWh and an INC and any load, generation or interchange transaction deviation paid $0.193 per MWh.
- **Reactive Services Rates.** The PENELEC, BGE and Pepco control zones had the three highest local voltage support rates: $0.232, $0.222 and $0.222 per MWh.

Characteristics of Credits

- **Types of units.** Coal units received 86.5 percent of all day-ahead generator credits. Combustion turbines received 75.6 percent of all balancing generator credits. Combustion turbines and diesels received 68.2 percent of the lost opportunity cost credits.
- **Concentration of Energy Uplift Credits.** The top 10 units receiving energy uplift credits received 44.7 percent of all credits. The top 10 organizations received 83.3 percent of all credits. Concentration indexes for energy uplift categories classify them as highly concentrated. Day-ahead operating reserves HHI was 7331, balancing operating reserves HHI was 3764 and lost opportunity cost HHI was 5581.
- **Economic and Noneconomic Generation.** In the first three months of 2017, 85.5 percent of the day-ahead generation eligible for operating reserve credits was economic and 80.1 percent of the real-time generation eligible for operating reserve credits was economic.
- **Day-Ahead Unit Commitment for Reliability.** In the first three months of 2017, 1.2 percent of the total day-ahead generation MWh was scheduled as must run by PJM, of which 60.1 percent received energy uplift payments.

Geography of Charges and Credits

- In the first three months of 2017, 89.0 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, 4.4 percent by transactions at hubs and aggregates and 6.6 percent by interchange transactions at interfaces.
- Generators in the Eastern Region received 58.7 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.
- Generators in the Western Region received 39.7 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.

- External generators received 1.6 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.

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. First reported 2015. Status: Not adopted.)
- The MMU recommends that if PJM believes it appropriate to modify the LMP price setting logic, PJM initiate a stakeholder process to create transparent and consistent modifications to the rules and incorporate the modifications in the PJM tariff. (Priority: Medium. First Reported 2016. 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 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 four additional modifications to the energy lost opportunity cost calculations:
- 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 for both the injection and the withdrawal sides of the UTC. (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 2012. Status: Not adopted. Stakeholder process.)
- The MMU recommends modifications to the calculation of lost opportunity costs credits paid to wind units. The lost opportunity costs credits paid to wind units should be based on the lesser of the desired output, the estimated output based on actual wind conditions and the capacity interconnection rights (CIRs). In addition, the MMU recommends that PJM allow and wind units submit CIRs that reflect the maximum output wind units want to inject into the transmission system at any time. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM revise Manual 11 attachment C consistent with the tariff to limit compensation to offered costs. The Manual 11 attachment C procedure should describe the steps market participants should take to change the availability of cost-based energy offers that have been submitted day ahead. The MMU recommends that PJM eliminate the Manual 11 attachment C procedure with the implementation of hourly offers (ER16-372-000). (Priority: Medium. First reported 2016. 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 to make all market participants 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 2015.)
- 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: Partially adopted.)
- 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.)

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 incurred when LMP is greater than or equal to the incremental offer but does not cover start up and no load costs. Loss is defined to be receiving revenue less than the short run marginal costs incurred in order to generate energy. 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 short run 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.

Competitive market outcomes result from energy offers equal to short run marginal costs and that incorporate flexible operating parameters. But when PJM permits a unit to include inflexible operating parameters in its offer and pays uplift based on those inflexible parameters, there is an incentive for the unit to remain inflexible. The rules regarding operating parameters should be implemented in a way that creates incentives for flexible operations rather than inflexible operations. PJM has failed to hold coal, gas and oil steam turbines to the standard used for combined cycles, combustion turbines and diesels. The standard should be the maximum achievable flexibility, based on OEM standards. Applying a weaker standard to steam units effectively subsidizes inflexible units by paying them based on inflexible parameters that result from lack of investment and that could be made more flexible. The result both inflates uplift costs and suppresses energy prices.

In PJM, all energy payments to demand response resources are 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 have 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. Some uplift payments are the result of inflexible operating parameters included in offers by generating units. Operating parameters should reflect the flexibility of the benchmark new entrant unit in the PJM capacity market if the unit is to receive uplift payments from other market participants. 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.[66]

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.[67] 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.[68] 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.[69]

The 2017/2018 RPM Third Incremental Auction was conducted in the first three months of 2017.

On 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 the 2016/2017 and 2017/2018 Delivery Years. Effective with the 2020/2021 Delivery Year,

66 The terms *PJM Region*, *RTO Region* and *RTO* are synonymous in this report and include all capacity within the PJM footprint.
67 See 126 FERC ¶ 61,275 (2009) at P 86.
68 See Order in Docket No. ER10-366-000 (January 22, 2010).
69 See 126 FERC ¶ 61,275 (2009) at P 88.
70 See Docket No. ER15-623-000 (December 12, 2014) and 151 FERC ¶ 61,208 (2015).

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. 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.

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 the first three months of 2017, PJM installed capacity increased 1,182.9 MW or 0.6 percent, from 182,410.7 MW on January 1 to 183,593.6 MW on March 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 March 31, 2017, 36.5 percent was coal; 35.9 percent was gas; 18.0 percent was nuclear; 3.6 percent was oil; 4.8 percent was hydroelectric; 0.6 percent was wind; 0.4 percent was solid waste; and 0.1 percent was solar.
- **Market Concentration.** In the 2016/2017 RPM Third Incremental Auction all participants in the total PJM market as well as the LDA RPM markets failed the three pivotal supplier (TPS) test.[73] Offer caps were applied to all sell offers for resources which were subject to mitigation when the Capacity Market Seller did not pass the test, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, increased the market clearing price.[74] [75] [76]
- **Imports and Exports.** Of the 15.9 MW of imports in the 2016/2017 RPM Third Incremental Auction, 11.4 MW cleared. Of the cleared imports, 8.6 MW (75.4 percent) were from MISO.
- **Demand-Side and Energy Efficiency Resources.** Capacity in the RPM load management programs was 10,248.9 MW for June 1, 2016, as a result of cleared capacity for Demand Resources and Energy Efficiency

71 See "PJM Manual 18: PJM Capacity Market," Rev. 36 (December 22, 2017) at 8.
72 Transmission constraints are local capacity import capability limitations (low capacity emergency transfer limit (CETL) margin over capacity emergency transfer objective (CETO)) caused by transmission facility limitations, voltage limitations or stability limitations.
73 There are 27 Locational Deliverability Areas (LDAs) identified to recognize locational constraints as defined in "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region", Schedule 10.1. PJM determines, in advance of each BRA, whether the defined LDAs will be modeled in the given delivery year using the rules defined in OATT Attachment DD (Reliability Pricing Model) § 5.10(a)(ii).
74 See 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).

Resources in RPM Auctions for the 2016/2017 Delivery Year (14,988.5 MW) less replacement capacity from sources other than Demand Resources and Energy Efficiency (4,739.6 MW).

Market Conduct

- **2017/2018 RPM Third Incremental Auction.** Of the 310 generation resources that submitted offers, the MMU calculated offer caps for nine generation resources (2.9 percent), of which five were based on the technology specific default (proxy) ACR values and four were unit-specific offer caps (1.3 percent).

Market Performance

- The 2017/2018 RPM Third Incremental Auction was conducted in the first three months of 2017. The weighted average capacity price for the 2017/2018 Delivery Year is $141.16 per MW-day, including all RPM Auctions for the 2017/2018 Delivery Year held through the first three months of 2017. The weighted average capacity price for the 2018/2019 Delivery Year is $177.38, including all RPM Auctions for the 2018/2019 Delivery Year held through the first three months of 2017. The weighted average capacity price for the 2019/2020 Delivery Year is $114.30, including all RPM Auctions for the 2019/2020 Delivery Year held through the first three months of 2017. RPM net excess increased 1,329.5 MW from 5,855.9 MW on June 1, 2015, to 7,185.4 MW on June 1, 2016.
- For the 2016/2017 Delivery Year, RPM annual charges to load are $7.7 billion.
- The delivery year weighted average capacity price was $121.84 per MW-day in 2016/2017 and $141.16 per MW-day in 2017/2018.

Generator Performance

- **Forced Outage Rates.** The average PJM EFORd for the first three months of 2017 was 6.2 percent, a decrease from 6.3 percent for the first three months of 2016.[77]
- **Generator Performance Factors.** The PJM aggregate equivalent availability factor for the first three months of 2017 was 87.7 percent, an increase from 86.6 percent for the first three months of 2016.
- **Outages Deemed Outside Management Control (OMC).** In the first three months of 2017, 0.5 percent of forced outages were classified as OMC outages.

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

- The MMU recommends the extension of minimum offer price rule (MOPR) to all existing and proposed units in order to protect competition in the capacity market from external subsidies. (Priority: High. First reported 2016. Status: Not adopted.)
- 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.)

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 was downloaded from the PJM GADS database on April 24, 2017. 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.

79 151 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, 2016," <http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Analysis_of_Replacement_Capacity_for_RPM_Commitments_06012007_to_06012016_20161227.pdf> (December 27, 2016).

- The MMU recommends that the test for determining modeled Locational Deliverability Areas (LDAs) 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 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 the following changes with respect to capacity imports into PJM:
  - The MMU recommends that all capacity imports be required to be deliverable to PJM load prior to the relevant delivery year to ensure that they are as close to full substitutes for internal, physical capacity resources as possible. Pseudo ties alone are not adequate to ensure deliverability. (Priority: High. First reported 2016. Status: Not adopted.)
  - The MMU recommends that all costs incurred as a result of a pseudo tied unit be borne by the unit itself and included as appropriate in unit offers in the capacity market. (Priority: High. First reported 2016. Status: Not adopted.)
- The MMU recommends improvements to the performance incentive requirements of RPM:
  - 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 2009. Status: Not adopted. Pending before FERC.)
  - The MMU recommends that retroactive replacement capacity transactions not be permitted. (Priority: Medium. First reported 2016. Status: Not adopted.)

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).

- The MMU recommends that treatment of costs in RMR filings be emphasized. Customers should bear all the incremental costs, including incremental investment costs, required by the RMR service that the unit owner would not have incurred if the unit owner had deactivated its unit as it proposed. Generation owners should bear all other costs. (Priority: Low. First reported 2010. Status: Not adopted.)
- The MMU recommends that the mitigation rules for Demand Resource and Energy Efficiency Resource offers be reevaluated and reviewed. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that Energy Efficiency Resources (EE) not be included on the supply side of the capacity market because PJM's load forecasts now account for future EE but did not when EE was first added to the capacity market. If EE is not included on the supply side, there is no reason to have an add back mechanism. If EE remains on the supply side, the implementation of the EE add back mechanism should be modified to ensure that market clearing prices are not affected. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that PJM reduce the number of incremental auctions to a single incremental auction held three months prior to the start of the delivery year and reevaluate the triggers for holding conditional incremental auctions. (Priority: Medium. First reported 2013. Modified Q1 2017. Status: Not adopted.)
- The MMU recommends that PJM release capacity in the incremental auction only in cases where the combination of quantities released and associated prices would increase the welfare of capacity market resource owners and load, including consideration of both capacity and energy market benefits in the determination of release quantities and prices. (Priority: Medium. New Recommendation. Status: Not adopted.)
- The MMU recommends that the notification requirement for deactivations be extended from 90 days prior to the date of deactivation to 12 months prior to the date of deactivation and that PJM and the MMU be provided 60 days rather than 30 days to complete their reliability and market power analyses. (Priority: Low. First reported 2012. Status: Partially adopted.)
- The MMU recommends clear, explicit and detailed rules that define the conditions under which PJM will and will not recall energy from PJM capacity resources and prohibit new energy exports from PJM capacity resources. The MMU recommends that those rules define the conditions under which PJM will purchase emergency energy while at the same time not recalling energy exports from PJM capacity resources. PJM has modified these rules, but they need additional clarification and operational details. (Priority: Low. First reported 2010. Status: Partially 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 2015.)
- 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 2012. Status: Adopted 2015.)
- The MMU recommends that all capacity imports have firm transmission to the PJM border acquired prior to offering in an RPM auction. (Priority: High. First reported 2014. Status: Adopted 2015.)
- 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 2015.)
- The MMU recommends that all resources importing capacity into PJM accept a must offer requirement. (Priority: High. First reported 2014. Status: Adopted 2015.)
- 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 2015.)

- 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 2015.)
- 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 2015.)

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 2017. 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 2017.

The MMU has identified serious market design issues with RPM and the MMU has made specific recommendations to address those issues.[86] [87] [88] [89] [90] In 2016 and 2017, the MMU prepared a number of RPM-related reports and testimony, shown in Table 52. 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 CP Auctions which include more specific issues and suggestions for improvements.

The issue of external subsidies emerged more fully in 2016. The subsidies are not part of the PJM market design but nonetheless threaten the foundations of the PJM capacity market as well as the competitiveness of PJM markets overall.

The Ohio subsidy proceedings and the Illinois ZEC subsidy proceeding all originate from the fact that competitive markets result in the exit of uneconomic and uncompetitive generating units. Regardless of the specific rationales offered by unit owners, the proposed solution for all such generating units has been to provide out of market subsidies in order to retain such units. The proposed solution in all cases ignores the opportunity cost of subsidizing uneconomic units, which is the displacement of resources and technologies that would otherwise be economic. These subsidies are not accurately characterized as state subsidies. These subsidies were all requested by the owners of specific uneconomic generating units in order to improve the profitability of those specific units. These subsidies were not requested to accomplish broader social goals. Broader social goals can all be met with market based mechanisms available to all market participants on a competitive basis and without discrimination.

Subsidies are contagious. Competition in the markets could be replaced by competition to receive subsidies. Similar threats to competitive markets are being discussed by unit owners in other states and the potentially precedential nature of these actions enhances the urgency of creating an effective rule to maintain competitive markets by modifying market rules to address these

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 See "Analysis of the 2016/2017 RPM Base Residual Auction," <http://www.monitoringanalytics.com/reports/Reports/2014/IMM_Analysis_of_the_20162017_RPM_Base_Residual_Auction_20140418.pdf> (April 18, 2014).

87 See "Analysis of the 2017/2018 RPM Base Residual Auction," <http://www.monitoringanalytics.com/reports/Reports/2014/IMM_Analysis_of_the_2017_2018_RPM_Base_Residual_Auction_20141006.pdf> (October 6, 2014).

88 See "Analysis of the 2018/2019 RPM Base Residual Auction Revised," <http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Analysis_of_the_20182019_RPM_Base_Residual_Auction_20160706.pdf> (July 6, 2016).

89 See "Analysis of the 2019/2020 RPM Base Residual Auction Revised," <http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Analysis_of_the_20192020_RPM_BRA_20160831-Revised.pdf> (August 31, 2016).

90 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2016," <http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Analysis_of_Replacement_Capacity_for_RPM_Commitments_06012007_to_06012016_20161227.pdf> (December 27, 2016).

subsidies. Fortunately, this can be accomplished quickly by expanding the coverage of an existing rule that already reflects stakeholder compromises.

PJM markets have no protection against this emergent threat. Accurate signals for entry and exit are necessary for well functioning and competitive markets. Competitive investors rely on accurate signals to make decisions. The current MOPR only addresses subsidies for new entry. The current subsidies demonstrate that the markets need protection against subsidized, noncompetitive offers from existing as well as new resources. The MOPR should be expanded to address subsidies for existing units, and this should be done expeditiously. This issue will not become moot unless and until the MOPR is reformed. Action is needed to correct the MOPR immediately. An existing unit MOPR is the best means to defend the PJM markets from the threat posed by subsidies intended to forestall retirement of financially distressed assets. The role of subsidies to renewables should also be clearly defined and be incorporated in this rule.

While the existing unit MOPR would protect markets in the short run, the underlying issues that have resulted in the pressure on markets should also be examined. Unit owners are seeking subsidies because gas prices are low resulting in low energy market margins and because flaws in the PJM capacity design have led to very substantial price suppression over the past 10 years.

To the extent that there are shared broader goals related to PJM markets, they should also be addressed, but this can happen with a slightly longer lead time. If a shared goal is to reduce carbon output, a price on carbon is the market based solution. If a shared goal is increased renewables in addition to their carbon attributes, a common approach to RECs would be a market based solution. Fuel diversity has also been mentioned as an issue. Current fuel diversity is higher than ever in PJM. If there is an issue, the real issue is fuel security and not fuel diversity. Significant reliance on specific fuels, including nuclear, coal and gas means that markets are at risk from a significant disruption in any one fuel. If fuel security for gas is a concern, a number of issues should be considered including the reliability of the pipelines, the compatibility of the gas pipeline and the merchant generator business models, the degree to which electric generators have truly firm gas service and the need for a gas RTO to help ensure reliability.

As a result of the fact that demand side resources have contributed to price suppression in PJM capacity markets, the place of demand side in PJM should be reexamined. There are ways to ensure and enhance the vibrancy of demand side without negatively affecting markets for generation. There are other price formation issues in the capacity market that should also be examined and addressed.

Overview: Section 6, “Demand Response”

Overview

- **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 and pre-emergency programs are part of the capacity market program which includes both capacity payments and associated energy revenues when the capacity is called on to respond.[91] In the first three months of 2017, the emergency program accounted for 98.7 percent of all revenue received by demand response providers, the economic program for 0.4 percent, synchronized reserve for 0.6 percent and the regulation market for 0.3 percent. Total emergency revenue decreased by $109.5 million, 48.7 percent, from $224.6 million in the first three months of 2016 to $115.1 million in the first three months of 2017. Capacity market revenue, which comprised 100.0 percent of the emergency demand response program in the first three months of 2017, decreased by $109.5 million, 48.7 percent, from $224.6 million in the first three months of 2016 to $115.1 million in the first three months of 2017.[92]

  Economic program revenue decreased by $0.3 million, from $0.7 million in the first three months of 2016 to $0.4 million in the first three months of 2017, a 38.4 percent decrease.[93] Synchronized reserve revenue decreased

91 Throughout this document, emergency demand response refers to both emergency and pre-emergency demand response.
92 The total credits and MWh numbers for demand resources were calculated as of April 10, 2017 and may change as a result of continued PJM billing updates.
93 Economic credits are synonymous with revenue received for reductions under the economic load response program.

by $0.1 million, from $0.8 million in the first three months of 2016 to $0.70 million in the first three months of 2017, a 7.2 percent decrease. Regulation revenue increased by $0.2 million, from $0.2 million in the first three months of 2016 to $0.4 million in the first three months of 2017, a 126.6 percent increase.

Total demand response revenue decreased by $109.6 million, from $226.2 million in the first three months of 2016 to $115.1 million in the first three months of 2017, a 48.5 percent decrease. Not all DR activities in the first three months of 2017 had been reported to PJM at the time of this report.

Emergency and Economic 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.[94]

- **Demand Response Market Concentration.** The ownership of economic demand response was highly concentrated in the first three months of 2016 and 2017. The HHI for economic demand response reductions increased from 7699 in the first three months of 2016 to 9250 in the first three months of 2017. The ownership of emergency demand response was moderately concentrated in 2016. The HHI for emergency demand response registrations was 1469 for the 2016/2017 Delivery Year. In the 2016/2017 Delivery Year, the four largest companies contributed 66.6 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, but only if the subzone is defined at least one day before it is dispatched and only until PJM removes the definition of the subzone. 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.

94 "PJM Manual 28: Operating Agreement Accounting," Rev. 75 (November 18, 2016) at 77.

Section 6 Recommendations

The MMU recognizes that PJM incorporated some of the recommendations related to Demand Response in the Capacity Performance filing. The status of each recommendation reflects the status at March 31, 2017.

- 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 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 treated as an economic resource, responding to economic price signals like other capacity resources and not an emergency program responding only after an emergency is called, and not triggering the definition of a PJM emergency and not triggering a Performance Assessment Hour under the new PJM Capacity Market rules. (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.[95] (Priority: High. First reported 2013. Status: Not 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 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.[96] (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 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. First reported 2015. 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 2015. Status: Not adopted.)
- The MMU recommends that PJM not remove any defined subzone and maintain a public record of all created and removed subzones. (Priority: Low. First reported 2016. 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. (Priority: High. First reported 2011. Status: Partially adopted.[97])

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

96 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 June 29, 2016) 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.

97 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 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 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 capping the baseline for measuring compliance under GLD, for the limited summer product, at the customers' PLC. (Priority: High. First reported 2010. Status: Adopted 2015.)
- 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, 2014.)

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 (PAH) will be measured on an hourly basis.

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 MMU.

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.

Overview: Section 7, "Net Revenue"

Net Revenue

- Energy net revenues are significantly affected by energy prices and fuel prices. Energy prices and fuel prices were higher in the first three months of 2017 than in the first three months of 2016. Gas prices increased more than LMP and CTs and CCs ran with lower margins as a result. Coal prices increased by less than LMP and CPs ran for more hours in the first three months of 2017 than in the first three months of 2016 and with higher margins.
- In the first three months of 2017, average energy market net revenues decreased by 66 percent for a new CT, 29 percent for a new CC, 68 percent for a new DS, and four percent for a new solar installation. Average energy market net revenues increased by 17 percent for a new CP, 17 percent for a new nuclear plant, and 16 percent for a new wind installation, as compared to the first three months of 2016.

Historical New Entrant CT and CC Revenue Adequacy

Total unit net revenues include energy and capacity revenues. Analysis of the total unit revenues of theoretical new entrant CTs and CCs for three representative locations shows that units that entered the PJM markets in 2007 have not covered their total costs, including the return on and of capital, on a cumulative basis through March 31, 2017. The analysis also shows that theoretical new entrant CTs and CCs that entered the PJM markets in 2012 have covered their total costs on a cumulative basis in the eastern PSEG and BGE zones but have not covered total costs in the western ComEd Zone. Energy market revenues were not sufficient to cover total costs in any scenario except the new entrant CC unit that went into operation in 2012 in BGE, which demonstrates the critical role of capacity market revenue in covering total costs.

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.

Unlike cost of service regulation, markets do not guarantee that units will cover their costs. New CT and CC units that began operation in 2007 have not covered their total costs from energy market and capacity market revenues through March 31, 2017 in the ComEd Zone, in the PSEG Zone and in the BGE Zone. New CT and CC units that began operation on June 1, 2012, have covered or more than covered their total costs in the PSEG Zone and the BGE Zone through March 31, 2017 and have not covered their total costs in the ComEd Zone through March 31, 2017.

Overview: Section 8, "Environmental and Renewables"

Federal Environmental Regulation

- **EPA Mercury and Air Toxics Standards Rule.** The U.S. Environmental Protection Agency's (EPA) Mercury and Air Toxics Standards rule (MATS) applies the Clean Air Act (CAA) maximum achievable control technology (MACT) requirement to new or modified sources of emissions of mercury and arsenic, acid gas, nickel, selenium and cyanide.[98] The future of MATS is currently uncertain. The U.S. Supreme Court ruled in 2015 that EPA acted unreasonably when it deemed cost irrelevant to the decision to regulate power plants."[99] The EPA performed a cost review and made the required determination on cost in a supplemental finding.[100] In a case now pending before the U.S. Court of Appeals for the District of Columbia Circuit, the supplemental finding is under review.[101] On April 28, 2017, the Court granted EPA's request to postpone scheduled oral argument "to allow the new Administration adequate time to review the Supplemental Finding to determine whether it will be reconsidered."[102]

- **Air Quality Standards (NO_X and SO_2 Emissions).** The CAA requires each state to attain and maintain compliance with fine particulate matter (PM) and ozone national ambient air quality standards (NAAQS). The CAA also requires that each state prohibit emissions that significantly interfere with the ability of another state to meet NAAQS.[103] In January 2016, the EPA began the implementation of the Cross-State Air Pollution Rule (CSAPR) to address this issue through an interstate emissions trading regime.[104] As of January 1, 2017, CSAPR's Phase 2 emissions budgets and assurance provisions apply.

- **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.[105] On May 3, 2016, the Court issued a mandate to implement its May 1, 2015, order. The provisions that allowed RICE participating in emergency demand response programs to operate for additional hours have been eliminated.[106] Zero hours are exempt.[107] As a result, the national emissions standards uniformly apply to all RICE.[108] All RICE are allowed to operate during emergencies, including declared Energy Emergency Alert Level 2 or five percent voltage/frequency deviations.[109]

- **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).[110] 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 of the rule that will prevent its taking effect until judicial review is completed.[111] The future of the Clean Power Plan is currently uncertain. The new administration is reviewing the Clean Power Plan and related rules and agency actions, and has indicated the possibility of suspension, revision or rescission of such rules and actions.[112] On April 28, 2017, the U.S. Court of Appeals for the District of Columbia Circuit issued an order granting a motion of the EPA to hold in abeyance for 60 days pending cases challenging the Clean Power Plan, and further directed the filing of

98 *National Emission Standards for Hazardous Air Pollutants From Coal and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil Fuel Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units*, EPA Docket No. EPA-HQ-OAR-2009-0234, 77 Fed. Reg. 9304 (February 16, 2012).
99 135 S. Ct. 2699, 2712 (2015).
100 *See 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; see also White Stallion Energy Center, LLC v EPA, Slip Op. No. 12-1100 (D.C. Cir. 2015) (per curiam).
101 *See* Case No. 16-1127, et al.
102 Respondent EPA's Motion to Continue Oral Argument, Case No. 16-1127, et al. (April 18, 2017) at 1.
103 CAA § 110(a)(2)(D)(i)(I).
104 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").
105 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).
106 EPA, Memorandum, Peter Tsirigotis Guidance on Vacatur of RICE NESHAP and NSPS Provisions for Emergency Engines (April 15, 2016).
107 *Id.*
108 *Id.*
109 See 40 CFR §§ 60.4211(f)(2)(ii)–(iii), 60.4243(d)(2)(ii)–(iii), and 63.6640(f)(2)(ii)–(iii) (Declared Energy Emergency Alert Level 2 or 5 percent voltage/frequency deviations); 0 CFR §§ 60.4211(f)(1), 60.4243(d)(1), and 63.6640(f)(1) ("There is no time limit on the use of emergency stationary ICE in emergency situations."); 40 §§ CFR 60.4211(f)(3), 60.4243(d)(3), 63.6640(f)(3)–(4).
110 *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."
111 North Dakota v. EPA, et al., Order 15A793.
112 Executive Order: Promoting Energy Independence and Economic Growth, Sec. 4 (March 28, 2017), which can be accessed at: <https://www.whitehouse.gov/the-press-office/2017/03/28/presidential-executive-order-promoting-energy-independence-and-economi-1>.

briefs on whether these cases "should be remanded to the agency rather than held in abeyance."

- **Cooling Water Intakes.** An EPA rule implementing Section 316(b) of the Clean Water Act (CWA) requires that cooling water intake structures reflect the best technology available for minimizing adverse environmental impacts.[113] 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 rule sets nonbinding criteria for coal ash disposal facilities.

State Environmental Regulation

- **NJ High Electric Demand Day (HEDD) Rule.** A New Jersey rule that imposes operational restrictions and emissions control requirements on units responsible for significant NO_X emissions on high electric demand days (HEDD).[114] 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.[115]
- **Illinois Air Quality Standards (NO_X, SO_2 and Hg).** The State of Illinois has its own standards for NO_X, SO_2 and Hg (mercury) known as Multi-Pollutant Standards (MPS) and Combined Pollutants Standards (CPS) that are more stringent and take effect earlier than comparable Federal regulations, such as the EPA MATS rule.[116]
- **Regional Greenhouse Gas Initiative (RGGI).** The Regional Greenhouse Gas Initiative (RGGI) is a CO_2 emissions cap and trade agreement among Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont that applies to power generation facilities. The auction price in the March 8, 2017, auction for the 2015–2017 compliance period was $3.00 per ton. The clearing price is equivalent to a price of $3.31 per metric tonne, the unit used in other carbon markets. The price decreased from $5.25 per ton from March 9, 2016, by $2.25 per ton, or 42.9 percent, to $3.00 per ton for March 8, 2017.

113 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).
114 N.J.A.C. § 7:27-19.
115 CTs must have either water injection or selective catalytic reduction (SCR) controls; steam units must have either an SCR or selective noncatalytic reduction (SNCR).
116 35 Ill. Admin. Code §§ 225.233 (Multi-Pollutant Standard (MPS)), 224.295 (Combined Pollutant Standard: Emissions Standards for NO_X and SO_2 (CPS)).

State Renewable Portfolio Standards

Many states in PJM have enacted legislation to require that a defined percentage of retail suppliers' load be served by renewable resources, for which definitions vary. These are typically known as renewable portfolio standards, or RPS. As of March 31, 2017, Delaware, Illinois, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, and Washington, DC had renewable portfolio standards. Virginia and Indiana had voluntary renewable portfolio standards. Kentucky and Tennessee did not have renewable portfolio standards. West Virginia had a voluntary standard, but the state legislature repealed their renewable portfolio standard effective February 3, 2015.[117]

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. As a result of environmental regulations and agreements to limit emissions, many PJM units burning fossil fuels have installed emission control technology. On March 31, 2017, 92.8 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 93.5 percent of fossil fuel fired capacity in PJM had NO_X emission control technology.

Section 8 Recommendations

- The MMU recommends that renewable energy credit markets based on state renewable portfolio standards be brought into PJM markets as they are an increasingly important component of the wholesale energy market. (Priority: Medium. First reported 2010. Status: Not adopted.)

117 See Enr. Com. Sub. For H. B. No. 2001.

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. The extension of the RPS concept to include nuclear power as a zero emissions source in order to provide subsidies to nuclear power will increase this impact. Renewable energy credit (REC) 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.[118]

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 same is true for nuclear power credits, ZECs (zero emissions credits). 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 in some cases the existence of these resources 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, clearing quantities and markets are not publicly available for all PJM states. RECs do not need to be consumed during the year of production which creates multiple prices for a REC based on the year of origination. 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. It would be preferable to have a single, transparent market for RECs operated by PJM that would meet the standards and requirements of all states in the PJM footprint including those with no RPS. This would provide better information for market participants about supply and demand and prices and contribute to a more efficient and competitive market and to better price formation. This could also facilitate entry by qualifying renewable resources by reducing the risks associated with lack of transparent market data. This would be a significant improvement even if some unusual or unique types of RECs remained outside this market.

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. If there is a social decision to limit carbon output, a carbon price would be the most efficient way to implement that decision. It would also be an alternative to specific subsidies to individual nuclear power plants and instead provide a market signal to which any resource could respond. 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. The provision of subsidies to individual units creates a discriminatory regime that is not consistent with competition.

118 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 the first three months of 2017, PJM was a monthly net exporter of energy in the Real-Time Energy Market in all months.[119] In the first three months of 2017, the real-time net interchange of -3,715.0 GWh was lower than the net interchange of 5,689.8 GWh in the first three months of 2016.
- **Aggregate Imports and Exports in the Day-Ahead Energy Market.** In the first three months of 2017, PJM was a monthly net exporter of energy in the Day-Ahead Energy Market in all months. In the first three months of 2017, the total day-ahead net interchange of -3,622.8 GWh was lower than net interchange of 1,369.2 GWh in the first three months of 2016.
- **Aggregate Imports and Exports in the Day-Ahead and the Real-Time Energy Market.** In the first three months of 2017, gross imports in the Day-Ahead Energy Market were 152.8 percent of gross imports in the Real-Time Energy Market (108.1 percent in the first three months of 2016). In the first three months of 2017, gross exports in the Day-Ahead Energy Market were 133.9 percent of the gross exports in the Real-Time Energy Market (174.3 percent in the first three months of 2016).
- **Interface Imports and Exports in the Real-Time Energy Market.** In the first three months of 2017, there were net scheduled exports at nine of PJM's 20 interfaces in the Real-Time Energy Market.
- **Interface Pricing Point Imports and Exports in the Real-Time Energy Market.** In the first three months of 2017, there were net scheduled exports at nine of PJM's 18 interface pricing points eligible for real-time transactions in the Real-Time Energy Market.[120]
- **Interface Imports and Exports in the Day-Ahead Energy Market.** In the first three months of 2017, there were net scheduled exports at 11 of PJM's 20 interfaces in the Day-Ahead Energy Market.
- **Interface Pricing Point Imports and Exports in the Day-Ahead Energy Market.** In the first three months of 2017, there were net scheduled exports at ten 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 the first three months of 2017, 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 Energy Market.
- **Inadvertent Interchange.** In the first three months of 2017, net scheduled interchange was -3,715 GWh and net actual interchange was -3,661 GWh, a difference of 54 GWh. In the first three months of 2016, the difference was 874 GWh. This difference is inadvertent interchange.
- **Loop Flows.** In the first three months of 2017, the Wisconsin Energy Corporation (WEC) Interface had the largest loop flows of any interface with -301 GWh of net scheduled interchange and 2,598 GWh of net actual interchange, a difference of 2,899 GWh. In the first three months of 2017, the SouthIMP interface pricing point had the largest loop flows of any interface pricing point with 3,736 GWh of net scheduled interchange and 7,250 GWh of net actual interchange, a difference of 3,514 GWh.

Interactions with Bordering Areas

PJM Interface Pricing with Organized Markets

- **PJM and MISO Interface Prices.** In the first three months of 2017, 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 64.3 percent of the hours.
- **PJM and New York ISO Interface Prices.** In the first three months of 2017, 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 50.4 percent of the hours.

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

- **Neptune Underwater Transmission Line to Long Island, New York.** In the first three months of 2017, 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 65.6 percent of the hours.
- **Linden Variable Frequency Transformer (VFT) Facility.** In the first three months of 2017, 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 61.7 percent of the hours.
- **Hudson DC Line.** In the first three months of 2017, 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 0.2 percent of the hours.[121]

Interchange Transaction Issues

- **PJM Transmission Loading Relief Procedures (TLRs).** PJM issued three TLRs of level 3a or higher in the first three months of 2017, compared to eight such TLRs issued in the first three months of 2016.
- **Up to congestion.** There was an increase in up to congestion volume starting in December 2015, coincident with the expiration of the fifteen month limit on the payment of prior uplift charges.[122] The average number of up to congestion bids submitted in the Day-Ahead Energy Market increased by 47.4 percent, from 134,610 bids per day in the first three months of 2016 to 198,362 bids per day in the first three months of 2017. The average cleared volume of up to congestion bids submitted in the Day-Ahead Energy Market increased by 16.0 percent, from 879,068 MWh per day in the first three months of 2016, to 1,019,907 MWh per day in the first three months of 2017.
- **45 Minute Schedule Duration Rule.** Effective May 19, 2014, PJM removed the 45 minute scheduling duration rule in response to FERC Order No. 764.[123] [124] 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.[125]

Section 9 Recommendations

- The MMU recommends that PJM implement rules to prevent sham scheduling. The MMU recommends that PJM apply after the fact market settlement adjustments to identified sham scheduling segments to ensure that market participants cannot benefit from sham scheduling. (Priority: High. First reported 2012. Status: Not adopted. Stakeholder process.)
- 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 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 end the practice of maintaining outdated definitions of interface pricing points, 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: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM eliminate the IMO interface pricing point, and assign the transactions that originate or sink in the IESO balancing

121 The Hudson line was out of service for all hours in the first three months of 2017. In the first three months of 2017, there were five hours with less than 1 MW of unscheduled flow across the Hudson line.
122 148 FERC ¶ 61,144 (2014).*Order Instituting Section 206 Proceeding and Establishing Procedures.* 16 U.S.C. § 824e.
123 *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).
124 *See* Letter Order, Docket No. ER14-381-000 (June 30, 2014).
125 *See* joint statement of PJM and the MMU re Interchange Scheduling issued July 29, 2014, which can be accessed at: <http://www.monitoringanalytics.com/reports/Market_Messages/Messages/PJM_IMM_Statement_on_Interchange_Scheduling_20140729.pdf>.

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 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 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 nonfirm 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 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 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. First reported 2015. Status: Not adopted.)
- The MMU recommends that the emergency interchange cap be replaced with a market based solution. (Priority: Low. First reported 2015. 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 2014. Status: Adopted partially, 2015.)
- 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, 2013.)

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 nonmarket areas, all electricity transactions are part of a single energy market. Nonetheless, there are significant differences between market and nonmarket 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. Nonmarket areas do not include these features. The market areas are extremely transparent and the nonmarket 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 outcomes 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 nonsynchronized, that can provide energy within 10 minutes. Primary reserve is PJM's implementation of the NERC 15-minute contingency reserve requirement.[126]

Market Structure

- **Supply.** Primary reserve is satisfied by both synchronized reserve (generation or demand response currently synchronized to the grid and available within 10 minutes), and nonsynchronized reserve (generation currently off-line but available to start and provide energy within 10 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 hourly average primary reserve requirement in the RTO Zone in the first three months of 2017 was 2,191.2 MW. The primary reserve requirement in the MAD Subzone was 1,700 MW for all hours.

126 See PJM. "Manual 10: Pre-Scheduling Operations," Revision. 34 (July 1, 2016), p. 24.

Tier 1 Synchronized Reserve

Synchronized reserve is provided by generators or demand response resources synchronized to the grid and capable of increasing output or decreasing load within 10 minutes. Synchronized reserve consists of tier 1 and tier 2 synchronized reserves.

Tier 1 synchronized reserve is part of primary reserve and is the capability of online resources following economic dispatch to ramp up in 10 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 the first three months of 2017, there was an average hourly supply of 1,252.2 MW of tier 1 for the RTO Synchronized Reserve Zone, and an average hourly supply of 1,059.4 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 nonsynchronized reserve market clearing price.

  Of the Degree of Generator Performance (DGP) adjusted tier 1 synchronized reserve MW estimated at market clearing, 59.3 percent actually responded during the one synchronized reserve event with duration of 10 minutes or longer in the first three months of 2017.

- **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 $89,719,045 to tier 1 resources in 2014, $34,397,441 in 2015, $4,948,084 in 2016, and $428,212 in the first three months of 2017.

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 the first three months of 2017, the supply of offered and eligible synchronized reserve was 23,563.7 MW in the RTO Zone of which 6,779.8 MW (including 1,514.4 MW of DSR) was available to the MAD 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. After subtracting the tier 1 synchronized reserve estimate from the default requirement, the hourly average required tier 2 synchronized reserve was 412.8 MW in the MAD Subzone and 616.4 MW in the RTO.
- **Market Concentration.** In the first three months of 2017, the weighted average HHI for tier 2 synchronized reserve in the Mid-Atlantic Dominion Subzone was 5689 which is classified as highly concentrated. The MMU calculates that 92.2 percent of hours would have failed a three pivotal supplier test in the Mid-Atlantic Dominion Subzone.

  In the first three months of 2017, the weighted average HHI for cleared tier 2 synchronized reserve in the RTO Synchronized Reserve Zone was 4672 which is classified as highly concentrated. The MMU calculates that 61.2 percent of hours would have failed a three pivotal supplier test in the RTO Synchronized Reserve Zone.

  The MMU concludes from these results that both the Mid-Atlantic Dominion Subzone Tier 2 Synchronized Reserve Market and the RTO Synchronized Reserve Zone Market were characterized by structural market power in the first three months of 2017.

Market Conduct

- **Offers.** There is a must offer requirement for tier 2 synchronized reserve. All nonemergency 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. There has been less than complete compliance with the tier 2 synchronized reserve must offer requirement.

Market Performance

- **Price.** The weighted average price for tier 2 synchronized reserve for all cleared hours in the Mid-Atlantic Dominion (MAD) Subzone was $2.22 per MW in the first three months of 2017, a decrease of $2.77, from the first three months of 2016.

  The weighted average price for tier 2 synchronized reserve for all cleared hours in the RTO Synchronized Reserve Zone was $2.32 per MW in the first three months of 2017, a decrease of $2.34, from the first three months of 2016.

NonSynchronized Reserve Market

Nonsynchronized reserve is part of primary reserve and includes the RTO Reserve Zone and the Mid-Atlantic Dominion Reserve Subzone (MAD). Nonsynchronized reserve is comprised of nonemergency energy resources not currently synchronized to the grid that can provide energy within 10 minutes. Nonsynchronized reserve is available to fill the primary reserve requirement above the synchronized reserve requirement. The market for nonsynchronized reserve does not include any direct participation by market participants. PJM defines the demand curve for nonsynchronized reserve and PJM defines the supply curve based on nonemergency generation resources that are available to provide energy and can start in 10 minutes or less, and on the associated resource opportunity costs calculated by PJM. Generation owners do not submit supply offers.

Market Structure

- **Supply.** In the first three months of 2017, the supply of eligible nonsynchronized reserve was 2,244.9 MW in the RTO Zone and 1,847.2 MW in MAD Subzone.
- **Demand.** Demand for nonsynchronized reserve is the remaining primary reserve requirement after tier 1 synchronized reserve is estimated and tier 2 synchronized reserve is scheduled.[127] In the RTO Zone, the market cleared an hourly average of 676.2 MW of nonsynchronized reserve in the first three months of 2017. The MAD Subzone cleared an average of 379.4 MW in the first **three months of 2017.**
- Market Concentration. In the first three months of 2017, the weighted average HHI for cleared nonsynchronized reserve in the MAD Subzone was 4107 which is classified as highly concentrated. In the RTO Zone the weighted average HHI was 4098, which is also highly concentrated. The MMU calculates that 33.8 percent of hours would have failed a three pivotal supplier test in the MAD Subzone and zero percent of hours would have failed a three pivotal supplier test in the RTO Zone.

127 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Revision 82 (July 1, 2016), p. 81. "Because Synchronized Reserve may be utilized to meet the Primary Reserve requirement, there is no explicit requirement for non-synchronized reserves. "

Market Conduct

- **Offers.** No offers are made for nonsynchronized reserve by resource owners. Nonemergency generation resources that are available to provide energy and can start in 10 minutes or less are considered available for nonsynchronized reserves by the market solution software. PJM calculates the associated offer prices based on PJM calculations of resource specific opportunity costs.

Market Performance

- **Price.** The nonsynchronized reserve price is determined by the opportunity cost of the marginal nonsynchronized reserve unit. The nonsynchronized reserve weighted average price for all cleared hours (284 hours) in the RTO Reserve Zone was $0.10 per MW in the first three months of 2017 and in 98.4 percent of hours the market clearing price was $0.00. The MAD Subzone cleared separately from the RTO Zone in 34 hours in the first three months of 2017, with a weighted average price of $0.10.

Secondary Reserve

There is no NERC standard for secondary reserve. PJM defines secondary reserve as reserves (online or offline available for dispatch) that can be converted to energy in 30 minutes. PJM defines a secondary reserve requirement but does not have a goal to maintain this reserve requirement in real time.

PJM maintains a day-ahead, offer based market for 30-minute day-ahead secondary reserve.[128] The Day-Ahead Scheduling Reserves Market (DASR) has no performance obligations except that a unit which clears the DASR market is required to be available for dispatch in real time.[129]

Market Structure

- **Supply.** The DASR Market is a must offer market. Any resources that do not make an offer have their offer set to $0.00 per MW. DASR is calculated by the day-ahead market solution as the lesser of the thirty minute energy ramp rate or the economic maximum MW minus the day-ahead dispatch

128 See PJM. "Glossary," <http://www.pjm.com/Glossary.aspx>.
129 See PJM, "Manual 11: Energy & Ancillary Services Market Operations," Revision 85 (November 1, 2016), p. 166 §11.1.

point for all online units. In the first three months of 2017, the average available hourly DASR was 37,058 MW.

- **Demand.** The DASR requirement for 2017 is 5.52 percent of peak load forecast, down from 5.70 percent in 2016. The average DASR MW purchased was 3,916.3 MW per hour in the first three months of 2017.
- **Concentration.** In the first three months of 2017, the DASR Market failed the three pivotal supplier test in 6.9 percent of hours.

Market Conduct

- **Withholding.** Economic withholding remains an issue in the DASR Market. The direct marginal cost of providing DASR is zero. PJM calculates the opportunity cost for each resource. All offers by resource owners greater than zero constitute economic withholding. In the first three months of 2017, a daily average of 39.3 percent of units offered above $0.00. A daily average of 14.2 percent of units offered above $5.
- **DR.** Demand resources are eligible to participate in the DASR Market. Some demand resources have entered offers for DASR. No demand resources cleared the DASR market in the first three months of 2017.

Market Performance

- **Price.** In the first three months of 2017, the weighted average DASR price for all hours when the DASRMCP was above $0.00 was $0.06, a decrease of $1.55 per MW from 2016.

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 one of two regulation signals, RegA or RegD. PJM jointly optimizes regulation with synchronized reserve and energy to provide all three products at least cost. The PJM regulation market design includes three clearing price components: capability; performance; and lost opportunity cost. The RegA signal is designed for energy unlimited resources with physically constrained ramp ability. The RegD signal is designed for energy limited resources with very fast ramp rates. In the Regulation Market RegD MW are converted to marginal effective MW using a marginal rate of substitution (MRTS), called a marginal benefit function (MBF). Correctly implemented, the MBF would define and be used as the marginal rate of technical substitution (MRTS) between RegA and RegD, holding the level of regulation service constant. The current market design is critically flawed as it has not properly implemented the MBF as an MRTS between RegA and RegD resource MW and the MBF has not been consistently applied in the optimization, clearing and settlement of the Regulation Market.

Market Structure

- **Supply.** In the first three months of 2017, the average hourly eligible supply of regulation for nonramp hours was 1,187.5 actual MW (852.4 effective MW). This was an increase of 4.2 actual MW (32.0 effective MW) from the first three months of 2016, when the average hourly eligible supply of regulation was 1,183.3 actual MW (820.4 effective MW). In the first three months of 2017, the average hourly eligible supply of regulation for ramp hours was 1,449.4 actual MW (1,158.4 effective MW). This was an increase of 236.9 actual MW (199.5 effective MW) from the first three months of 2016, when the average hourly eligible supply of regulation was 1,212.4 actual MW (958.9 effective MW).
- **Demand.** Prior to January 9, 2017, the hourly regulation demand was set to 525.0 effective MW for nonramp hours and 700.0 effective MW for ramp hours. Starting January 9, 2017, the hourly regulation demand was set to 525.0 effective MW for nonramp hours and 800.0 effective MW for ramp hours.[130]
- **Supply and Demand.** The nonramp regulation requirement of 525.0 effective MW was provided by a combination of RegA and RegD resources equal to 503.4 hourly average actual MW in the first three months of 2017. This is a decrease of 36.6 actual MW from the first three months of 2016, when the average hourly total regulation cleared MW for nonramp hours were 540.1 actual MW. The ramp regulation requirement of 700.0 effective MW prior to January 9, 2017, and 800.0 effective MW after

130 On peak and off peak hours are now designated as ramp and nonramp hours. The definitions change by season. See "Regulation requirement definition," <http://www.pjm.com/~/media/markets-ops/ancillary/regulation-requirement-definition.ashx>

January 9, 2017, was provided by a combination of RegA and RegD resources equal to 702.1 hourly average actual MW in the first three months of 2017. This is an increase of 48.5 actual MW from the first three months of 2016, where the average hourly regulation cleared MW for ramp hours were 653.6 actual MW.

The ratio of the average hourly eligible supply of regulation to average hourly regulation demand for ramp hours was 2.06 in the first three months of 2017. This is an increase of 11.3 percent from the first three months of 2016, when the ratio was 1.85. The ratio of the average hourly eligible supply of regulation to average hourly regulation demand required for nonramp hours was 2.36 in the first three months of 2017. This is an increase of 7.7 percent from the first three months of 2016, when the ratio was 2.19.

- **Market Concentration.** In the first three months of 2017, the three pivotal supplier test was failed in 92.1 percent of hours. In the first three months of 2017, the weighted average HHI of RegA resources was 2860, which is highly concentrated and the weighted average HHI of RegD resources was 1642, which is highly concentrated. The weighted average HHI of all resources was 1155 which is moderately concentrated.

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 the first three months of 2017, there were 147 resources following the RegA signal and 44 resources following the RegD signal.

Market Performance

- **Price and Cost.** The weighted average clearing price for regulation was $13.87 per effective MW of regulation in the first three months of 2017, a decrease of $1.68 per MW, or 10.8 percent, from of the first three months of 2016. The cost of regulation in the first three months of 2017 was $18.40 per effective MW of regulation, an increase of $0.48 per MW, or 2.7 percent, from the first three months of 2016. The decrease in regulation price in the first three months of 2017 resulted primarily from reductions in the LOC component of the regulation clearing prices due to low energy prices in the first three months of 2017 compared to the first three months of 2016.

- **Prices.** 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. 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 MBF is less than one, RegD resources are generally overpaid on a per effective MW basis. Currently, the MBF is less than one, resulting in persistent overpayment of RegD resources that creates an artificial incentive for inefficient entry of RegD resources. The MBF averaged less than one in each of the first three months of 2017, resulting in RegD resources being paid an average of 1,016.4 percent more than they should have in the first three months of 2017. In the first three months of 2016, the MRTS averaged was also less than one, resulting in RegD resources being paid an average of 222.4 percent more than they should have been.

- **Marginal Benefit Factor Function.** The marginal benefit factor (MBF) is intended to measure the substitutability of RegD resources for RegA resources. The marginal benefit factor function is currently incorrectly defined and applied in the PJM market clearing and incorrectly describes the operational relationship between RegA and RegD regulation resources. Correctly defined, the MBF function represents the Marginal Rate of Technical Substitution (MRTS) between RegA and RegD. Correctly implemented, the MBF would be consistently applied in the Regulation

131 See the *2016 State of the Market Report for PJM*, Volume II, Appendix F "Ancillary Services Markets."

Market clearing and settlement. The current incorrect and inconsistent implementation of the MBF function has resulted in the PJM Regulation Market over procuring RegD relative to RegA in most hours and in 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.

- **Interim changes to the MBF function.** On December 14, 2015, PJM changed the MBF curve in an attempt to reduce the over procurement of RegD. The modification to the marginal benefit curve did not correct the identified issues.
- **Changes to the Regulation Market.** Changes were approved by the Regulation Market Issues Senior Task Force (RMISTF), which went into effect on January 9, 2017. These include changing the definition of off-peak and on-peak hours (now called nonramp and ramp hours) based on the season, increasing the effective MW requirement during ramp hours from 700 MW to 800 MW, adjusting the currently independent RegA and RegD signals to be interdependent, and changing the 15-minute neutrality requirement of the RegD signal to a 30-minute conditional neutrality requirement.

Black Start Service

Black start service is required for the reliable restoration of the grid following a blackout. Black start service is the ability of a generating unit to start without an outside electrical supply, or is the demonstrated ability of a generating unit to automatically remain operating at reduced levels when disconnected from the grid (automatic load rejection or ALR).[132]

In the first three months of 2017, total black start charges were $17.1 million with $17.0 million in revenue requirement charges and $.057 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 for first three months of 2017 ranged from $0.05 per MW-day in the DLCO Zone (total charges were $12,507) to $4.30 per MW-day in the PENELEC Zone (total charges were $1,127,246).

132 OATT Schedule 1 § 1.3BB.

Reactive

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

Reactive capability revenue requirements are based on FERC approved filings. Reactive service charges are paid to units that operate in real time outside of their normal range at the direction of PJM for the purpose of providing reactive service. Reactive service charges are paid for scheduling in the Day-Ahead Energy Market and committing units in real time that provide reactive service. In the first three months of 2017, total reactive charges were $86.4 million, a 17.6 percent increase from $73.4 million in 2016. Reactive capability revenue requirement charges increased from $73.2 million in 2016 to $80.5 million and reactive service charges increased from $0.3 million to $5.9 million in 2017. Total charges in 2017 ranged from $636 in the RECO Zone to $9.7 million in the AEP Zone.

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 that all data necessary to perform the Regulation Market three pivotal supplier test be saved so that the test can be replicated. (Priority: Medium. First reported 2016. Status: Not adopted.)

- The MMU recommends that there be a penalty enforced in the Regulation Market as a reduction in performance score and/or a forfeiture of revenues when resource owners elect to deassign assigned regulation resources within the hour, to prevent gaming. (Priority: Medium. First reported 2016. Status: Not adopted.)
- 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: Not adopted.)
- The MMU recommends that the rule requiring the payment of the tier 2 synchronized reserve price to tier 1 synchronized reserve resources when the nonsynchronized reserve price is above zero be eliminated immediately and that tier 1 synchronized reserve resources not be paid the tier 2 price when they do not respond. (Priority: High. First reported 2013. Status: Not adopted.)
- 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 unit owners to select a reason in Markets Gateway whenever making a unit unavailable either daily or hourly or setting the offer MW to 0 MW. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM be more explicit and transparent about why tier 1 biasing is used in defining demand in the Tier 2 Synchronized Reserve Market. The MMU recommends that PJM define rules for estimating tier 1 MW, define rules for the use and amount of tier 1 biasing and identify the rule based reasons for each instance of biasing. (Priority: Medium. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM modify the DASR Market to ensure that all resources cleared incur a real-time performance obligation. (Priority: Low. First reported 2013. Modified 2017. Status: Not adopted.)
- 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 2015. Status: Not adopted.)
- The MMU recommends that separate payments for reactive capability be eliminated and the cost of reactive capability be recovered in the capacity market. (Priority: Medium. First reported 2016. 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 five minute clearing price based on actual LMP and actual LOC, modifications to the LOC calculation, a software change to save some data elements necessary for verifying market outcomes, and further documentation of the implementation of the market design. (Priority: Medium. First reported 2010. Status: Partially adopted in 2012.)
- 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 single clearing price for synchronized reserves be determined based on the actual five minute LMP and actual LOC and not the forecast LMP. (Priority: Low. First reported 2010. Status: Adopted.)
- 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 2014. Status: Adopted 2014.)

Section 10 Conclusion

The design of the PJM Regulation Market is significantly flawed. The market design has failed to correctly incorporate the marginal benefit factor, or marginal rate of technical substitution, in optimization, pricing and settlement. The market design uses the marginal benefit factor in the optimization (incorrectly) and pricing (correctly), but a mileage ratio instead of the marginal benefit factor in settlement. This failure to correctly and consistently 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 all hours. The market results continue to include the incorrect definition of opportunity cost. These issues have led to the MMU's conclusion that the regulation market design is flawed. PJM and the MMU have developed a joint proposal to correct these issues.

The structure of the 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 product 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 remains less than 100 percent. For the six spinning events 10 minutes or longer in 2016, the average tier 2 synchronized reserve response was 85.5 percent of all scheduled MW. For the one spinning event of 10 minutes or longer in 2017, the response was 75.3 percent of scheduled tier 2 MW.

The rule that requires payment of the tier 2 synchronized reserve price to tier 1 synchronized reserve resources when the nonsynchronized 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, and tier 1 resources do not incur any costs when they are part of the tier 1 estimate in the market solution. Tier 1 resources are paid for their response if they do respond. Tier 1 resources require no additional payment. If tier 1 resources wish to be paid as tier 2 resources, the rules provide the opportunity to make competitive offers in the tier 2 market and take on the associated obligations. Overpayment of tier 1 resources based on this rule added $89.7 million to the cost of primary reserve in 2014, $34.1 million in 2015, $4.9 million in 2016, and $0.4 million in the first three months of 2017.

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, although the market design is flawed. The MMU concludes that the synchronized reserve market results were competitive. The MMU concludes that the DASR market results were competitive, although offers above the competitive level continue to affect prices.

Overview: Section 11, "Congestion and Marginal Losses"

Congestion Cost

- **Total Congestion.** Total congestion costs decreased by $134.2 million or 45.9 percent, from $292.2 million in the first three months of 2016 to $157.9 million in the first three months of 2017.
- **Day-Ahead Congestion.** Day-ahead congestion costs decreased by $158.0 million or 48.9 percent, from $322.9 million in the first three months of 2016 to $164.9 million in the first three months of 2017.
- **Balancing Congestion.** Balancing congestion costs increased by $23.8 million or 77.4 percent, from -$30.8 million in the first three months of 2016 to -$6.9 million in the first three months of 2017.
- **Real-Time Congestion.** Real-time congestion costs decreased by $135.1 million or 45.9 percent, from $294.3 million in the first three months of 2016 to $159.2 million in the first three months of 2017.
- **Monthly Congestion.** Monthly total congestion costs in the first three months of 2017 ranged from $46.5 million in February to $59.9 million in January.

- **Geographic Differences in CLMP.** Differences in CLMP among eastern, southern and western control zones in PJM were primarily a result of congestion on the Cherry Valley Transformer, the Alpine – Belvidere Flowgate, the AP South Interface, the Emilie – Falls Line, and the Westwood Flowgate.
- **Congestion Frequency.** Congestion frequency continued to be significantly higher in the Day-Ahead Energy Market than in the Real-Time Energy Market in the first three months of 2017. The number of congestion event hours in the Day-Ahead Energy Market was about 14 times the number of congestion event hours in the Real-Time Energy Market.

  Day-ahead congestion event hours decreased significantly after September 8, 2014. The decrease 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. However, day-ahead congestion frequency increased by 22.5 percent from 66,431 congestion event hours in the first three months of 2016 to 81,409 congestion event hours in the first three months of 2017. The increase was a result of the increase in UTC transactions that followed the expiration of the fifteen month resettlement period for the proceeding related to uplift charges for UTC transactions.[133]

  Real-time congestion frequency decreased by 13.9 percent from 6,763 congestion event hours in the first three months of 2016 to 5,823 congestion event hours in the first three months of 2017.
- **Congested Facilities.** Day-ahead, congestion-event hours increased on all types of facilities. Real-time, congestion-event hours increased on interfaces and transformers and decreased on lines and flowgates.

  The Cherry Valley Transformer was the largest contributor to congestion costs in the first three months of 2017. With $10.9 million in total congestion costs, it accounted for 6.9 percent of the total PJM congestion costs in the first three months of 2017.
- **Zonal Congestion.** ComEd had the largest total congestion costs among all control zones in the first three months of 2017. ComEd had $52.1 million in total congestion costs, comprised of -$56.2 million in total load congestion payments, -$108.0 million in total generation congestion credits and $0.3 million in explicit congestion costs. The Alpine – Belvidere Transformer, the Cherry Valley Transformer, the Nelson Flowgate, the Byron - Cherry Valley Flowgate and the Lakeview – Greenfield Line contributed $27.0 million, or 51.8 percent of the total ComEd control zone congestion costs.
- **Ownership.** In the first three months of 2017, both financial entities and physical entities were net payers of congestion charges. In the first three months of 2017, financial entities paid $1.1 million in congestion charges compared to $16.7 million received in congestion credits in the first three months of 2016. In the first three months of 2017, physical entities paid $156.9 million in congestion charges, a decrease of $152.0 million or 49.2 percent compared to the first three months of 2016.

133 *See* FERC Docket No. EL14-37.

Marginal Loss Cost

- **Total Marginal Loss Costs.** Total marginal loss costs increased by $1.5 million or 0.9 percent, from $170.1 million in the first three months of 2016 to $171.5 million in the first three months of 2017. The loss MWh in PJM decreased by 10.3 GWh or 0.3 percent, from 3,879.2 GWh in the first three months of 2016 to 3,889.5 GWh in the first three months of 2017. The loss component of real-time LMP increased from $0.0141 in the first three months of 2016 to $0.0151 or 6.7 percent in the first three months of 2017.
- **Monthly Total Marginal Loss Costs.** Monthly total marginal loss costs in the first three months of 2017 ranged from $46.4 million in February to $62.8 million in March.
- **Day-Ahead Marginal Loss Costs.** Day-ahead marginal loss costs increased by $16.6 million or 9.0 percent, from $183.3 million in the first three months of 2016 to $199.9 million in the first three months of 2017.
- **Balancing Marginal Loss Costs.** Balancing marginal loss costs decreased by $15.1 million or 114.6 percent, from -$13.2 million in the first three months of 2016 to -$28.3 million in the first three months of 2017.

- **Total Marginal Loss Surplus.** The total marginal loss surplus decreased in the first three months of 2017 by $6.3 million or 11.3 percent, from $55.7 million in the first three months of 2016, to $49.4 million in the first three months of 2017.

Energy Cost

- **Total Energy Costs.** Total energy costs decreased by $8.3 million or 7.3 percent, from -$113.6 million in the first three months of 2016 to -$121.9 million in the first three months of 2017.
- **Day-Ahead Energy Costs.** Day-ahead energy costs decreased by $33.4 million or 22.2 percent, from -$150.4 million in the first three months of 2016 to -$183.8 million in the first three months of 2017.
- **Balancing Energy Costs.** Balancing energy costs increased by $27.4 million or 76.5 percent, from $35.8 million in the first three months of 2016 to $63.2 million in the first three months of 2017.
- **Monthly Total Energy Costs.** Monthly total energy costs in the first three months of 2017 ranged from -$48.2 million in January to -$31.8 million in February.

Section 11 Conclusion

Congestion is defined to be 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 63.8 and 86.5 percent of total congestion costs including congestion in the Day-Ahead Energy Market and the balancing energy market for the 14/15 and 15/16 planning periods. For the first 10 months of the 16/17 planning period ARRs and self scheduled FTRs offset 92.4 percent of total congestion costs.

Overview: Section 12, “Planning”

Planned Generation and Retirements

- **Planned Generation.** As of March 31, 2017, 99,325.3 MW of capacity were in generation request queues for construction through 2024, compared to an average installed capacity of 195,870.3 MW as of March 31, 2017. Of the capacity in queues, 9,586.4 MW, or 9.7 percent, are uprates and the rest are new generation. Wind projects account for 15,494.6 MW of nameplate capacity or 15.6 percent of the capacity in the queues. Natural gas fired projects account for 64,672.3 MW of capacity or 65.1 percent of the capacity in the queues.
- **Generation Retirements.** As shown in Table 1-25, 32,314.5 MW have been, or are planned to be, retired between 2011 and 2020. Of that, 8,007.3 MW are planned to retire after the first three months of 2017. In the first three months of 2017, 209.0 MW were retired. Of the 8,007.3 MW pending retirement, 6,516.0MW are coal units. The coal unit retirements were a result of low gas prices, low capacity prices and the investments required for compliance with 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. There are 291.0 MW of coal fired steam capacity and 64,672.3 MW of gas fired capacity in the queue. The replacement of coal steam units by units burning natural gas will 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.[134] 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, 3,441 projects, representing 455,032.7 MW, have entered the queue process since its inception. Of those, 700 projects, 47,521.8 MW, went into service. Of the projects that entered the queue process, 67.4 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, which resulted in revisions to the PJM Open Access Transmission Tariff, effective October 31, 2016. [135] [136] On December 15, 2016, the Commission issued a notice of proposed rulemaking proposing additional queue reforms intended to improve certainty, promote more informed interconnection, and enhance interconnection processes.[137]

- 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."[138] 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.[139] [140] On August 5, 2016, PJM announced that the Artificial Island project was to be suspended immediately due to unanticipated project complexities and significant cost overruns. On March 3, 2017, PJM held a special Transmission Expansion Advisory Committee (TEAC) meeting to discuss their updated analysis of the Artificial Island project. PJM staff presented updated assumptions that went into the new project analysis. In consultation with project developers and stakeholders, PJM made several major revisions to the project. These included switching the interconnection point from the Salem Substation to the Hope Creek Substation, removal of the New Freedom switched vertical circuit (SVC) from the project scope, and removal of the optical

134 See OATT Parts IV & VI.
135 See Earlier Queue Submittal Task Force at <http://www.pjm.com/committees-and-groups/task-forces/eqstf.aspx>
136 See Letter Order, ER16-2518-000 (Oct. 7, 2016).
137 157 FERC ¶ 61,212 (2016).
138 See OATT § 1 (Transmission Owner).
139 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>.
140 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>.

ground wire (OPGW) from the project scope. These revisions led to a revised total project cost estimate of $280 million, $240 million less than the previous $420 million project cost estimate released in February 2016. On April 6, 2017, the PJM Board lifted a suspension of the project. It is expected to be in service by June 2020.

- 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. The allocation process has been upheld by the FERC despite repeated challenges.[141]

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 are currently three backbone projects under development, Surry Skiffes Creek 500kV, the Northern New Jersey 345 kV Upgrades, and Byron Wayne 345 kV.[142]

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 or late and whether or not they will allow the outage.[143]
- There were 4,516 transmission outage requests submitted in the first three months of 2017. Of the requested outages, 73.9 percent were planned for five days or shorter and 11.4 percent were planned for longer than 30 days. Of the requested outages, 54.2 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. First reported 2015. 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.)

141 See 155 FERC ¶ 61,090 (2016); 155 FERC ¶ 61,089 (2016); 155 FERC ¶ 61,088 (2016); see also Order No. 1000, FERC Stats. & Regs. ¶ 31,323 (2011), *order on reh'g*, Order No. 1000-A, 139 FERC ¶ 61,132, *order on reh'g and clarification*, Order No. 1000-B, 141 FERC ¶ 61,044 (2012), *aff'd sub nom.* 762 F.3d 41, 412 (D.C. Cir. 2014); 142 FERC ¶ 61,074 (2013) (accepting the proposed PJM cost allocation method, effective February 1, 2013, subject to the outcome of PJM's Order No. 1000 regional compliance filing proceeding); 142 FERC ¶ 61,214 (2013), *order on reh'g and compliance*, 147 FERC ¶ 61,128 (2014), *order on reh'g and compliance*, 150 FERC ¶ 61,038 (2015), *order on reh'g and compliance*, 151 FERC ¶ 61,250 (2015).

142 See "2016 RTEP Process Scope and Input Assumptions White Paper," P 23. <http://www.pjm.com/~/media/documents/reports/2016-rtep-process-scope-and-input-assumptions.ashx> Accessed November 7, 2016.

143 PJM. "Manual 03: Transmission Operations," Revision 50 (Dec. 1, 2016), Section 4.

- 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.[144] (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 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 2015. Status: Not adopted.)
- The MMU recommends consideration of changing the minimum distribution factor in the allocation from 0.01 to 0.00 and adding a threshold minimum usage impact on the line. (Priority: Medium. First reported 2015. 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. First reported 2015. 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 2014. Status: Partially 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

144 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>.

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, "FTRs and ARRs"

Auction Revenue Rights

Market Structure

- **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 first 10 months of the 16/17 planning period, PJM allocated a total of 28,451.4 MW of residual ARRs, down from 30,118.1 MW in the first 10 months of the 15/16 planning period, with a total target allocation of $6.6 million for the first 10 months of the 16/17 planning period, down from $7.7 million for the first 10 months of the 15/16 planning period.

- **ARR Reassignment for Retail Load Switching.** There were 53,343 MW of ARRs associated with $503,400 of revenue that were reassigned in the first 10 months of the 15/16 planning period. There were 38,194 MW of

ARRs associated with $426,200 of revenue that were reassigned for the first 10 months of the 16/17 planning period.

Market Performance

- **Revenue Adequacy.** For the 16/17 planning period, the ARR target allocations, which are based on the nodal price differences from the Annual FTR Auction, were $913.8 million, while PJM collected $940.3 million from the combined Long Term, Annual and Monthly Balance of Planning Period FTR Auctions, making ARRs revenue adequate. For the 15/16 planning period, the ARR target allocations were $931.6 million while PJM collected $968.1 million from the combined Long Term, Annual and Monthly Balance of Planning Period FTR Auctions. The year over year decrease in ARR target allocations and auction revenue is a result of decreased prices from the previous planning period resulting from continued reduced allocation of Stage 1B and Stage 2 ARRs. ARR revenue adequacy is also affected by PJM's clearing of additional counter flow FTRs to alleviate infeasibilities from Stage 1A.
- **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, which include congestion in the Day-Ahead Energy Market and the balancing energy market, for the 14/15 planning period. In the first 10 months of the 16/17 planning period, total ARR and self scheduled FTR revenues offset 92.4 percent of total congestion costs. The total offset for the last six planning periods is 72.4 percent. The goal of the design should be to return 100 percent of the congestion revenues to the load.

Financial Transmission Rights

Market Structure

- **Supply.** In the Monthly Balance of Planning Period FTR Auctions for the first 10 months of the 16/17 planning period, total participant FTR sell offers were 3,965,903 MW, down from 4,500,555 MW for the same period during the 15/16 planning period.
- **Demand.** The total FTR buy bids from the Monthly Balance of Planning Period FTR Auctions for the first 10 months of the 16/17 planning period decreased 19.8 percent from 23,243,499 MW for the same time period of the prior planning period, to 18,651,410 MW.
- **Patterns of Ownership.** For the Monthly Balance of Planning Period Auctions, financial entities purchased 74.0 percent of prevailing flow and 79.2 percent of counter flow FTRs for January through March of 2017. Financial entities owned 63.7 percent of all prevailing and counter flow FTRs, including 53.4 percent of all prevailing flow FTRs and 77.4 percent of all counter flow FTRs during the period from January through March 2017.

Market Behavior

- **FTR Forfeitures.** Total forfeitures for the first 10 months of the 16/17 planning period were $0.5 million for Increment Offers, Decrement Bids and UTC Transactions using PJM's method. FTR forfeitures were not billed after January 19, 2017.
- **Credit Issues.** There were no defaults in the first three months of 2017.

Market Performance

- **Volume.** In the first 10 months of the 16/17 planning period Monthly Balance of Planning Period FTR Auctions cleared 2,074,581 MW (11.1 percent) of FTR buy bids and 897,198 MW (22.6 percent) of FTR sell offers cleared.
- **Price.** The weighted average buy bid cleared FTR price in the Monthly Balance of Planning Period FTR Auctions for the first 10 months of the 16/17 planning period was $0.13, down from $0.21 per MW for the same period in the 15/16 planning period.
- **Revenue.** The Monthly Balance of Planning Period FTR Auctions generated $31.3 million in net revenue for all FTRs for the first 10 months of the 16/17 planning period, up from $31.1 million for the same time period in the 15/16 planning period.

- **Revenue Adequacy.** FTRs were paid at 100 percent of the target allocation level for the first 10 months of the 16/17 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 decision to include more outages and PJM's decision to include additional constraints (closed loop interfaces) in the model, 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 the first three months of 2017, physical entities lost money on FTRs, with -$21.4 million in profits, and financial entities had profits of $2.7 million.

Section 13 Recommendations

- The MMU recommends that the ARR/FTR design be modified to ensure that the rights to all congestion revenues are assigned to load. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that all FTR auction revenue be distributed to ARR holders. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that FTR auction revenues not be used to buy counter flow FTRs for the purpose of improving FTR payout ratios.[145] (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that all historical generation to load paths be eliminated as a basis for allocating ARRs. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that counter flow FTRs be eliminated. (Priority: High. First reported 2015. 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.)
- 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 implement a seasonal ARR and FTR allocation system to better represent outages. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM 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.)
- 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 report correct monthly payout ratios to reduce understatement of payout ratios on a monthly basis. (Priority: Low. First reported 2012. Status: Adopted 2016.)

Section 13 Conclusion

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

145 See "PJM Manual 6: Financial Transmission Rights," Rev. 17 (June 1, 2016) at 55.

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 the benefits of firm low cost generation delivered using the transmission system in the form of revenues which offset congestion. Financial transmission rights and the associated revenues were directly provided to loads in recognition of the fact that loads pay for the transmission system which permits low cost generation to be delivered to load and loads pay congestion. 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 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 the rights to all the congestion revenues and 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 14/15 planning period. For the 15/16 planning period, ARRs and self scheduled FTRs offset 86.5 percent of total congestion costs. For the first 10 months of the 16/17 planning period, ARRs and self scheduled FTRs offset 92.4 percent of total congestion costs.

Load should never be required to subsidize payments to FTR holders, regardless of the reason. Such subsidies have been suggested repeatedly.[146] 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.

The Commission's order will shift substantial revenue from load to the holders of FTRs and reduce the ability of load to offset congestion. If these rules had been in place for the first 10 months of the 16/17 planning period, and ARR/FTR allocations had remained constant, ARR holders would have gone from an offset of 92.4 percent under the current rule, to 86.3 percent under the new rule, a loss of $57.5 million for the first 10 months. FTR holders would have received a corresponding windfall and revenues to FTR holder would have exceeded target allocations by $158.1 million.

If these rules had been in place beginning with the 11/12 planning period, ARR holders would have received $1,010.3 million less in congestion offsets from the 11/12 through the 16/17 planning period. The total overpayment to FTR holders for the 11/12 through 16/17 planning period would have been $923.5 million. The underpayment to load and the overpayment to FTR holders is

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

a result of several factors in the new rules all of which mean the transfer of revenues to FTR holders and the shifting of costs to load. Load is now required to pay for balancing congestion, which significantly increases costs to load and significantly increases revenues paid to FTR holders. PJM will continue to clear counter flow FTRs using excess auction revenues in order to make it possible to sell more prevailing flow FTRs. FTR holders will receive excess day-ahead congestion revenues in excess of target allocations. FTR holders will receive excess auction revenue, which is what FTR holders were willing to pay for FTRs in excess of what is provided to ARR 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 balancing 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.

PJM used a more conservative approach to modeling the transmission capability for the 14/15 through 16/17 planning periods compared to the 13/14 planning period. PJM simply used 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 10/11 planning period through the 13/14 planning period. The market response to lower revenue adequacy was to reduce bid prices and to increase bid volumes and offer volumes. In the 14/15 and 15/16 planning periods, due to reduced ARR allocations, FTR volume decreased relative to the 13/14 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 13/14 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 13/14 planning period from the reported 72.8 percent to 91.0 percent. For the 14/15 and 15/16 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 are 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. There is a reason that transmission is not built to address the Stage 1A overallocation issue. PJM's transmission planning process (RTEP) does not identify a need for new transmission because there is, in fact, no need for new transmission associated with Stage 1A ARRs. The Stage 1A overallocation issue is a fiction based on the use of outdated and irrelevant generation to load paths to assign Stage 1A rights that have nothing to do with actual power flows.

The result of removing portfolio netting, applying a payout ratio to counter flow FTRs and eliminating Stage 1A ARR overallocation in the 13/14 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 different line ratings, 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; the payment of congestion revenues to UTCs; 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.

It is not clear, in a competitive market, why FTR purchases by financial entities remain persistently profitable. In a competitive market, it would be expected that profits would be competed away.

For the 14/15 and 15/16 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.
- **Partially adopted:** 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 and Modified Recommendations

Consistent with its core function to "[e]valuate existing and proposed market rules, tariff provisions and market design elements and recommend proposed rule and tariff changes,"[6] the MMU recommends specific enhancements to existing market rules and implementation of new rules that are required for competitive results in PJM markets and for continued improvements in the functioning of PJM markets.

In this *2017 Quarterly State of the Market Report for PJM: January through March*, the MMU includes one new recommendation and two modified recommendations.[7]

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.
7 New or modified recommendations include all MMU recommendations that were reported for the first time, or substantially modified, in this *2017 Quarterly State of the Market Report for PJM: January through March.*

New and Modified Recommendations from Section 5, Capacity Market

- The MMU recommends that PJM reduce the number of incremental auctions to a single incremental auction held three months prior to the start of the delivery year and reevaluate the triggers for holding conditional incremental auctions. (Priority: Medium. First reported 2013. Modified Q1 2017. Status: Not adopted.)
- The MMU recommends that PJM release capacity in the incremental auction only in cases where the combination of quantities released and associated prices would increase the welfare of capacity market resource owners and load, including consideration of both capacity and energy market benefits in the determination of release quantities and prices. (Priority: Medium. New Recommendation. Status: Not adopted.)

Modified Recommendation from Section 10, Ancillary Service Markets

- The MMU recommends that PJM modify the DASR Market to ensure that all resources cleared incur a real-time performance obligation. (Priority: Low. First reported 2013. Modified 2017. Status: Not adopted.)

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 the market rules should explicitly require that offers into the Day-Ahead Energy Market be competitive, where competitive is defined to be the short run marginal cost of the units. The short run marginal cost should reflect opportunity cost when and where appropriate. (Priority: Medium. First reported 2009. Status: Not adopted.)
- The MMU recommends that PJM require every market participant to make available at least one cost schedule with the same fuel type and parameters as that of their offered price schedule. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM require that the level of incremental costs includable in cost offers not exceed the unit's short run marginal cost. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that PJM require that all fuel cost policies be algorithmic, verifiable, and systematic. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that Manual 15 be replaced with a straightforward description of the components of cost offers based on short run marginal costs and the correct calculation of cost offers. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends removal of all use of the FERC System of Accounts in the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends the removal of all use of cyclic starting and peaking factors from the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends the removal of all labor costs from the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends changing the definition of the start heat input for combined cycles to include only the amount of fuel used from firing each combustion turbine in the combined cycle to the breaker close of each combustion turbine. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends the removal of nuclear fuel and nonfuel operations and maintenance costs that are not short run marginal costs from the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Not adopted.)

- The MMU recommends revising the pumped hydro fuel cost calculation to include day-ahead and real-time power purchases. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends revisions to the calculation of energy market opportunity costs to incorporate all time based offer parameters and all limitations that impact the opportunity cost of generating unit output. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends removing the catastrophic designation for force majeure fuel supply limitations in Schedule 2. (Priority: Medium. First reported 2016. Status: Not adopted.)
- 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 the full MWh range of 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. First reported 2015. 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. First reported 2015. 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 and that this standard be applied to all technologies on a uniform basis. (Priority: Medium. First reported 2015. 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 nonperformance charges and the amount of uplift payments to those generators should reflect the flexibility goals of the capacity performance construct. (Priority: Medium. First reported 2015. Status: Not adopted.)
- 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 retain other existing rules that limit incentives to exercise market power. (Priority: High. First reported 1999. Status: Partially adopted, 1999.)
- The MMU recommends that PJM not allow nuclear generators which do not respond to prices or which only respond to manual instructions from the dispatcher to set the LMPs in the real-time market. (Priority: Low. First reported 2016. Status: Not adopted.)
- The MMU recommends that PJM document 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 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; the allowed duration of the violation; the use of constraint relaxation logic; and when the transmission penalty factors will be used to set the shadow price. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that the definition of maximum emergency status in the tariff apply at all times rather than just during maximum emergency events.[8] (Priority: Medium. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM update the outage impact studies, the reliability analyses used in RPM for capacity deliverability and

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

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 remove nonspecific 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 2015. Status: Partially 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 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: Partially adopted, 2014.)
- The MMU recommends that PJM require all generating units to identify the fuel type associated with each of their offered schedules. (Priority: Low. First reported 2014. Status: Adopted in full, 2014.)

Section 4, Energy Uplift

- 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. First reported 2015. Status: Not adopted.)
- The MMU recommends that if PJM believes it appropriate to modify the LMP price setting logic, PJM initiate a stakeholder process to create transparent and consistent modifications to the rules and incorporate the

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 the PJM.com Glossary <http://www.pjm.com/Glossary.aspx>.

modifications in the PJM tariff. (Priority: Medium. First Reported 2016. 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 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 four additional modifications to the energy lost opportunity cost calculations:
  - 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 for both the injection and the withdrawal sides of the UTC. (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 2012. Status: Not adopted. Stakeholder process.)
- The MMU recommends modifications to the calculation of lost opportunity costs credits paid to wind units. The lost opportunity costs credits paid to wind units should be based on the lesser of the desired output, the estimated output based on actual wind conditions and the capacity interconnection rights (CIRs). In addition, the MMU recommends that PJM allow and wind units submit CIRs that reflect the maximum output wind units want to inject into the transmission system at any time. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM revise Manual 11 attachment C consistent with the tariff to limit compensation to offered costs. The Manual 11 attachment C procedure should describe the steps market participants should take to change the availability of cost-based energy offers that have been submitted day ahead. The MMU recommends that PJM eliminate the Manual 11 attachment C procedure with the implementation of hourly offers (ER16-372-000). (Priority: Medium. First reported 2016. 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 to make all market participants 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 2015.)
- 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: Partially adopted.)
- 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.)

Section 5, Capacity[11]

- The MMU recommends the extension of minimum offer price rule (MOPR) to all existing and proposed units in order to protect competition in the capacity market from external subsidies. (Priority: High. First reported 2016. Status: Not adopted.)
- 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.[12 13] (Priority: High. First reported 2013. Status: Not adopted. Pending before FERC.)

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 See also Comments of the Independent Market Monitor for PJM, Docket No. ER14-503-000 (December 20, 2013).
13 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2016," <http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Analysis_of_Replacement_Capacity_for_RPM_Commitments_06012007_to_06012016_20161227.pdf> (December 27, 2016).

- The MMU recommends that the test for determining modeled Locational Deliverability Areas (LDAs) 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 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.[14] [15] 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.[16] (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 the following changes with respect to capacity imports into PJM:
  - The MMU recommends that all capacity imports be required to be deliverable to PJM load prior to the relevant delivery year to ensure that they are as close to full substitutes for internal, physical capacity resources as possible. Pseudo ties alone are not adequate to ensure deliverability. (Priority: High. First reported 2016. Status: Not adopted.)
  - The MMU recommends that all costs incurred as a result of a pseudo tied unit be borne by the unit itself and included as appropriate in unit offers in the capacity market. (Priority: High. First reported 2016. Status: Not adopted.)
- The MMU recommends improvements to the performance incentive requirements of RPM:
  - 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 2009. Status: Not adopted. Pending before FERC.)
  - The MMU recommends that retroactive replacement capacity transactions not be permitted. (Priority: Medium. First reported 2016. Status: Not adopted.)

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

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

16 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).

- The MMU recommends that treatment of costs in RMR filings be emphasized. Customers should bear all the incremental costs, including incremental investment costs, required by the RMR service that the unit owner would not have incurred if the unit owner had deactivated its unit as it proposed. Generation owners should bear all other costs. (Priority: Low. First reported 2010. Status: Not adopted.)
- The MMU recommends that the mitigation rules for Demand Resource and Energy Efficiency Resource offers be reevaluated and reviewed. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that Energy Efficiency Resources (EE) not be included on the supply side of the capacity market because PJM's load forecasts now account for future EE but did not when EE was first added to the capacity market. If EE is not included on the supply side, there is no reason to have an add back mechanism. If EE remains on the supply side, the implementation of the EE add back mechanism should be modified to ensure that market clearing prices are not affected. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that PJM reduce the number of incremental auctions to a single incremental auction held three months prior to the start of the delivery year and reevaluate the triggers for holding conditional incremental auctions. (Priority: Medium. First reported 2013. Modified Q1 2017. Status: Not adopted.)
- The MMU recommends that PJM release capacity in the incremental auction only in cases where the combination of quantities released and associated prices would increase the welfare of capacity market resource owners and load, including consideration of both capacity and energy market benefits in the determination of release quantities and prices. (Priority: Medium. New Recommendation. Status: Not adopted.)
- The MMU recommends that the notification requirement for deactivations be extended from 90 days prior to the date of deactivation to 12 months prior to the date of deactivation and that PJM and the MMU be provided 60 days rather than 30 days to complete their reliability and market power analyses. (Priority: Low. First reported 2012. Status: Partially adopted.)
- The MMU recommends clear, explicit and detailed rules that define the conditions under which PJM will and will not recall energy from PJM capacity resources and prohibit new energy exports from PJM capacity resources. The MMU recommends that those rules define the conditions under which PJM will purchase emergency energy while at the same time not recalling energy exports from PJM capacity resources. PJM has modified these rules, but they need additional clarification and operational details. (Priority: Low. First reported 2010. Status: Partially 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 2015.)
- 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 2012. Status: Adopted 2015.)
- The MMU recommends that all capacity imports have firm transmission to the PJM border acquired prior to offering in an RPM auction. (Priority: High. First reported 2014. Status: Adopted 2015.)
- 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 2015.)
- The MMU recommends that all resources importing capacity into PJM accept a must offer requirement. (Priority: High. First reported 2014. Status: Adopted 2015.)
- 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 2015.)

- 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 2015.)
- The MMU recommends that PJM eliminate the broad exception related to lack of gas during the winter period for single-fuel, natural gas-fired units.[17] (Priority: Medium. First reported 2013. Status: Adopted 2015.)

Section 6, Demand Response

- 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 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 treated as an economic resource, responding to economic price signals like other capacity resources and not an emergency program responding only after an emergency is called, and not triggering the definition of a PJM emergency and not triggering a Performance Assessment Hour under the new PJM Capacity Market rules. (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.[18] (Priority: High. First reported 2013. Status: Not 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 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

17 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).

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

be calculated based on interval meter data at the site of the demand reductions.[19] (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 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. First reported 2015. 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 2015. Status: Not adopted.)
- The MMU recommends that PJM not remove any defined subzone and maintain a public record of all created and removed subzones. (Priority: Low. First reported 2016. 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. (Priority: High. First reported 2011. Status: Partially adopted.[20])
- 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 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 capping the baseline for measuring compliance under GLD, for the limited summer product, at the customers' PLC. (Priority: High. First reported 2010. Status: Adopted 2015.)
- 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, 2014.)

Section 7, Net Revenue

There are no recommendations in this section.

Section 8, Environmental

- The MMU recommends that renewable energy credit markets based on state renewable portfolio standards be brought into PJM markets as they are an increasingly important component of the wholesale energy market. (Priority: Medium. First reported 2010. Status: Not adopted.)

Section 9, Interchange Transactions

- The MMU recommends that PJM implement rules to prevent sham scheduling. The MMU recommends that PJM apply after the fact market settlement adjustments to identified sham scheduling segments to ensure

19 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 June 29, 2016) 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.

20 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.

that market participants cannot benefit from sham scheduling. (Priority: High. First reported 2012. Status: Not adopted. Stakeholder process.)

- 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 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 end the practice of maintaining outdated definitions of interface pricing points, 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: Medium. First reported 2013. Status: Not adopted.)
- 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 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 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 nonfirm 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 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 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. First reported 2015. Status: Not adopted.)
- The MMU recommends that the emergency interchange cap be replaced with a market based solution. (Priority: Low. First reported 2015. 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 2014. Status: Adopted partially, 2015.)

- 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, 2013.)

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 that all data necessary to perform the Regulation Market three pivotal supplier test be saved so that the test can be replicated. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that there be a penalty enforced in the Regulation Market as a reduction in performance score and/or a forfeiture of revenues when resource owners elect to deassign assigned regulation resources within the hour, to prevent gaming. (Priority: Medium. First reported 2016. Status: Not adopted.)
- 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: Not adopted.)
- The MMU recommends that the rule requiring the payment of the tier 2 synchronized reserve price to tier 1 synchronized reserve resources when the nonsynchronized reserve price is above zero be eliminated immediately and that tier 1 synchronized reserve resources not be paid the tier 2 price when they do not respond. (Priority: High. First reported 2013. Status: Not adopted.)
- 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 unit owners to select a reason in Markets Gateway whenever making a unit unavailable either daily or hourly or setting the offer MW to 0 MW. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM be more explicit and transparent about why tier 1 biasing is used in defining demand in the Tier 2 Synchronized Reserve Market. The MMU recommends that PJM define rules for estimating tier 1 MW, define rules for the use and amount of tier 1 biasing and identify the rule based reasons for each instance of biasing. (Priority: Medium. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM modify the DASR Market to ensure that all resources cleared incur a real-time performance obligation. (Priority: Low. First reported 2013. Modified 2017. Status: Not adopted.)
- 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 2015. Status: Not adopted.)
- The MMU recommends that separate payments for reactive capability be eliminated and the cost of reactive capability be recovered in the capacity market. (Priority: Medium. First reported 2016. 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 five minute clearing price based on actual LMP and actual LOC, modifications to the LOC calculation, a software change to save some data elements necessary for verifying market outcomes, and further documentation of the implementation of the market design. (Priority: Medium. First reported 2010. Status: Partially adopted in 2012.)
- 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 single clearing price for synchronized reserves be determined based on the actual five minute LMP and actual LOC and not the forecast LMP. (Priority: Low. First reported 2010. Status: Adopted.)
- 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 2014. Status: Adopted 2014.)

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. First reported 2015. 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.[21] (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 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 2015. Status: Not adopted.)
- The MMU recommends consideration of changing the minimum distribution factor in the allocation from 0.01 to 0.00 and adding a

21 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>.

threshold minimum usage impact on the line. (Priority: Medium. First reported 2015. 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. First reported 2015. 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 2014. Status: Partially adopted.)

Section 13, FTRs and ARRs

- The MMU recommends that the ARR/FTR design be modified to ensure that the rights to all congestion revenues are assigned to load. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that all FTR auction revenue be distributed to ARR holders. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that FTR auction revenues not be used to buy counter flow FTRs for the purpose of improving FTR payout ratios.[22] (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that all historical generation to load paths be eliminated as a basis for allocating ARRs. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that counter flow FTRs be eliminated. (Priority: High. First reported 2015. 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.)
- 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 implement a seasonal ARR and FTR allocation system to better represent outages. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM 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.)

22 See "PJM Manual 6: Financial Transmission Rights," Rev. 17 (June 1, 2016) at 55.

- 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.)
- 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 report correct monthly payout ratios to reduce understatement of payout ratios on a monthly basis. (Priority: Low. First reported 2012. Status: Adopted 2016.)

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 in the first three months of 2017, including market size, concentration, residual supply index, and price.[1] The MMU concludes that the PJM energy market results were competitive in the first three months of 2017.

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. The hourly HHI (Herfindahl-Hirschman Index) results indicate that by the FERC standards, the PJM Energy Market in the first three months of 2017 was unconcentrated. Average HHI was 980 with a minimum of 882and a maximum of 1126in the first three months of 2017. The fact that the average HHI is in the unconcentrated range and the maximum hourly HHI is in the moderately concentrated range does not mean that the aggregate market was competitive in all hours. It is possible to have pivotal suppliers in the aggregate market even when the HHI level is not in the highly concentrated range. It is possible to have an exercise of market power even when the HHI level is not in the highly concentrated range. The PJM Energy Market peaking segment of supply was 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 because unit owners can exercise market power even when mitigated.
- 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 in most cases

1 Analysis of 2017 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."

although issues with the implementation of market power mitigation and development of cost-based offers remain. 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 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 even when market power mitigation rules are applied. 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 issues related to the level of variable operating and maintenance expense 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 and there are pivotal suppliers in the aggregate market. Aggregate market power needs to be addressed. Now that generators will be allowed to modify offers hourly, market design must reflect appropriate incentives for competitive behavior, the application of local market power mitigation needs to be fixed, the definition of a competitive offer needs to be fixed, and aggregate market power mitigation rules need to be developed. The importance of these issues is amplified by the new rules permitting cost-based offers in excess of $1,000 per MWh.

2 OATT Attachment M (PJM Market Monitoring Plan).

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.

Overview

Market Structure

- **Supply.** Supply includes physical generation and imports and virtual transactions. The maximum of average offered real-time generation decreased by 2,613 MW, or 1.5 percent, from 173,439 MW in the first three months of 2016 to 170,827 MW in the first three months of 2017. In the first three months 2017, 1,317.7 MW of new capacity resources were added. In the first three months 2017, 209.0 MW were retired.

  PJM average real-time cleared generation in the first three months of 2017 increased by 2,604 MW, or 2.9 percent, from the first three months of 2016, from 88,470 MW to 91,074 MW.

  PJM average day-ahead cleared supply in the first three months of 2017, including INCs and up to congestion transactions, increased by 5.6 percent from the first three months of 2016, from 133,263 MW to 140,756 MW, primarily as a result of an increase in UTC volumes.

- **Market Concentration.** The PJM Energy Market was unconcentrated overall with moderate concentration in the baseload and intermediate segments, and high concentration in the peaking segment.

- **Generation Fuel Mix.** In the first three months of 2017, coal units provided 33.3 percent, nuclear units 35.8 percent and natural gas units 24.4 percent of total generation. Compared to the first three months of 2016, generation from coal units increased 7.0 percent, generation from natural gas units increased 1.3 percent and generation from nuclear units increased 0.5 percent.

- **Fuel Diversity.** In the first three months of 2017, the fuel diversity of energy generation, measured by the fuel diversity index for energy (FDI_e), increased 0.2 percent over the first three months of 2016.

- **Marginal Resources.** In the PJM Real-Time Energy Market, in the first three months of 2017, coal units were 34.2 percent of marginal resources and natural gas units were 51.0 percent of marginal resources. In the first three months of 2016, coal units were 45.9 percent and natural gas units were 42.0 percent of the marginal resources.

In the PJM Day-Ahead Energy Market, in the first three months of 2017, up to congestion transactions were 83.7 percent of marginal resources, INCs were 4.6 percent of marginal resources, DECs were 7.6 percent of marginal resources, and generation resources were 4.1 percent of marginal resources. In the first three months of 2016, up to congestion transactions were 83.2 percent of marginal resources, INCs were 4.0 percent of marginal resources, DECs were 6.9 percent of marginal resources, and generation resources were 5.9 percent of marginal resources.

- **Demand.** Demand includes physical load and exports and virtual transactions. The PJM accounting peak load during the first three months 2017 was 127,543 MW in the HE 0700 on January 09, 2017, which was 2,333 MW, 1.8 percent, lower than the PJM peak load for the first three months 2016, which was 129,876 MW in the HE 0700 on January 19, 2016.

  PJM average real-time load in the first three months of 2017 decreased from 2016, from 89,322 MW to 87,598 MW. PJM average day-ahead demand in the first three months of 2017, including DECs and up to congestion transactions, increased by 3.9 percent in the first three months of 2016, from 130,534 MW to 135,560 MW.

- **Supply and Demand: Load and Spot Market.** Companies that serve load in PJM can do so using a combination of self-supply, bilateral market purchases and spot market purchases. For the first three months of 2017, 17.9 percent of real-time load was supplied by bilateral contracts, 20.9 percent by spot market purchases and 61.1 percent by self-supply. Compared with the first three months of 2016, reliance on bilateral contracts increased by 5.1 percentage points, reliance on spot market purchases decreased by 3.0 percentage points and reliance on self-supply decreased by 2.1 percentage points.

- **Supply and Demand: Scarcity.** There were no shortage pricing events in the first three months of 2017.

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 when the rules are designed and implemented properly. 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 decreased from 0.1 percent in the first three months of 2016 to 0 percent in the first three months of 2017. In the Real-Time Energy Market, for units committed to provide energy for local constraint relief, offer-capped unit hours decreased from 0.4 percent in the first three months of 2016 to 0.2 percent in the first three months of 2017.

  In the first three months of 2017, nine control zones experienced congestion resulting from one or more constraints binding for 25 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 increased from 0.1 percent in the first three months of 2016 to 0.2 percent in the first three months of 2017. In the Real-Time Energy Market, for units committed for reliability reasons, offer-capped unit hours increased from 0.1 percent in the first three months of 2016to 0.2 percent in the first three months of 2017.

- **Markup Index.** The markup index is a summary measure of participant offer behavior for individual marginal units. In the first three months of 2017, in the PJM Real-Time Energy Market, 91.4 percent of marginal units had offer prices less than $50 per MWh. The average dollar markups of units with offer prices less than $25 was negative when using unadjusted cost offers. The average dollar markups of units with offer prices between $25 and $50 was positive when using unadjusted cost offers. Negative markup means the unit is offering to run at a price less than its cost-based offer, demonstrating a revealed short run marginal cost that is less than the allowable cost-based offer under the PJM Market Rules. Some marginal units did have substantial markups. Using the unadjusted cost offers, the highest markup for any marginal unit in the first three months of 2017 was $235.44 while the highest markup in the first three months of 2016 was $219.30.

In the PJM Day-Ahead Energy Market, when using unadjusted cost offers, In the first three months of 2017, 89.3 percent of marginal generating units had offer prices less than $50 per MWh and the average dollar markup was positive, and the 1.1 percent of marginal generating units had offers in the $75 to $100 per MWh range and the average dollar markup was positive.

- **Markup.** The markup frequency distributions show that a significant proportion of units make price-based offers less than the cost-based offers permitted under the PJM market rules. This behavior means that competitive price-based offers reveal actual unit marginal costs and that PJM market rules permit the inclusion of costs in cost-based offers that are not short run marginal costs.

  The markup behavior shown in the markup frequency distributions also shows that a substantial number of units were offered with high markups, consistent with the exercise of market power.

- **Frequently Mitigated Units (FMU) and Associated Units (AU).** A new FMU rule became effective November 1, 2014, limiting the availability of FMU adders to units with net revenues less than unit going forward costs. The 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 since December 2014.

- **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. In the first three months of 2017, the average hourly increment offers submitted MW increased by 40.3 percent from 7,425 MW in the first three months of 2016 to 10,419 MW in the first three months of 2017, and cleared MW increased by 30.4 percent from 4,691 MW in the first three months of 2016 to 6,115 MW in the first three months of 2017. In the first three months of 2017, the average hourly decrement bids submitted MW increased by 22.5 percent from 7,901 MW in the first three months of 2016 to 9,676 MW in the first three months of 2017, and cleared MW increased by 4.5 percent from 4,661 MW in the first three months of 2016 to 4,869 MW in the first three months of 2017. In the first three months of 2017, the average hourly up to congestion submitted MW increased by 30.1 percent from 145,311 MW in the first three months of 2016 to 188,905 MW in the first three months of 2017, and cleared MW increased by 15.8 percent from 36,711 MW in the first three months of 2016 to 42,516 MW in the first three months of 2017.

- **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 the first three months of 2017, 57.1 percent were offered as available for economic dispatch, 3.6 percent were offered as emergency dispatch, 20.3 percent were offered as self scheduled, and 19.0 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, emissions related expenses, markup and local price differences caused by congestion. PJM also may administratively set prices with the creation of closed loop interfaces related to demand side resources or reactive power, the application of transmission penalty factors, or the application of price setting logic.

PJM real-time energy market prices increased in the first three months of 2017 compared to the first three months of 2016. The load-weighted average real-time LMP was 13.0 percent higher in the first three months of 2017 than in first three months of 2016, $30.28 per MWh versus $26.80 per MWh.

PJM day-ahead energy market prices increased in the first three months of 2017 compared to the first three months of 2016. The load-weighted average day-ahead LMP was 8.8 percent higher in the first three months of 2017 than in the first three months of 2016, $30.40 per MWh versus $27.94 per MWh.

- **Components of LMP.** In the PJM Real-Time Energy Market, in 2016, 40.3 percent of the load-weighted LMP was the result of coal costs, 32.4 percent was the result of gas costs and 2.09 percent was the result of the cost of emission allowances.

  In the PJM Day-Ahead Energy Market in the first three months of 2017, 21.0 percent of the load-weighted LMP was the result of the cost of coal, 24.7 percent was the result of DECs, 21.1 percent was the result of the cost of gas, 19.5 percent was the result of INCs, and 3.4 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 the first three months of 2017, the adjusted markup component of LMP was $3.81 per MWh or 12.6 percent of the PJM real-time, load-weighted average LMP. January had the highest adjusted peak markup component, $5.88 per MWh, or 17.13 percent of the real-time peak hour load-weighted average LMP. Using the unadjusted cost offers, the highest markup of a marginal unit in the first three months of 2017 was $235.44 per MWh. There were 12 hours in the first three months of 2017 where the positive markup contribution to the PJM system wide, load-weighted, average LMP exceeded $42.99 per MWh.

  In the PJM Day-Ahead Energy Market, INCs, DECs and UTCs have zero markups. In the first three months of 2017, the adjusted markup component of LMP resulting from generation resources was $1.56 per MWh or 5.1 percent of the PJM day-ahead load-weighted average LMP. March had the highest adjusted markup component, $1.99 per MWh or 5.1 percent of the day-ahead load-weighted average LMP.

  Participant behavior was evaluated as competitive because the analysis of markup shows that marginal units generally make offers at, or close to, their marginal costs in both the Day-Ahead and Real-Time Energy Markets, although the behavior of some participants 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 -$1.30 per MWh in the first three months of 2016 and -$0.20 per MWh in the first three months of 2017. The difference between average day-ahead and real-time prices, by itself, is not a measure of the competitiveness or effectiveness of the Day-Ahead Energy Market.

Scarcity

- There were no shortage pricing events in the first three months of 2017.

Recommendations

- The MMU recommends that the market rules should explicitly require that offers into the Day-Ahead Energy Market be competitive, where competitive is defined to be the short run marginal cost of the units. The short run marginal cost should reflect opportunity cost when and where appropriate. (Priority: Medium. First reported 2009. Status: Not adopted.)

- The MMU recommends that PJM require every market participant to make available at least one cost schedule with the same fuel type and parameters as that of their offered price schedule. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM require that the level of incremental costs includable in cost offers not exceed the unit's short run marginal cost. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that PJM require that all fuel cost policies be algorithmic, verifiable, and systematic. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that Manual 15 be replaced with a straightforward description of the components of cost offers based on short run marginal costs and the correct calculation of cost offers. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends removal of all use of the FERC System of Accounts in the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends the removal of all use of cyclic starting and peaking factors from the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends the removal of all labor costs from the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends changing the definition of the start heat input for combined cycles to include only the amount of fuel used from firing each combustion turbine in the combined cycle to the breaker close of each combustion turbine. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends the removal of nuclear fuel and nonfuel operations and maintenance costs that are not short run marginal costs from the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends revising the pumped hydro fuel cost calculation to include day-ahead and real-time power purchases. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends revisions to the calculation of energy market opportunity costs to incorporate all time based offer parameters and all limitations that impact the opportunity cost of generating unit output. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends removing the catastrophic designation for force majeure fuel supply limitations in Schedule 2. (Priority: Medium. First reported 2016. Status: Not adopted.)
- 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 the full MWh range of 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. First reported 2015. 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. First reported 2015. 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 and that this standard be applied to all technologies on a uniform basis. (Priority: Medium. First reported 2015. 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 nonperformance charges and the amount of uplift payments to those generators should reflect the flexibility goals of the capacity performance construct. (Priority: Medium. First reported 2015. Status: Not adopted.)

- 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 retain other existing rules that limit incentives to exercise market power. (Priority: High. First reported 1999. Status: Partially adopted, 1999.)
- The MMU recommends that PJM not allow nuclear generators which do not respond to prices or which only respond to manual instructions from the dispatcher to set the LMPs in the real-time market. (Priority: Low. First reported 2016. Status: Not adopted.)
- The MMU recommends that PJM document 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 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; the allowed duration of the violation; the use of constraint relaxation logic; and when the transmission penalty factors will be used to set the shadow price. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that the definition of maximum emergency status in the tariff apply at all times rather than just during maximum emergency events.[4] (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.[5] There is currently no PJM documentation in the tariff or manuals explaining how hubs are created and how their definitions are changed.[6] (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 remove nonspecific 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 2015. Status: Partially 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

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

5 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.

6 The general definition of a hub can be found in the PJM.com Glossary <http://www.pjm.com/Glossary.aspx>.

system are accurate and reflect standard ratings practice. (Priority: Low. First reported 2013. Status: Partially 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: Partially adopted, 2014.)
- The MMU recommends that PJM require all generating units to identify the fuel type associated with each of their offered schedules. (Priority: Low. First reported 2014. Status: Adopted in full, 2014.)

Conclusion

The MMU analyzed key elements of PJM energy market structure, participant conduct and market performance in the first three months of 2017, 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 cleared generation increased by 2,604 MW, 2.9 percent, and peak load decreased by 2,333 MW, 1.8 percent, in the first three months of 2017 compared to the first three months of 2016. Market concentration levels remained in the unconcentrated range on average although there is high concentration in the peaking segment 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 and the extent of pivotal suppliers, 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. Low average aggregate concentration does not mean that market power cannot be exercised. It is possible that market power can be exercised at times when individual suppliers or small groups of suppliers are pivotal even when the HHI level does not indicate that the market is highly concentrated. High markups for some units demonstrate the potential to exercise market power during high demand conditions.

Prices are a key outcome of markets. Prices vary across hours, days and years for multiple reasons. Price is an indicator of the level of competition in a market although individual prices are not always easy to interpret. In a competitive market, prices are directly related to the marginal cost of the most expensive unit required to serve load in each hour. The pattern of prices within days and across months and years illustrates how prices are directly related to supply and demand conditions and thus also illustrates the potential significance of the impact of the price elasticity of demand on prices. Energy market results in the first three months of 2017 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.[7] 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

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

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 market power 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.

Another issue with the application of market power mitigation in the Day-Ahead Energy Market and the Real-Time Energy Market when market sellers fail the TPS test is related to the definition of a competitive offer. A competitive offer is equal to short run marginal costs. The enforcement of market power mitigation rules is undermined if the definition of a competitive offer is not correct. The significance of competition metrics like markup is also undermined if the definition of a competitive offer is not correct. The definition of a competitive offer, as interpreted by PJM, is not currently correct. Some unit owners include costs that are not short run marginal costs in offers, including maintenance costs. This issue can be resolved by simple changes to the PJM Market Rules to incorporate a clear and accurate definition of short run marginal costs.

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 in 2014, 2015 or 2016. This is evidence of generally competitive behavior and competitive market outcomes, although the behavior of some participants during the high demand periods 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 the first three months of 2017.

Market Structure

Market Concentration

Analysis of supply curve segments of the PJM Energy Market in the first three months of 2017 indicates moderate concentration in the base load and intermediate segments, but high concentration in the peaking segment.[8] 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. The fact that the average HHI is in the unconcentrated range and the maximum hourly HHI is in the moderately concentrated range does not mean that the aggregate market was competitive in all hours. It is possible to have pivotal suppliers in the aggregate market even when the HHI level does not indicate highly concentrated. It is possible to have an exercise of market power even when the HHI level does not indicate highly concentrated.

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

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 the first three months of 2017, although there are issues with the application of market power mitigation for resources whose owners fail the TPS test that permit local market power to be exercised even when mitigation rules are applied. These issues include the lack of a method for consistently determining the cheaper of the cost and price schedules, and the lack of rules requiring that cost based offers equal to short run marginal costs.

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 with the ownership of incremental resources. 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.[9]

PJM HHI Results

Calculations for hourly HHI indicate that by the FERC standards, the PJM Energy Market during the first three months of 2017 was unconcentrated (Table 3-2).

Table 3-2 PJM hourly energy market HHI: January 1 through March 31, 2016 and 2017[10]

	Hourly Market HHI (Jan - Mar, 2016)	Hourly Market HHI (Jan - Mar, 2017)
Average	1300	980
Minimum	1133	882
Maximum	1561	1126
Highest market share (One hour)	31%	23%
Average of the highest hourly market share	23%	17%
# Hours	2,183	2,159
# Hours HHI > 1800	0	0
% Hours HHI > 1800	0%	0%

Table 3-3 includes HHI values by supply curve segment, including base, intermediate and peaking plants for the first three months of 2016 and 2017. The PJM Energy Market was moderately concentrated overall with moderate concentration in the baseload and intermediate segments, and high concentration in the peaking segment.

Table 3-3 PJM hourly energy market HHI (By supply segment): January 1 through March 31, 2016 and 2017

	Jan - Mar, 2016			Jan - Mar, 2017		
	Minimum	Average	Maximum	Minimum	Average	Maximum
Base	990	1132	1347	840	1006	1273
Intermediate	767	1965	5603	668	1617	6764
Peak	951	6073	10000	821	6323	10000

9 77 FERC ¶ 61,263, pp. 64-70 (1996), "*Inquiry Concerning the Commission's Merger Policy under the Federal Power Act: Policy Statement.*"
10 This analysis includes all hours in the first three months of 2016 and 2017, regardless of congestion.

Figure 3-1 shows the total installed capacity (ICAP) MW of units in the baseload, intermediate and peaking segments by fuel source in the first three months of 2017.

Figure 3-1 Fuel source distribution in unit segments: January 1 through March 31, 2017[11]

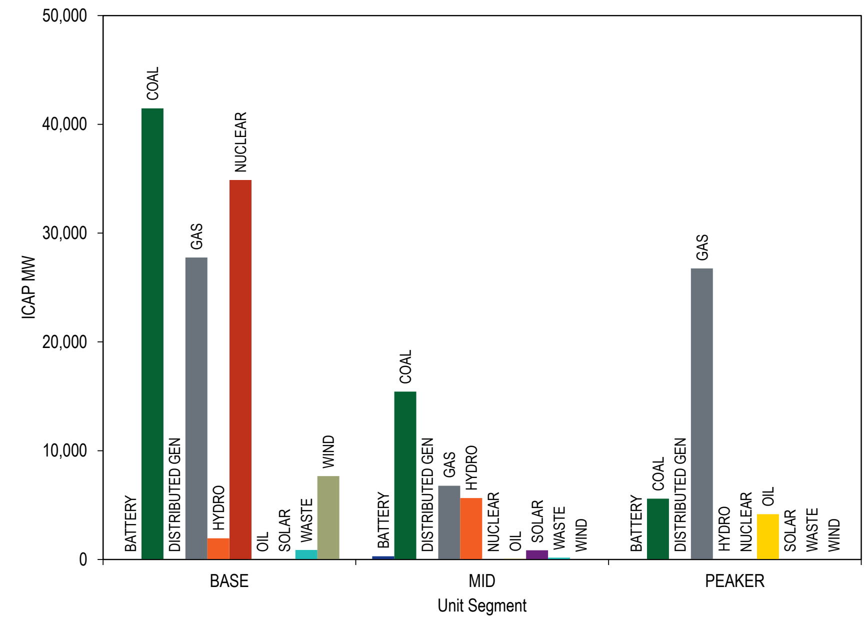
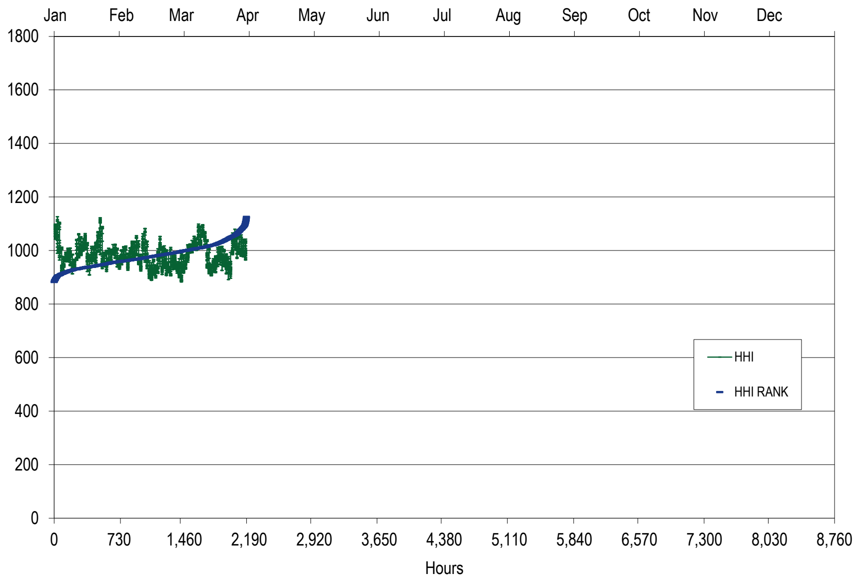


Figure 3-2 presents the hourly HHI values in chronological order and an HHI duration curve for the first three months of 2017.

11 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. See PJM. "Net Energy Metering Senior Task Force (NEMSTF) Action on Proposed Manual 28 Revisions," (July 26, 2012) <http://www.pjm.com/~/media/committees-groups/committees/mrc/20120726/20120726-item-04-nemstf-report-and-proposed-manual-revisions.ashx>.

Figure 3-2 PJM hourly energy market HHI: January 1 through March 31, 2017



Ownership of Marginal Resources

Table 3-4 shows the contribution to real-time, load-weighted LMP by individual marginal resource owner.[12] The contribution of each marginal resource to price at each load bus is calculated for each five-minute interval of 2017, and summed by the parent company that offers the marginal resource into the Real-Time Energy Market. In the first three months of 2017, the offers of one company resulted in 16.8 percent of the real-time, load-weighted PJM system LMP and that the offers of the top four companies resulted in 56.5percent of the real-time, load-weighted, average PJM system LMP. During the first three months of 2016, the offers of one company resulted in 25.0 percent of the real time, load-weighted PJM system LMP and offers of the top four companies resulted in 62.6 percent of the real-time, load-weighted, average PJM system LMP. In the first three months of 2017, the offers of one company resulted in 16.5 percent of the peak hour real-time, load weighted PJM system LMP. In the first three months of 2016, the offers of one company resulted in 28.1 percent of the peak hour, real-time, load weighted PJM system LMP.

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

Table 3-4 Marginal unit contribution to PJM real-time, load-weighted LMP (By parent company): January 1 through March 31, 2016 and 2017

2016 (Jan-Mar)						2017 (Jan - Mar)					
All Hours			Peak Hours			All Hours			Peak Hours		
Company	Percent of Price	Cumulative Percent	Company	Percent of Price	Cumulative Percent	Company	Percent of Price	Cumulative Percent	Company	Percent of Price	Cumulative Percent
1	25.0%	25.0%	1	28.0%	28.0%	1	16.8%	16.8%	1	16.5%	16.5%
2	16.2%	41.2%	2	18.0%	46.0%	2	16.7%	33.5%	2	16.3%	32.8%
3	10.7%	52.0%	3	10.9%	56.9%	3	14.6%	48.0%	3	13.1%	45.9%
4	10.7%	62.6%	4	8.3%	65.2%	4	8.4%	56.5%	4	7.8%	53.7%
5	8.4%	71.0%	5	7.1%	72.4%	5	6.7%	63.2%	5	7.4%	61.1%
6	7.1%	78.1%	6	6.9%	79.3%	6	4.8%	68.0%	6	6.4%	67.5%
7	2.7%	80.8%	7	3.8%	83.1%	7	4.4%	72.4%	7	4.2%	71.7%
8	2.5%	83.3%	8	2.7%	85.7%	8	3.3%	75.6%	8	2.9%	74.6%
9	2.3%	85.6%	9	2.2%	88.0%	9	2.6%	78.2%	9	2.6%	77.2%
Other (58 companies)	14.4%	100.0%	Other (51 companies)	12.0%	100.0%	Other (57 companies)	21.8%	100.0%	Other (52 companies)	22.8%	100.0%

Table 3-5 Marginal resource contribution to PJM day-ahead, load-weighted LMP (By parent company): January 1 through March 31, 2016 and 2017

2016 (Jan - Mar)						2017 (Jan - Mar)					
All Hours			Peak Hours			All Hours			Peak Hours		
Company	Percent of Price	Culmulative Percent	Company	Percent of Price	Culmulative Percent	Company	Percent of Price	Culmulative Percent	Company	Percent of Price	Culmulative Percent
1	17.0%	17.0%	1	16.5%	16.5%	1	8.9%	8.9%	1	9.6%	9.6%
2	9.7%	26.7%	2	9.7%	9.7%	2	8.9%	17.8%	2	7.6%	17.2%
3	8.1%	34.8%	3	8.7%	8.7%	3	7.3%	25.1%	3	7.3%	24.5%
4	7.4%	42.3%	4	8.6%	8.6%	4	7.0%	32.1%	4	6.5%	31.0%
5	7.1%	49.4%	5	7.2%	7.2%	5	6.3%	38.5%	5	5.4%	36.3%
6	4.8%	54.2%	6	3.5%	3.5%	6	6.1%	44.6%	6	5.4%	41.7%
7	4.5%	58.7%	7	3.3%	3.3%	7	4.5%	49.1%	7	5.0%	46.7%
8	3.9%	62.6%	8	2.8%	2.8%	8	3.9%	53.0%	8	4.6%	51.4%
9	2.7%	65.3%	9	2.8%	2.8%	9	3.0%	56.0%	9	3.8%	55.2%
Other (137 companies)	34.7%	100.0%	Other (128 companies)	36.9%	36.9%	Other (126 companies)	44.0%	100.0%	Other (122 companies)	44.8%	100.0%

Table 3-5 shows the contribution to day-ahead, load-weighted LMP by individual marginal resource owners.[13] 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 the first three months of 2017, the offers of one company contributed 8.9 percent of the day-ahead, load-weighted PJM system LMP and that the offers of the top four companies contributed 32.1 percent of the day-ahead, load-weighted, average PJM system LMP. In the first three months of 2016, the offers of one company contributed 17.0 percent of the day-ahead, load-weighted PJM system LMP and offers of the top four companies contributed 42.3 percent of the day-ahead, load-weighted, average PJM system LMP.

Type of Marginal Resources

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

Table 3-6 shows the type of fuel used by marginal resources in the Real-Time Energy Market. There can be more than one marginal resource in any given interval as a result of transmission constraints. In the first three months of 2017, coal units were 34.23 percent and natural gas units were 51.05 percent of marginal resources. In the first three months of 2016, coal units were

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

45.86 percent and natural gas units were 42.03 percent of the total marginal resources. In the first three months of 2017, 80.1 percent of the wind marginal units had negative offer prices, 4.0 percent had zero offer prices and 15.9 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.[14]

The proportion of marginal nuclear units increased from 0.09 percent in the first three months of 2016 to 0.78 percent in the first three months of 2017. The increase was primarily due to a small number of nuclear units offering with a dispatchable range. Most nuclear units are offered as fixed generation in the PJM market. The dispatchable nuclear units do not always respond to dispatch instructions.

Table 3-6 Type of fuel used (By real-time marginal units): January 1 through March 31, 2013 through 2017

	Jan-Mar				
Type/Fuel	2013	2014	2015	2016	2017
Gas	32.40%	42.61%	33.10%	42.03%	51.05%
Coal	57.74%	46.59%	57.21%	45.86%	34.23%
Wind	4.76%	5.17%	2.91%	4.06%	7.05%
Oil	4.79%	4.53%	6.29%	7.65%	6.56%
Uranium	0.02%	0.15%	0.01%	0.09%	0.78%
Other	0.02%	0.76%	0.43%	0.20%	0.26%
Municipal Waste	0.07%	0.03%	0.05%	0.11%	0.07%
Emergency DR	0.02%	0.15%	0.00%	0.00%	0.00%

Figure 3-3 shows the type of fuel used by marginal resources in the Real-Time Energy Market since 2004. The role of coal as a marginal resource has declined while the role of gas as a marginal resource has increased.

Figure 3-3 Type of fuel used (By real-time marginal units): January 1 through March 31, 2004 through 2017

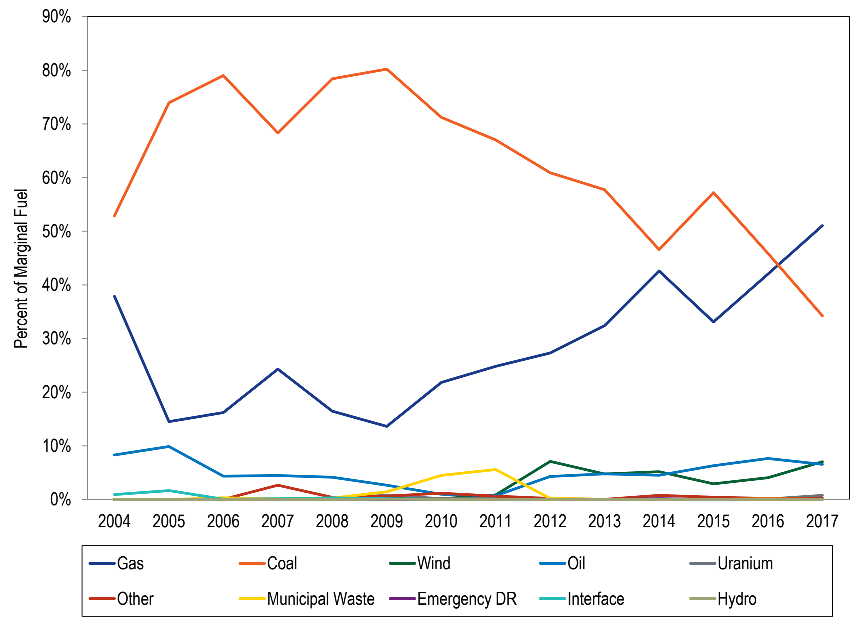


Table 3-7 shows the type and fuel type where relevant, of marginal resources in the Day-Ahead Energy Market. In the first three months of 2017, up to congestion transactions were 83.70 percent of marginal resources. Up to congestion transactions were 83.21 percent of marginal resources in the first three months of 2016.

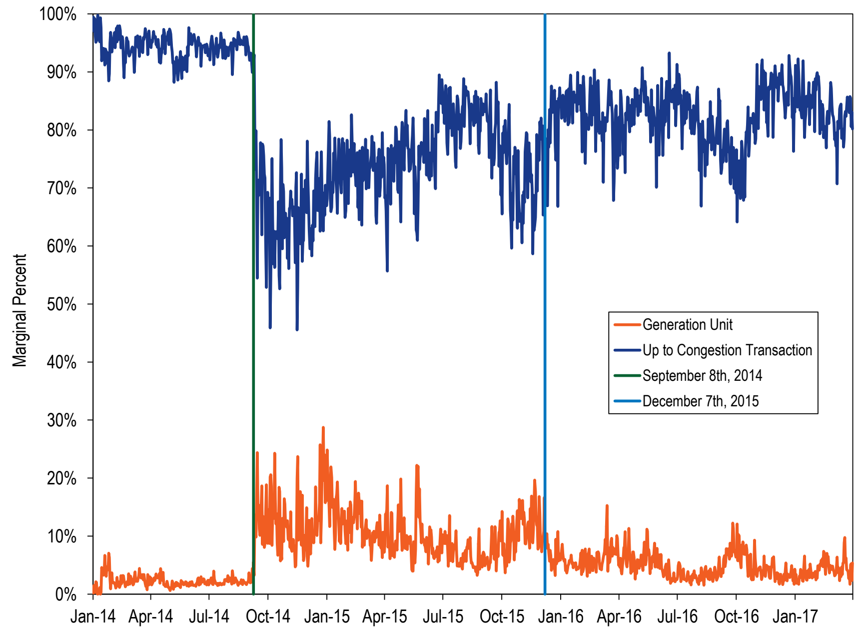
14 Prior to April 1, 2015, for the generation units that are capable of using multiple fuel types, PJM did not require the participants to disclose the fuel type associated with their offer schedule. For these units, the cleared offer schedules on a given day were compared to the cost associated with 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: January 1 through March 31, 2011 through 2017

	(Jan - Mar)						
Type/Fuel	2011	2012	2013	2014	2015	2016	2017
Up to Congestion Transaction	65.72%	84.85%	93.54%	94.68%	94.68%	83.21%	83.70%
DEC	14.80%	5.78%	1.71%	1.60%	1.60%	6.86%	7.62%
INC	9.08%	5.51%	1.44%	1.07%	1.07%	3.99%	4.57%
Coal	7.43%	2.70%	2.26%	1.27%	1.27%	2.76%	1.71%
Gas	2.40%	0.95%	0.92%	1.08%	1.08%	2.44%	1.80%
Oil	0.00%	0.00%	0.00%	0.04%	0.04%	0.59%	0.38%
Dispatchable Transaction	0.27%	0.08%	0.09%	0.19%	0.19%	0.06%	0.04%
Wind	0.00%	0.03%	0.02%	0.05%	0.05%	0.04%	0.16%
Uranium	0.00%	0.00%	0.00%	0.00%	0.00%	0.04%	0.02%
Other	0.00%	0.00%	0.00%	0.00%	0.00%	0.01%	0.00%
Municipal Waste	0.02%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Total	100.00%	100.00%	99.99%	100.00%	100.00%	100.00%	100.00%

Figure 3-4 shows, for the Day-Ahead Market from January 1, 2014, through March 31, 2017, the daily proportion of marginal resources that were up to congestion transaction and/or generation units. The percent 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.[15] The percent of marginal up to congestion transaction decreased and that of generation units increased. That trend has reversed as a result of the expiration of the fifteen month uplift refund period for UTC transactions.

Figure 3-4 Day-ahead marginal up to congestion transaction and generation units: January 1, 2014 through March 31, 2017



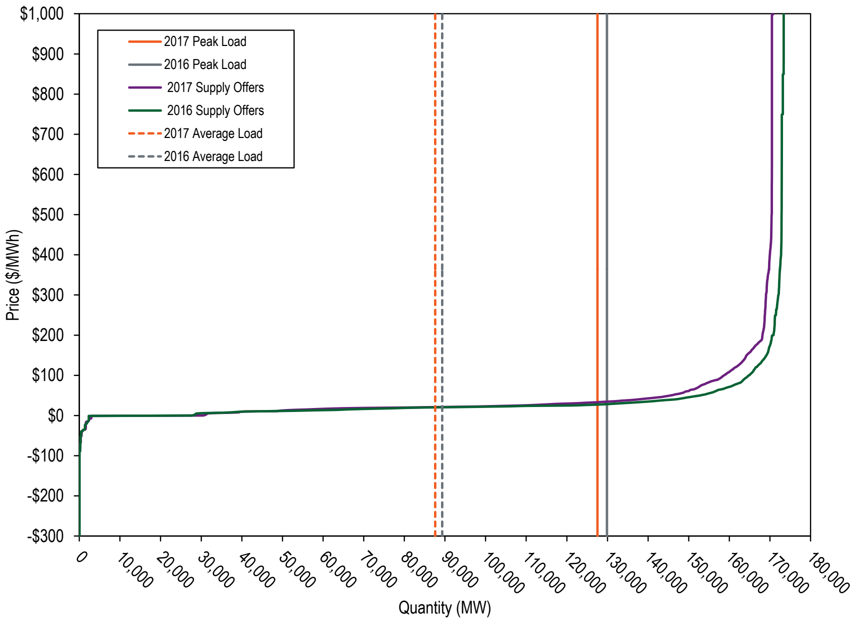
Supply

Supply includes physical generation and imports and virtual transactions.

Figure 3-5 shows the average PJM aggregate real-time generation supply curves by offer price, peak load and average load for the first three months of 2016 and 2017. The maximum of average offered real-time generation decreased by 2,613 MW, or 1.5 percent, from 173,439 MW in the first three months of 2016 to 170,827 MW in the first three months of 2016.

15 See 18 CFR § 385.213 (2014).

Figure 3-5 Average PJM aggregate real-time generation supply curves by offer price: January 1 through March 31, 2016 and 2017



Energy Production by Fuel Source

Table 3-8 shows PJM generation by fuel source in GWh for the first three months of 2016 and 2017. In the first three months of 2017, generation from coal units increased 7.0 percent and generation from natural gas units increased 1.3 percent compared to the first three months of 2016.[16]

Table 3-8 PJM generation (By fuel source (GWh)): January 1 through March 31, 2016 and 2017[17 18]

Jan - Mar		2016		2017		Change in
		GWh	Percent	GWh	Percent	Output
Coal		62,503.2	32.0%	66,884.2	33.3%	7.0%
	Bituminous	56,062.4	28.7%	57,284.4	28.5%	2.2%
	Sub Bituminous	5,089.0	2.6%	7,383.4	3.7%	45.1%
	Other Coal	1,351.8	0.7%	2,216.3	1.1%	64.0%
Nuclear		71,578.3	36.6%	71,964.8	35.8%	0.5%
Gas		48,989.1	25.1%	49,673.5	24.7%	1.4%
	Natural Gas	48,453.7	24.8%	49,074.8	24.4%	1.3%
	Landfill Gas	535.3	0.3%	598.1	0.3%	11.7%
	Other Gas	0.1	0.0%	0.6	0.0%	950.0%
Hydroelectric		4,156.8	2.1%	3,618.7	1.8%	(12.9%)
	Pumped Storage	975.6	0.5%	905.9	0.5%	(7.2%)
	Run of River	2,825.7	1.4%	2,372.6	1.2%	(16.0%)
	Other Hydro	355.5	0.2%	340.2	0.2%	(4.3%)
Wind		5,802.7	3.0%	6,573.7	3.3%	13.3%
Waste		979.4	0.5%	957.1	0.5%	(2.3%)
	Solid Waste	979.4	0.5%	957.1	0.5%	(2.3%)
	Miscellaneous	0.0	0.0%	0.0	0.0%	NA
Oil		617.2	0.3%	481.3	0.2%	(22.0%)
	Heavy Oil	137.7	0.1%	3.6	0.0%	(97.4%)
	Light Oil	142.0	0.1%	87.3	0.0%	(38.5%)
	Diesel	26.4	0.0%	7.1	0.0%	(73.0%)
	Gasoline	0.0	0.0%	0.0	0.0%	NA
	Kerosene	65.5	0.0%	0.8	0.0%	(98.7%)
	Jet Oil	0.0	0.0%	0.0	0.0%	NA
	Other Oil	245.5	0.1%	382.4	0.2%	55.8%
Solar, Net Energy Metering		181.3	0.1%	267.8	0.1%	47.8%
Energy Storage		4.2	0.0%	9.2	0.0%	118.5%
	Battery	4.2	0.0%	9.2	0.0%	118.5%
	Compressed Air	0.0	0.0%	0.0	0.0%	NA
Biofuel		516.9	0.3%	493.0	0.2%	(4.6%)
Geothermal		0.0	0.0%	0.0	0.0%	NA
Other Fuel Type		0.0	0.0%	48.2	0.0%	NA
Total		195,329.0	100.0%	200,971.5	100.0%	2.9%

16 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.

17 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.
18 Net Energy Metering is combined with Solar due to data confidentiality reasons.

Table 3-9 Monthly PJM generation (By fuel source (GWh)): January 1 through March 31, 2017

		Jan	Feb	Mar	Total
Coal		25,111.3	19,246.2	22,526.7	66,884.2
	Bituminous	21,142.1	16,596.5	19,545.7	57,284.4
	Sub Bituminous	3,189.9	1,945.5	2,248.1	7,383.4
	Other Coal	779.3	704.2	732.9	2,216.3
Nuclear		26,016.6	22,140.8	23,807.5	71,964.8
Gas		16,071.3	15,213.3	18,388.9	49,673.5
	Natural Gas	15,884.4	15,017.6	18,172.8	49,074.8
	Landfill Gas	186.9	195.7	215.6	598.1
	Other Gas	0.0	0.1	0.6	0.6
Hydroelectric		1,266.9	1,083.6	1,268.2	3,618.7
	Pumped Storage	335.8	252.3	317.8	905.9
	Run of River	811.4	731.2	830.0	2,372.6
	Other Hydro	119.8	100.0	120.4	340.2
Wind		2,017.5	2,178.6	2,377.6	6,573.7
Waste		364.9	281.5	310.7	957.1
	Solid Waste	364.9	281.5	310.7	957.1
	Miscellaneous	0.0	0.0	0.0	0.0
Oil		210.9	152.6	117.8	481.3
	Heavy Oil	0.5	3.1	0.0	3.6
	Light Oil	59.7	21.8	5.8	87.3
	Diesel	6.0	0.1	1.1	7.1
	Gasoline	0.0	0.0	0.0	0.0
	Kerosene	0.8	0.0	0.1	0.8
	Jet Oil	0.0	0.0	0.0	0.0
	Other Oil	144.0	127.6	110.9	382.4
Solar, Net Energy Metering		52.6	93.1	122.1	267.8
Energy Storage		2.6	3.2	3.5	9.2
	Battery	2.6	3.2	3.5	9.2
	Compressed Air	0.0	0.0	0.0	0.0
Biofuel		152.7	158.3	182.0	493.0
Geothermal		0.0	0.0	0.0	0.0
Other Fuel Type		48.2	0.0	0.0	48.2
Total		71,315.5	60,551.1	69,104.8	200,971.5

Figure 3-6 shows the fuel diversity index (FDI_e) for PJM energy generation.[19] The FDI_e is defined as $1-\sum_{i=1}^{N} s_i^2$

where s_i is the share of fuel type i. The minimum possible value for the FDI_e is zero, corresponding to all generation from a single fuel type. The maximum possible value for the FDI_e is achieved when each fuel type has an equal share of total generation. For a generation fleet composed of 10 fuel types, the maximum achievable index is 0.9. The fuel type categories used in the calculation of the FDI_e are the 10 primary fuel sources in Table 3-8 with nonzero generation values. The FDI_e exhibits seasonality with most of the peaks occurring in the spring and summer months, and the valleys occurring in the fall and winter months. A significant drop in the FDI_e occurred in fall of 2004 as a result of the expansion of the PJM market footprint into ComEd, AEP, and Dayton Power & Light control zones and the increased shares of coal and nuclear that resulted.[20] The increasing trend that begins in 2008 corresponds with a period of decreasing coal generation and increasing gas generation. Coal generation as a share of total generation dropped 20.5 percentage points from 2008 to 2016, and gas generation as a share of total generation increased 19.3 percentage points. Wind generation, at 2.2 percent of total generation in 2016, also contributes to the rising trend. The average FDI_e increased 0.2 percent from the first three months of 2016 to the first three months of 2017.

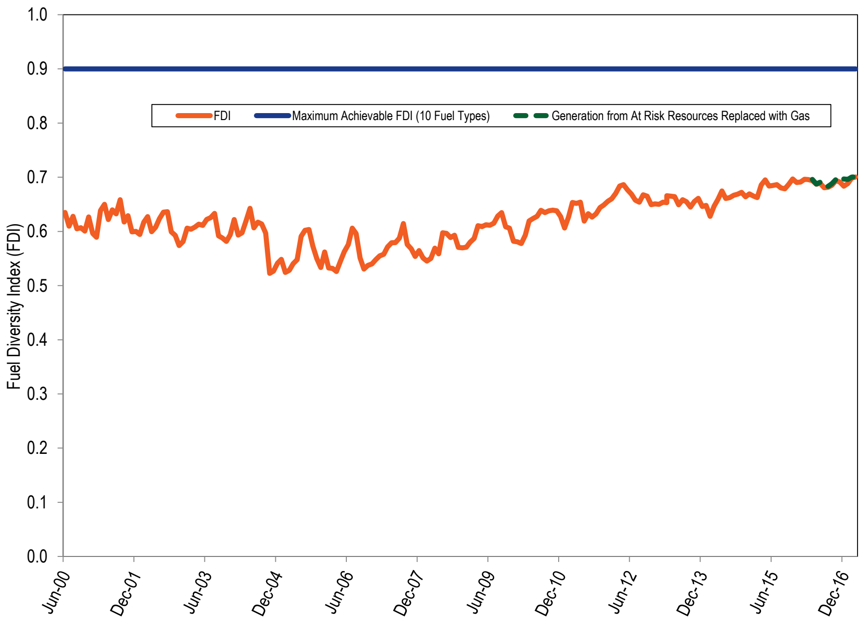
The FDI_e was used to measure the impact of potential retirements by resources that have been identified as being at risk of retirement by the MMUs net revenue adequacy analysis.[21] There were 96 resources with installed capacity totaling 14,500 MW identified as at risk. These 96 resources generated 43 GW in the twelve month period ending March 31, 2017. The dashed line in Figure 3-6 shows the FDI_e calculated assuming that the 43 GW of generation from the 96 at risk resources were replaced by gas generation. The FDI_e under these assumptions would have increased in eleven of the twelve months with an average monthly increase of 0.4 percent over the actual FDI_e.

19 Monitoring Analytics developed the FDI to provide an objective metric of fuel diversity. The FDI metric is similar to the HHI used to measure market concentration. The FDI is calculated separately for energy output and for installed capacity.

20 See the *2016 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography" for an explanation of the expansion of the PJM footprint. The integration of the ComEd Control Area occurred in May 2004 and the integration of the AEP and Dayton control zones occurred in October 2004.

21 See the *2016 State of the Market Report for PJM*, Volume 2, Section 7: Net Revenue, Units at Risk.

Figure 3-6 Fuel diversity index for PJM monthly generation: June 1, 2000 through March 31, 2017



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

The maximum of average offered real-time generation decreased by 2,613 MW, or 1.5 percent, from 173,439 MW in the first three months of 2016 to 170,827 MW in the first three months of 2017.[22]

In 2016, 5,421.4 MW of new capacity resources were added. In 2016, 395.5 MW were retired.

PJM average real-time cleared generation in the first three months of 2017 increased by 2.9 percent from first three months of 2016, from 88,470 MW to 91,074 MW.[23]

PJM average real-time cleared supply including imports increased by 0.8 percent in 2016 from 2015, from 94,329 MW to 95,054 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.

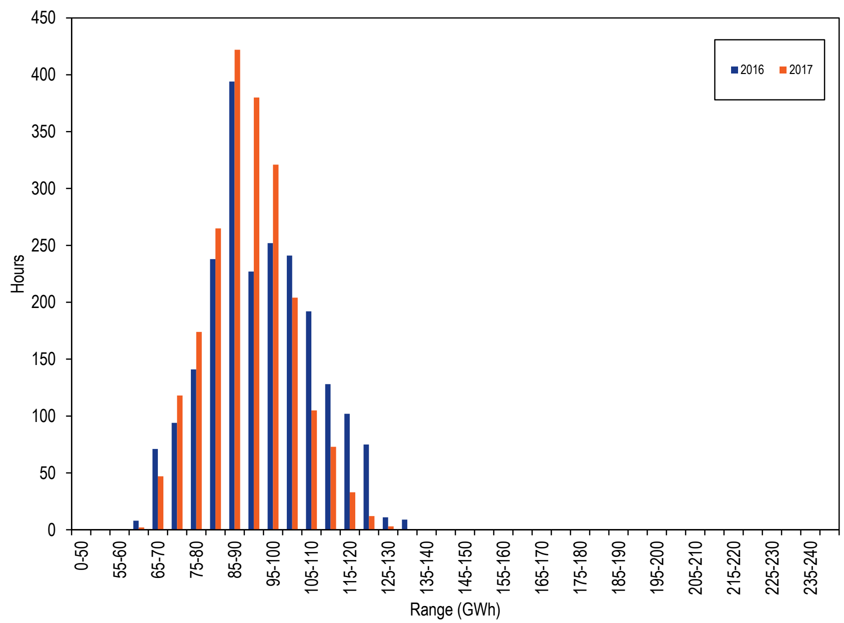
22 Calculated values shown in Section 3, "Energy Market," are based on unrounded, underlying data and may differ from calculations based on the rounded values shown in tables.
23 Generation data are the net MWh injections and withdrawals MWh at every generation bus in PJM.

- **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 3-7 shows the hourly distribution of PJM real-time generation plus imports for the first three months of 2016 and 2017.

Figure 3-7 Distribution of PJM real-time generation plus imports: January 1 through March 31, 2016 and 2017[24]



24 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 18-year period from 2000 through 2017.[25]

Table 3-10 PJM real-time average hourly generation and real-time average hourly generation plus average hourly imports: January 1 through March 31, 2000 through 2017

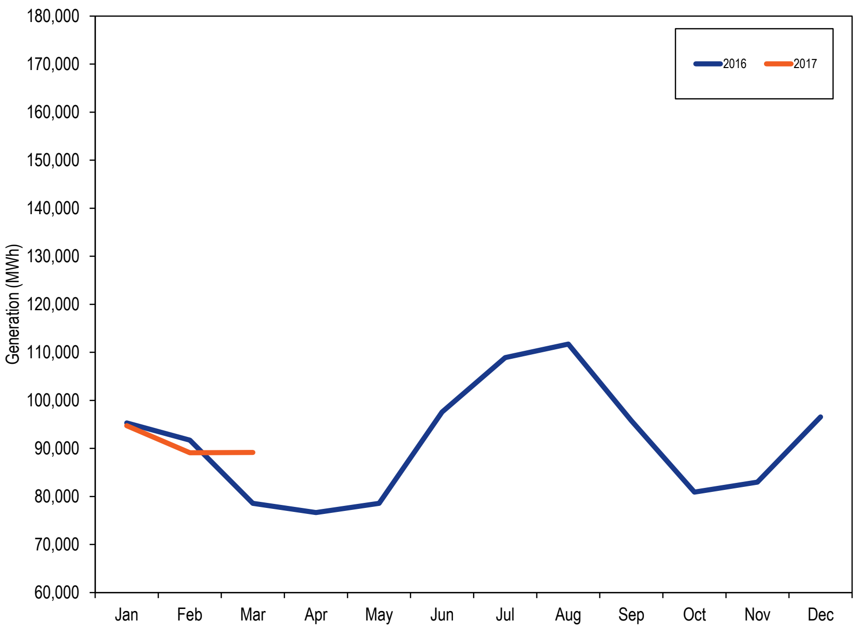
	PJM Real-Time Supply (MWh)				Year-to-Year Change			
	Generation		Generation Plus Imports		Generation		Generation Plus Imports	
Jan-Mar	Generation	Standard Deviation	Supply	Standard Deviation	Generation	Standard Deviation	Supply	Standard Deviation
2000	NA	NA	NA	NA	NA	NA	NA	NA
2001	30,923	3,488	33,806	3,358	NA	NA	NA	NA
2002	27,948	3,416	31,465	3,508	(9.6%)	(2.1%)	(6.9%)	4.5%
2003	38,731	5,187	42,498	5,092	38.6%	51.8%	35.1%	45.1%
2004	37,790	4,660	41,960	4,899	(2.4%)	(10.2%)	(1.3%)	(3.8%)
2005	74,187	8,269	80,184	9,017	96.3%	77.4%	91.1%	84.1%
2006	82,550	7,921	87,729	8,565	11.3%	(4.2%)	9.4%	(5.0%)
2007	86,286	10,018	91,454	11,351	4.5%	26.5%	4.2%	32.5%
2008	86,690	9,375	92,075	10,150	0.5%	(6.4%)	0.7%	(10.6%)
2009	81,987	11,417	88,148	12,213	(5.4%)	21.8%	(4.3%)	20.3%
2010	81,676	12,801	87,009	13,236	(0.4%)	12.1%	(1.3%)	8.4%
2011	83,505	10,116	88,750	10,884	2.2%	(21.0%)	2.0%	(17.8%)
2012	88,068	11,177	93,128	11,685	5.5%	10.5%	4.9%	7.4%
2013	92,776	10,030	98,002	10,812	5.3%	(10.3%)	5.2%	(7.5%)
2014	100,655	12,427	106,879	13,255	8.5%	23.9%	9.1%	22.6%
2015	97,741	13,085	105,027	14,350	(2.9%)	5.3%	(1.7%)	8.3%
2016	88,470	12,666	94,383	13,890	(9.5%)	(3.2%)	(10.1%)	(3.2%)
2017	91,074	11,009	91,074	11,009	2.9%	(13.1%)	(3.5%)	(20.7%)

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

PJM Real-Time, Monthly Average Generation

Figure 3-8 compares the real-time, monthly average hourly generation in 2016 and the first three months of 2017.

Figure 3-8 PJM real-time average monthly hourly generation: January 1, 2016 through March 31, 2017



Day-Ahead Supply

PJM average day-ahead supply in the first three months of 2017, including INCs and up to congestion transactions, increased by 5.6 percent from the first three months of 2016, from 133,263 MW to 140,756 MW.

PJM average day-ahead supply in the first three months of 2017, including INCs, up to congestion transactions, and imports, increased by 3.8 percent from the first three months of 2016, from 135,638 MW to 140,756 MW. The increase in PJM day-ahead supply was a result of an increase in UTCs beginning in December 2015 based on a FERC order setting December 8, 2015, as the last effective date for any uplift charges subsequently assigned to UTCs.[26]

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

- **Self-Scheduled Generation Offer.** Offer to supply a fixed block of MWh, as a price taker, from a unit that may also have a dispatchable component above the minimum.
- **Dispatchable Generation Offer.** Offer to supply a schedule of MWh and corresponding offer prices from a unit.
- **Increment Offer (INC).** Financial offer to supply MWh and corresponding offer prices. INCs can be submitted by any market participant.
- **Up to Congestion Transaction (UTC).** Conditional transaction that permits a market participant to specify a maximum price spread between the transaction source and sink. An up to congestion transaction is evaluated as a matched pair of an injection and a withdrawal analogous to a matched pair of an INC offer and a DEC bid.
- **Import.** An import is an external energy transaction scheduled to PJM from another balancing authority. An import must have a valid willing to pay congestion (WPC) OASIS reservation when offered. An import energy transaction that clears the Day-Ahead Energy Market is financially binding. There is no link between transactions submitted in the PJM Day-Ahead Energy Market and the PJM Real-Time Energy Market, so an import energy transaction approved in the Day-Ahead Energy Market will not physically flow in real time unless it is also submitted through the real-time energy market scheduling process.

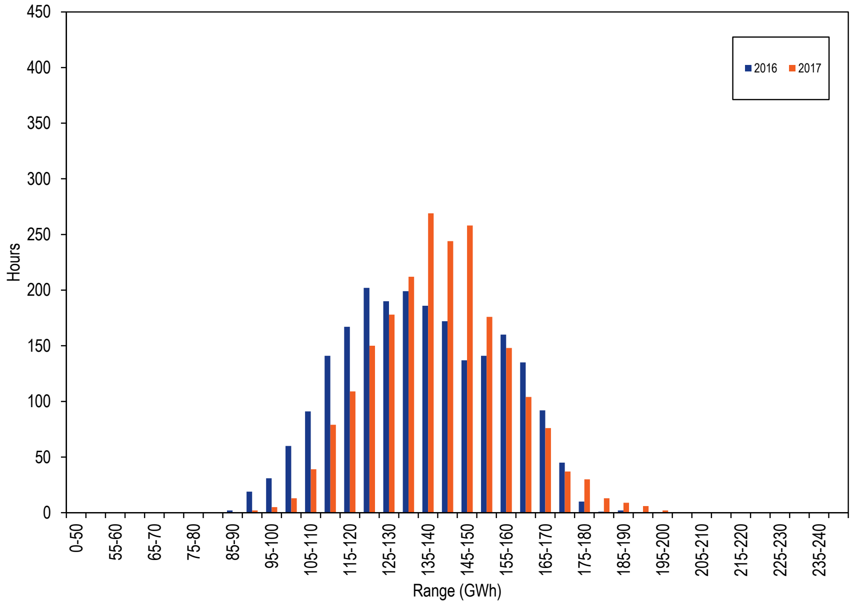
PJM Day-Ahead Supply Duration

Figure 3-9 shows the hourly distribution of PJM day-ahead supply, including increment offers, up to congestion transactions, and imports for 2015 and 2016. There was an increase in up to congestion volume, which resulted in an increase in day-ahead supply, as a result of the expiration of the fifteen month

26 148 FERC ¶ 61,144 (2014).

potential refund period for uplift charges for UTC transactions on December 7, 2015.

Figure 3-9 Distribution of PJM day-ahead supply plus imports: January 1 through March 31, 2016 and 2017[27]



PJM Day-Ahead, Average Supply

Table 3-11 presents summary day-ahead supply statistics for each year of the 18-year period from 2000 through 2017.[28]

Table 3-11 PJM day-ahead average hourly supply and day-ahead average hourly supply plus average hourly imports: January 1 through March 31, 2000 through 2017

	PJM Day-Ahead Supply (MWh)				Year-to-Year Change			
	Supply		Supply Plus Imports		Supply		Supply Plus Imports	
Jan-Mar	Supply	Standard Deviation	Supply	Standard Deviation	Supply	Standard Deviation	Supply	Standard Deviation
2000	NA	NA	NA	NA	NA	NA	NA	NA
2001	28,494	2,941	29,252	3,021	NA	NA	NA	NA
2002	20,274	10,131	20,827	10,134	(28.8%)	244.5%	(28.8%)	235.5%
2003	37,147	4,337	37,807	4,389	83.2%	(57.2%)	81.5%	(56.7%)
2004	46,591	4,794	47,377	5,039	25.4%	10.5%	25.3%	14.8%
2005	89,011	9,434	90,502	9,443	91.0%	96.8%	91.0%	87.4%
2006	97,319	9,035	99,551	9,061	9.3%	(4.2%)	10.0%	(4.0%)
2007	110,099	11,938	112,561	12,141	13.1%	32.1%	13.1%	34.0%
2008	109,711	10,479	112,165	10,671	(0.4%)	(12.2%)	(0.4%)	(12.1%)
2009	104,880	13,895	107,325	14,031	(4.4%)	32.6%	(4.3%)	31.5%
2010	101,733	13,835	104,858	13,917	(3.0%)	(0.4%)	(2.3%)	(0.8%)
2011	110,310	12,200	112,854	12,419	8.4%	(11.8%)	7.6%	(10.8%)
2012	132,178	13,701	134,405	13,804	19.8%	12.3%	19.1%	11.2%
2013	147,246	13,054	149,300	13,244	11.4%	(4.7%)	11.1%	(4.1%)
2014	168,373	11,875	170,778	11,935	14.3%	(9.0%)	14.4%	(9.9%)
2015	123,424	14,671	125,973	14,915	(26.7%)	23.5%	(26.2%)	25.0%
2016	133,263	19,105	135,638	19,405	8.0%	30.2%	7.7%	30.1%
2017	140,756	16,933	140,756	16,933	5.6%	(11.4%)	3.8%	(12.7%)

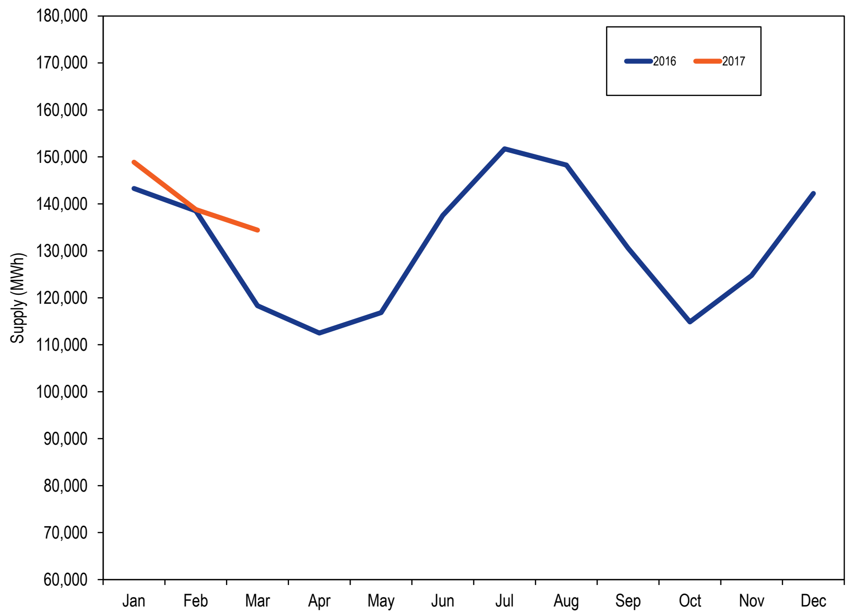
PJM Day-Ahead, Monthly Average Supply

Figure 3-10 compares the day-ahead, monthly average hourly supply, including increment offers and up to congestion transactions, for 2016 and the first three months of 2017.

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

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

Figure 3-10 PJM day-ahead monthly average hourly supply: January 1, 2016 through March 31, 2017



Real-Time and Day-Ahead Supply

Table 3-12 presents summary statistics for the first three months of 2016 and 2017, for day-ahead and real-time supply. All data are cleared MW. The last two columns of Table 3-12 are the day-ahead supply minus the real-time supply. The first of these columns is the total day-ahead supply less the total real-time supply and the second of these columns is the total physical day-ahead generation less the total physical real-time generation. In the first three months of 2017, up-to congestion transactions were 27.1 percent of the total day-ahead supply compared to 29.9 percent in the first three months of 2016.

Table 3-12 Day-ahead and real-time supply (MW): January 1 through March 31, 2016 and 2017

		Day Ahead					Real Time		Day Ahead Less Real Time	
	(Jan-Mar)	Generation	INC Offers	Up-to Congestion	Imports	Total Supply	Generation	Total Supply	Total Supply	Total Generation
Average	2016	91,348	5,202	36,705	2,375	135,638	88,470	94,383	41,255	2,877
	2017	92,125	6,115	42,516	1,323	142,079	91,074	94,388	47,692	1,051
Median	2016	90,440	5,070	36,131	2,296	134,690	87,392	93,082	41,607	3,048
	2017	91,972	6,111	42,702	1,363	141,842	90,623	93,731	48,111	1,349
Standard Deviation	2016	14,074	948	7,490	526	19,405	12,666	13,890	5,515	1,408
	2017	11,876	1,098	7,515	243	16,947	11,009	11,673	5,274	867
Peak Average	2016	98,217	5,357	38,741	2,479	144,832	94,434	100,852	43,980	3,783
	2017	98,367	6,626	45,126	1,271	151,390	96,856	100,304	51,086	1,512
Peak Median	2016	98,337	5,182	37,989	2,389	144,990	94,091	100,313	44,677	4,246
	2017	97,245	6,591	44,873	1,342	150,120	95,955	99,413	50,707	1,291
Peak Standard Deviation	2016	11,631	939	7,506	598	16,837	10,883	12,107	4,730	748
	2017	8,655	984	6,733	254	13,142	8,226	9,039	4,104	429
Off-Peak Average	2016	85,097	5,061	34,852	2,281	127,274	83,044	88,498	38,776	2,053
	2017	86,324	5,641	40,090	1,372	133,426	85,700	88,889	44,537	624
Off-Peak Median	2016	83,797	4,977	34,172	2,248	125,757	81,979	87,218	38,539	1,817
	2017	85,365	5,575	40,154	1,398	132,181	84,759	87,856	44,324	606
Off-Peak Standard Deviation	2016	13,165	934	6,980	430	17,737	11,702	12,748	4,989	1,463
	2017	11,519	980	7,392	223	15,436	10,538	11,148	4,288	981

Figure 3-11 shows the average hourly cleared volumes of day-ahead supply and real-time supply for the first three months of 2017. The day-ahead supply consists of cleared MW of day-ahead generation, imports, increment offers and up to congestion transactions. The real-time generation includes generation and imports.

Figure 3-11 Day-ahead and real-time supply (Average hourly volumes): January 1 through March 31, 2017

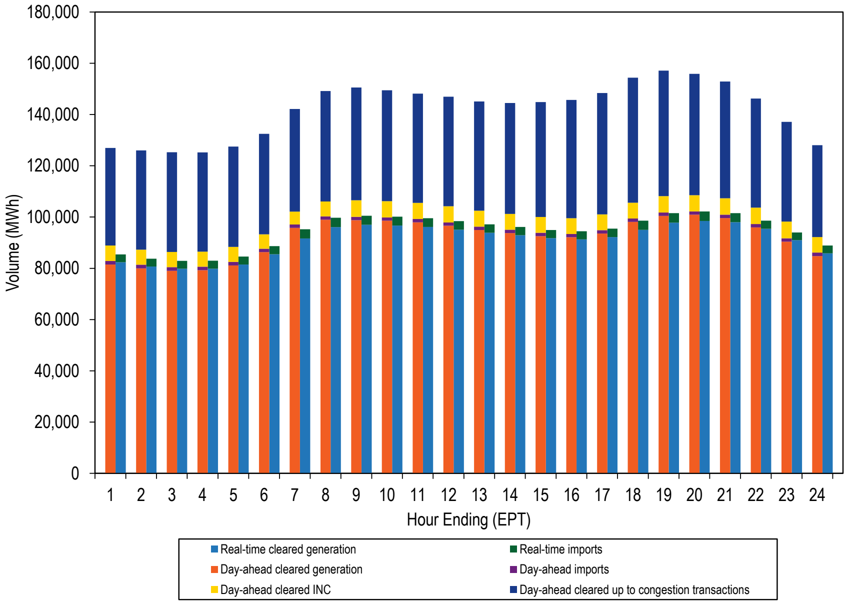


Figure 3-12 shows the difference between the day-ahead and real-time average daily supply for 2016 and the first three months of 2017.

Figure 3-12 Difference between day-ahead and real-time supply (Average daily volumes): January 1, 2016 through March 31, 2017

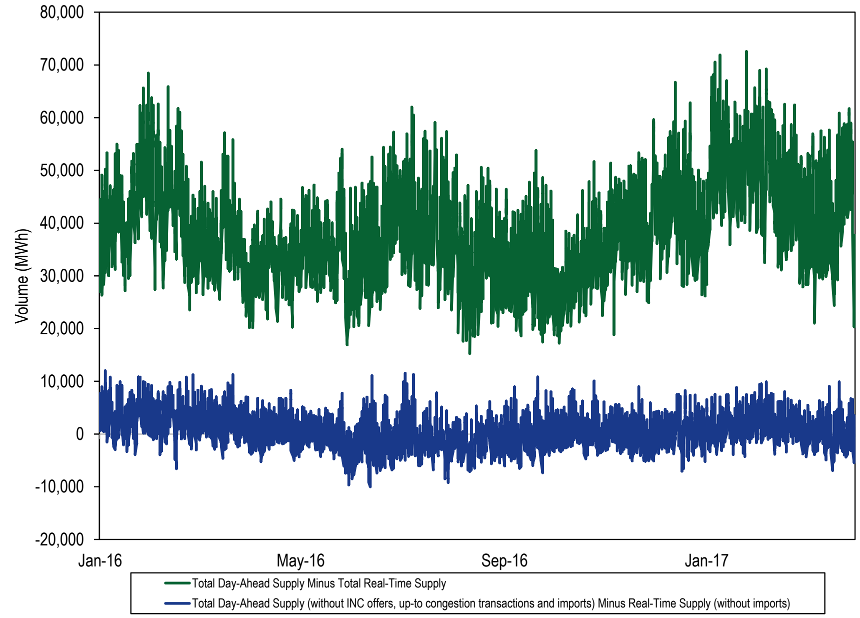
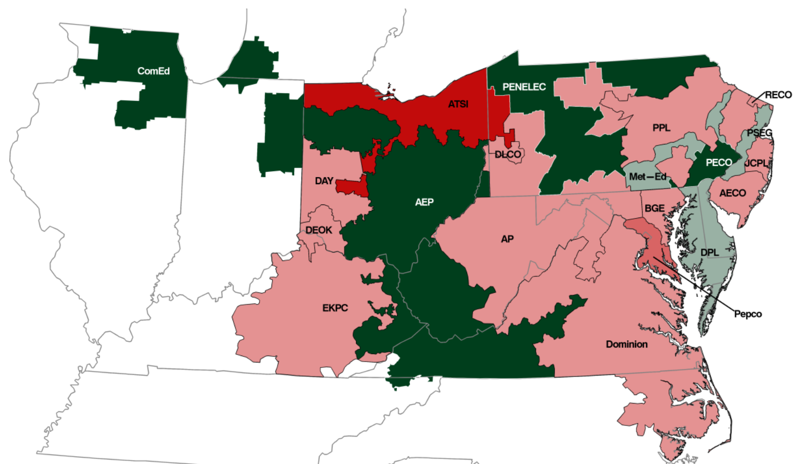


Figure 3-13 shows the difference between the PJM real-time generation and real-time load by zone in the first three months of 2017. Figure 3-13 is color coded on a scale on which red shades represent zones that have less generation than load and green shades represent zones that have more generation 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. Table 3-13 shows the difference between the PJM real-time generation and real-time load by zone in the first three months of 2017 and 2016.

Figure 3-13 Map of PJM real-time generation, less real-time load, by zone: January 1 through March 31, 2017[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	(494)	ComEd	8,574	DPL	(2,957)	PENELEC	7,484
AEP	8,075	DAY	(1,876)	EKPC	(1,247)	Pepco	(5,489)
AP	(917)	DEOK	(884)	JCPL	(989)	PPL	(7)
ATSI	(7,949)	DLCO	1,017	Met-Ed	1,334	PSEG	919
BGE	(3,270)	Dominion	(520)	PECO	7,024	RECO	(323)

Table 3-13 PJM real-time generation less real-time load by zone (GWh): January 1 through March 31, 2016 and 2017

	Zonal Generation and Load (GWh)					
	2016 (Jan - Mar)			2017 (Jan - Mar)		
Zone	Generation	Load	Net	Generation	Load	Net
AECO	1,649.8	2,276.3	(626.4)	1,726.5	2,220.9	(494.4)
AEP	33,313.9	32,946.3	367.6	39,504.4	31,429.8	8,074.7
AP	11,506.0	12,767.4	(1,261.4)	11,419.3	12,336.2	(916.9)
ATSI	9,757.6	16,688.1	(6,930.6)	8,521.5	16,470.2	(7,948.7)
BGE	4,963.0	7,988.7	(3,025.7)	4,223.0	7,493.1	(3,270.2)
ComEd	30,737.3	23,440.7	7,296.6	31,476.1	22,902.6	8,573.5
DAY	3,853.0	4,316.3	(463.3)	2,319.9	4,196.4	(1,876.5)
DEOK	2,818.6	6,654.2	(3,835.6)	5,482.3	6,365.9	(883.5)
DLCO	4,262.6	3,348.5	914.1	4,280.2	3,262.9	1,017.3
Dominion	25,147.3	24,387.2	760.1	22,862.1	23,381.9	(519.8)
DPL	1,600.2	4,594.7	(2,994.5)	1,502.7	4,459.8	(2,957.1)
EKPC	2,478.2	3,471.6	(993.4)	1,932.4	3,179.9	(1,247.5)
JCPL	3,992.9	5,339.8	(1,346.9)	4,267.2	5,256.3	(989.2)
Met-Ed	5,758.7	3,878.3	1,880.4	5,181.9	3,848.1	1,333.8
PECO	16,178.3	9,721.3	6,457.0	16,736.6	9,712.9	7,023.6
PENELEC	8,625.1	4,369.6	4,255.5	11,845.7	4,361.5	7,484.1
Pepco	2,218.3	7,489.0	(5,270.7)	1,588.3	7,077.3	(5,489.1)
PPL	12,354.7	10,667.6	1,687.0	10,574.7	10,581.9	(7.2)
PSEG	11,915.2	10,208.0	1,707.2	11,183.8	10,264.8	919.0
RECO	0.0	330.9	(330.9)	0.0	322.7	(322.7)

Demand

Demand includes physical load and exports and virtual transactions.

Peak Demand

In this section, demand refers to accounting load and exports and in the Day-Ahead Energy Market also includes virtual transactions.[30]

The PJM system real-time peak load for the first three months of 2017 was 127,543 MW in the HE 0700 on January 09, 2017, which was 2,333MW, or 1.8 percent, lower than the peak load for the first three months of 2016, which was 129,876 MW in the HE 0700 on January 19, 2016.

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>.

30 PJM reports peak load including accounting load plus an addback equal to PJM's estimated load drop from demand side resources. This will generally result in PJM reporting peak load values greater than accounting load values. PJM's load drop estimate is based PJM Manual 19: Load Forecasting and Analysis Attachment A: Load Drop Estimate Guidelines at <http://www.pjm.com/~/media/documents/manuals/m19.ashx>.

Table 3-14 shows the peak loads for the first three months of 1999 through 2017.

Table 3-14 Actual PJM footprint peak loads: January through March, 1999 to 2017[31]

(Jan - Mar)	Date	Hour Ending (EPT)	PJM Load (MW)	Annual Change (MW)	Annual Change (%)
1999	Tue, January 05	19	99,982	NA	NA
2000	Thu, January 27	20	102,359	2,377	2.4%
2001	Tue, January 02	19	100,411	(1,948)	(1.9%)
2002	Mon, March 04	20	97,334	(3,077)	(3.1%)
2003	Thu, January 23	19	112,755	15,421	15.8%
2004	Mon, January 26	19	106,760	(5,995)	(5.3%)
2005	Tue, January 18	19	111,973	5,213	4.9%
2006	Mon, February 13	20	100,065	(11,908)	(10.6%)
2007	Mon, February 05	20	118,800	18,736	18.7%
2008	Thu, January 03	19	111,724	(7,076)	(6.0%)
2009	Fri, January 16	19	117,169	5,445	4.9%
2010	Mon, January 04	19	109,210	(7,959)	(6.8%)
2011	Mon, January 24	8	110,659	1,448	1.3%
2012	Tue, January 03	19	122,539	11,880	10.7%
2013	Tue, January 22	19	126,632	4,093	3.3%
2014	Tue, January 07	19	140,467	13,835	10.9%
2015	Fri, February 20	8	143,086	2,619	1.9%
2016	Tue, January 19	8	129,876	(13,210)	(9.2%)
2017	Mon, January 09	8	127,543	(2,333)	(1.8%)

Figure 3-14 shows the peak loads for the first three months of 1999 through 2017.

Figure 3-14 PJM footprint calendar year peak loads: January 1 through March 31, 1999 to 2017

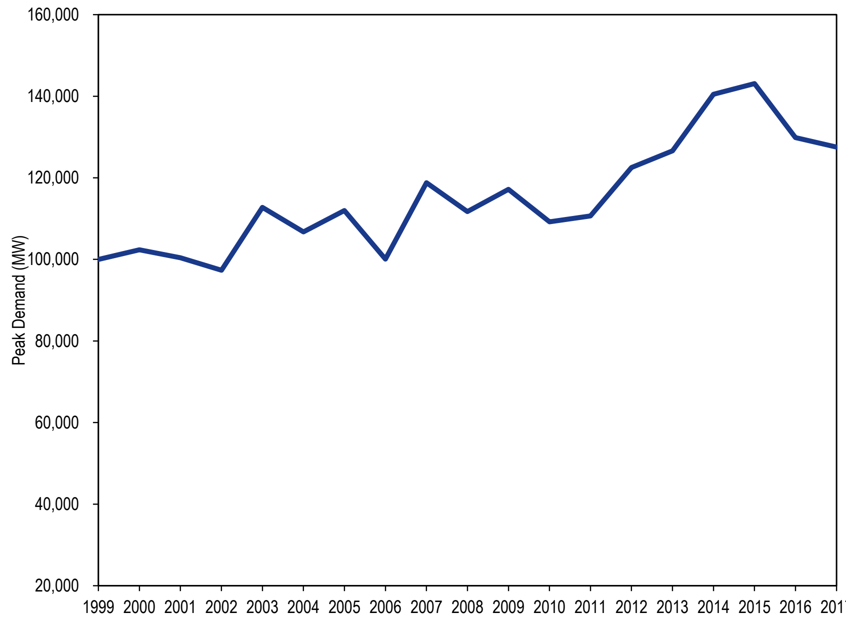
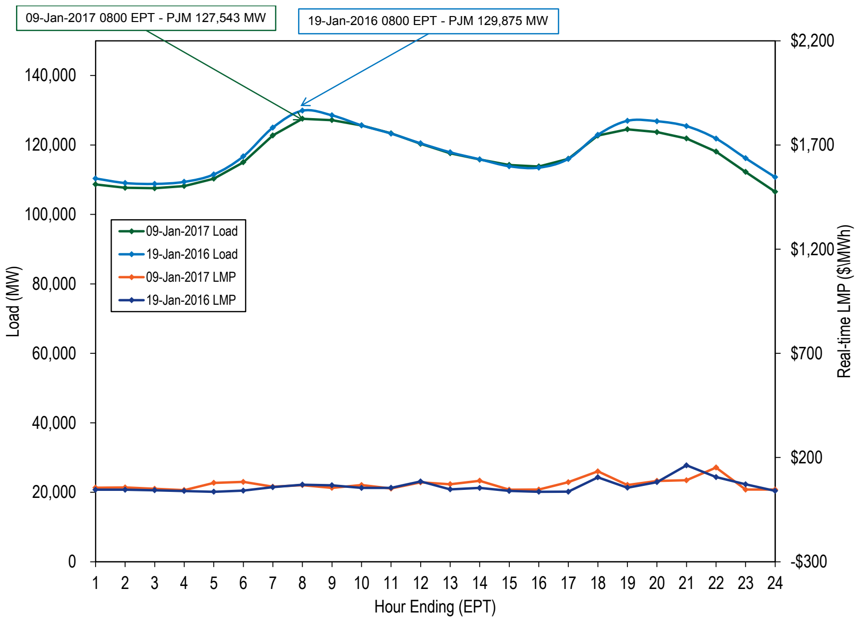


Figure 3-15 compares the peak load days during the first three months of 2016 and 2017. The highest average hourly real-time LMP on January 09, 2017 was $151.98 and on January 19, 2016 was $162.73.

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

Figure 3-15 PJM peak-load comparison Tuesday, January 19, 2016 and Monday, January 09, 2017



Real-Time Demand

PJM average real-time load in the first three months of 2017 decreased from the first three months of 2016, from 89,322 MW to 87,598 MW.[32]

PJM average real-time demand in the first three months of 2017 slightly increased from the first three months of 2016, from 92,777 MW to 92,791 MW.

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

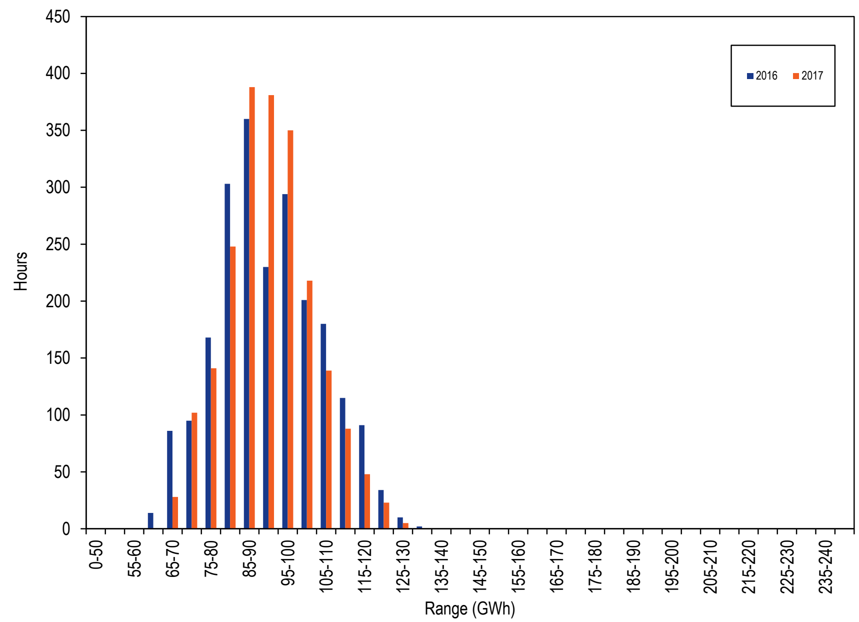
- **Load.** The actual MWh level of energy used by load within PJM.
- **Export.** An export is an external energy transaction scheduled from PJM to another balancing authority. A real-time export must have a valid OASIS reservation when offered, must have available ramp room to support the export, must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

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

PJM Real-Time Demand Duration

Figure 3-16 shows the hourly distribution of PJM real-time load plus exports for the first three months of 2016 and 2017.[33]

Figure 3-16 Distribution of PJM real-time accounting load plus exports: January through March, 2016 and 2017[34]



33 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>.

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

PJM Real-Time, Average Load

Table 3-15 presents summary real-time demand statistics for the first three months of 1998 to 2017. 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.[35]

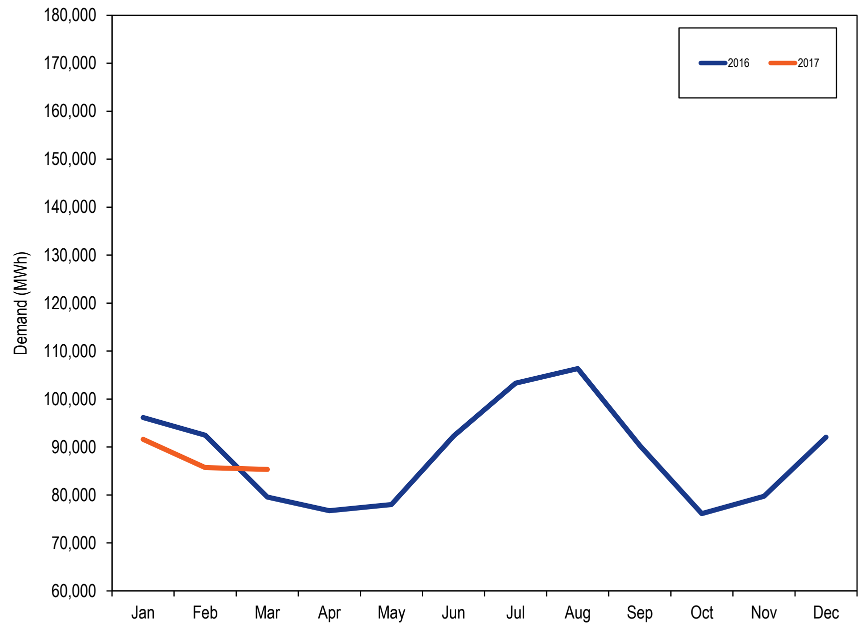
Table 3-15 PJM real-time average hourly load and real-time average hourly load plus average hourly exports: January 1 through March 31, 1998 through 2017[36]

	PJM Real-Time Demand (MWh)				Year-to-Year Change			
	Load		Load Plus Exports		Load		Load Plus Exports	
Jan-Mar	Load	Standard Deviation	Demand	Standard Deviation	Load	Standard Deviation	Demand	Standard Deviation
1998	28,019	3,762	28,019	3,762	NA	NA	NA	NA
1999	29,784	4,027	29,784	4,027	6.3%	7.0%	6.3%	7.0%
2000	30,367	4,624	30,367	4,624	2.0%	14.8%	2.0%	14.8%
2001	31,254	3,846	33,452	3,704	2.9%	(16.8%)	10.2%	(19.9%)
2002	29,968	4,083	30,988	3,932	(4.1%)	6.1%	(7.4%)	6.1%
2003	39,249	5,546	41,600	5,701	31.0%	35.8%	34.2%	45.0%
2004	39,549	5,761	41,198	5,394	0.8%	3.9%	(1.0%)	(5.4%)
2005	71,388	8,966	79,319	9,587	80.5%	55.6%	92.5%	77.8%
2006	80,179	8,977	86,567	9,378	12.3%	0.1%	9.1%	(2.2%)
2007	84,586	12,040	90,304	12,012	5.5%	34.1%	4.3%	28.1%
2008	82,235	10,184	89,092	10,621	(2.8%)	(15.4%)	(1.3%)	(11.6%)
2009	81,170	11,718	86,110	11,948	(1.3%)	15.1%	(3.3%)	12.5%
2010	81,121	10,694	86,843	11,262	(0.1%)	(8.7%)	0.9%	(5.7%)
2011	81,018	10,273	86,635	10,613	(0.1%)	(3.9%)	(0.2%)	(5.8%)
2012	86,329	10,951	91,090	11,293	6.6%	6.6%	5.1%	6.4%
2013	91,337	10,610	95,835	10,452	5.8%	(3.1%)	5.2%	(7.4%)
2014	98,317	13,484	104,454	12,843	7.6%	27.1%	9.0%	22.9%
2015	97,936	13,445	102,821	13,855	(0.4%)	(0.3%)	(1.6%)	7.9%
2016	89,322	13,262	92,777	13,409	(8.8%)	(1.4%)	(9.8%)	(3.2%)
2017	87,598	11,208	92,791	11,295	(1.9%)	(15.5%)	0.0%	(15.8%)

PJM Real-Time, Monthly Average Load

Figure 3-17 compares the real-time, monthly average hourly loads for 2016 and the first three months of 2017.

Figure 3-17 PJM real-time monthly average hourly load: January 1, 2016 through March 31, 2107



PJM real-time load is significantly affected by temperature. Figure 3-18 and Table 3-16 compare the PJM monthly heating and cooling degree days in 2016 and the first three months of 2017.[37] Heating degree days decreased 10.6 percent from the first three months of 2016 to 2017.

35 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 excluded losses prior to June 1 and includes losses after June 1.

36 Export data are not available before June 1, 2000. The export data for 2000 are for the last six months of 2000.

37 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

Figure 3-18 PJM heating and cooling degree days: January 1, 2016 through March 31, 2017

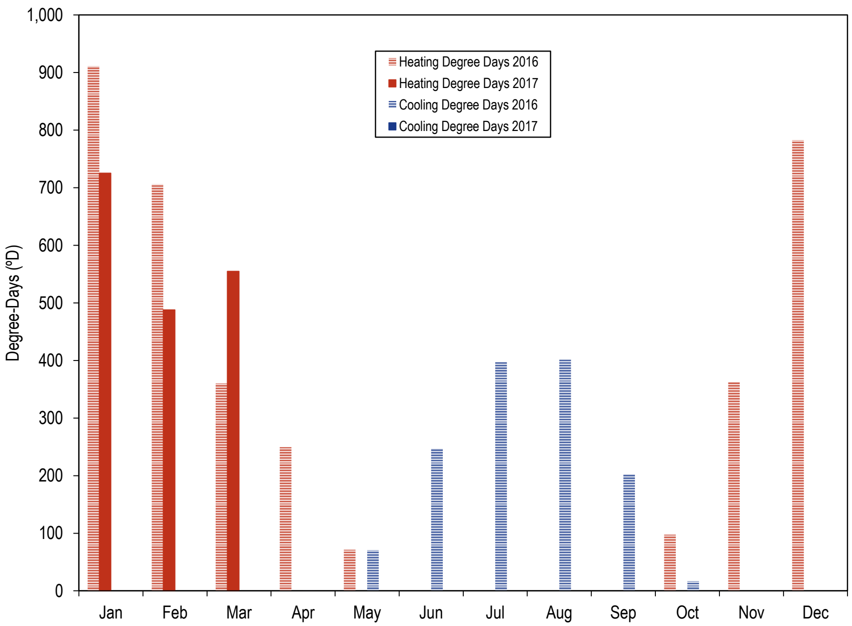


Table 3-16 PJM heating and cooling degree days: 2016 and January through March, 2017

	2016		2017		Percent Change	
	Heating Degree Days	Cooling Degree Days	Heating Degree Days	Cooling Degree Days	Heating Degree Days	Cooling Degree Days
Jan	911	0	725	0	(20.4%)	0.0%
Feb	706	0	488	0	(30.9%)	0.0%
Mar	360	0	555	0	54.1%	0.0%
Apr	250	1				
May	71	71				
Jun	0	247				
Jul	0	397				
Aug	0	402				
Sep	0	203				
Oct	98	17				
Nov	363	0				
Dec	782	0				
Total	3,541	1,337	1,768	0	(23.1%)	
Jan-Mar	1,977	0	1,768	0	(10.6%)	0.0%

Day-Ahead Demand

PJM average day-ahead demand in the first three months of 2017, including DECs and up to congestion transactions, increased by 3.9 percent from the first three months of 2016, from 130,534 MW to 135,560 MW.

PJM average day-ahead demand in the first three months of 2017, including DECs, up to congestion transactions, and exports, increased by 4.6 percent from the first three months of 2016, from 133,386 MW to 139,467 MW.

The reduction in up to congestion transactions (UTC) that had followed a FERC order setting September 8, 2014, as the effective date for any uplift charges subsequently assigned to UTCs, was reversed. There was an increase in up to congestion volume as a result of the expiration of the 15 month refund period for the proceeding related to uplift charges for UTC transactions.[38]

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

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.

38 148 FERC ¶ 61,144 (2014).

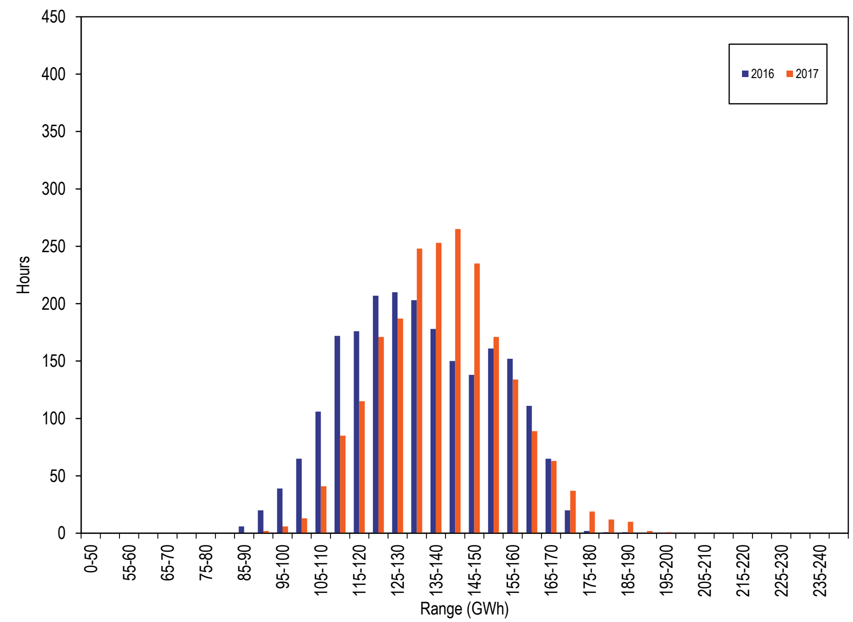
- **Fixed-Demand Bid.** Bid to purchase a defined MWh level of energy, regardless of LMP.
- **Price-Sensitive Bid.** Bid to purchase a defined MWh level of energy only up to a specified LMP, above which the load bid is zero.
- **Decrement Bid (DEC).** Financial bid to purchase a defined MWh level of energy up to a specified LMP, above which the bid is zero. A DEC can be submitted by any market participant.
- **Up to Congestion Transaction (UTC).** A conditional transaction that permits a market participant to specify a maximum price spread between the transaction source and sink. An up to congestion transaction is evaluated as a matched pair of an injection and a withdrawal analogous to a matched pair of an INC offer and a DEC bid.
- **Export.** An external energy transaction scheduled from PJM to another balancing authority. An export must have a valid willing to pay congestion (WPC) OASIS reservation when offered. An export energy transaction that clears the Day-Ahead Energy Market is financially binding. There is no link between transactions submitted in the PJM Day-Ahead Energy Market and the PJM Real-Time Energy Market, so an export energy transaction approved in the Day-Ahead Energy Market will not physically flow in real time unless it is also submitted through the Real-Time Energy Market scheduling process.

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

PJM Day-Ahead Demand Duration

Figure 3-19 shows the hourly distribution of PJM day-ahead demand, including decrement bids, up to congestion transactions, and exports for the first three months of 2016 and 2017.

Figure 3-19 Distribution of PJM day-ahead demand plus exports: January 1 through March 31, 2016 and 2017[39]



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

PJM Day-Ahead, Average Demand

Table 3-17 presents summary day-ahead demand statistics for the first three months of each year from 2000 to 2017.[40]

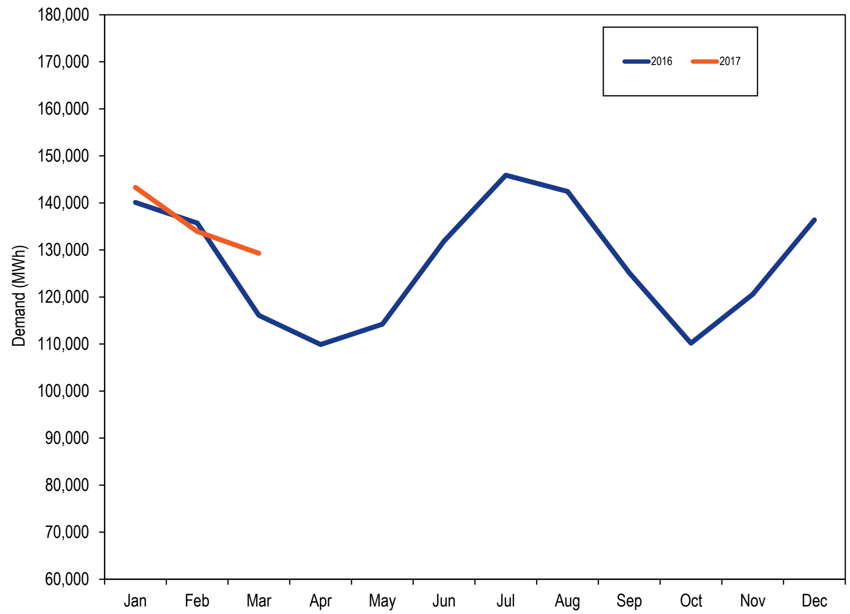
Table 3-17 PJM day-ahead average demand and day-ahead average hourly demand plus average hourly exports: January 1 through March 31, 2000 through 2017

	PJM Day-Ahead Demand (MWh)				Year-to-Year Change			
	Demand		Demand Plus Exports		Demand		Demand Plus Exports	
Jan-Mar	Demand	Standard Deviation	Demand	Standard Deviation	Demand	Standard Deviation	Demand	Standard Deviation
2000	NA	NA	NA	NA	NA	NA	NA	NA
2001	33,731	4,557	34,523	4,390	NA	NA	NA	NA
2002	33,976	4,960	34,004	4,964	0.7%	8.9%	(1.5%)	13.1%
2003	47,034	6,841	47,147	6,853	38.4%	37.9%	38.7%	38.1%
2004	46,885	5,591	47,123	5,537	(0.3%)	(18.3%)	(0.1%)	(19.2%)
2005	87,341	9,810	90,288	9,947	86.3%	75.5%	91.6%	79.7%
2006	96,244	9,453	99,342	9,777	10.2%	(3.6%)	10.0%	(1.7%)
2007	108,699	12,601	111,831	12,746	12.9%	33.3%	12.6%	30.4%
2008	105,995	10,677	109,428	10,975	(2.5%)	(15.3%)	(2.1%)	(13.9%)
2009	102,366	13,619	105,023	13,758	(3.4%)	27.5%	(4.0%)	25.4%
2010	101,012	11,937	104,866	12,103	(1.3%)	(12.4%)	(0.1%)	(12.0%)
2011	107,116	11,890	110,865	12,157	6.0%	(0.4%)	5.7%	0.4%
2012	129,258	13,163	132,757	13,481	20.7%	10.7%	19.7%	10.9%
2013	143,585	13,120	146,878	13,108	11.1%	(0.3%)	10.6%	(2.8%)
2014	163,031	11,914	167,318	11,717	13.5%	(9.2%)	13.9%	(10.6%)
2015	119,078	14,226	123,282	14,565	(27.0%)	19.4%	(26.3%)	24.3%
2016	130,534	18,683	133,386	18,860	9.6%	31.3%	8.2%	29.5%
2017	135,560	16,273	139,467	16,462	3.9%	(12.9%)	4.6%	(12.7%)

PJM Day-Ahead, Monthly Average Demand

Figure 3-20 compares the day-ahead, monthly average hourly demand, including decrement bids and up to congestion transactions in 2016 and the first three months of 2017

Figure 3-20 PJM day-ahead monthly average hourly demand: January 1, 2016 through March 31, 2017



Real-Time and Day-Ahead Demand

Table 3-18 presents summary statistics for the first three months of 2016 and 2017 day-ahead and real-time demand. All data are cleared MW. 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.

40 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.

Table 3-18 Cleared day-ahead and real-time demand (MWh): January 1 through March 31, 2016 and 2017

		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	2016	86,525	3,221	4,075	36,705	2,852	133,386	89,322	92,777	40,608	48,714
	2017	85,432	2,743	4,869	42,516	3,907	139,467	87,598	92,791	46,676	40,923
Median	2016	85,443	3,208	3,735	36,131	2,762	132,475	87,962	91,595	40,880	47,082
	2017	85,446	2,742	4,678	42,702	3,855	139,254	87,106	92,183	47,071	40,035
Standard Deviation	2016	12,090	396	1,305	7,490	608	18,860	13,262	13,409	5,452	7,810
	2017	10,669	308	1,179	7,515	863	16,462	11,208	11,295	5,167	6,041
Peak Average	2016	92,978	3,428	4,315	38,741	2,851	142,351	95,708	99,063	43,288	52,420
	2017	91,430	2,938	5,109	45,126	3,986	148,589	93,329	98,584	50,004	43,325
Peak Median	2016	92,889	3,404	4,166	37,989	2,785	142,530	95,338	98,602	43,928	51,410
	2017	90,895	2,973	4,904	44,873	3,981	147,313	92,487	97,826	49,487	43,000
Peak Standard Deviation	2016	9,791	323	1,157	7,506	571	16,338	11,312	11,683	4,655	6,657
	2017	7,701	252	1,045	6,733	843	12,754	8,562	8,743	4,011	4,551
Off-Peak Average	2016	80,653	3,031	3,856	34,852	2,853	125,228	83,511	87,058	38,170	45,341
	2017	79,858	2,562	4,647	40,090	3,833	130,989	82,272	87,407	43,582	38,690
Off-Peak Median	2016	79,956	2,984	3,417	34,172	2,745	123,918	82,392	85,932	37,985	44,407
	2017	79,081	2,548	4,385	40,154	3,739	129,778	81,321	86,473	43,305	38,017
Off-Peak Standard Deviation	2016	10,937	360	1,392	6,980	640	17,234	12,194	12,272	4,961	7,233
	2017	10,002	238	1,251	7,392	876	14,919	10,743	10,724	4,196	6,547

Figure 3-21 shows the average hourly cleared volumes of day-ahead demand and real-time demand for the first three months of 2017. The day-ahead demand includes day-ahead load, day-ahead exports, decrement bids and up to congestion transactions. The real-time demand includes real-time load and real-time exports.

Figure 3-21 Day-ahead and real-time demand (Average hourly volumes): January 1 through March 31, 2017

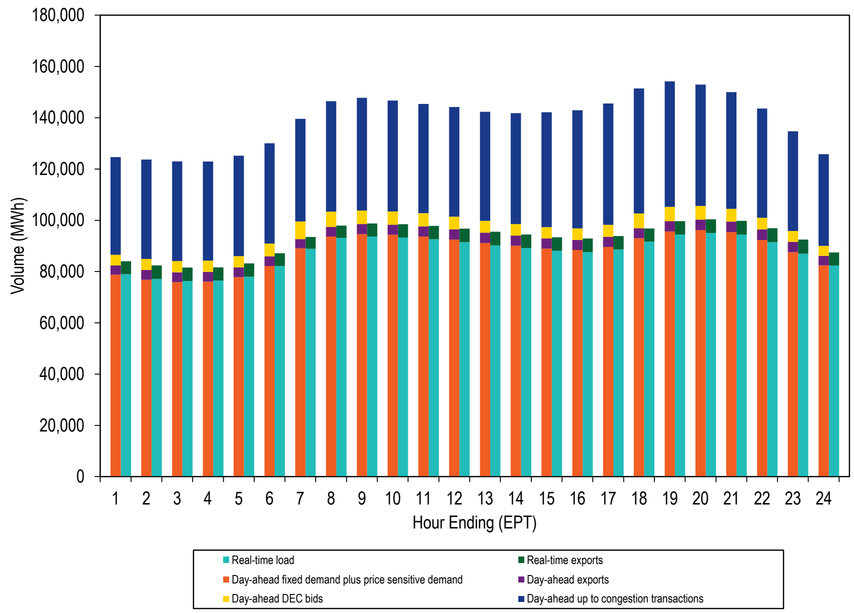


Figure 3-22 Difference between day-ahead and real-time demand (Average daily volumes): January 1, 2016 through March 31, 2017

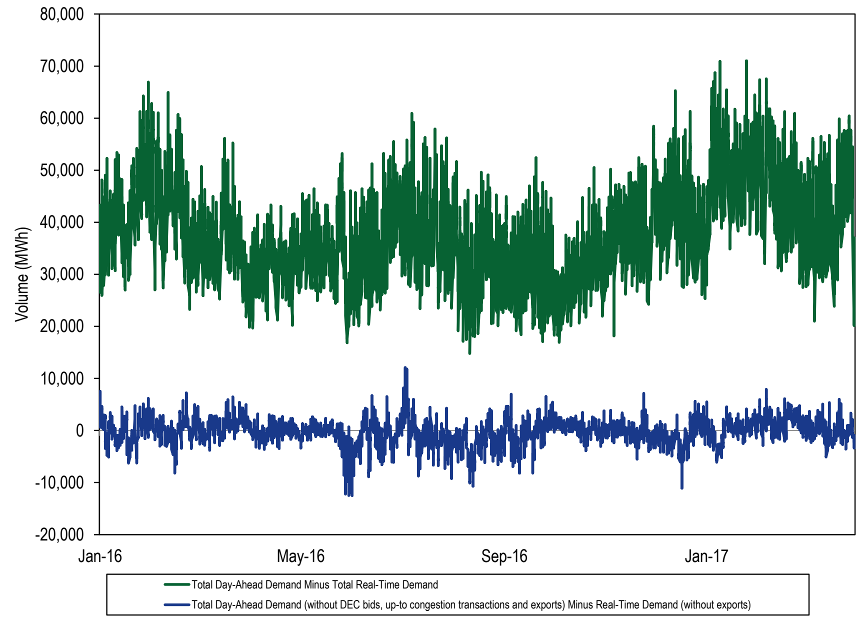


Figure 3-22 shows the difference between the day-ahead and real-time average daily demand from January 2016 through March 2017. There was an increase in up to congestion volume as a result of the expiration of the fifteen month potential refund period for the proceeding related to uplift charges for UTC transactions on December 7, 2015.

Supply and Demand: Load and Spot Market

Real-Time Load and Spot Market

Participants in the PJM Real-Time Energy Market can use their own generation to meet load, to sell in the bilateral market or to sell in the spot market in any hour. Participants can both buy and sell via bilateral contracts and buy and sell in the spot market in any hour. If a participant has positive net bilateral transactions in an hour, it is buying energy through bilateral contracts (bilateral purchase). If a participant has negative net bilateral transactions in an hour, it is selling energy through bilateral contracts (bilateral sale). If a participant has positive net spot transactions in an hour, it is buying energy from the spot market (spot purchase). If a participant has negative net spot transactions in an hour, it is selling energy to the spot market (spot sale).

Real-time load is served by a combination of self-supply, bilateral market purchases and spot market purchases. From the perspective of a parent company of a PJM billing organization that serves load, its load could be supplied by any combination of its own generation, net bilateral market purchases and net spot market purchases. In addition to directly serving load, load serving entities can also transfer their responsibility to serve load to other parties through eSchedules transactions referred to as wholesale load responsibility (WLR) or retail load responsibility (RLR) transactions. When the responsibility to serve load is transferred via a bilateral contract, the entity to which the responsibility is transferred becomes the load serving entity. Supply from its own generation (self-supply) means that the parent company is generating power from plants that it owns in order to meet demand. Supply from bilateral purchases means that the parent company is purchasing power under bilateral contracts from a nonaffiliated company at the same time that it is meeting load. Supply from spot market purchases means that the parent company is generating less power from owned plants and/or purchasing less power under bilateral contracts than required to meet load at a defined time and, therefore, is purchasing the required balance from the spot market.

The PJM system's reliance on self-supply, bilateral contracts and spot purchases to meet real-time load is calculated by summing across all the parent companies of PJM billing organizations that serve load in the Real-Time Energy Market for each hour. Table 3-19 shows the monthly average share of real-time load served by self-supply, bilateral contracts and spot purchase in 2016 and through March 2017 based on parent company. In the first three months of 2017, 17.9 percent of real-time load was supplied by bilateral contracts, 20.9 percent by spot market purchase and 61.1 percent by self-supply. Compared with the first three months of 2016, reliance on bilateral contracts increased by 5.1 percentage points, reliance on spot supply decreased by 3.0 percentage points and reliance on self-supply increased by 2.1 percentage points.

Table 3-19 Monthly average percent of real-time self-supply load, bilateral-supply load and spot-supply load based on parent companies: January 1, 2016 through March 31, 2017[41]

	2016			2017			Difference in Percentage Points		
	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply
Jan	11.1%	25.9%	63.0%	18.2%	20.3%	61.5%	7.1%	(5.7%)	(1.5%)
Feb	11.5%	25.5%	63.0%	19.4%	19.9%	60.7%	8.0%	(5.6%)	(2.3%)
Mar	11.7%	26.4%	61.9%	16.2%	22.6%	61.1%	4.5%	(3.8%)	(0.8%)
Apr	12.7%	24.0%	63.4%						
May	12.6%	24.5%	62.9%						
Jun	12.5%	24.2%	63.2%						
Jul	12.8%	23.3%	63.9%						
Aug	12.7%	23.6%	63.7%						
Sep	12.4%	22.7%	64.9%						
Oct	14.6%	21.4%	64.0%						
Nov	14.3%	23.2%	62.4%						
Dec	15.6%	22.3%	62.1%						
Annual	12.9%	23.9%	63.2%	17.9%	20.9%	61.1%	5.1%	(3.0%)	(2.1%)

Day-Ahead Load and Spot Market

In the PJM Day-Ahead Energy Market, participants can not only use their own generation, bilateral contracts and spot market purchases to supply their load serving obligation, but can also use virtual resources to meet their load serving obligations in any hour. Virtual supply is treated as supply in the day-ahead analysis and virtual demand is treated as demand in the day-ahead analysis.

The PJM system's reliance on self-supply, bilateral contracts, and spot purchases to meet day-ahead demand (cleared fixed-demand, price-sensitive load and decrement bids) is calculated by summing across all the parent companies of PJM billing organizations that serve demand in the Day-Ahead Energy Market for each hour. Table 3-20 shows the monthly average share of day-ahead demand served by self-supply, bilateral contracts and spot purchases in 2016 through March 2017, based on parent companies. In the first three months of 2017, 10.5 percent of day-ahead demand was supplied by bilateral contracts, 21.1 percent by spot market purchases, and 68.4 percent

41 Table 3-19 and Table 3-20 were calculated as of April 20, 2017. The values may change slightly as billing values are updated by PJM.

by self-supply. Compared with the first three months of 2016, reliance on bilateral contracts increased by 1.6 percentage points, reliance on spot supply decreased by 2.3 percentage points, and reliance on self-supply increased by 0.8 percentage points.

Table 3-20 Monthly average share of day-ahead self-supply demand, bilateral supply demand, and spot-supply demand based on parent companies: January 1, 2016 through March 31, 2017

	2016			2017			Difference in Percentage Points		
	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply
Jan	8.2%	25.9%	65.9%	11.0%	20.6%	68.4%	2.8%	(5.3%)	2.5%
Feb	8.5%	25.5%	66.0%	11.2%	20.6%	68.2%	2.7%	(4.9%)	2.2%
Mar	8.0%	27.0%	65.0%	9.2%	22.4%	68.4%	1.2%	(4.6%)	3.4%
Apr	9.9%	24.3%	65.8%						
May	9.6%	24.4%	66.0%						
Jun	8.3%	22.3%	69.4%						
Jul	8.7%	22.8%	68.6%						
Aug	8.5%	22.7%	68.8%						
Sep	7.9%	22.7%	69.4%						
Oct	9.5%	21.3%	69.2%						
Nov	9.4%	22.3%	68.2%						
Dec	10.4%	21.4%	68.2%						
Annual	8.9%	23.5%	67.6%	10.5%	21.2%	68.4%	1.6%	(2.3%)	0.8%

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 local market power mitigation to situations where the local 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.

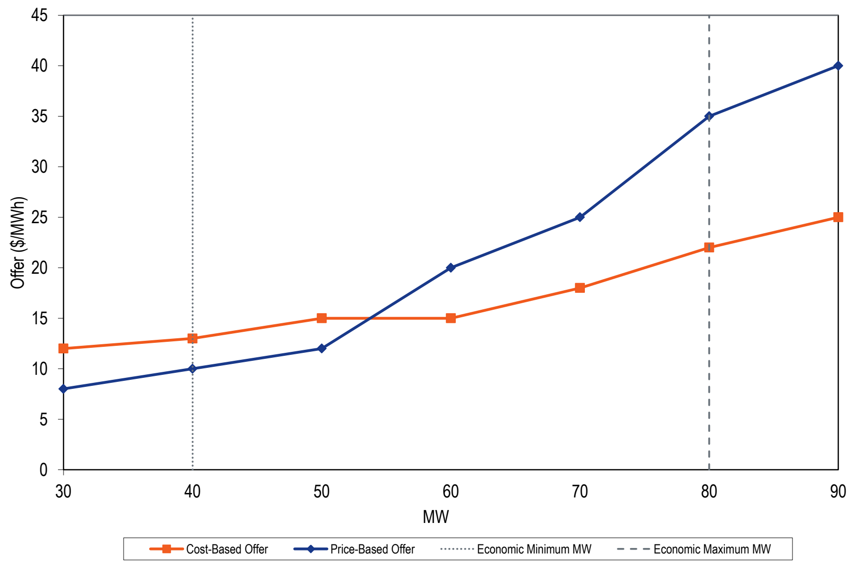
When an owner fails the TPS test, the units offered by the owner that are committed to provide relief are committed on the cheaper of cost or price-based offers. PJM uses a dispatch cost formula to compare price-based offers and cost-based offers to select the cheaper offer.[42] Dispatch cost is calculated as:

((Incremental Energy Offer @ EcoMin*EcoMin MW) + No-Load Cost)*Min Run Time + Startup Cost.

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 3-23 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 TPS test would be committed on its price-based offer that has a lower dispatch cost, even though the price-based offer is higher than cost-based offer at higher output levels and includes positive markups, inconsistent with the explicit goal of local market power mitigation.

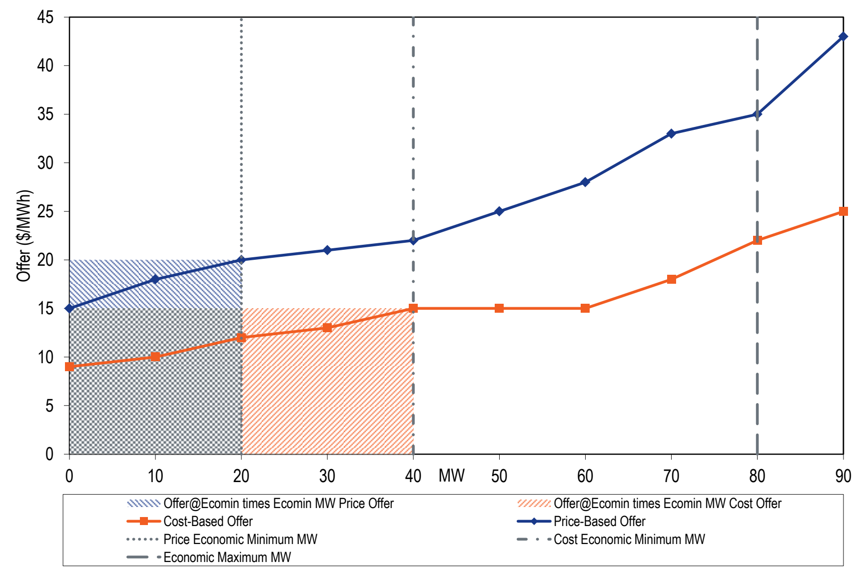
42 See, PJM OA Schedule 1 § 6.4.1 (g).

Figure 3-23 Offers with varying markups at different MW output levels



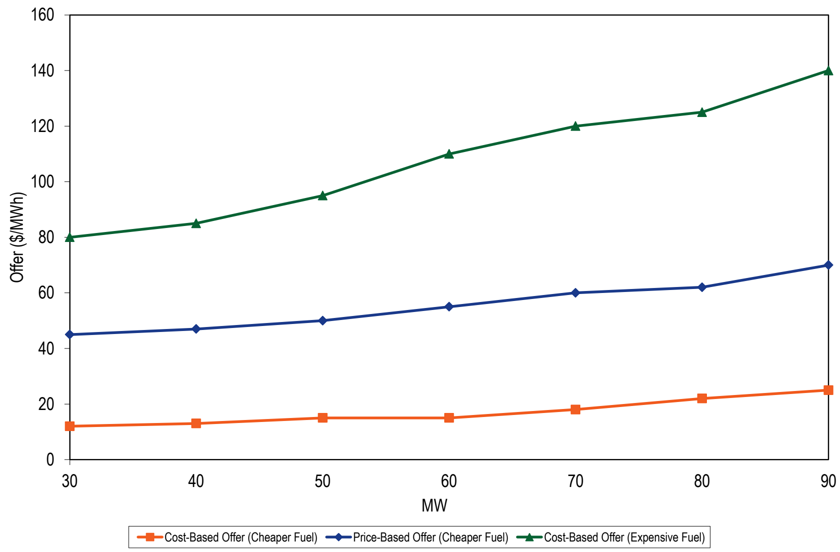
Offering a different economic minimum MW level, different minimum run times, different start up and notification times on the cost-based and price-based offers can also be used to avoid mitigation. For example, a unit may offer its price-based offer with a positive markup, but have a shorter minimum run time (MRT) on the price-based offer resulting in a lower dispatch cost for the price based offer but setting prices at a level that includes a positive markup. 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. A unit with a positive markup can have lower dispatch cost on price-based offer because of a lower economic minimum level compared to cost-based offer. Figure 3-24 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. Keeping the startup cost, Minimum Run Time and No-load cost constant between the price-based offer and cost-based offer, the dispatch cost 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 noncompetitive level even after the resource owner fails the TPS test.

Figure 3-24 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 3-25 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 3-25 Dual fuel unit offers



These issues can be solved by simple rule changes.[43] 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 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 3-21. The offer capping percentages shown in Table 3-21 include units that are committed to provide constraint relief whose owners failed the TPS test in the energy market as well as units committed as part of conservative operations, excluding units that were committed for providing black start and reactive service.

Table 3-21 Offer capping statistics – energy only: January 1 through March 31, 2013 to 2017

	Real-Time		Day-Ahead	
(Jan-Mar)	Unit Hours Capped	MW Capped	Unit Hours Capped	MW Capped
2013	0.3%	0.1%	0.1%	0.0%
2014	1.1%	0.4%	0.3%	0.2%
2015	0.6%	0.2%	0.3%	0.1%
2016	0.4%	0.2%	0.1%	0.1%
2017	0.2%	0.1%	0.0%	0.0%

Table 3-22 shows the offer capping percentages including units committed to provide constraint relief and units committed to provide black start service and reactive support. The units that are committed and offer capped for black start service and reactive support reasons increased from 2012 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, 2015 and 2016 because higher LMPs (in the first six 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 3-21.

43 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) and subsequently in the MMU's protest in the hourly offers proceeding in Docket No. ER16-372-000, filed December 14, 2015.

Table 3-22 Offer capping statistics for energy and reliability: January 1 through March 31, 2013 to 2017

	Real-Time		Day-Ahead	
(Jan-Mar)	Unit Hours Capped	MW Capped	Unit Hours Capped	MW Capped
2013	2.7%	1.9%	3.1%	1.8%
2014	1.5%	0.9%	0.8%	0.6%
2015	0.8%	0.4%	0.5%	0.3%
2016	0.5%	0.3%	0.2%	0.1%
2017	0.4%	0.7%	0.3%	0.6%

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

Table 3-23 Offer capping statistics for reliability: January 1 through March 31, 2013 to 2017

	Real-Time		Day-Ahead	
(Jan-Mar)	Unit Hours Capped	MW Capped	Unit Hours Capped	MW Capped
2013	2.4%	1.8%	3.0%	1.8%
2014	0.4%	0.5%	0.5%	0.4%
2015	0.3%	0.2%	0.3%	0.2%
2016	0.1%	0.1%	0.1%	0.1%
2017	0.2%	0.6%	0.2%	0.5%

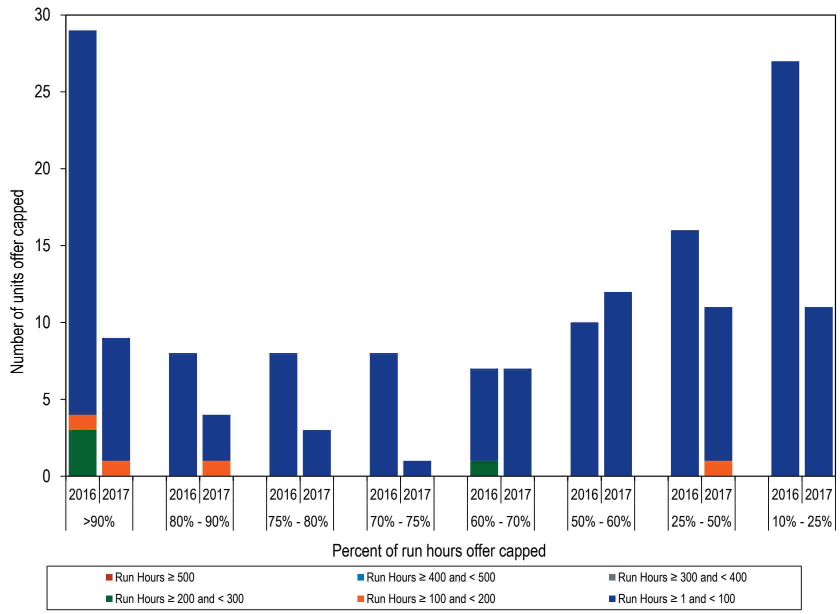
Table 3-24 presents data on the frequency with which units were offer capped in the first three months of 2016 and 2017 for failing the TPS test to provide energy for constraint relief in the Real-Time Energy Market. Table 3-24 shows that 29 units were offer capped for 90 percent or more of their run hours in the first three months of 2017 compared to nine in the first three months of 2016.

Table 3-24 Real-time offer capped unit statistics: January 1 through March 31, 2016 and 2017

		Offer-Capped Hours					
Run Hours Offer-Capped, Percent Greater Than Or Equal To:	Jan - Mar	Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	2016	0	0	0	3	1	25
	2017	0	0	0	0	1	8
80% and < 90%	2016	0	0	0	0	0	8
	2017	0	0	0	0	1	3
75% and < 80%	2016	0	0	0	0	0	8
	2017	0	0	0	0	0	3
70% and < 75%	2016	0	0	0	0	0	8
	2017	0	0	0	0	0	1
60% and < 70%	2016	0	0	0	1	0	6
	2017	0	0	0	0	0	7
50% and < 60%	2016	0	0	0	0	0	10
	2017	0	0	0	0	0	12
25% and < 50%	2016	0	0	0	0	0	16
	2017	0	0	0	0	1	10
10% and < 25%	2016	0	0	0	0	0	27
	2017	0	0	0	0	0	11

Figure 3-26 shows the frequency with which units were offer capped in the first three months of 2016 and 2017 for failing the TPS test to provide energy for constraint relief in the Real-Time Energy Market.

Figure 3-26 Real-time offer capped unit statistics: January 1 through March 31, 2016 and 2017



TPS Test Statistics

In the first three months of 2017, the AEP, ATSI, BGE, ComEd, Dominion, DPL, PECO, PENELEC, and PPL control zones experienced congestion resulting from one or more constraints binding for 25 or more hours or resulting from an interface constraint (Table 3-25). The AECO, AP, DAY, DEOK, DLCO, EKPC, JCPL, Met-Ed, Pepco, PSEG and RECO control zones did not have constraints binding for 25 or more hours in the first three months of 2017. Table 3-25 shows that AEP and ComEd were the control zones that experienced congestion resulting from one or more constraints binding for 25 or more hours or resulting from an interface constraint that was binding for one or more hours in the first three months of every year from 2009 through 2017.

Table 3-25 Numbers of hours when control zones experienced congestion resulting from one or more constraints binding for 25 or more hours or from an interface constraint: January 1 through March 31, 2009 through 2017

	(Jan - Mar)								
	2009	2010	2011	2012	2013	2014	2015	2016	2017
AECO	149	0	70	40	32	0	41	252	0
AEP	890	157	556	100	447	840	1,405	283	54
AP	125	165	89	56	38	309	417	72	0
ATSI	101	37	0	1	46	428	391	30	349
BGE	0	25	0	650	150	29	232	1,418	551
ComEd	325	816	123	525	973	1,233	651	1,426	766
DEOK	0	0	0	33	0	68	0	0	0
DLCO	0	141	0	146	0	211	674	0	0
Dominion	130	114	73	0	0	52	423	458	52
DPL	43	0	28	133	0	297	388	694	389
JCPL	0	0	0	0	0	44	79	0	0
Met-Ed	0	0	0	0	0	34	144	0	0
PECO	30	0	158	0	77	327	242	287	537
PENELEC	0	0	58	32	29	179	517	237	578
Pepco	0	0	44	66	71	39	0	0	0
PPL	0	0	52	0	167	41	0	0	166
PSEG	336	344	281	199	1,408	1,445	2,550	55	0

The local market structure in the Real-Time Energy Market associated with each of the frequently binding constraints was analyzed using the three pivotal supplier results in the first three months of 2017.[44] 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.

44 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 3-26 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owners passing and failing for the transfer interface constraints.

Table 3-26 Three pivotal supplier test details for interface constraints: January 1 through March 31, 2017

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
AEP - DOM	Peak	341	87	7	0	7
	Off Peak	225	173	7	0	7
AP South	Peak	492	650	14	0	14
	Off Peak	431	645	11	0	10
Bedington - Black Oak	Peak	158	255	14	5	9
	Off Peak	105	99	8	1	7
Seneca	Peak	132	138	1	0	1
	Off Peak	150	162	1	0	1

Table 3-27 Summary of three pivotal supplier tests applied for interface constraints: January 1 through March 31, 2017

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
AEP - DOM	Peak	1	1	100%	0	0%	0%
	Off Peak	95	53	56%	7	7%	13%
AP South	Peak	166	88	53%	10	6%	11%
	Off Peak	384	178	46%	9	2%	5%
Bedington - Black Oak	Peak	23	20	87%	2	9%	10%
	Off Peak	140	93	66%	7	5%	8%
Seneca	Peak	341	2	1%	0	0%	0%
	Off Peak	477	0	0%	0	0%	NA

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. Steam units that are offer capped in the Day-Ahead Energy Market continue to be offer capped in the Real-Time Energy Market regardless of their inclusion in the TPS test in real time and the outcome of the TPS test in real time. Only uncommitted resources, which would be started as a result of incremental relief needs, are eligible to be offer capped. Already committed units that can provide incremental relief cannot, regardless of test score, be switched from price to cost offers. Table 3-27 provides, for the identified interface constraints, information on total tests applied, the subset of three pivotal supplier tests that could have resulted in the offer capping of uncommitted units and the portion of those tests that did result in offer capping uncommitted units. The three pivotal supplier tests that resulted in offer capping do not explain all the offer capped units in the Real-Time Energy Market. PJM operators also manually commit units for reliability reasons that are not specifically for providing relief to a binding constraint.

Parameter Limited Schedules

Cost-Based Offers

All capacity resources in PJM are required to submit at least one cost-based offer. During the 2016/2017 and 2017/2018 delivery years, all cost-based offers, submitted by resources that are not capacity performance resources, are parameter limited in accordance with the Parameter Limited Schedule (PLS) matrix or with the level of an approved exception.[45] During the 2016/2017 and 2017/2018 delivery years, all cost-based offers, submitted by capacity performance resources, are parameter limited in accordance with predetermined unit specific parameter limits. During the 2016/2017 and 2017/2018 delivery years, there was no base capacity procured.

For the 2018/2019 and 2019/2020 delivery years, PJM procured two types of capacity resources, capacity performance resources and base capacity

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

resources. Beginning June 1, 2018, there will no longer be any resources committed as the current annual capacity product. All cost-based offers, submitted by capacity performance resources and base capacity resources, are parameter limited in accordance with predetermined unit specific parameter limits.

Price-Based Offers

All capacity resources that choose to offer price-based offers are required to make available at least one price-based parameter limited offer (referred to as price-based PLS). For resources that are not capacity performance resources or not base capacity resources, the price-based parameter limited schedule is to be used by PJM for committing generation resources when a maximum emergency generation alert is declared. For capacity performance resources, the price-based parameter limited schedule is to be used by PJM for committing generation resources when hot weather alerts and cold weather alerts are declared. For base capacity resources (during the 2018/2019 and 2019/2020 delivery years only), the price-based parameter limited schedule is to be used by PJM for committing generation resources when hot weather alerts are declared.

Parameter Limits

During the extreme cold weather conditions in the first three months of 2016, as well as 2015 and 2014, 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, the ratio of economic maximum MW to economic minimum MW). When pipelines issue critical notices and enforce ratable take requirements, generators may, depending on the nature of the transportation service purchased, 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 1.0, to avoid deviations from the hourly nominated quantity.

Key parameters like startup and notification time were not included in the PLS matrix in 2016 and prior periods for annual resources that do not have capacity performance obligations. 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. Startup and notification times are limited for capacity performance resources beginning June 1, 2016, in accordance with predetermined unit specific parameter limits. The unit specific parameter limits for capacity performance resources were based on default minimum operating parameter limits posted by PJM by technology type. These default parameters were based on analysis by the MMU. Market participants could request an adjustment to the default values by submitting supporting documentation, which was reviewed by PJM and the MMU. The default minimum operating parameter limits or approved adjusted values are used by capacity performance resources for their parameter limited schedules.

PJM has the authority to approve adjusted parameters with input from the MMU. PJM has inappropriately applied different review standards to coal units than to CTs and CCs despite the objections of the MMU. PJM has approved parameter limits for steam units based on historical performance and existing equipment while holding CTs and CCs to higher standards based on OEM documentation and up to date equipment configuration.

Currently, there are no rules in the PJM tariff or manuals that limit the nonparameter attributes of 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 preventing units from offering inflexible operating parameters in order to extract higher market revenues or higher uplift payments. However, a generator can include a higher markup in the price-based PLS offer than in the price-based non-PLS schedule. The result is that the offer is higher and market prices are higher as a result of the exercise of market power using the PLS offer. This defeats the purpose of requiring 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.

Parameter Limited Schedules under Capacity Performance

Beginning in the 2016/2017 delivery year, 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. For the 2018/2019 and 2019/2020 delivery years, resources that have base capacity commitments are also required to submit, in their parameter limited schedules, 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 capacity performance 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.[46] The Commission directed that capacity performance resources with parameters based on nonphysical constraints should receive uplift payments.[47] The Commission directed PJM to submit tariff language to establish a process through which capacity performance resources that operate outside the defined unit-specific parameter limits can justify such operation and therefore remain eligible for make whole payments.[48]

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 June 9th Order's determination on parameters is not consistent with that goal. By permitting generation owners to establish unit parameters based on nonphysical 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 or that such a contract can reasonably impose costs on customers who were not party to the contract. 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 will increase energy market uplift payments substantially. Uplift costs are unpredictable, opaque and unhedgeable. While some uplift is necessary and efficient in an LMP market, this uplift is not. 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

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

those generators should reflect the flexibility goals of the capacity performance construct and the assignment of performance risk to generation owners.

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 and that this standard be applied to all technologies on a uniform basis. This solution creates the incentives for flexibility and preserves, to the extent possible, the incentives to follow PJM's dispatch instructions during high demand 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 high demand 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 will be exempt from nonperformance 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 high demand conditions. If any of the less flexible resources need to be dispatched down by PJM for reliability reasons, they would be exempt from nonperformance charges.

Such an approach is consistent with the Commission's no excuses policy for nonperformance 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 nonperformance 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 nonperformance. 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

Markup is a summary measure of participant offer behavior or conduct for individual units. The markup index for each marginal unit is calculated as (Price – Cost)/Price.[49] 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. The dollar markup for a unit is the difference between price and cost.

Real-Time Markup

Table 3-28 shows the average markup index of marginal units in the Real-Time Energy Market, by offer price category using unadjusted cost offers. Table 3-29 shows the average markup index of marginal units in the Real-Time Energy Market, by offer price category using adjusted cost offers. The unadjusted markup is the difference between the price offer and the cost offer including the 10 percent adder in the cost offer. The adjusted markup is the difference between the price offer and the cost offer excluding the 10 percent adder from the cost offer. The adjusted markup is calculated for coal, gas and oil units because these units have consistently had price-based offers less than cost-based offers.[50] The markup is negative if the cost-based offer of the marginal unit exceeds its price-based offer at its operating point.

49 In order to normalize the index results (i.e., bound the results between +1.00 and -1.00) for comparison across both low and high cost units, the index is calculated as (Price – Cost)/Price when price is greater than cost, and (Price – Cost)/Cost when price is less than cost.

50 The MMU will calculate adjusted markup for gas units also in future reports because gas units also more consistently have price-based offers less than cost-based offers.

In the first three months of 2017, 91.4 percent of marginal units had offer prices less than $50 per MWh. The average dollar markups of units with offer prices less than $25 was negative (-$0.36 per MWh) when using unadjusted cost offers. The average dollar markups of units with offer prices between $25 and $50 was positive ($0.95 per MWh) when using unadjusted cost offers. Negative markup means the unit is offering to run at a price less than its cost-based offer, implying a revealed short run marginal cost that is less than the allowable cost-based offer under the PJM Market Rules.

Some marginal units did have substantial markups. Among the units that were marginal in the first three months of 2017, none had offer prices above $400 per MWh. Among the units that were marginal in the first three months of 2016, none had offer prices greater than $400 per MWh. Using the unadjusted cost offers, the highest markup for any marginal unit in the first three months of 2017 was $235.44 while the highest markup in the first three months of 2016 was $216.98.

Table 3-28 Average, real-time marginal unit markup index (By offer price category unadjusted): January 1 through March 31, 2016 and 2017

	2016 (Jan-Mar)			2017 (Jan-Mar)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $25	(0.00)	($1.41)	65.7%	0.33	($0.36)	63.9%
$25 to $50	(0.05)	($3.19)	24.0%	0.05	$0.95	27.5%
$50 to $75	0.11	$6.82	1.7%	0.28	$16.10	1.3%
$75 to $100	0.23	$19.84	0.7%	0.07	$5.72	1.1%
$100 to $125	0.05	$5.83	2.0%	0.25	$27.11	0.2%
$125 to $150	0.01	$0.91	5.5%	0.43	$56.87	0.2%
>= $150	0.20	$37.17	0.4%	0.01	$1.46	5.8%

Table 3-29 Average, real-time marginal unit markup index (By offer price category adjusted): January 1 through March 31, 2016 and 2017

	2016 (Jan-Mar)			2017 (Jan-Mar)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $25	0.08	$0.28	65.7%	0.41	$1.32	63.9%
$25 to $50	0.04	($0.01)	24.0%	0.14	$3.71	27.5%
$50 to $75	0.19	$11.57	1.7%	0.34	$19.86	1.3%
$75 to $100	0.30	$25.99	0.7%	0.16	$13.57	1.1%
$100 to $125	0.14	$15.85	2.0%	0.32	$34.62	0.2%
$125 to $150	0.11	$12.83	5.5%	0.48	$63.79	0.2%
>= $150	0.28	$49.61	0.4%	0.11	$16.04	5.8%

Table 3-30 shows the percentage of marginal units that had markups, calculated using unadjusted cost offers, below, above and equal to zero for coal, gas and oil fuel types.[51] Table 3-31 shows the percentage of marginal units that had markups, calculated using adjusted cost offers, below, above and equal to zero for coal, gas and oil fuel types. In the first three months of 2017, using unadjusted cost-based offers for coal units, 43.65 percent of coal units had negative markups. In the first three months of 2017, using adjusted cost-based offers for coal units, 22.81 percent of coal units had negative markups.

Table 3-30 Percent of marginal units with markup below, above and equal to zero (By fuel type unadjusted): January 1 through March 31, 2016 and 2017

	2016 (Jan-Mar)			2017 (Jan-Mar)		
Type/Fuel	Negative	Zero	Positive	Negative	Zero	Positive
Coal	63.56%	19.63%	16.81%	43.65%	26.81%	29.54%
Gas	19.74%	20.48%	59.78%	39.40%	10.67%	49.92%
Oil	1.07%	92.54%	6.39%	3.34%	96.09%	0.56%

Table 3-31 Percent of marginal units with markup below, above and equal to zero (By fuel type adjusted): January 1 through March 31, 2016 and 2017

	2016 (Jan-Mar)			2017 (Jan-Mar)		
Type/Fuel	Negative	Zero	Positive	Negative	Zero	Positive
Coal	52.29%	2.23%	45.48%	22.81%	8.36%	68.83%
Gas	5.36%	3.77%	90.87%	6.08%	3.16%	90.77%
Oil	0.00%	0.00%	100.00%	0.00%	0.00%	100.00%

51 Other fuel types were excluded based on data confidentiality rules.

Figure 3-27 shows the frequency distribution of hourly markups for all gas units offered in the first three months of 2016 and 2017. The highest markup within the economic operating range of the unit's offer curve was used for creating the frequency distributions.[52] Of the gas units offered in the PJM market in the first three months of 2017, nearly 28 percent of gas unit-hours had a maximum markup that was negative. More than seven percent of gas fired unit-hours had a highest markup within the economic operating range above $100 per MWh.

Figure 3-27 Frequency distribution of highest markup of gas units offered in January 1 through March 31, 2016 and 2017

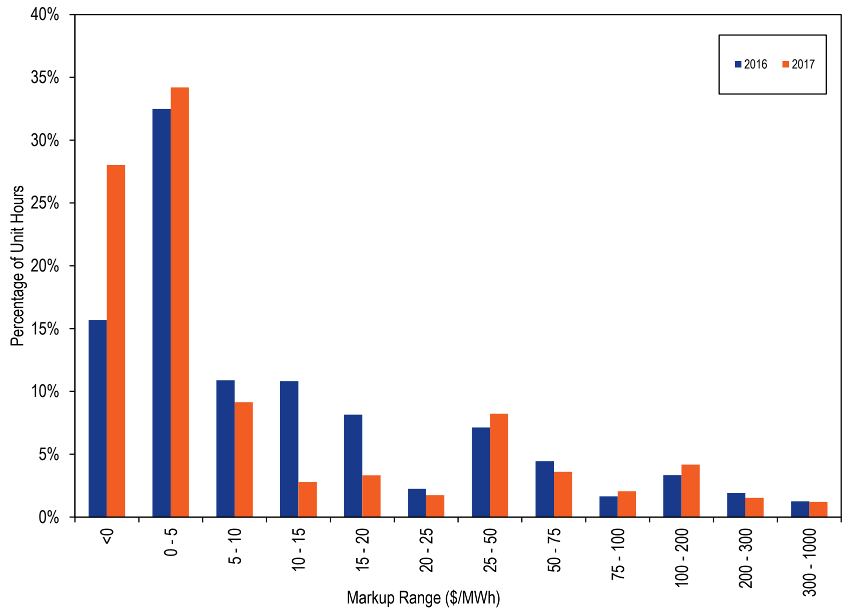


Figure 3-28 shows the frequency distribution of hourly markups for all coal units offered in the first three months of 2016 and 2017. Of the coal units offered in the PJM market in the first three months of 2017, nearly 41 percent of coal unit-hours had a maximum markup that was negative.

52 The categories in the frequency distribution were chosen so as to maintain data confidentiality.

Figure 3-28 Frequency distribution of highest markup of coal units offered in January 1 through March 31, 2016 and 2017

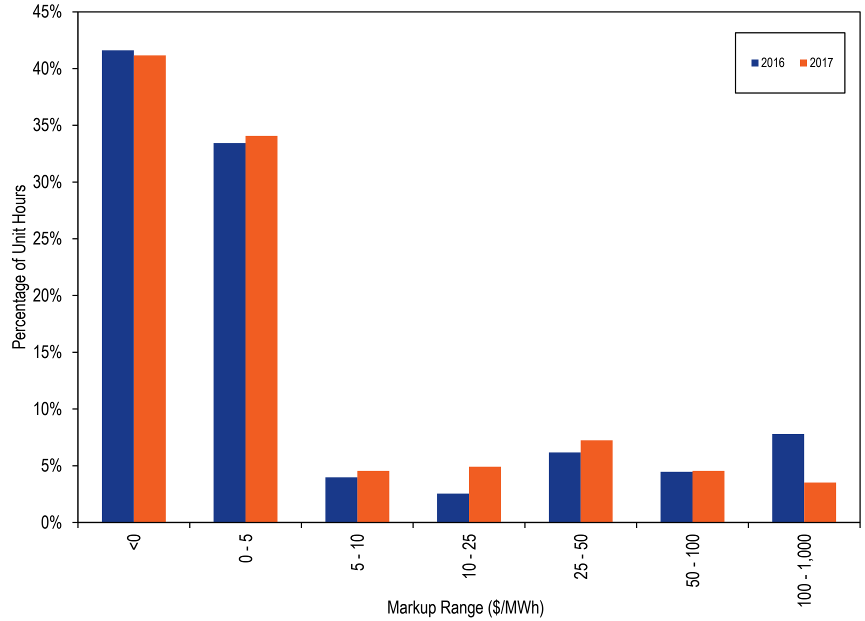


Figure 3-29 shows the frequency distribution of hourly markups for all offered oil units in the first three month of 2016 and 2017. Of the oil units offered in the PJM market in the first three months of 2017, nearly 51 percent of oil unit-hours had a maximum markup that was negative.

Figure 3-29 Frequency distribution of highest markup of oil units offered in January 1 through March 31, 2016 and 2017

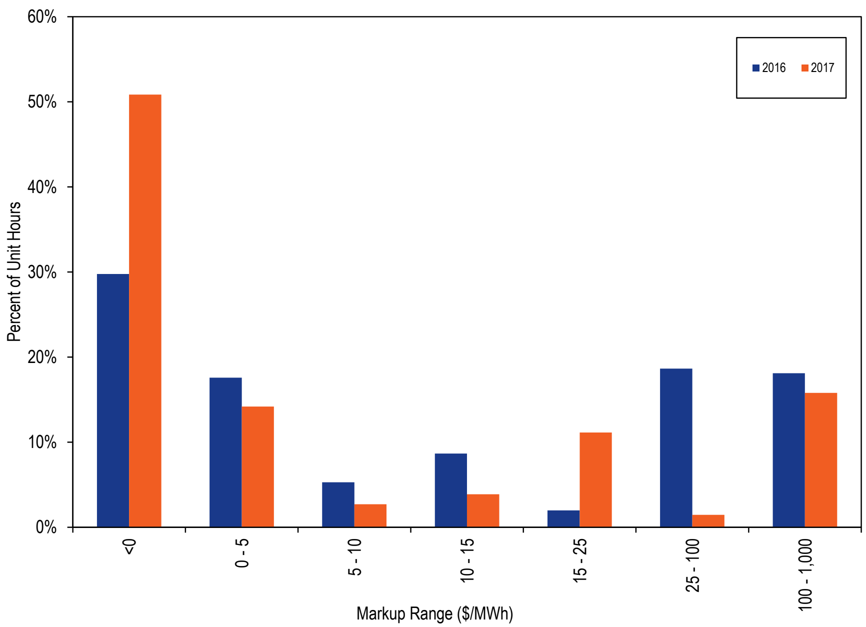
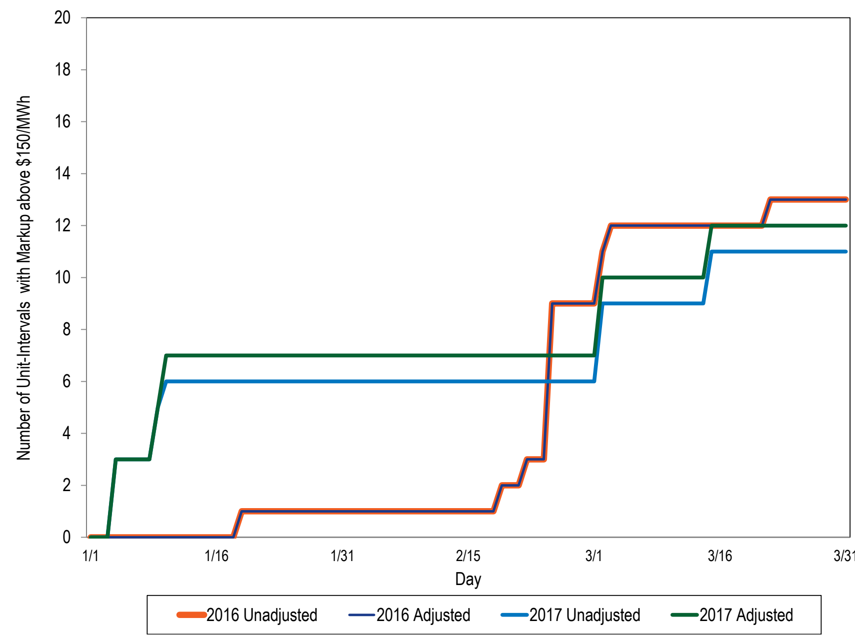


Figure 3-30 Cumulative number of unit intervals with markups above $150 per MWh: January 1 through March 31, 2016 and 2017



The markup frequency distributions show that a significant proportion of units make price-based offers less than the cost-based offers permitted under the PJM market rules. This behavior means that competitive price-based offers reveal actual unit marginal costs and imply that PJM market rules permit the inclusion of costs in cost-based offers that are not short run marginal costs.

The markup behavior shown in the markup frequency distributions also shows that a substantial number of units were offered with high markups, consistent with the exercise of market power.

Figure 3-30 and Figure 3-32 show the number of marginal unit intervals in the first three months of 2017 and 2016 with markup above $150 per MWh.

Day-Ahead Markup

Table 3-32 shows the average markup index of marginal generating units in the Day-Ahead Energy Market, by offer price category using unadjusted offers. The majority of marginal units are virtual transactions, which do not have markup. In the first three months of 2017, 89.3 percent of marginal generating units had offer prices less than $50 per MWh and the average dollar markup was positive, and the 1.1 percent of marginal generating units had offers in the $75 to $100 per MWh range and the average dollar markup was positive.

Table 3-32 Average day-ahead marginal unit markup index (By offer price category, unadjusted): January 1 through March 31, 2016 and 2017

	2016 (Jan - Mar)			2017 (Jan - Mar)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $25	0.06	($0.43)	58.8%	0.24	$0.59	55.6%
$25 to $50	(0.03)	($1.91)	28.1%	0.08	$2.23	33.7%
$50 to $75	0.05	$2.94	2.6%	0.05	$2.60	1.2%
$75 to $100	0.06	$4.41	0.2%	0.00	$0.25	1.1%
$100 to $125	0.00	$0.33	0.7%	0.00	$0.00	0.0%
$125 to $150	0.00	$0.01	9.5%	0.00	$0.00	0.0%
>= $150	0.00	$0.00	0.0%	(0.00)	($0.06)	8.4%

Table 3-33 shows the average markup index of marginal generating units in the Day-Ahead Energy Market, by offer price category using adjusted offers. In the first three months of 2017, 1.1 percent of marginal generating units had offers between $75 and $100 per MWh and the average dollar markup and the average markup index were both positive. The average markup index increased from 0.13 in the first three months of 2016, to 0.32 in the first three months of 2017 in the offer price category less than $25.

Table 3-33 Average day-ahead marginal unit markup index (By offer price category, adjusted): January 1 through March 31, 2016 and 2017

	2016 (Jan - Mar)			2017 (Jan - Mar)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $25	0.13	$1.36	58.8%	0.32	$2.39	55.6%
$25 to $50	0.05	$1.20	28.1%	0.15	$4.77	33.7%
$50 to $75	0.13	$7.77	2.6%	0.13	$7.16	1.2%
$75 to $100	0.14	$11.49	0.2%	0.09	$8.78	1.1%
$100 to $125	0.09	$11.09	0.7%	0.00	$0.00	0.0%
$125 to $150	0.09	$11.96	9.5%	0.09	$11.86	0.0%
>= $150	0.00	$0.00	0.0%	0.09	$14.51	8.4%

Energy Market Cost-Based Offers

The application of market power mitigation rules in the Day-Ahead Energy Market and the Real-Time Energy Market helps ensure competitive market outcomes even in the presence of structure market power. But the efficacy of market power mitigation rules depends on the definition of a competitive offer. A competitive offer is equal to short run marginal costs. The enforcement of market power mitigation rules is undermined if the definition of a competitive offer is not correct. The significance of competition metrics like markup is also undermined if the definition of a competitive offer is not correct. The definition of a competitive offer, as interpreted by PJM, is not currently correct. Some unit owners include costs that are not short run marginal costs in offers, including maintenance costs. This issue can be resolved by simple changes to the PJM Market Rules to incorporate a clear and accurate definition of short run marginal costs.

Short Run Marginal Costs

There are three types of costs identified under PJM rules:

- Short run marginal costs (or incremental costs). Short run costs incurred directly as a result of producing energy for an hour;
- Avoidable costs. Annual costs that would be avoided if energy were not produced over an annual period;
- Fixed costs. Costs associated with an investment in a facility including the return on and of capital.

Marginal costs are the only costs relevant to the energy market. Specifically, the competitive energy offer level is the short run marginal cost of production.

The MMU recommends that PJM require that the level of incremental costs includable in cost-based offers not exceed the unit's short run marginal cost.

Fuel Cost Policies

The fuel cost policy documents the process by which the Market Seller calculates the fuel cost component of its cost-based offers. Short run marginal fuel costs include commodity costs, transportation costs, fees, and taxes for the purchase of fuel. Fuel handling costs and fuel additive costs are included in the cost-based offer as variable operations and maintenance (VOM) costs. The fuel cost policy documents the frequency with which the Market Seller updates VOM and other nonfuel cost inputs.

The verification of accurate fuel costs in cost-based offers is not possible unless the fuel cost policy is algorithmic, verifiable, and systematic. Algorithmic means that the fuel cost policy must use a set of defined, logical steps to use defined inputs to get to defined outputs. Verifiable means that the fuel cost policy must provide a fuel price that can be calculated by the Market Monitor after the fact with the same data available to the generation owner at the time the decision was made, and documentation for that data from a public or a private source. Systematic means that the fuel cost policy must document a standardized method or methods for calculating fuel costs including objective triggers for each method.

The MMU recommends that PJM require that all fuel cost policies be algorithmic, verifiable, and systematic.

Cost Development Guidelines

The Cost Development Guidelines contained in PJM Manual 15 do not clearly or accurately describe the short run marginal cost of generation. The MMU recommends that Manual 15 be replaced with a straightforward description of the components of cost offers based on short run marginal costs and the correct calculation of cost offers.

FERC System of Accounts

PJM Manual 15 relies heavily on the FERC System of Accounts, which predates markets and does not define costs consistently with market economics.

The MMU recommends removal of all use of the FERC System of Accounts in the Cost Development Guidelines.

Cyclic Starting and Peaking Factors

The use of cyclic starting and peaking factors for calculating VOM costs for combined cycles and combustion turbines is designed to allocate a greater proportion of long term maintenance costs to starts and the tail block of the cost curve. The use of such factors is not appropriate given that long term maintenance costs are not short run marginal costs and should not be included in cost offers.

The MMU recommends the removal of all cyclic starting and peaking factors from the Cost Development Guidelines.

Labor Costs

PJM Manual 15 allows for the inclusion of plant staffing costs in energy market cost offers. This is inappropriate given that labor costs are avoidable costs, not short run marginal costs, and are correctly includable in the RPM Avoidable Cost Rate.

The MMU recommends the removal of all labor costs from the Cost Development Guidelines.

Combined Cycle Start Heat Input Definition

PJM Manual 15 defines the start heat input of combined cycles as the amount of fuel used from the firing of the first combustion turbine to the close of the steam turbine breaker plus any fuel used by other combustion turbines in the combined cycle from firing to the point at which the HRSG steam pressure matches the steam turbine steam pressure. This definition is inappropriate given that after each combustion turbine is synchronized, some of the fuel is used to produce energy for which the resource is compensated in the energy market.

The MMU recommends changing the definition of the start heat input for combined cycles to include only the amount of fuel used from firing each combustion turbine in the combined cycle to the breaker close of each combustion turbine. This change will make the treatment of combined cycles consistent with steam turbines.

Nuclear Costs

The fuel costs for nuclear plants are fixed in the short run and amortized over the period between refueling outages. The short run marginal cost of fuel for nuclear plants is zero. Operations and maintenance costs for nuclear power plants consist primarily of labor and maintenance costs incurred during outages, which are also fixed in the short run.

The MMU recommends the removal of nuclear fuel and nonfuel operations and maintenance costs that are not short run marginal costs from the Cost Development Guidelines.

Pumped Hydro Costs

The calculation of pumped hydro costs for energy storage in Section 7.3 of PJM Manual 15 is inaccurate. The mathematical formulation contains an error in the calculation of the weighted average pumping cost, and it does not take into account the purchase of power for pumping in the day-ahead market.

The MMU recommends revising the pumped hydro fuel cost calculation to include day-ahead and real-time power purchases.

Energy Market Opportunity Costs

The calculation of energy market opportunity costs for energy limited units in Section 12 of PJM Manual 15 fails to account for a number of physical unit characteristics and environmental restrictions that influence opportunity costs. These include start up time, notification time, minimum down time, multiple fuel capability, multiple emissions limitations, and fuel usage limitations.

The MMU recommends revisions to the calculation of energy market opportunity costs to incorporate all time based offer parameters and all limitations that impact the opportunity cost of generating unit output.

The use of Catastrophic Force Majeure as the criterion for the use of opportunity costs for fuel supply limitations in Schedule 2 of the Operating Agreement is overly restrictive. This criterion would not allow the use of opportunity costs to allocate limited fuel in the case of regional fuel transportation disruptions or extreme weather events.

The MMU recommends removing the catastrophic designation for force majeure fuel supply limitations in Schedule 2.

Frequently Mitigated Units (FMU) and Associated Units (AU)

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.[53] 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.[54] FMU and AU adders no longer serve the purpose for which they were created and interfere with the efficient operation of PJM markets.

53 110 FERC ¶ 61,053 (2005).
54 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>.

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.[55]

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.[56] 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.

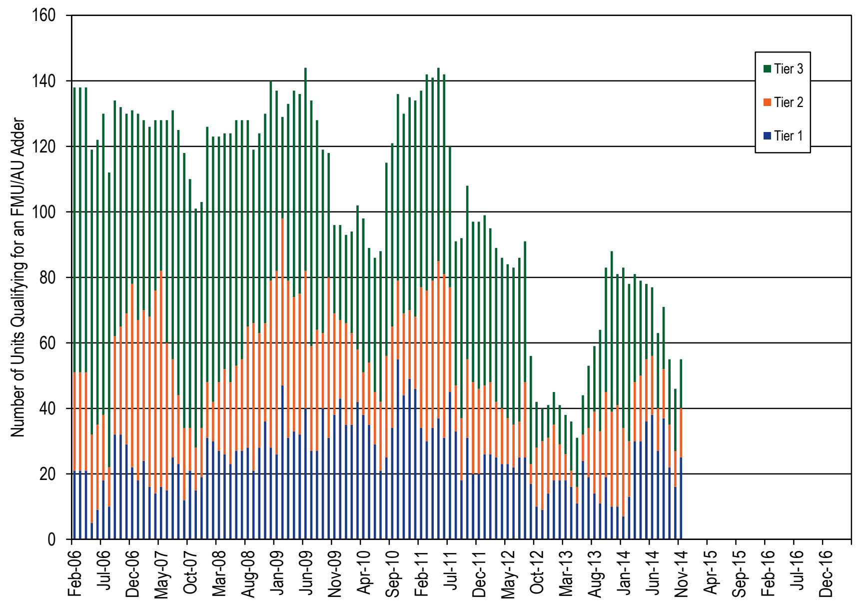
Figure 3-31 shows the total number of FMUs and AUs that qualified for an adder since the inception of the business rule in February 2006. The new rules for determining the qualification of a unit as an FMU or AU became effective November 1, 2014. FMUs and AUs are designated monthly, and a unit's capping percentage is based on a rolling 12-month average, effective with a one-month lag.[57] 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 since December 2014.

55 PJM. OA, Schedule 1 § 6.4.2.

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

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

Figure 3-31 Frequently mitigated units and associated units (By month): February 1, 2006 through March 31, 2017



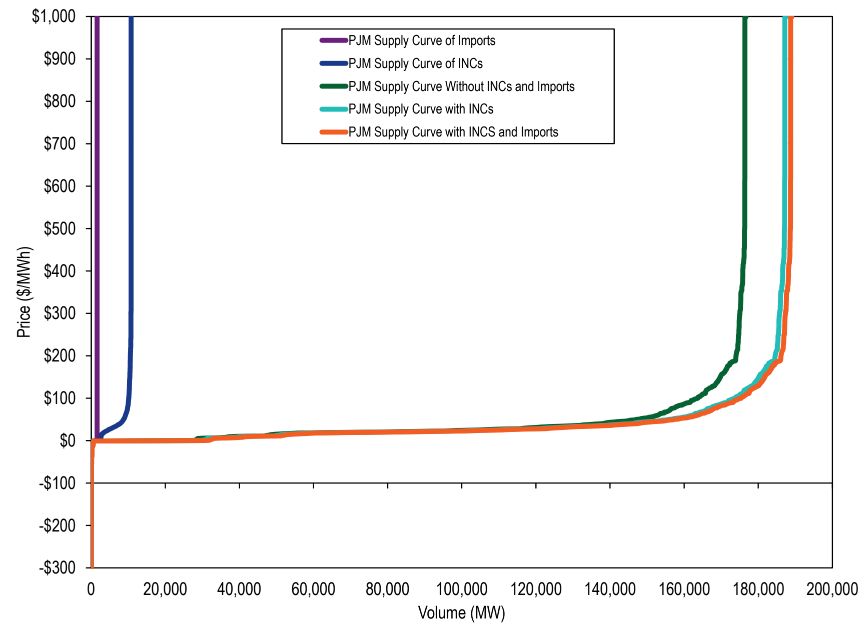
Virtual Offers and Bids

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.[58] 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 3-32 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 2017.

Figure 3-32 PJM day-ahead aggregate supply curves: 2017 example day



58 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>.

Table 3-34 shows the hourly average number of cleared and submitted increment offers and decrement bids by month in 2016 and the first three months of 2017. The hourly average submitted and cleared increment MW increased by 40.3 and 30.4 percent, from 7,425 MW and 4,691 MW in the first three months of 2016 to 10,419 MW and 6,115 MW in the first three months of 2017. The hourly average submitted and cleared decrement MW increased by 22.5 percent and 4.5 percent, from 7,901 MW and 4,661 MW in the first three months of 2016 to 9,676 MW and 4,869 MW in the first three months of 2017.

Table 3-34 Hourly average number of cleared and submitted INCs, DECs by month: January 1, 2016 through March 31, 2017

	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
2016 Jan	4,350	6,447	78	398	5,153	7,320	76	295
2016 Feb	4,754	7,109	116	578	4,511	7,445	72	409
2016 Mar	4,973	8,689	142	760	4,305	8,894	101	648
2016 Apr	4,511	6,351	187	558	3,453	6,990	84	451
2016 May	5,089	7,459	181	656	4,171	6,823	94	404
2016 Jun	4,592	7,043	143	697	4,196	6,696	89	410
2016 Jul	4,101	6,534	128	745	3,335	5,830	86	448
2016 Aug	4,457	6,956	135	749	3,433	5,506	74	398
2016 Sep	4,527	6,772	148	733	4,391	7,030	112	437
2016 Oct	4,631	7,112	199	846	3,990	6,757	112	462
2016 Nov	5,022	7,822	223	1,008	3,671	6,435	109	482
2016 Dec	5,102	7,775	189	1,010	4,028	6,869	129	486
2016 Annual	4,675	7,175	156	729	4,051	6,879	95	444
2017 Jan	5,855	10,169	205	1,288	4,811	9,753	136	821
2017 Feb	6,058	10,590	266	1,430	4,599	9,326	149	784
2017 Mar	6,427	10,516	312	1,669	5,170	9,915	170	1,019
2017 Annual	6,115	10,419	261	1,463	4,869	9,676	152	878

Table 3-35 shows the average hourly number of up to congestion transactions and the average hourly MW in 2016 and the first three months of 2017. In the first three months of 2017, the average hourly up to congestion submitted MW increased 30.1 percent and cleared MW increased 15.9 percent, compared to the first three months of 2016.

Table 3-35 Hourly average of cleared and submitted up to congestion bids by month: January 1, 2016 through March 31, 2017

	Up to Congestion			
Year	Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume
2016 Jan	39,639	135,369	2,466	6,015
2016 Feb	38,814	152,891	2,091	5,748
2016 Mar	31,817	148,162	1,703	5,101
2016 Apr	29,212	128,349	2,689	6,079
2016 May	32,883	120,132	2,977	6,006
2016 Jun	35,469	151,414	2,528	6,406
2016 Jul	37,668	181,720	2,413	7,158
2016 Aug	32,986	147,289	2,294	6,774
2016 Sep	29,368	129,498	2,309	6,065
2016 Oct	28,250	121,377	2,612	6,498
2016 Nov	36,506	141,491	2,927	7,324
2016 Dec	40,090	147,343	3,552	8,803
2016 Annual	34,387	142,075	2,549	6,503
2017 Jan	46,856	196,472	3,568	10,246
2017 Feb	41,841	207,994	2,711	8,309
2017 Mar	38,780	164,063	2,272	6,252
2017 Annual	42,516	188,905	2,855	8,269

Table 3-36 shows the average hourly number of import and export transactions and the average hourly MW in 2016 and first three months of 2017. In the first three months of 2017, the average hourly submitted and cleared import transaction MW decreased by 8.9 and 12.8 percent, and the average hourly submitted and cleared export transaction MW increased 9.3 and 4.2 percent, compared to the first three months of 2016.

Table 3-36 Hourly average day-ahead number of cleared and submitted import and export transactions by month: January 1, 2016 through March 31, 2017

		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
2016	Jan	2,633	2,103	20	20	3,044	2,571	16	16
2016	Feb	2,396	2,480	20	22	2,634	2,653	13	13
2016	Mar	2,097	2,145	17	18	2,324	2,330	11	11
2016	Apr	2,150	2,180	16	16	2,620	2,635	13	13
2016	May	1,889	1,947	12	14	2,484	2,492	14	15
2016	Jun	1,335	1,366	6	7	4,428	4,471	23	24
2016	Jul	1,315	1,247	6	6	4,327	3,389	21	21
2016	Aug	1,384	1,424	6	7	4,331	4,351	20	20
2016	Sep	939	956	5	5	3,997	4,004	21	21
2016	Oct	1,104	997	6	6	3,800	2,902	22	22
2016	Nov	1,012	1,030	6	7	2,883	2,894	17	17
2016	Dec	1,302	1,354	8	9	4,284	4,306	22	22
2016	Annual	1,628	1,600	11	11	3,434	3,250	18	17
2017	Jan	2,633	1,289	20	20	3,044	3,171	16	16
2017	Feb	2,396	1,418	20	8	2,634	3,552	13	19
2017	Mar	2,097	1,157	17	7	2,324	3,813	11	18
2017	Annual	1,560	1,600	10	11	3,499	3,510	17	17

Table 3-37 shows the frequency with which generation offers, import or export transactions, up to congestion transactions, decrement bids, increment offers and price-sensitive demand were marginal in January 1, 2016 through March 31, 2017.

Table 3-37 Type of day-ahead marginal units: January 1, 2016 through March 31, 2017

	2016						2017				
	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
Jan	5.3%	0.1%	85.2%	5.6%	3.8%	0.0%	3.2%	0.0%	85.3%	7.7%	3.7%
Feb	5.5%	0.0%	83.5%	7.4%	3.6%	0.0%	4.9%	0.0%	83.9%	6.5%	4.6%
Mar	7.0%	0.1%	80.6%	7.7%	4.7%	0.0%	4.3%	0.1%	81.5%	8.5%	5.6%
Apr	5.8%	0.0%	82.3%	8.1%	3.7%	0.0%					
May	6.2%	0.1%	83.8%	6.5%	3.4%	0.0%					
Jun	3.5%	0.0%	84.2%	8.5%	3.7%	0.0%					
Jul	3.0%	0.0%	83.1%	10.1%	3.7%	0.0%					
Aug	3.1%	0.0%	78.4%	13.1%	5.4%	0.0%					
Sep	6.1%	0.0%	76.3%	11.4%	6.2%	0.0%					
Oct	6.1%	0.1%	77.0%	10.9%	5.9%	0.0%					
Nov	4.0%	0.0%	86.5%	6.3%	3.1%	0.0%					
Dec	3.1%	0.0%	86.6%	6.9%	3.3%	0.0%					
Annual	4.7%	0.0%	82.4%	8.6%	4.2%	0.0%	4.1%	0.0%	83.7%	7.6%	4.6%

Figure 3-33 shows the monthly volume of bid and cleared INC, DEC and up to congestion bids by month for 2005 through the first three months of 2017.

Figure 3-33 Monthly bid and cleared INCs, DECs and UTCs (MW): January 1, 2005 through March 31, 2017

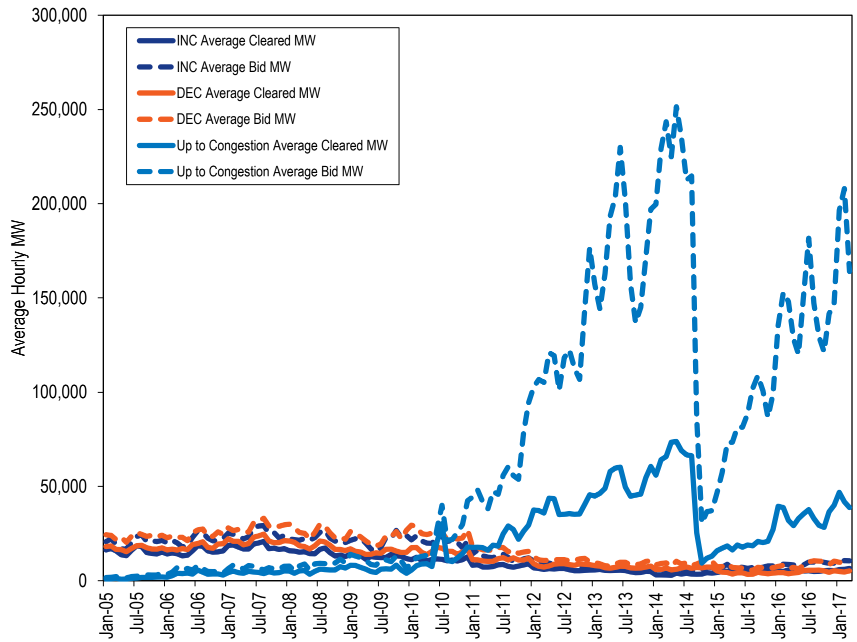
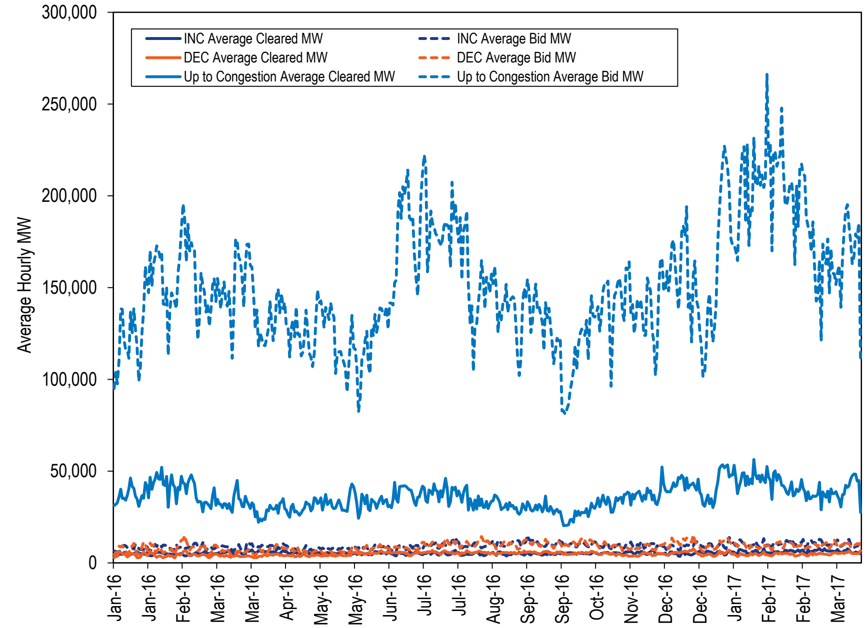


Figure 3-34 shows the daily volume of bid and cleared INC, DEC and up to congestion bids for the period 2016 through the first three months of 2017.

Figure 3-34 Daily bid and cleared INCs, DECs, and UTCs (MW): January 1, 2016 through March 31, 2017



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 3-38 shows, in the first three months of 2016 and 2017, the total increment offers and decrement bids and cleared MW by whether the parent organization is financial or physical.

Table 3-38 PJM INC and DEC bids and cleared MW by type of parent organization (MW): January 1 through March 31, 2016 and 2017

	Jan-Mar 2016				Jan-Mar 2017			
Category	Total Virtual Bid MW	Percent	Total Virtual Cleared MW	Percent	Total Virtual Bid MW	Percent	Total Virtual Cleared MW	Percent
Financial	18,035,687	52.3%	6,268,151	31.0%	24,827,459	57.2%	9,688,435	40.9%
Physical	16,435,855	47.7%	13,982,822	69.0%	18,560,931	42.8%	14,026,693	59.1%
Total	34,471,542	100.0%	20,250,973	100.0%	43,388,390	100.0%	23,715,128	100.0%

Table 3-39 shows, in the first three months of 2016 and 2017, the total up to congestion bids and cleared MW by whether the parent organization was financial or physical.

Table 3-39 PJM up to congestion transactions by type of parent organization (MW): January 1 through March 31, 2016 and 2017

	Jan-Mar 2016				Jan-Mar 2017			
Category	Total Up to Congestion Bid MW	Percent	Total Up to Congestion Cleared MW	Percent	Total Up to Congestion Bid MW	Percent	Total Up to Congestion Cleared MW	Percent
Financial	295,275,386	93.1%	71,891,904	89.7%	400,356,768	98.2%	88,612,664	96.5%
Physical	21,935,772	6.9%	8,235,260	10.3%	7,488,886	1.8%	3,178,964	3.5%
Total	317,211,158	100.0%	80,127,163	100.0%	407,845,654	100.0%	91,791,629	100.0%

Table 3-40 shows, in the first three months of 2016 and 2017, the total import and export transactions by whether the parent organization was financial or physical.

Table 3-40 PJM import and export transactions by type of parent organization (MW): January 1 through March 31, 2016 and 2017

		Jan-Mar 2016		Jan-Mar 2017	
	Category	Total Import and Export MW	Percent	Total Import and Export MW	Percent
Day-Ahead	Financial	19,015,698	39.9%	5,109,129	46.9%
	Physical	28,635,508	60.1%	5,790,217	53.1%
	Total	47,651,206	100.0%	10,899,346	100.0%
Real-Time	Financial	25,595,400	30.4%	6,928,946	38.4%
	Physical	58,569,000	69.6%	11,095,123	61.6%
	Total	84,164,400	100.0%	18,024,069	100.0%

Table 3-41 shows increment offers and decrement bids bid by top 10 locations in the first three months of 2016 and 2017.

Table 3-41 PJM virtual offers and bids by top 10 locations (MW): January 1 through March 31, 2016 and 2017

Jan-Mar 2016					Jan-Mar 2017				
Aggregate/Bus Name	Aggregate/Bus Type	INC MW	DEC MW	Total MW	Aggregate/Bus Name	Aggregate/Bus Type	INC MW	DEC MW	Total MW
WESTERN HUB	HUB	5,403,807	5,218,719	10,622,527	WESTERN HUB	HUB	6,169,328	4,965,019	11,134,347
SOUTHIMP	INTERFACE	1,503,450	0	1,503,450	SOUTHIMP	INTERFACE	1,504,206	0	1,504,206
N ILLINOIS HUB	HUB	189,476	589,534	779,010	MISO	INTERFACE	83,285	1,136,449	1,219,734
NYIS	INTERFACE	466,833	253,568	720,401	AEP-DAYTON HUB	HUB	943,957	185,449	1,129,406
BGE	ZONE	96,804	612,646	709,450	NYIS	INTERFACE	388,256	441,364	829,620
AEP-DAYTON HUB	HUB	321,804	173,426	495,230	N ILLINOIS HUB	HUB	120,502	590,226	710,728
IMO	INTERFACE	426,618	1,050	427,668	BGE	ZONE	169,858	455,246	625,103
SOUTHEXP	INTERFACE	0	415,678	415,678	FOWLER 34.5 KV FWL2-1WF	GEN	170,451	356,677	527,127
LINDENVFT	INTERFACE	874	380,395	381,269	DCKCRKCE345 KV UN1 DYN	GEN	333,180	193,444	526,624
MISO	INTERFACE	131,637	208,923	340,560	FOWLER 34.5 KV FWLR1AWF	GEN	76,342	405,828	482,171
Top ten total		8,541,304	7,853,939	16,395,243			9,959,365	8,729,701	18,689,067
PJM total		18,437,329	16,034,213	34,471,542			22,495,581	20,892,809	43,388,390
Top ten total as percent of PJM total		46.3%	49.0%	47.6%			44.3%	41.8%	43.1%

Table 3-42 shows up to congestion transactions by import bids for the top 10 locations and associated profits at each path in the first three months of 2016 and 2017.[59]

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 PJM cleared up to congestion import bids by top 10 source and sink pairs (MW): January 1 through March 31, 2016 and 2017

Jan-Mar 2016							
Imports							
Source	Source Type	Sink	Sink Type	MW	Source Profit	Sink Profit	UTC Profit
MISO	INTERFACE	COOK	EHVAGG	242,432	$168,662	($114,928)	$53,734
HUDSONTP	INTERFACE	LEONIA 230 T-2	AGGREGATE	182,923	$644,527	($640,838)	$3,689
OVEC	INTERFACE	CONESVILLE 5	AGGREGATE	180,391	$304,760	($259,032)	$45,728
OVEC	INTERFACE	CABOT	EHVAGG	178,741	$234,845	($162,667)	$72,178
MISO	INTERFACE	112 WILTON	EHVAGG	171,689	$102,843	($25,225)	$77,618
SOUTHWEST	INTERFACE	DUMONT	EHVAGG	150,019	$159,478	($103,274)	$56,204
NEPTUNE	INTERFACE	SOUTHRIV 230	AGGREGATE	146,950	$92,597	($15,352)	$77,245
MISO	INTERFACE	CHICAGO GEN HUB	HUB	128,058	$169,196	($169,821)	($626)
OVEC	INTERFACE	COOK	EHVAGG	125,000	$147,679	($91,827)	$55,852
NORTHWEST	INTERFACE	POWERTON 5-6	AGGREGATE	118,597	$138,234	$12,222	$150,456
Top ten total				1,624,800	$2,162,821	($1,570,743)	$592,078
PJM total				8,037,920	$11,266,571	($7,728,186)	$3,538,385
Top ten total as percent of PJM total				20.2%	19.2%	20.3%	16.7%
Jan-Mar 2017							
Imports							
Source	Source Type	Sink	Sink Type	MW	Source Profit	Sink Profit	UTC Profit
MISO	INTERFACE	COOK	EHVAGG	361,736	$166,034	($276,119)	($110,085)
HUDSONTP	INTERFACE	LEONIA 230 T-2	AGGREGATE	314,191	($13,069)	$15,272	$2,203
OVEC	INTERFACE	BUCKEYE - AEP	AGGREGATE	179,081	$82,546	($83,839)	($1,293)
SOUTHEAST	INTERFACE	WILLIAMSPORT - AP	AGGREGATE	173,267	$91,472	($74,636)	$16,836
SOUTHIMP	INTERFACE	COOK	EHVAGG	157,299	($121,473)	($180,807)	($302,281)
MISO	INTERFACE	AELC	AGGREGATE	132,837	($10,816)	$17,199	$6,383
OVEC	INTERFACE	DEOK	ZONE	128,389	($18,719)	$24,950	$6,231
SOUTHEAST	INTERFACE	SCOTTSVI 138 KV T1T2	AGGREGATE	126,678	$193,979	($183,452)	$10,527
NYIS	INTERFACE	HUDSON BC	AGGREGATE	118,598	$185,364	($165,910)	$19,454
NYIS	INTERFACE	PSEG	ZONE	116,500	($34,404)	$38,065	$3,661
Top ten total				1,808,574	$520,913	($869,276)	($348,364)
PJM total				7,606,307	$4,613,702	($4,592,928)	$20,774
Top ten total as percent of PJM total				23.8%	11.3%	18.9%	(1676.9%)

Table 3-43 shows up to congestion transactions by export bids for the top 10 locations and associated profits at each path in the first three months of 2016 and 2017.

Table 3-43 PJM cleared up to congestion export bids by top 10 source and sink pairs (MW): January 1 through March 31, 2016 and 2017

Jan-Mar 2016							
Exports							
Source	Source Type	Sink	Sink Type	MW	Source Profit	Sink Profit	UTC Profit
COMED	ZONE	NIPSCO	INTERFACE	397,071	$425,560	($173,232)	$252,328
21 KINCA ATR24304	AGGREGATE	NIPSCO	INTERFACE	269,188	$362,997	($208,900)	$154,097
SULLIVAN-AEP	EHVAGG	OVEC	INTERFACE	267,964	$608,470	($483,421)	$125,049
SOMERVIL 230 KV T-2	AGGREGATE	NEPTUNE	INTERFACE	138,665	$113,267	($164,488)	($51,222)
UNIV PARK 1-6	AGGREGATE	NIPSCO	INTERFACE	131,157	$59,659	$20,372	$80,030
EAST BEND 2	AGGREGATE	SOUTHWEST	INTERFACE	129,678	$173,707	($194,746)	($21,039)
NAGELAEP	EHVAGG	SOUTHEXP	INTERFACE	127,681	$267,255	($208,045)	$59,210
21 KINCA ATR24404	AGGREGATE	SOUTHWEST	INTERFACE	113,339	$109,427	($156,454)	($47,027)
21 KINCA ATR24304	AGGREGATE	SOUTHWEST	INTERFACE	109,798	$276,731	($218,547)	$58,184
MADISON	AGGREGATE	SOUTHWEST	INTERFACE	103,633	$63,444	($32,621)	$30,823
Top ten total				1,788,174	$2,460,517	($1,820,084)	$640,434
PJM total				6,032,764	$6,272,078	($5,255,836)	$1,016,242
Top ten total as percent of PJM total				29.6%	39.2%	34.6%	63.0%
Jan-Mar 2017							
Exports							
Source	Source Type	Sink	Sink Type	MW	Source Profit	Sink Profit	UTC Profit
21 KINCA ATR24304	AGGREGATE	SOUTHWEST	INTERFACE	311,464	$285,782	($241,403)	$44,380
COMED	ZONE	NIPSCO	INTERFACE	224,622	$314,886	($170,316)	$144,570
QUAD CITIES 2	AGGREGATE	MISO	INTERFACE	216,386	$122,618	($73,908)	$48,710
ROCKPORT	EHVAGG	SOUTHWEST	INTERFACE	199,820	$69,343	($88,012)	($18,669)
GENEVA	AGGREGATE	NIPSCO	INTERFACE	174,512	$219,375	($144,847)	$74,528
WAUKEGAN TR412	AGGREGATE	NIPSCO	INTERFACE	126,589	$147,085	($84,125)	$62,959
JEFFERSON	EHVAGG	NIPSCO	INTERFACE	124,869	$155,137	($76,213)	$78,924
QUAD CITIES 2	AGGREGATE	NORTHWEST	INTERFACE	120,095	$72,763	$5,803	$78,566
QUAD CITIES 1	AGGREGATE	NORTHWEST	INTERFACE	111,835	$24,173	($2,710)	$21,463
21 KINCA ATR24304	AGGREGATE	NIPSCO	INTERFACE	105,652	$87,414	($8,118)	$79,295
Top ten total				1,715,844	$1,498,576	($883,850)	$614,725
PJM total				6,043,159	$3,958,509	($2,504,066)	$1,454,443
Top ten total as percent of PJM total				28.4%	37.9%	35.3%	42.3%

Table 3-44 shows up to congestion transactions by wheel bids and associated profits at each path for the top 10 locations in the first three months of 2016 and 2017.

Table 3-44 PJM cleared up to congestion wheel bids by top 10 source and sink pairs (MW): January 1 through March 31, 2016 and 2017

Source	Source Type	Sink	Sink Type	MW	Source Profit	Sink Profit	UTC Profit
Jan-Mar 2016							
Wheels							
NORTHWEST	INTERFACE	MISO	INTERFACE	139,843	$249,475	($82,485)	$166,991
MISO	INTERFACE	NIPSCO	INTERFACE	133,330	$172,964	($67,117)	$105,848
SOUTHWEST	INTERFACE	SOUTHEXP	INTERFACE	74,640	$90,875	($62,491)	$28,384
NYIS	INTERFACE	IMO	INTERFACE	64,680	$57,359	$5,834	$63,193
MISO	INTERFACE	NORTHWEST	INTERFACE	56,605	$24,639	$69,209	$93,849
IMO	INTERFACE	NYIS	INTERFACE	53,799	$40,161	($56,622)	($16,461)
SOUTHWEST	INTERFACE	NIPSCO	INTERFACE	41,078	$67,873	($29,490)	$38,383
HUDSONTP	INTERFACE	NYIS	INTERFACE	23,450	($114,659)	$110,743	($3,916)
MISO	INTERFACE	SOUTHEXP	INTERFACE	21,489	$27,041	($21,030)	$6,011
IMO	INTERFACE	MISO	INTERFACE	21,422	$25,558	($25,695)	($137)
Top ten total				630,337	$641,288	($159,143)	$482,144
PJM total				717,476	$830,005	($283,709)	$546,296
Top ten total as percent of PJM total				87.9%	77.3%	56.1%	88.3%
Jan-Mar 2017							
Wheels							
Source	Source Type	Sink	Sink Type	MW	Source Profit	Sink Profit	UTC Profit
MISO	INTERFACE	NIPSCO	INTERFACE	121,431	$191,057	($93,183)	$97,874
NORTHWEST	INTERFACE	MISO	INTERFACE	74,099	$132,188	($42,843)	$89,344
SOUTHWEST	INTERFACE	SOUTHEXP	INTERFACE	58,499	$7,560	($15,442)	($7,882)
MISO	INTERFACE	NORTHWEST	INTERFACE	58,162	$9,107	($35,970)	($26,862)
SOUTHWEST	INTERFACE	NIPSCO	INTERFACE	32,795	$62,414	($66,816)	($4,401)
OVEC	INTERFACE	SOUTHWEST	INTERFACE	15,251	($14,424)	$16,256	$1,832
SOUTHEAST	INTERFACE	SOUTHEXP	INTERFACE	11,446	$20,552	($255)	$20,297
NORTHWEST	INTERFACE	NIPSCO	INTERFACE	10,843	$6,122	($2,751)	$3,371
NYIS	INTERFACE	HUDSONTP	INTERFACE	9,055	$12,885	($13,316)	($431)
SOUTHIMP	INTERFACE	MISO	INTERFACE	7,565	$24,233	($15,705)	$8,529
Top ten total				399,146	$451,695	($270,024)	$181,671
PJM total				471,556	$449,391	($247,475)	$201,916
Top ten total as percent of PJM total				84.6%	100.5%	109.1%	90.0%

On November 1, 2012, PJM eliminated the requirement for market participants to specify an interface pricing point as either the source or sink of an up to congestion transaction. The top 10 internal up to congestion transaction locations were 6.2 percent of the PJM total internal up to congestion transactions in the first three months of 2017.

Table 3-45 shows up to congestion transactions by internal bids for the top 10 locations and associated profits at each path in the first three months of 2016 and 2017. The total UTC profit by top 10 locations increased by $716,481, from $26,800 in the first three months of 2016 to $743,281 in the first three months of 2017. The total internal cleared MW increased by 12.3 million MW, or 18.9 percent, from 65.3 million MW in the first three months of 2016 to 77.7 million MW in the first three months of 2017.

Table 3-45 PJM cleared up to congestion internal bids by top 10 source and sink pairs (MW): January 1 through March 31, 2016 and 2017

Jan-Mar 2016							
Internal							
Source	Source Type	Sink	Sink Type	MW	Source Profit	Sink Profit	UTC Profit
112 WILTON	EHVAGG	DUMONT	EHVAGG	586,362	$368,797	($412,765)	($43,968)
BERGEN 2CC	AGGREGATE	LEONIA 230 T-1	AGGREGATE	576,605	$1,663,972	($1,675,613)	($11,640)
21 KINCA ATR24404	AGGREGATE	MICHFE	AGGREGATE	507,970	$288,707	($411,863)	($123,156)
ROCKPORT	EHVAGG	JEFFERSON	EHVAGG	410,366	$447,955	($392,689)	$55,266
21 KINCA ATR24404	AGGREGATE	DUMONT - OLIVE	AGGREGATE	359,025	$393,800	($321,276)	$72,524
21 KINCA ATR24304	AGGREGATE	DUMONT - OLIVE	AGGREGATE	337,626	$558,197	($521,474)	$36,723
WHIPPANY BK 7	AGGREGATE	TRAYNOR	AGGREGATE	336,485	$169,224	($163,878)	$5,346
MOUNTAINEER	EHVAGG	COOK	EHVAGG	269,624	$438,348	($325,005)	$113,343
JEFFERSON	EHVAGG	COOK	EHVAGG	256,334	$243,410	($149,691)	$93,719
BLACKOAK	EHVAGG	BEDINGTON	EHVAGG	251,293	$313,916	($485,270)	($171,354)
Top ten total				3,891,689	$4,886,325	($4,859,525)	$26,800
PJM total				65,339,002	$82,606,618	($67,059,522)	$15,547,096
Top ten total as percent of PJM total				6.0%	5.9%	7.2%	.2%
Jan-Mar 2017							
Internal							
Source	Source Type	Sink	Sink Type	MW	Source Profit	Sink Profit	UTC Profit
DUMONT	EHVAGG	COOK	EHVAGG	1,298,185	$937,776	($705,680)	$232,096
21 KINCA ATR24304	AGGREGATE	SULLIVAN-AEP	EHVAGG	443,188	$457,131	($151,381)	$305,749
BERGEN 2CC	AGGREGATE	LEONIA 230 T-1	AGGREGATE	410,312	$59,210	($57,514)	$1,695
QUAD CITIES 1	AGGREGATE	CORDOVA	AGGREGATE	407,562	$308,209	($331,363)	($23,154)
FE GEN	AGGREGATE	ATSI	ZONE	400,736	($117,126)	$165,617	$48,491
QUAD CITIES 2	AGGREGATE	CORDOVA	AGGREGATE	392,311	$518,419	($526,891)	($8,472)
HOMERCIT	AGGREGATE	AEC - PN	AGGREGATE	371,257	$208,356	($196,756)	$11,600
AEP-DAYTON HUB	HUB	N ILLINOIS HUB	HUB	369,685	$125,216	($225,655)	($100,439)
BAKER	EHVAGG	AMP-OHIO	AGGREGATE	367,064	$138,765	($17,670)	$121,095
CAYUGA RIDGE S WF	AGGREGATE	AELC	AGGREGATE	367,017	$438,857	($284,238)	$154,619
Top ten total				4,827,318	$3,074,811	($2,331,530)	$743,281
PJM total				77,670,606	$34,862,468	($27,757,531)	$7,104,937
Top ten total as percent of PJM total				6.2%	8.8%	8.4%	10.5%

Table 3-46 shows the number of source-sink pairs that were offered and cleared monthly in 2013 through March 2017. The annual row in Table 3-46 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. The subsequent reduction in up to congestion transactions (UTC) that followed a FERC order setting September 8, 2014, as the effective date for any uplift charges subsequently assigned to UTCs, was reversed. There was an increase in up to congestion volume as a result of the expiration of the fifteen month refund period for the proceeding related to uplift charges for UTC transactions on December 7, 2015.[60]

60 See 148 FERC ¶ 61,144 (2014)..

Table 3-46 Number of PJM offered and cleared source and sink pairs: January 2013 through March 2017

		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
2016	Jan	7,714	8,793	6,174	7,374
2016	Feb	9,200	11,172	7,203	7,957
2016	Mar	8,826	11,572	6,338	8,126
2016	Apr	7,697	8,473	5,958	6,767
2016	May	8,521	9,398	6,707	7,273
2016	Jun	9,261	10,948	6,913	7,770
2016	Jul	12,401	16,103	8,571	11,695
2016	Aug	12,464	13,576	8,725	9,224
2016	Sep	12,297	16,324	7,736	9,230
2016	Oct	11,248	13,114	7,648	8,539
2016	Nov	13,151	16,725	8,173	11,581
2016	Dec	12,688	15,868	8,101	9,630
2016	Annual	10,455	12,672	7,354	8,764
2017	Jan	11,893	13,258	7,785	8,839
2017	Feb	9,337	11,902	6,756	7,758
2017	Mar	7,795	8,776	6,051	7,001
2017	Jan-Mar	9,675	11,312	6,864	7,866

Table 3-47 and Figure 3-35 show total cleared up to congestion transactions by type in the first three months of 2016 and 2017. Total up to congestion transactions in the first three months of 2017 increased by 14.6 percent from 80.1 million MW in the first three months of 2016 to 91.8 million MW in the first three months of 2017. Internal up to congestion transactions in the first three months of 2017 were 84.6 percent of all up to congestion transactions compared to 81.5 percent in the first three months of 2016.

Table 3-47 PJM cleared up to congestion transactions by type (MW): January 1 through March 31, 2016 and 2017

	Jan-Mar 2016				
	Cleared Up to Congestion Bids				
	Import	Export	Wheel	Internal	Total
Top ten total (MW)	1,624,800	1,788,174	630,337	3,891,689	7,935,000
PJM total (MW)	8,037,920	6,032,764	717,476	65,339,002	80,127,162
Top ten total as percent of PJM total	20.2%	29.6%	87.9%	6.0%	9.9%
PJM total as percent of all up to congestion transactions	10.0%	7.5%	0.9%	81.5%	100.0%
	Jan-Mar 2017				
	Cleared Up to Congestion Bids				
	Import	Export	Wheel	Internal	Total
Top ten total (MW)	1,808,574	1,715,844	399,416	4,827,318	8,751,152
PJM total (MW)	7,606,307	6,043,159	471,556	77,670,606	91,791,628
Top ten total as percent of PJM total	23.8%	28.4%	84.7%	6.2%	9.5%
PJM total as percent of all up to congestion transactions	8.3%	6.6%	0.5%	84.6%	100.0%

Figure 3-35 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. The reduction in up to congestion transactions (UTC) that followed a FERC order setting September 8, 2014, as the effective date for any uplift charges subsequently assigned to UTCs, was reversed. There was an increase in up to congestion volume as a result of the expiration of the fifteen month refund period for the proceeding related to uplift charges for UTC transactions.[61]

Figure 3-35 PJM monthly cleared up to congestion transactions by type (MW): January 1, 2005 through March 1, 2017

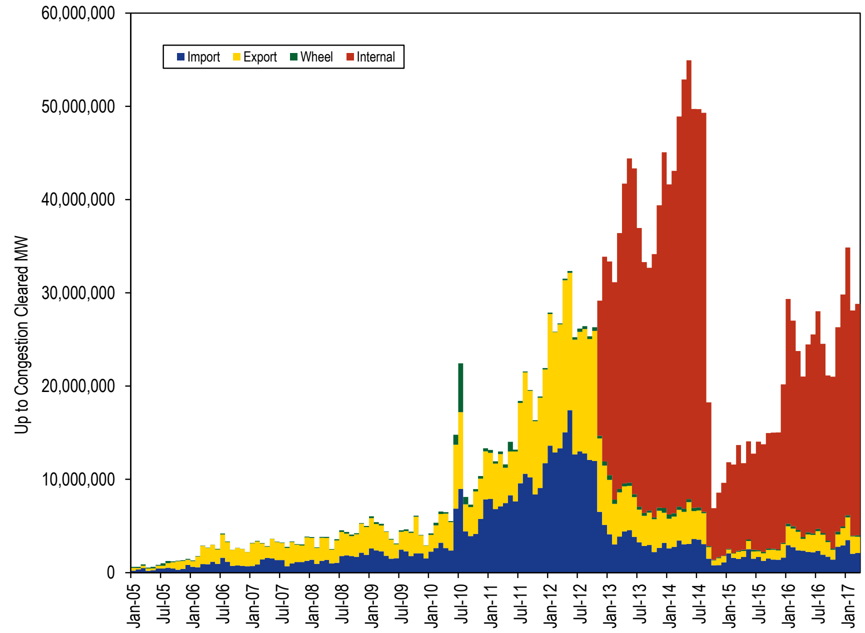
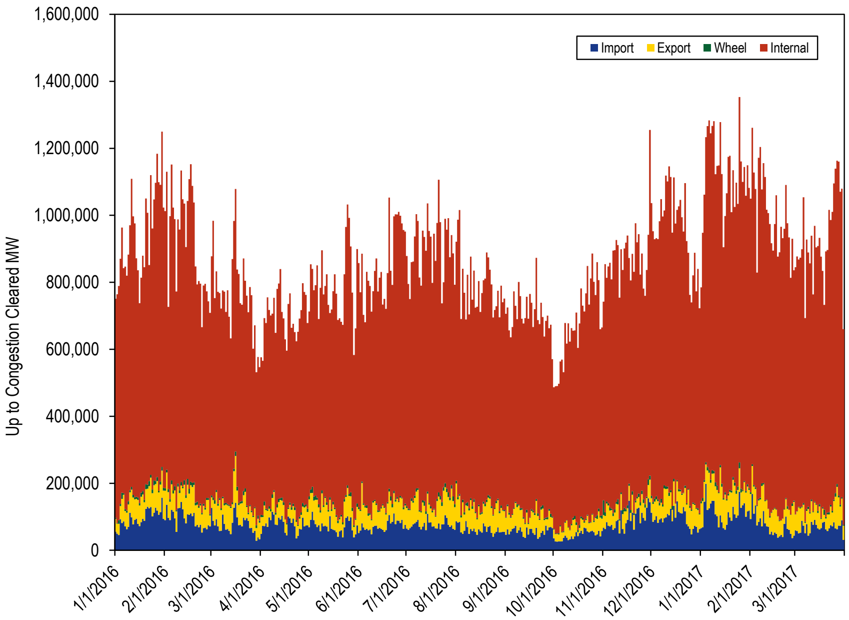


Figure 3-36 shows the daily cleared up to congestion MW by transaction type for the period from January 2016 through March 2017.

61 See 148 FERC ¶ 61,144 (2014).

Figure 3-36 PJM daily cleared up to congestion transaction by type (MW): January 1, 2016 through March 31, 2017



Generator Offers

Generator offers are categorized as dispatchable (Table 3-48) or self scheduled (Table 3-49).[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 3-48 and Table 3-49 do not include units that did not indicate their offer status and units that were offered as available to run only during emergency events. Units that do not indicate their offer status are unavailable for dispatch by PJM. The MW offered beyond the economic range of a unit are categorized as emergency MW. Emergency MW are included in both tables.

Table 3-48 shows the proportion of MW offers by dispatchable units, by unit type and by offer price range, in the first three months of 2017. For example, 78.4 percent of CC offers were dispatchable and in the $0 to $200 per MWh price range. The total column is the proportion of all MW offers by unit type that were dispatchable. For example, 83.5 percent of all CC MW offers were dispatchable, including the 4.6 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, 52.6 percent of all dispatchable offers were in the $0 to $200 per MWh price range. The total column in the all dispatchable offers row is the proportion of all MW offers that were offered as available for economic dispatch, including emergency MW. Among all the generator offers in the first three months of 2017, 57.1 percent were offered as available for economic dispatch.

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 3-48 Distribution of MW for dispatchable unit offer prices: January 1 through March 31, 2017

	Dispatchable (Range)							
Unit Type	($200) - $0	$0 - $200	$200 - $400	$400 - $600	$600 - $800	$800 - $1,000	Emergency	Total
CC	0.0%	78.4%	0.2%	0.1%	0.0%	0.1%	4.6%	83.5%
CT	0.0%	84.4%	4.8%	1.3%	0.0%	0.0%	8.7%	99.2%
Diesel	0.0%	37.0%	18.9%	2.4%	0.1%	0.0%	16.9%	75.4%
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%	6.6%
Pumped Storage	69.4%	0.0%	0.0%	0.0%	0.0%	0.0%	1.8%	71.2%
Run of River	0.2%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%
Solar	56.8%	2.9%	0.0%	0.0%	0.0%	0.0%	0.0%	59.8%
Steam	0.1%	54.6%	0.1%	0.1%	0.0%	0.5%	2.6%	58.1%
Transaction	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Wind	55.8%	8.4%	0.0%	0.0%	0.0%	0.0%	0.4%	64.6%
All Dispatchable Offers	3.0%	52.6%	1.0%	0.3%	0.0%	0.2%	3.6%	60.7%

Table 3-49 Distribution of MW for self scheduled and dispatchable unit offer prices: January 1 through March 31, 2017

	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	2.5%	0.5%	0.3%	11.2%	0.0%	0.0%	0.0%	0.0%	2.0%	16.5%
CT	0.1%	0.0%	0.0%	0.5%	0.0%	0.0%	0.0%	0.0%	0.1%	0.8%
Diesel	21.2%	1.0%	2.2%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	24.6%
Fuel Cell	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%
Nuclear	82.7%	1.0%	8.6%	1.0%	0.0%	0.0%	0.0%	0.0%	0.0%	93.4%
Pumped Storage	16.4%	8.0%	2.1%	0.0%	0.0%	0.0%	0.0%	0.0%	2.3%	28.8%
Run of River	62.6%	15.9%	0.4%	18.8%	0.0%	0.0%	0.0%	0.0%	2.1%	99.8%
Solar	28.0%	8.7%	3.4%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	40.2%
Steam	3.9%	1.3%	0.2%	34.8%	0.0%	0.0%	0.0%	0.0%	1.8%	41.9%
Transaction	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Wind	2.6%	2.4%	23.8%	3.3%	0.0%	0.0%	0.0%	0.0%	3.3%	35.4%
All Self-Scheduled Offers	19.1%	1.2%	2.3%	15.5%	0.0%	0.0%	0.0%	0.0%	1.2%	39.3%

Table 3-49 shows the proportion of MW offers by unit type that were self scheduled to generate fixed output and by unit type and price range for self-scheduled and dispatchable units, for the first three months of 2017. For example, 11.2 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, 16.5 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 2.0 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 19.1 percent of all offers and self scheduled and dispatchable units accounted for 17.8 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 of the first three months of 2017, 20.3 percent were offered as self scheduled and 19.0 percent were offered as self scheduled and dispatchable.

Market Performance

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

Markup

The markup index is a measure of participant conduct for individual marginal units. The markup in dollars is a measure of the impact of participant behavior on the generator bus market price when a unit is marginal. 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 index 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. Markup can also affect prices when units with high markups are not marginal.

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 LMP based on a comparison between the price-based offer and the cost-based offer of each actual marginal unit on the system.[63]

The MMU calculated an explicit measure of the impact of marginal unit markups on LMP using the mathematical relationships among LMPs given the market solution. 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.

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. 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.

63 This is the same method used to calculate the fuel cost adjusted LMP and the components of LMP. *See* Calculation and Use of Generator Sensitivity/Unit Participation Factors, 2010 State of the Market Report for PJM: Technical Reference for PJM Markets.

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 3-50 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 3-50 on the system-wide load-weighted LMP. The negative markup components of LMP reflect the negative markups shown in the Table 3-28.

All generating units, including coal units, are allowed to add an additional 10 percent to their cost offer. The additional 10 percent 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 additional 10 percent from their actual offers. The unadjusted markup is calculated as the difference between the price offer and the cost offer including the additional 10 percent in the cost offer for coal units. The adjusted markup is calculated as the difference between the price offer and the cost offer excluding the additional 10 percent from the cost offer. Even the adjusted markup overestimates the negative markup because coal units facing increased competitive pressure have excluded both the 10 percent 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 PJM Market Rules, they are not part of a competitive offer because they are not actually short run marginal costs, and actual market behavior reflected that fact.[64]

Table 3-50 shows the mark-up component of the real-time load-weighted LMP by fuel type and unit type using unadjusted and adjusted offers. The adjusted markup component of LMP increased from $1.13 per MWh in the first three months of 2016 to $3.81 per MWh in the first three months of 2017. The adjusted markup contribution of coal units in the first three months of 2017 was $1.23 per MWh. The mark-up component of gas-fired units in the first three months of 2017 was $2.31 per MWh, an increase of $0.68 per MWh from the first three months of 2016. The markup component of wind units was $0.19 per MWh. If a price-based offer is negative, but less negative than a cost-based offer, the markup is positive. In the first three months of 2017, among the wind units that were marginal, 15.9 percent had positive offer prices.

64 See PJM. "Manual 15: Cost Development Guidelines," Revision 27 (April 20, 2016).

Table 3-50 Markup component of the overall PJM real-time, load-weighted, average LMP by primary fuel type and unit type: January 1 through March 31, 2016 and 2017[65]

		2016 (Jan-Mar)		2017 (Jan-Mar)	
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	($2.21)	($0.50)	$0.11	$1.23
Gas	CC	$0.83	$1.31	$0.89	$2.04
Gas	CT	$0.08	$0.11	$0.13	$0.25
Gas	Diesel	($0.00)	$0.00	($0.00)	$0.00
Gas	Steam	$0.17	$0.22	($0.01)	$0.03
Municipal Waste	Diesel	$0.00	$0.00	$0.00	$0.00
Oil	CC	($0.00)	$0.01	$0.00	$0.00
Oil	CT	$0.02	$0.06	$0.01	$0.04
Oil	Diesel	$0.00	$0.00	$0.00	$0.00
Oil	Steam	$0.00	$0.01	$0.00	$0.00
Other	Steam	($0.11)	($0.11)	$0.02	$0.02
Wind	Wind	$0.02	$0.02	$0.19	$0.19
Total		($1.21)	$1.13	$1.35	$3.81

Markup Component of Real-Time Price

Table 3-51 shows the markup component, calculated using unadjusted offers, of average prices and of average monthly on-peak and off-peak prices. Table 3-52 shows the markup component, calculated using adjusted offers, of average prices and of average monthly on-peak and off-peak prices. In the first three months of 2017, when using unadjusted cost offers, $1.35 per MWh of the PJM real-time load-weighted average LMP was attributable to markup. Using adjusted cost offers, $3.81 per MWh of the PJM real-time load-weighted average LMP was attributable to markup. In the first three months of 2017, the peak markup component was highest in January, $3.11 per MWh using unadjusted cost offers and $5.88 per MWh using adjusted cost offers. This corresponds to 9.04 percent and 17.13 percent of the real-time peak load-weighted average LMP in January.

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.

Table 3-51 Monthly markup components of real-time load-weighted LMP (Unadjusted): January 1 through March 31, 2016 and 2017

	2016			2017		
	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component
Jan	($1.89)	($1.95)	($1.82)	$1.75	$0.47	$3.11
Feb	($0.43)	($0.59)	($0.28)	$1.13	$0.53	$1.70
Mar	($1.24)	($1.22)	($1.25)	$1.12	$1.70	$0.60
Total	($1.21)	($1.30)	($1.12)	$1.35	$0.89	$1.80

Table 3-52 Monthly markup components of real-time load-weighted LMP (Adjusted): January 1 through March 31, 2016 and 2017

	2016			2017		
	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component
Jan	$0.76	$0.44	$1.12	$4.43	$3.07	$5.88
Feb	$1.98	$1.55	$2.39	$3.33	$2.60	$4.03
Mar	$0.63	$0.49	$0.76	$3.58	$3.82	$3.37
Total	$1.13	$0.81	$1.43	$3.81	$3.17	$4.44

Hourly Markup Component of Real-Time Prices

Figure 3-37 shows the markup contribution to the hourly load-weighted LMP using unadjusted cost offers in the first three months of 2017 and 2016. Figure 3-38 shows the markup contribution to the hourly load-weighted LMP using adjusted cost offers in the first three months of 2017 and 2016.

Figure 3-37 Markup contribution to real-time hourly load-weighted LMP (Unadjusted): January 1 through March 31, 2016 and 2017

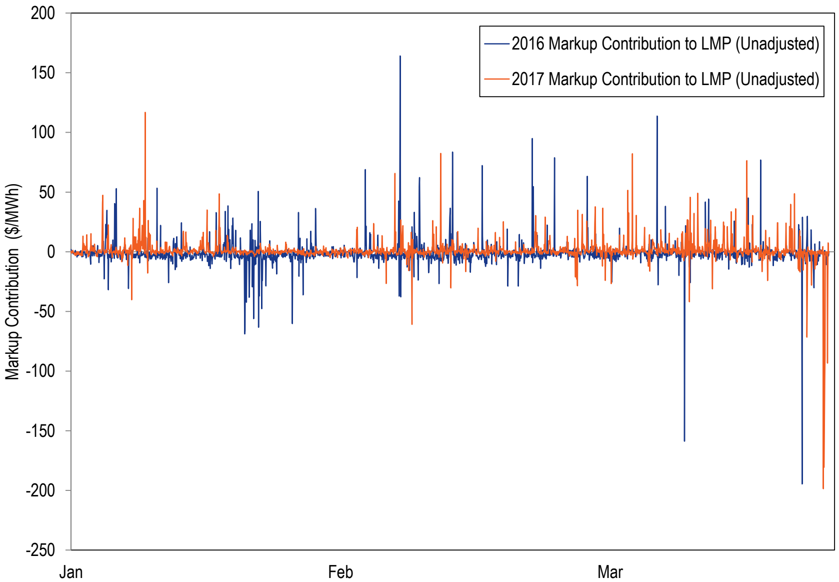
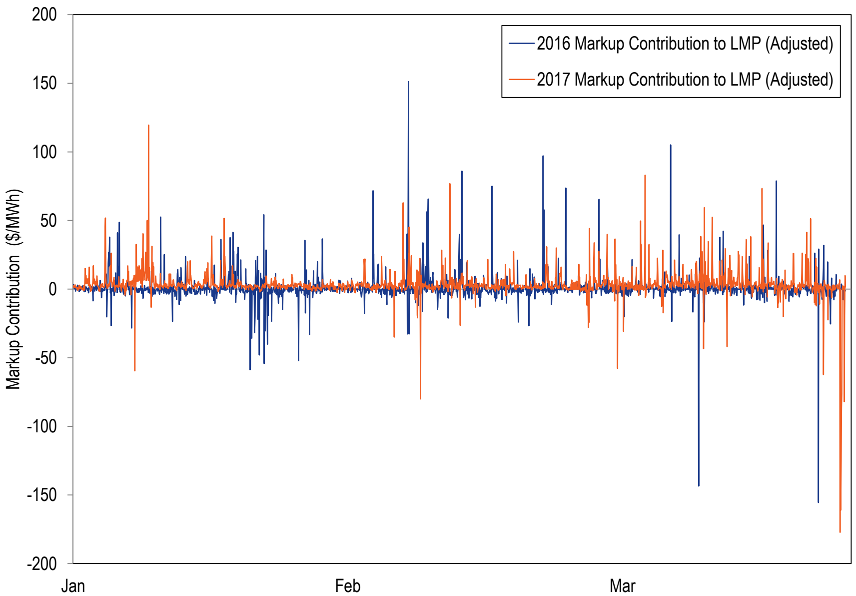


Figure 3-38 Markup contribution to real-time hourly load-weighted LMP (Adjusted): January 1 through March 31, 2016 and 2017



Markup Component of Real-Time Zonal Prices

The unit markup component of average real-time price using unadjusted offers is shown for each zone in the first three months of 2016 and 2017 in Table 3-53 and for adjusted offers in Table 3-54. The smallest zonal all hours average markup component using unadjusted offers in the first three months of 2017 was in the Met-Ed Zone, $0.90 per MWh, while the highest was in the BGE Control Zone, $2.34 per MWh. The smallest zonal on peak average markup was in the RECO Control Zone, $0.60 per MWh, while the highest was in the BGE Control Zone, $3.23 per MWh.

Table 3-53 Average real-time zonal markup component (Unadjusted): January 1 through March 31, 2016 and 2017

	2016 (Jan-Mar)			2017(Jan-Mar)		
	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component
AECO	($0.34)	($0.59)	($0.08)	$1.16	$0.65	$1.68
AEP	($1.43)	($1.52)	($1.34)	$1.23	$0.83	$1.62
APS	($1.52)	($1.65)	($1.39)	$1.38	$0.97	$1.80
ATSI	($1.68)	($1.77)	($1.60)	$1.32	$0.80	$1.80
BGE	($2.11)	($2.47)	($1.74)	$2.34	$1.47	$3.23
ComEd	($1.19)	($1.34)	($1.05)	$1.08	$0.77	$1.37
DAY	($1.88)	($1.74)	($2.02)	$1.35	$0.88	$1.79
DEOK	($1.52)	($1.65)	($1.39)	$1.18	$0.83	$1.52
DLCO	($1.60)	($1.73)	($1.47)	$1.22	$0.77	$1.65
DPL	($0.12)	($0.34)	$0.11	$1.48	$1.24	$1.74
Dominion	($1.59)	($1.67)	($1.51)	$1.79	$1.11	$2.49
EKPC	($1.39)	($1.17)	($1.62)	$1.27	$0.88	$1.68
JCPL	($0.35)	($0.17)	($0.53)	$0.99	$0.59	$1.38
Met-Ed	($0.23)	($0.28)	($0.18)	$0.90	$0.38	$1.40
PECO	($0.09)	($0.17)	($0.01)	$1.21	$0.85	$1.55
PENELEC	($1.01)	($1.11)	($0.91)	$1.37	$1.30	$1.43
PPL	($0.14)	($0.33)	$0.05	$1.00	$0.43	$1.56
PSEG	($0.48)	($0.14)	($0.80)	$1.10	$0.82	$1.36
Pepco	($1.85)	($2.12)	($1.58)	$2.09	$1.19	$2.97
RECO	($0.55)	($0.52)	($0.58)	$0.98	$1.40	$0.60

Table 3-54 Average real-time zonal markup component (Adjusted): January 1 through March 31, 2016 and 2017

	2016 (Jan-Mar)			2017 (Jan-Mar)		
	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component
AECO	$1.73	$1.31	$2.15	$3.69	$2.94	$4.44
AEP	$0.92	$0.63	$1.22	$3.60	$3.07	$4.12
APS	$0.93	$0.56	$1.29	$3.84	$3.26	$4.41
ATSI	$0.64	$0.33	$0.93	$3.83	$3.14	$4.49
BGE	$1.05	$0.43	$1.69	$4.90	$3.76	$6.04
ComEd	$0.94	$0.49	$1.36	$3.34	$2.93	$3.72
DAY	$0.46	$0.39	$0.54	$3.81	$3.18	$4.40
DEOK	$0.75	$0.41	$1.09	$3.50	$3.03	$3.95
DLCO	$0.68	$0.34	$1.01	$3.63	$3.04	$4.21
DPL	$2.25	$1.87	$2.64	$4.38	$4.06	$4.72
Dominion	$1.19	$0.87	$1.52	$4.25	$3.44	$5.09
EKPC	$0.93	$0.94	$0.91	$3.59	$3.10	$4.12
JCPL	$1.58	$1.56	$1.60	$3.65	$2.84	$4.41
Met-Ed	$1.70	$1.43	$1.95	$3.48	$2.59	$4.33
PECO	$1.79	$1.53	$2.04	$3.74	$3.14	$4.31
PENELEC	$1.19	$0.87	$1.49	$3.83	$3.60	$4.04
PPL	$1.79	$1.42	$2.16	$3.60	$2.75	$4.42
PSEG	$1.48	$1.58	$1.39	$3.74	$3.06	$4.38
Pepco	$1.05	$0.52	$1.58	$4.57	$3.45	$5.65
RECO	$1.40	$1.17	$1.61	$3.60	$3.71	$3.50

Markup by Real Time Price Levels

Table 3-55 shows the average markup component of LMP, 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 3-55 Average real-time markup component (By price category, unadjusted): January 1 through March 31, 2016 and 2017

	2016 (Jan-Mar)		2017 (Jan-Mar)	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $25	($1.26)	100.0%	($0.60)	44.9%
$25 to $50	$0.00	0.0%	$0.93	49.2%
$50 to $75	$0.00	0.0%	$0.64	4.4%
$75 to $100	$0.00	0.0%	$0.29	1.1%
$100 to $125	$0.00	0.0%	$0.04	0.1%
$125 to $150	$0.00	0.0%	$0.00	0.1%
>= $150	$0.00	0.0%	$0.07	0.1%

Table 3-56 Average real-time markup component (By price category, adjusted): January 1 through March 31, 2016 and 2017

	2016 (Jan-Mar)		2017 (Jan-Mar)	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $25	$1.17	100.0%	$0.28	45.0%
$25 to $50	$0.00	0.0%	$2.29	49.2%
$50 to $75	$0.00	0.0%	$0.82	4.4%
$75 to $100	$0.00	0.0%	$0.35	1.1%
$100 to $125	$0.00	0.0%	$0.04	0.1%
$125 to $150	$0.00	0.0%	($0.00)	0.1%
>= $150	$0.00	0.0%	$0.07	0.1%

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 3-57. INC, DEC and up to congestion transactions have zero markups. INCs were 4.6 percent of marginal resources and DECs were 7.6 percent of marginal resources in the first three months of 2017. 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.[66] However, the share of marginal up to congestion transactions increased from 83.2 percent in the first three months of 2016 to 83.7 percent in the first three

66 See 18 CFR § 385.213 (2014).

months of 2017 due to the expiration of the fifteen months resettlement period for the proceeding related to uplift charges for UTC transactions. The adjusted markup of coal, gas and oil units is calculated as the difference between the price offer, and the cost offer excluding the 10 percent adder. Table 3-57 shows the markup component of LMP for marginal generating resources. Generating resources were only 4.1 percent of marginal resources in the first three months of 2017. Using adjusted offers, the markup component of LMP for marginal generating resources increased for coal-fired steam units from a negative markup to a positive markup and for gas-fired CT units from $0.02 to $0.04. The markup component of LMP for coal-fired steam units increased from -$1.95 in the first three months of 2016 to -$0.13 in the first three months of 2017 using unadjusted offers. The markup component of LMP for gas-fired steam units decreased from $0.43 in the first three months of 2016 to $0.31 in the first three months of 2017 using unadjusted offers.

Table 3-57 Markup component of the annual PJM day-ahead, load-weighted, average LMP by primary fuel type and unit type: January 1 through March 31, 2016 and 2017

		2016 (Jan - Mar)		2017 (Jan - Mar)	
Fuel Type	Unit Type	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)
Coal	Steam	($1.95)	($0.70)	($0.13)	$0.58
Gas	CT	($0.01)	$0.02	($0.00)	$0.04
Gas	Diesel	$0.00	$0.00	$0.00	$0.00
Gas	Steam	$0.43	$0.77	$0.31	$0.91
Oil	CT	$0.00	$0.00	($0.00)	$0.00
Oil	Diesel	$0.00	$0.00	$0.00	($0.00)
Oil	Steam	$0.00	$0.00	$0.00	$0.00
Other	Steam	($0.11)	($0.11)	$0.01	$0.01
Wind	Wind	$0.02	$0.02	$0.01	$0.01
Total		($1.63)	$0.00	$0.20	$1.56

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 3-58 shows the markup component of average prices and of average monthly on-peak and off-peak prices using unadjusted offers. In the first three months of 2017, when using unadjusted cost-based offers, $0.20 per MWh of the PJM day-ahead load-weighted average LMP was attributable to markup. In the first three months of 2017, the peak markup component was highest in March, $0.83 per MWh using unadjusted cost offers.

Table 3-58 Monthly markup components of day-ahead (Unadjusted), load-weighted LMP: January 1 through March 31, 2016 and 2017

	2016			2017		
	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
Jan	($2.04)	($1.71)	($2.33)	($0.03)	$0.19	($0.23)
Feb	($1.15)	($1.32)	($0.96)	$0.25	$0.59	($0.10)
Mar	($1.66)	($1.26)	($2.12)	$0.38	$0.83	($0.12)
Apr	($0.37)	$0.76	($1.54)			
May	($0.71)	($0.16)	($1.26)			
Jun	$0.19	$0.74	($0.48)			
Jul	($3.73)	($6.42)	($1.05)			
Aug	($0.05)	$0.08	($0.22)			
Sep	($0.99)	($0.57)	($1.47)			
Oct	$0.65	$1.75	($0.45)			
Nov	$0.08	$0.52	($0.37)			
Dec	$0.30	$0.89	($0.27)			
Annual	($1.63)	($1.43)	($1.83)	$0.20	$0.54	($0.15)

Table 3-59 shows the markup component of average prices and of average monthly on-peak and off-peak prices using adjusted offers. In the first three months of 2017, when using adjusted cost-based offers, $1.56 per MWh of the PJM day-ahead load-weighted average LMP was attributable to markup. In the first three months of 2017, the peak markup component was highest in March, $1.99 per MWh using adjusted cost offers.

Table 3-59 Monthly markup components of day-ahead (Adjusted), load-weighted LMP: January 1 2016 through March 31, 2017

	2016			2017		
	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
Jan	($0.17)	$0.19	($0.48)	$1.40	$1.49	$1.32
Feb	$0.44	$0.27	$0.62	$1.65	$1.89	$1.39
Mar	($0.26)	$0.14	($0.72)	$1.65	$1.99	$1.27
Apr	$0.92	$1.86	($0.05)			
May	$0.60	$1.10	$0.09			
Jun	$1.58	$2.16	$0.89			
Jul	($2.90)	($6.38)	$0.58			
Aug	$3.94	$6.08	$1.27			
Sep	$0.17	$0.17	$0.16			
Oct	$1.69	$2.46	$0.91			
Nov	$1.25	$1.51	$0.99			
Dec	$1.82	$2.14	$1.50			
Annual	$0.00	$0.20	($0.20)	$1.56	$1.79	$1.33

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 3-60. The markup component of annual average day-ahead price using adjusted offers is shown for each zone in Table 3-61. Using unadjusted offers, the markup component of the average day-ahead price increased in all zones from the first three months of 2016 to the first three months of 2017. The smallest zonal all hours average markup component using adjusted offers for the first three months of 2017 was in the Pepco Zone, $1.38 per MWh, while the highest was in the DPL Control Zone, $2.15 per MWh. The smallest zonal on peak average markup using adjusted offers was in the ComEd Control Zone, $1.61 per MWh, while the highest was in the DPL Control Zone, $2.54 per MWh.

Table 3-60 Day-ahead, average, zonal markup component (Unadjusted): January 1 through March 31, 2016 and 2017

	2016 (Jan - Mar)			2017 (Jan - Mar)		
	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
AECO	($0.52)	($0.35)	($0.70)	$0.63	$1.13	$0.11
AEP	($1.79)	($1.61)	($1.97)	$0.10	$0.42	($0.22)
AP	($1.89)	($1.70)	($2.07)	$0.13	$0.45	($0.20)
ATSI	($1.83)	($1.61)	($2.06)	$0.13	$0.44	($0.21)
BGE	($2.44)	($2.44)	($2.44)	($0.03)	$0.32	($0.40)
ComEd	($1.73)	($1.56)	($1.91)	$0.09	$0.39	($0.22)
DAY	($1.92)	($1.71)	($2.15)	$0.13	$0.44	($0.20)
DEOK	($1.84)	($1.64)	($2.04)	$0.13	$0.43	($0.19)
DLCO	($1.80)	($1.60)	($2.01)	$0.13	$0.46	($0.22)
Dominion	($2.14)	($2.07)	($2.21)	$0.02	$0.38	($0.32)
DPL	($0.82)	($0.54)	($1.09)	$0.65	$1.15	$0.15
EKPC	($1.78)	($1.53)	($2.02)	$0.11	$0.43	($0.19)
JCPL	($0.74)	($0.54)	($0.95)	$0.47	$0.81	$0.11
Met-Ed	($0.86)	($0.70)	($1.04)	$0.49	$0.84	$0.13
PECO	($0.68)	($0.36)	($1.01)	$0.64	$1.10	$0.17
PENELEC	($1.44)	($1.16)	($1.72)	$0.27	$0.60	($0.08)
Pepco	($2.30)	($2.22)	($2.38)	($0.04)	$0.29	($0.37)
PPL	($0.80)	($0.59)	($1.02)	$0.51	$0.89	$0.12
PSEG	($0.77)	($0.26)	($1.32)	$0.41	$0.75	$0.05
RECO	($0.77)	($0.42)	($1.16)	$0.43	$0.73	$0.11

Table 3-61 Day-ahead, average, zonal markup component (Adjusted): January 1 through March 31, 2016 and 2017

	2016 (Jan - Mar)			2017 (Jan - Mar)		
	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
AECO	$0.95	$1.17	$0.73	$2.02	$2.37	$1.65
AEP	($0.13)	$0.02	($0.28)	$1.46	$1.67	$1.25
AP	($0.20)	($0.03)	($0.38)	$1.50	$1.72	$1.28
ATSI	($0.15)	$0.04	($0.35)	$1.52	$1.72	$1.29
BGE	($0.81)	($0.77)	($0.84)	$1.39	$1.67	$1.11
ComEd	($0.16)	$0.00	($0.34)	$1.41	$1.61	$1.20
DAY	($0.21)	($0.01)	($0.41)	$1.50	$1.71	$1.28
DEOK	($0.17)	$0.02	($0.36)	$1.45	$1.66	$1.24
DLCO	($0.15)	$0.04	($0.34)	$1.49	$1.71	$1.25
Dominion	($0.45)	($0.35)	($0.55)	$1.43	$1.68	$1.18
DPL	$0.92	$1.21	$0.64	$2.15	$2.54	$1.76
EKPC	($0.15)	$0.04	($0.32)	$1.44	$1.64	$1.24
JCPL	$0.84	$1.06	$0.60	$1.83	$2.01	$1.64
Met-Ed	$0.70	$0.89	$0.49	$1.85	$2.05	$1.64
PECO	$0.88	$1.21	$0.54	$2.04	$2.35	$1.71
PENELEC	$0.20	$0.47	($0.07)	$1.60	$1.83	$1.35
Pepco	($0.62)	($0.52)	($0.72)	$1.38	$1.62	$1.13
PPL	$0.76	$0.99	$0.52	$1.87	$2.09	$1.64
PSEG	$0.76	$1.30	$0.19	$1.78	$1.96	$1.59
RECO	$0.69	$1.09	$0.26	$1.78	$1.93	$1.62

Markup by Day-Ahead Price Levels

Table 3-62 and Table 3-63 show the average markup component of LMP, 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 3-62 Average, day-ahead markup (By LMP category, unadjusted): January 1 through March 31, 2016 and 2017

	2016 (Jan - Mar)		2017 (Jan - Mar)	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $25	($2.20)	50.2%	($0.66)	37.2%
$25 to $50	($1.81)	47.4%	$0.63	60.3%
$50 to $75	$4.38	2.3%	$1.08	2.1%
$75 to $100	$6.46	0.1%	$0.86	0.3%

Table 3-63 Average, day-ahead markup (By LMP category, adjusted): January 1 through March 31, 2016 and 2017

	2016 (Jan - Mar)		2017 (Jan - Mar)	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $25	($0.53)	50.2%	$1.07	37.2%
$25 to $50	$0.08	47.4%	$2.20	60.3%
$50 to $75	$5.88	2.3%	$2.79	2.1%
$75 to $100	$6.88	0.1%	$1.12	0.3%

Prices

The conduct of individual market entities within a market structure is reflected in market prices. PJM locational marginal prices (LMPs) are a direct measure of market performance. Price level is a good, general indicator of market performance, although overall price results must be interpreted carefully because of the multiple factors that affect them. Among other things, overall average prices reflect changes in supply and demand, generation fuel mix, the cost of fuel, emission related expenses, 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 13.0 percent and 8.8 percent higher in the first three months of 2017 than in the first three months of 2016.

PJM real-time energy market prices increased in the first three months of 2017 compared to the first three months of 2016. The average LMP was 14.8 percent higher in the first three months of 2017 than in the first three months of 2016, $29.39 per MWh versus $25.60 per MWh. The load-weighted average LMP was 13.0 percent higher in the first three months of 2017 than in the first three months of 2016, $30.28 per MWh versus $26.80 per MWh.

The fuel-cost adjusted, load-weighted, average LMP in the first three months of 2017 was 22.9 percent lower than the load-weighted, average LMP for the first three months of 2016. If fuel and emission costs in the first three months of 2017 had been the same as in the first three months of 2016, holding everything else constant, the load-weighted LMP would have been lower, $23.35 per MWh instead of the observed $30.28 per MWh.

PJM day-ahead energy market prices increased in the first three months of 2017 compared to the first three months of 2016. The day-ahead average LMP was 10.0 percent higher in the first three months of 2017 than in the first three months of 2016, $29.59 per MWh versus $26.90 per MWh. The day-ahead load-weighted average LMP was 8.8 percent higher in the first three months of 2017 than in the first three months of 2016, $30.40 per MWh versus $27.94 per MWh.

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.[67] 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 the LMPs at some pricing nodes exceed $1,000 per MWh, the cap on the generators' offer price in the PJM market.[68]

67 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.

68 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).

Real-Time LMP

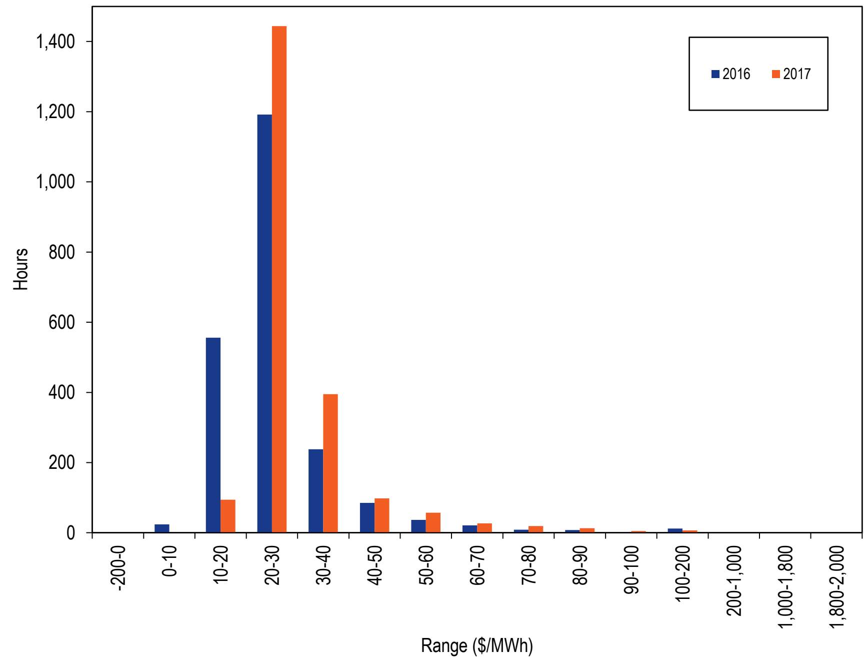
Real-time average LMP is the hourly average LMP for the PJM Real-Time Energy Market.[69]

Real-Time Average LMP

PJM Real-Time Average LMP Duration

Figure 3-39 shows the hourly distribution of PJM real-time average LMP for the first three months of 2016 and 2017.

Figure 3-39 Average LMP for the PJM Real-Time Energy Market: January 1 through March 31, 2016 and 2017



69 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>.

PJM Real-Time, Average LMP

Table 3-64 shows the PJM real-time, average LMP for the first three months of each year from 1998 through 2017.[70]

Table 3-64 PJM real-time, average LMP (Dollars per MWh): January 1 through March 31, 1998 through 2017

	Real-Time LMP			Year-to-Year Change		
Jan-Mar	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$17.51	$15.30	$7.84	NA	NA	NA
1999	$18.79	$16.56	$7.29	7.3%	8.3%	(7.0%)
2000	$23.66	$17.73	$16.22	25.9%	7.0%	122.4%
2001	$33.77	$26.01	$20.79	42.8%	46.8%	28.2%
2002	$22.23	$19.22	$9.61	(34.2%)	(26.1%)	(53.8%)
2003	$49.57	$43.08	$30.54	123.0%	124.2%	217.9%
2004	$46.37	$41.04	$24.07	(6.5%)	(4.8%)	(21.2%)
2005	$46.51	$40.62	$22.07	0.3%	(1.0%)	(8.3%)
2006	$52.98	$46.15	$23.29	13.9%	13.6%	5.5%
2007	$55.34	$47.15	$33.29	4.5%	2.2%	43.0%
2008	$66.75	$57.05	$35.54	20.6%	21.0%	6.8%
2009	$47.29	$40.56	$21.99	(29.2%)	(28.9%)	(38.1%)
2010	$44.13	$37.82	$21.87	(6.7%)	(6.8%)	(0.6%)
2011	$44.76	$38.14	$23.10	1.4%	0.8%	5.6%
2012	$30.38	$28.82	$11.63	(32.1%)	(24.4%)	(49.7%)
2013	$36.33	$32.29	$18.47	19.6%	12.1%	58.9%
2014	$84.04	$48.77	$119.84	131.3%	51.0%	548.8%
2015	$47.39	$31.95	$42.42	(43.6%)	(34.5%)	(64.6%)
2016	$25.60	$22.91	$12.99	(46.0%)	(28.3%)	(69.4%)
2017	$29.39	$25.71	$12.28	14.8%	12.2%	(5.4%)

Real-Time, Load-Weighted, Average LMP

Higher demand (load) generally results in higher prices, all else constant. As a result, load-weighted, average prices are generally higher than average prices. Load-weighted LMP reflects the average LMP paid for actual MWh consumed during a year. Load-weighted, average LMP is the average of PJM hourly LMP, each weighted by the PJM total hourly load.

PJM Real-Time, Load-Weighted, Average LMP

Table 3-65 shows the PJM real-time, load-weighted, average LMP in the first three months of 1998 through 2017.

Table 3-65 PJM real-time, load-weighted, average LMP (Dollars per MWh): January 1 through March 31, 1998 through 2017

	Real-Time, Load-Weighted, Average LMP			Year-to-Year Change		
Jan-Mar	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$18.13	$15.80	$8.14	NA	NA	NA
1999	$19.38	$16.90	$7.66	6.9%	7.0%	(5.9%)
2000	$25.10	$18.25	$17.22	29.5%	8.0%	124.9%
2001	$35.16	$27.38	$21.52	40.1%	50.0%	25.0%
2002	$23.01	$19.89	$9.93	(34.6%)	(27.4%)	(53.8%)
2003	$51.93	$46.12	$30.99	125.6%	131.9%	211.9%
2004	$48.77	$43.22	$24.62	(6.1%)	(6.3%)	(20.6%)
2005	$48.37	$42.20	$22.62	(0.8%)	(2.4%)	(8.1%)
2006	$54.43	$47.62	$23.69	12.5%	12.9%	4.7%
2007	$58.07	$50.60	$34.44	6.7%	6.3%	45.4%
2008	$69.35	$60.11	$36.56	19.4%	18.8%	6.2%
2009	$49.60	$42.23	$23.38	(28.5%)	(29.8%)	(36.1%)
2010	$45.92	$39.01	$22.99	(7.4%)	(7.6%)	(1.7%)
2011	$46.35	$39.11	$24.26	0.9%	0.3%	5.5%
2012	$31.21	$29.25	$12.02	(32.7%)	(25.2%)	(50.5%)
2013	$37.41	$32.79	$19.90	19.9%	12.1%	65.7%
2014	$92.98	$51.62	$134.40	148.5%	57.4%	575.3%
2015	$50.91	$33.51	$46.43	(45.2%)	(35.1%)	(65.5%)
2016	$26.80	$23.45	$13.98	(47.4%)	(30.0%)	(69.9%)
2017	$30.28	$26.26	$13.08	13.0%	12.0%	(6.4%)

Table 3-66 shows zonal real-time, and real-time, load-weighted, average LMP in the first three months of 2016 and 2017.

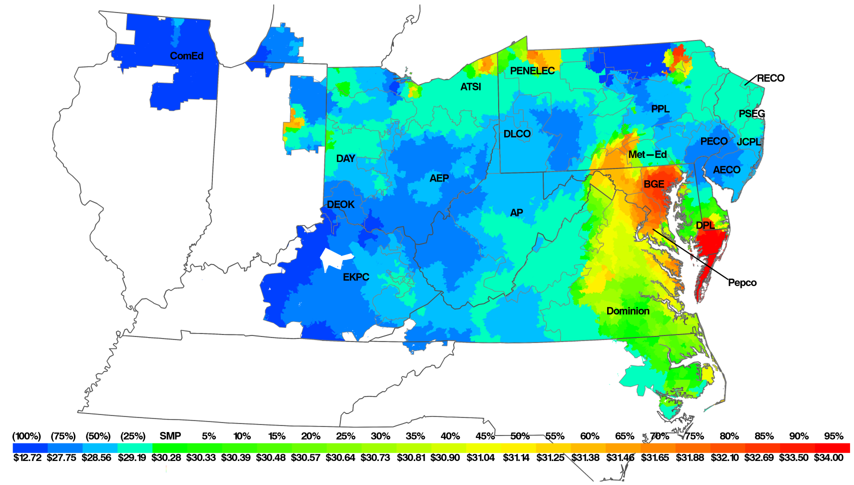
70 The system average LMP is the average of the hourly LMP without any weighting. The only exception is that market-clearing prices (MCPs) are included for January to April 1998. MCP was the single market-clearing price calculated by PJM prior to implementation of LMP.

Table 3-66 Zone real-time and real-time, load-weighted, average LMP (Dollars per MWh): January 1 through March 31, 2016 and 2017

	Real-Time Average LMP			Real-Time, Load-Weighted, Average LMP		
Zone	2016 (Jan-Mar)	2017 (Jan-Mar)	Percent Change	2016 (Jan-Mar)	2017 (Jan-Mar)	Percent Change
AECO	$24.13	$28.48	18.0%	$25.73	$29.59	15.0%
AEP	$25.46	$28.70	12.7%	$26.49	$29.39	10.9%
AP	$26.36	$29.68	12.6%	$27.63	$30.63	10.9%
ATSI	$25.28	$29.81	17.9%	$26.03	$30.45	17.0%
BGE	$33.96	$33.15	(2.4%)	$36.11	$34.79	(3.6%)
ComEd	$22.80	$26.52	16.3%	$23.45	$26.95	14.9%
Day	$25.19	$29.20	15.9%	$26.08	$29.88	14.6%
DEOK	$24.52	$27.94	13.9%	$25.42	$28.57	12.4%
DLCO	$24.92	$29.03	16.5%	$25.68	$29.67	15.5%
Dominion	$29.09	$30.88	6.1%	$31.29	$32.58	4.1%
DPL	$28.02	$31.16	11.2%	$30.56	$33.13	8.4%
EKPC	$24.56	$27.79	13.2%	$25.78	$28.75	11.5%
JCPL	$22.39	$29.45	31.5%	$23.79	$30.63	28.8%
Met-Ed	$22.32	$29.37	31.6%	$23.63	$30.41	28.7%
PECO	$21.94	$28.53	30.0%	$23.29	$29.58	27.0%
PENELEC	$24.34	$29.07	19.4%	$25.29	$29.79	17.8%
Pepco	$30.50	$31.76	4.1%	$32.38	$33.26	2.7%
PPL	$22.46	$29.22	30.1%	$23.88	$30.35	27.1%
PSEG	$22.77	$29.61	30.0%	$23.95	$30.51	27.4%
RECO	$22.61	$29.84	32.0%	$23.79	$30.77	29.4%
PJM	$25.60	$29.39	14.8%	$26.80	$30.28	13.0%

Figure 3-40 is a contour map of the real-time, load-weighted, average LMP in the first three months of 2017. 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 3-40 PJM real-time, load-weighted, average LMP: January 1 through March 31, 2017



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

Figure 3-41 shows the PJM real-time monthly and annual load-weighted LMP in 1999 through the first three months of 2017. PJM real-time monthly load-weighted average LMP in March 2016 was $22.90, which is the lowest real-time monthly load-weighted average LMP since February 2002 at $21.39.

Figure 3-41 PJM real-time, monthly and annual, load-weighted, average LMP:January 1, 1999 through March 31, 2017

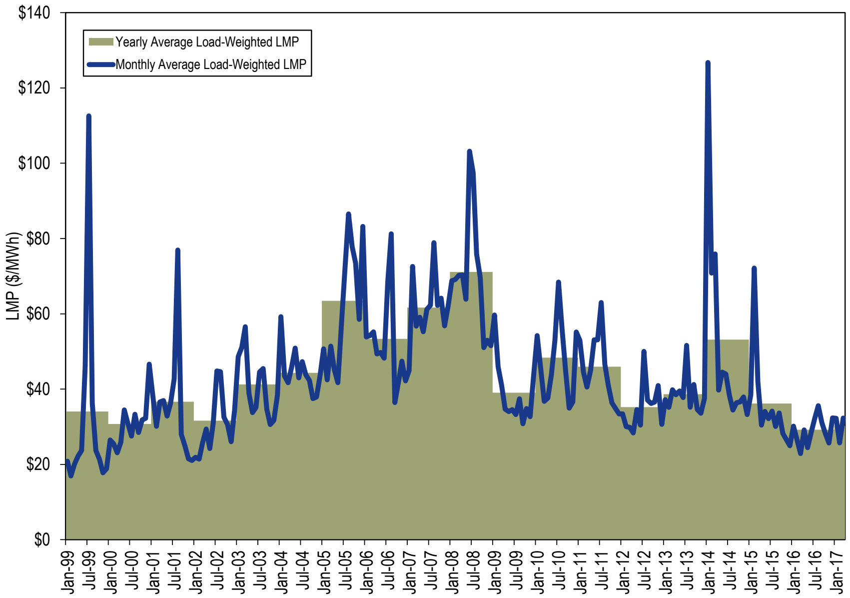
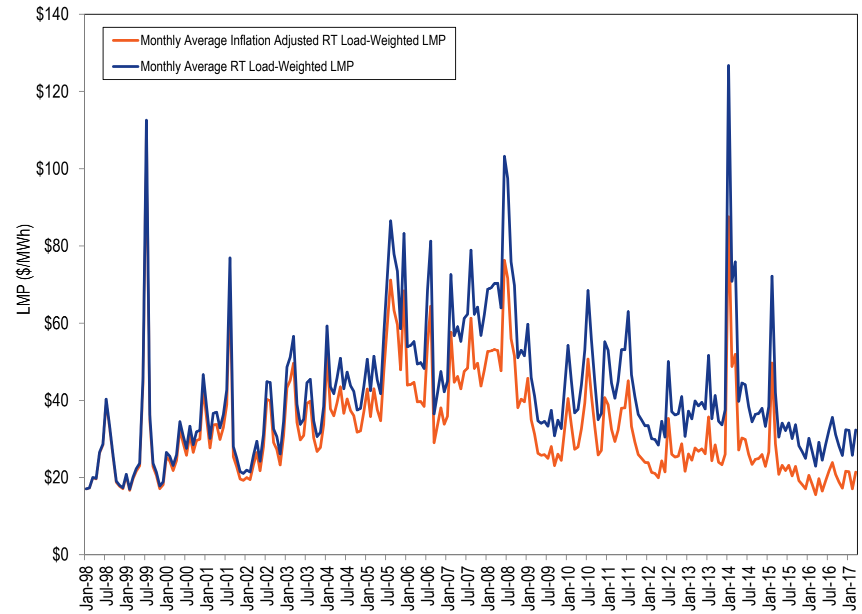


Figure 3-42 PJM real-time, monthly, load-weighted, average LMP and real-time, monthly inflation adjusted load-weighted, average LMP: January 1, 1998 through March 31, 2017



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

Figure 3-42 shows the PJM real-time monthly load-weighted average LMP and inflation adjusted monthly load-weighted average LMP for January 1, 1998, through March 31, 2017.[71] Table 3-67 shows the PJM real-time yearly load-weighted average LMP and inflation adjusted yearly load-weighted average LMP for the first three months of every year starting from 1998 through 2017.

71 To obtain the inflation adjusted monthly load-weighted average LMP, the PJM system-wide load-weighted average LMP is deflated using the US Consumer Price Index for all items, Urban Consumers (base period: January 1998), published by *Bureau of Labor Statistics*. <http://download.bls.gov/pub/time.series/cu/cu.data.1.AllItems> (April22, 2017)

Table 3-67 PJM real-time, yearly, load-weighted, average LMP and real-time, yearly inflation adjusted load-weighted, average LMP: January 1 through March 31, 1998 through 2017

Year (Jan-Mar)	Load-Weighted, Average LMP	Inflation Adjusted Load-Weighted, Average LMP
1998	$18.13	$18.10
1999	$19.38	$19.03
2000	$25.10	$23.89
2001	$35.16	$32.35
2002	$23.01	$20.90
2003	$51.93	$45.86
2004	$48.77	$42.36
2005	$48.37	$40.73
2006	$54.43	$44.21
2007	$58.07	$46.05
2008	$69.35	$52.85
2009	$49.60	$37.83
2010	$45.92	$34.21
2011	$46.35	$33.83
2012	$31.21	$22.14
2013	$37.41	$26.09
2014	$92.98	$64.01
2015	$50.91	$35.04
2016	$26.80	$18.25
2017	$30.28	$20.11

Fuel Price Trends and LMP

Changes in LMP can result from changes in the marginal costs of marginal units, the units setting LMP. In general, fuel costs make up between 80 percent and 90 percent of marginal cost depending on generating technology, unit efficiency, unit age and other factors. The impact of fuel cost on marginal cost and on LMP depends on the fuel burned by marginal units and changes in fuel costs. Changes in emission allowance costs are another contributor to changes in the marginal cost of marginal units. Natural gas prices and coal prices increased in the first three months of 2017 compared to the first three months of 2016. The price of Northern Appalachian coal was 30.1 percent higher; the price of Central Appalachian coal was 34.6 percent higher; the price of Powder River Basin coal was 17.1 percent higher; the price of eastern natural gas was 36.0 percent higher; and the price of western natural gas was 64.6 percent higher. Figure 3-43 shows monthly average spot fuel prices.[72]

Figure 3-43 Spot average fuel price comparison with fuel delivery charges: January 1, 2012 through March 31, 2017 ($/MMBtu)

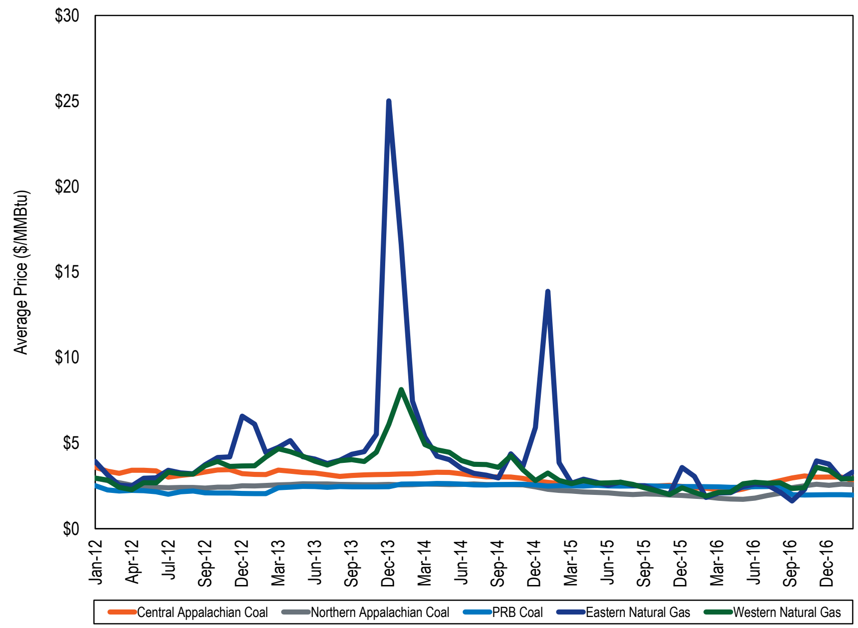


Table 3-68 compares the 2017 PJM real-time fuel-cost adjusted, load-weighted, average LMP to 2017 load-weighted, average LMP.[73] The real-time fuel-cost adjusted, load-weighted, average LMP for the first three months of 2017 was 22.9 percent lower than the real-time load-weighted, average LMP for the first three months of 2017. The real-time, fuel-cost adjusted, load-weighted, average LMP for the first three months of 2017 was 12.9 percent lower than the real-time load-weighted LMP for the first three months of 2016. If fuel

72 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.

73 The fuel-cost adjusted LMP reflects both the fuel and emissions where applicable, including NO_x, CO_2 and SO_x costs.

and emissions costs in the first three months of 2017 had been the same as in the first three months of 2016, holding everything else constant, the real-time load-weighted LMP in the first three months of 2017 would have been lower, \$23.25 per MWh, than the observed \$30.28 per MWh.

Table 3-68 PJM real-time annual, fuel-cost adjusted, load-weighted average LMP (Dollars per MWh): quarter over quarter

	2017 Load-Weighted LMP	2017 Fuel-Cost Adjusted, Load-Weighted LMP	Change
Average	\$30.28	\$23.35	(22.9%)
	2016 Load-Weighted LMP	2017 Fuel-Cost Adjusted, Load-Weighted LMP	Change
Average	\$26.80	\$23.35	(12.9%)
	2016 Load-Weighted LMP	2017 Load-Weighted LMP	Change
Average	\$26.80	\$30.28	13.0%

Table 3-69 shows the impact of each fuel type on the difference between the fuel-cost adjusted, load-weighted average LMP and the load-weighted LMP in the first three months of 2017. Table 3-69 shows that higher natural gas prices explains most of the fuel-cost related increase in the real-time annual load-weighted average LMP in the first three months of 2017.

Table 3-69 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	\$2.48	35.8%
Gas	\$4.27	61.6%
Municipal Waste	\$0.00	0.0%
Oil	\$0.17	2.4%
Other	\$0.00	0.0%
Uranium	(\$0.00)	-0.0%
Wind	(\$0.00)	-0.0%
Total	\$6.93	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.[74] 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 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.[75] 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

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

75 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 a RTO-wide shortage of synchronized reserve.

penalty factors are administratively determined and can be thought of as a form of locational scarcity pricing.

Table 3-72 shows the frequency and average shadow price of transmission constraints in PJM. In the first three months of 2017, there were 45,165 transmission constraints in the real-time market with a non-zero shadow price. For nearly nine percent of these transmission constraints, the line limit was violated, meaning that the flow exceeded the facility limit.[76] In the first three months of 2017, the average shadow price of transmission constraints when the line limit was violated was nearly five times higher than when transmission constraint was binding at its limit.

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 when line limits are violated, PJM uses a procedure called constraint relaxation logic to prevent the penalty factors from directly setting the shadow price of the constraint. The result is that the transmission penalty factor does not directly set the shadow price. The details of PJM's logic and practice are not entirely clear. But in 2016, for all transmission constraints for which the penalty factor was greater than or equal to $2,000 per MWh, 41 percent of the constraints' shadow prices were within 10 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; the allowed duration of the violation; the use of constraint relaxation logic; and when the transmission penalty factors will be used to set the shadow price.

The components of LMP are shown in Table 3-70, including markup using unadjusted cost offers.[77] Table 3-70 shows that in the first three months of 2017, 40.3 percent of the load-weighted LMP was the result of coal costs, 32.4 percent was the result of gas costs and 2.09 percent was the result of the cost of emission allowances. Using adjusted cost offers, markup was 12.6 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 the first three months of 2017, nearly 14.4 percent of all five-minute intervals had insufficient data. The percent column is the difference in the proportion of LMP represented by each component between the first three months of 2017 and 2016.

76 The line limit of a facility associated with a transmission constraint is not necessarily the rated line limit. In PJM, the dispatcher has the discretion to lower the rated line limit.

77 These components are explained in the *Technical Reference for PJM Markets*, at p 27 "Calculation and Use of Generator Sensitivity/Unit Participation Factors." <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

Table 3-70 Components of PJM real-time (Unadjusted), load-weighted, average LMP: January 1 through March 31, 2016 and 2017

	2016 (Jan-Mar)		2017 (Jan-Mar)		Change
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Percent
Gas	$5.30	19.8%	$12.21	40.3%	20.6%
Coal	$14.78	55.1%	$9.81	32.4%	(22.7%)
Ten Percent Adder	$2.35	8.8%	$2.45	8.1%	(0.7%)
Markup	($1.21)	(4.5%)	$1.35	4.5%	9.0%
VOM	$2.04	7.6%	$1.34	4.4%	(3.2%)
Increase Generation Adder	$0.19	0.7%	$0.96	3.2%	2.5%
LPA Rounding Difference	$0.21	0.8%	$0.51	1.7%	0.9%
NA	$1.66	6.2%	$0.50	1.6%	(4.6%)
NO_x Cost	$0.52	1.9%	$0.43	1.4%	(0.5%)
Oil	$0.51	1.9%	$0.40	1.3%	(0.6%)
Ancillary Service Redispatch Cost	$0.27	1.0%	$0.29	0.9%	(0.0%)
CO_2 Cost	$0.05	0.2%	$0.14	0.5%	0.3%
SO_2 Cost	$0.09	0.3%	$0.06	0.2%	(0.1%)
Municipal Waste	$0.01	0.0%	$0.04	0.1%	0.1%
Other	$0.11	0.4%	$0.02	0.1%	(0.4%)
Market-to-Market Adder	$0.01	0.0%	$0.00	0.0%	(0.0%)
Uranium	$0.00	0.0%	($0.00)	(0.0%)	(0.0%)
Decrease Generation Adder	($0.03)	(0.1%)	($0.01)	(0.0%)	0.1%
LPA-SCED Differential	($0.01)	(0.0%)	($0.01)	(0.0%)	(0.0%)
Wind	($0.04)	(0.2%)	($0.20)	(0.7%)	(0.5%)
Total	$26.80	100.0%	$30.28	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 3-70 and Table 3-77), markup is simply the difference between the price offer and the cost offer (unadjusted markup). In the second approach (Table 3-71 and Table 3-78), the 10 percent markup is removed from the cost offers of coal gas and oil units (adjusted markup).

The components of LMP are shown in Table 3-71, including markup using adjusted cost offers.

Table 3-71 Components of PJM real-time (Adjusted), load-weighted, average LMP: January 1 through March 31, 2016 and 2017

	2016 (Jan-Mar)		2017 (Jan-Mar)		Change
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Percent
Gas	$5.30	19.8%	$12.21	40.3%	20.6%
Coal	$14.78	55.1%	$9.81	32.4%	(22.7%)
Markup	$1.13	4.2%	$3.81	12.6%	8.4%
VOM	$2.04	7.6%	$1.34	4.4%	(3.2%)
Increase Generation Adder	$0.19	0.7%	$0.96	3.2%	2.5%
LPA Rounding Difference	$0.21	0.8%	$0.51	1.7%	0.9%
NA	$1.66	6.2%	$0.50	1.6%	(4.6%)
NO_x Cost	$0.52	1.9%	$0.43	1.4%	(0.5%)
Oil	$0.51	1.9%	$0.40	1.3%	(0.6%)
Ancillary Service Redispatch Cost	$0.27	1.0%	$0.29	0.9%	(0.0%)
CO_2 Cost	$0.05	0.2%	$0.14	0.5%	0.3%
SO_2 Cost	$0.09	0.3%	$0.06	0.2%	(0.1%)
Municipal Waste	$0.01	0.0%	$0.04	0.1%	0.1%
Other	$0.11	0.4%	$0.02	0.1%	(0.4%)
Market-to-Market Adder	$0.01	0.0%	$0.00	0.0%	(0.0%)
Uranium	$0.00	0.0%	($0.00)	(0.0%)	(0.0%)
Decrease Generation Adder	($0.03)	(0.1%)	($0.01)	(0.0%)	0.1%
Ten Percent Adder	$0.01	0.0%	($0.01)	(0.0%)	(0.1%)
LPA-SCED Differential	($0.01)	(0.0%)	($0.01)	(0.0%)	(0.0%)
Wind	($0.04)	(0.2%)	($0.20)	(0.7%)	(0.5%)
Total	$26.80	100.0%	$30.28	100.0%	0.0%

Table 3-72 Frequency and average shadow price of transmission constraints in PJM: 2016 and January 1 through March 31, 2017

	Frequency		Average Shadow Price	
Description	2016	2017 (Jan-Mar)	2016	2017 (Jan-Mar)
PJM Internal Violated Transmission Constraints	19,536	4,163	$643.04	$367.28
PJM Internal Binding Transmission Constraints	130,855	25,038	$120.13	$104.28
Market to Market Transmission Constraints	54,848	15,964	$264.34	$166.35
All Transmission Constraints	205,239	45,165	$208.44	$150.46

Day-Ahead LMP

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

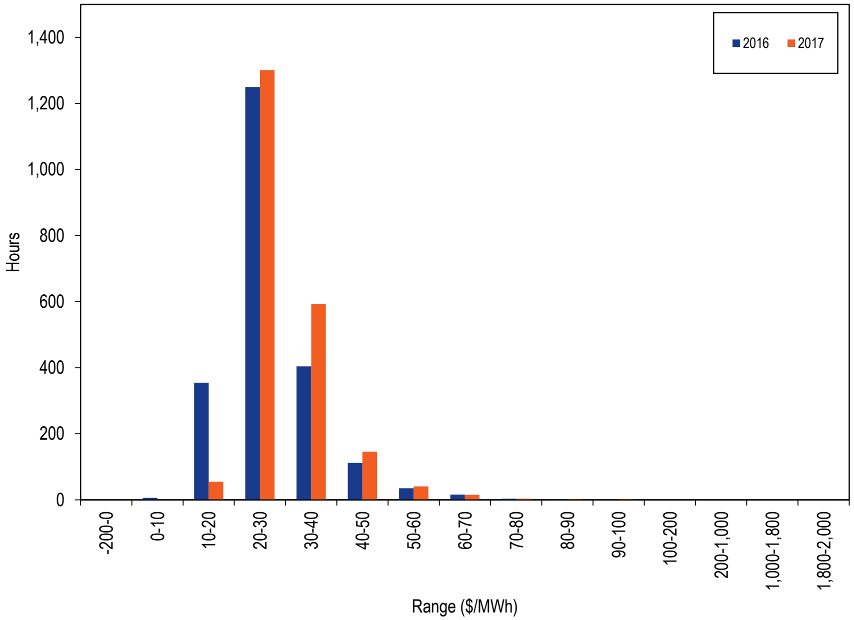
Day-Ahead Average LMP

PJM Day-Ahead Average LMP Duration

Figure 3-44 shows the hourly distribution of PJM day-ahead average LMP in the first three months of 2016 and 2017.

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

Figure 3-44 Average LMP for the PJM Day-Ahead Energy Market: January 1 through March 31, 2016 and 2017



PJM Day-Ahead, Average LMP

Table 3-73 shows the PJM day-ahead, average LMP in the first three months of the 17-year period 2001 through 2017.

Table 3-73 PJM day-ahead, average LMP (Dollars per MWh): January 1 through March 31, 2001 through 2017

	Day-Ahead LMP			Year-to-Year Change		
Jan-Mar	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2001	$36.45	$32.72	$16.39	NA	NA	NA
2002	$22.43	$20.59	$7.56	(38.5%)	(37.1%)	(53.9%)
2003	$51.20	$46.06	$25.65	128.2%	123.7%	239.3%
2004	$45.84	$43.01	$18.85	(10.5%)	(6.6%)	(26.5%)
2005	$45.14	$41.56	$16.19	(1.5%)	(3.4%)	(14.1%)
2006	$51.23	$48.53	$14.16	13.5%	16.8%	(12.6%)
2007	$52.76	$49.43	$22.59	3.0%	1.9%	59.5%
2008	$66.10	$62.57	$23.90	25.3%	26.6%	5.8%
2009	$47.41	$43.43	$16.85	(28.3%)	(30.6%)	(29.5%)
2010	$46.13	$41.99	$15.93	(2.7%)	(3.3%)	(5.5%)
2011	$45.60	$41.10	$16.82	(1.2%)	(2.1%)	5.6%
2012	$30.82	$30.04	$6.63	(32.4%)	(26.9%)	(60.6%)
2013	$36.46	$34.45	$9.78	18.3%	14.7%	47.5%
2014	$86.52	$52.80	$92.80	137.3%	53.3%	848.8%
2015	$48.62	$35.48	$36.77	(43.8%)	(32.8%)	(60.4%)
2016	$26.90	$25.11	$8.83	(44.7%)	(29.2%)	(76.0%)
2017	$29.59	$27.33	$8.54	10.0%	8.8%	(3.3%)

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 3-74 shows the PJM day-ahead, load-weighted, average LMP in the first three months of the 17-year period 2001 through 2017.

Table 3-74 PJM day-ahead, load-weighted, average LMP (Dollars per MWh): January 1 through March 31, 2001 through 2017

	Day-Ahead, Load-Weighted, Average LMP			Year-to-Year Change		
Jan-Mar	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2001	$37.70	$34.55	$16.66	NA	NA	NA
2002	$23.17	$21.18	$7.76	(38.5%)	(38.7%)	(53.4%)
2003	$53.16	$48.69	$25.75	129.5%	129.9%	231.7%
2004	$47.75	$45.02	$19.19	(10.2%)	(7.5%)	(25.4%)
2005	$46.54	$42.88	$16.46	(2.5%)	(4.8%)	(14.2%)
2006	$52.40	$49.51	$14.29	12.6%	15.5%	(13.2%)
2007	$54.87	$51.89	$23.16	4.7%	4.8%	62.0%
2008	$68.00	$64.70	$24.35	23.9%	24.7%	5.1%
2009	$49.44	$44.85	$17.54	(27.3%)	(30.7%)	(28.0%)
2010	$47.77	$43.62	$16.52	(3.4%)	(2.7%)	(5.8%)
2011	$47.14	$42.49	$17.73	(1.3%)	(2.6%)	7.3%
2012	$31.51	$30.44	$6.83	(33.2%)	(28.3%)	(61.5%)
2013	$37.26	$35.02	$10.26	18.3%	15.0%	50.3%
2014	$94.97	$56.53	$102.23	154.9%	61.4%	896.7%
2015	$52.02	$36.94	$40.10	(45.2%)	(34.7%)	(60.8%)
2016	$27.94	$25.99	$9.28	(46.3%)	(29.6%)	(76.8%)
2017	$30.40	$27.99	$8.98	8.8%	7.7%	(3.3%)

Table 3-75 shows zonal day-ahead, and day-ahead, load-weighted, average LMP in the first three months of 2016 and 2017.

Table 3-75 Zone day-ahead and day-ahead, load-weighted, average LMP (Dollars per MWh): January 1 through March 31, 2016 and 2017

	Day-Ahead Average LMP			Day-Ahead, Load-Weighted, Average LMP		
Zone	2016 (Jan-Mar)	2017 (Jan-Mar)	Percent Change	2016 (Jan-Mar)	2017 (Jan-Mar)	Percent Change
AECO	$24.35	$28.77	18.2%	$25.38	$29.62	16.7%
AEP	$26.44	$29.02	9.7%	$27.30	$29.69	8.8%
AP	$27.78	$29.93	7.7%	$28.84	$30.80	6.8%
ATSI	$26.35	$30.03	13.9%	$27.04	$30.69	13.5%
BGE	$36.43	$33.28	(8.6%)	$38.70	$34.70	(10.3%)
ComEd	$23.64	$27.18	15.0%	$24.21	$27.70	14.4%
Day	$26.30	$29.42	11.8%	$27.02	$30.05	11.2%
DEOK	$25.78	$28.40	10.2%	$26.55	$29.05	9.4%
DLCO	$25.99	$29.28	12.6%	$26.71	$29.89	11.9%
Dominion	$31.17	$31.14	(0.1%)	$33.27	$32.59	(2.1%)
DPL	$30.52	$31.33	2.7%	$32.49	$32.80	0.9%
EKPC	$25.42	$28.17	10.8%	$26.41	$29.21	10.6%
JCPL	$23.04	$29.50	28.0%	$24.08	$30.42	26.3%
Met-Ed	$23.10	$29.42	27.4%	$23.96	$30.26	26.3%
PECO	$22.57	$28.49	26.2%	$23.56	$29.29	24.3%
PENELEC	$25.42	$29.11	14.5%	$26.45	$29.77	12.6%
Pepco	$32.88	$32.12	(2.3%)	$34.70	$33.32	(4.0%)
PPL	$23.23	$29.19	25.6%	$24.20	$30.01	24.0%
PSEG	$24.20	$29.85	23.3%	$25.19	$30.68	21.8%
RECO	$23.74	$30.00	26.4%	$24.56	$30.74	25.2%
PJM	$26.90	$29.59	10.0%	$27.94	$30.40	8.8%

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

Figure 3-45 shows the PJM day-ahead, monthly and annual, load-weighted LMP from June 2000 through March 2017.[79] The PJM day-ahead monthly load-weighted average LMP in May 2016 was $24.32, which is the lowest day-ahead monthly load-weighted average since May 2002 at $23.74.

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

Figure 3-45 Day-ahead, monthly and annual, load-weighted, average LMP: June 1, 2000 through March 31, 2017

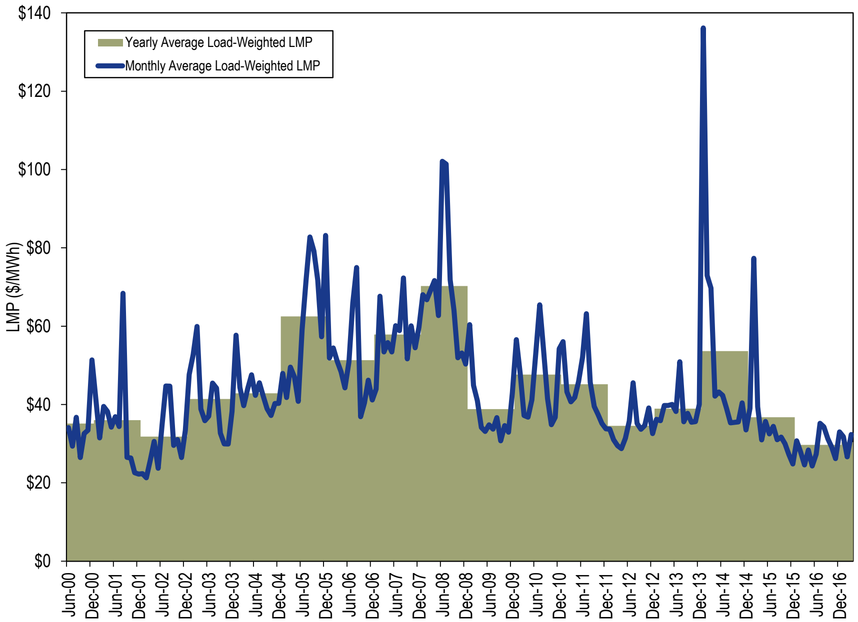
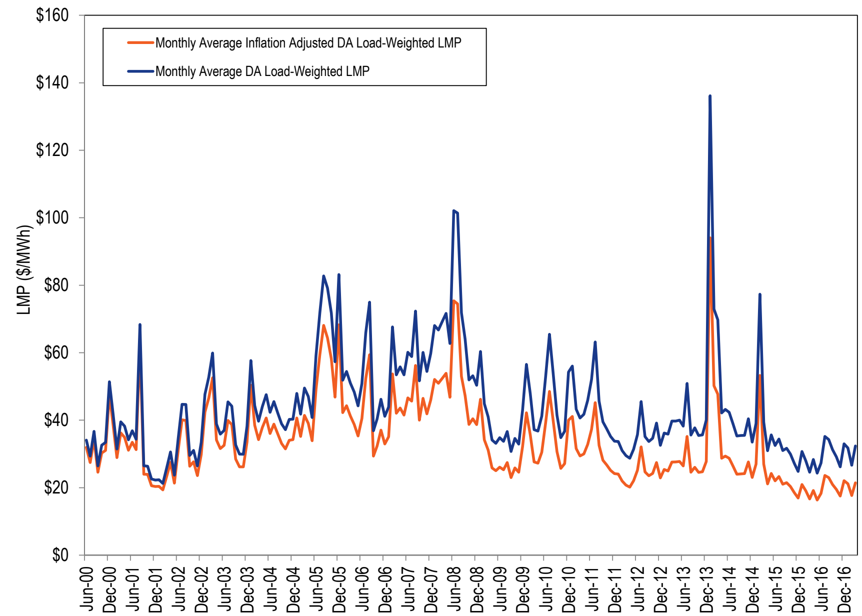


Figure 3-46 PJM day-ahead, monthly, load-weighted, average LMP and day-ahead, monthly inflation adjusted load-weighted, average LMP: June 1, 2000 through March 31, 2017



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

Figure 3-48 shows the PJM day-ahead monthly load-weighted average LMP and inflation adjusted monthly day-ahead load-weighted average LMP for June 2000 through December 2016.[80] The PJM day-ahead inflation adjusted monthly load-weighted average LMP in May 2016 was $16.36, which is the lowest day-ahead monthly load-weighted average real LMP observed since PJM day-ahead markets started in 2000. Table 3-76 shows the PJM day-ahead yearly load- weighted average LMP and inflation adjusted yearly load-weighted average LMP for the first three months of every year from 2000 through 2017.

80 To obtain the inflation adjusted monthly load-weighted average LMP, the PJM system-wide load-weighted average LMP is deflated using US Consumer Price Index for all items, Urban Consumers (base period: January 1998), published by *Bureau of Labor Statistics*. <http://download.bls.gov/pub/time.series/cu/cu.data.1.AllItems>. (April 22, 2017).

Table 3-76 PJM day-ahead, yearly, load-weighted, average LMP and day-ahead, yearly inflation adjusted load-weighted, average LMP: January 1 through March 31, 2000 through 2017

Year	Load-Weighted, Average LMP	Inflation Adjusted Load-Weighted, Average LMP
2001	$37.70	$34.68
2002	$23.17	$21.04
2003	$53.16	$46.94
2004	$47.75	$41.47
2005	$46.54	$39.19
2006	$52.40	$42.57
2007	$54.87	$43.51
2008	$68.00	$51.82
2009	$49.44	$37.71
2010	$47.77	$35.59
2011	$47.14	$34.41
2012	$31.51	$22.35
2013	$37.26	$25.98
2014	$94.97	$65.40
2015	$52.02	$35.80
2016	$27.94	$19.03
2017	$30.40	$20.18

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 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.[81] 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 cost.

Table 3-77 shows the components of the PJM day-ahead, annual, load-weighted average LMP. In the first three months of 2017, 21.0 percent of the load-weighted LMP was the result of coal cost, 21.1 percent of the load-weighted LMP was the result of gas cost, 3.4 percent was the result of the up to congestion transaction cost, 24.7 percent was the result of DEC bid cost and 19.5 percent was the result of INC bid cost.

Table 3-77 Components of PJM day-ahead, (unadjusted), load-weighted, average LMP (Dollars per MWh): January 1 through March 31, 2016 and 2017

	2016 (Jan - Mar)		2017 (Jan - Mar)		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change Percent
DEC	$5.82	20.8%	$7.52	24.7%	3.9%
Gas	$3.55	12.7%	$6.40	21.1%	8.4%
Coal	$10.95	39.2%	$6.38	21.0%	(18.2%)
INC	$3.84	13.8%	$5.94	19.5%	5.8%
Ten Percent Cost Adder	$1.65	5.9%	$1.40	4.6%	(1.3%)
Up to Congestion Transaction	$1.29	4.6%	$1.04	3.4%	(1.2%)
VOM	$1.39	5.0%	$0.81	2.7%	(2.3%)
NO_x	$0.37	1.3%	$0.28	0.9%	(0.4%)
Dispatchable Transaction	$0.42	1.5%	$0.26	0.9%	(0.6%)
Markup	($1.63)	(5.8%)	$0.20	0.6%	6.5%
CO_2	$0.04	0.1%	$0.09	0.3%	0.1%
SO_2	$0.07	0.2%	$0.04	0.1%	(0.1%)
Oil	$0.06	0.2%	$0.03	0.1%	(0.1%)
Other	$0.11	0.4%	$0.01	0.0%	(0.4%)
Constrained Off	$0.01	0.0%	$0.00	0.0%	(0.0%)
DASR LOC Adder	$0.02	0.1%	$0.00	0.0%	(0.1%)
DASR Offer Adder	$0.00	0.0%	$0.00	0.0%	(0.0%)
Wind	($0.01)	(0.1%)	($0.01)	(0.0%)	0.0%
NA	($0.00)	(0.0%)	$0.00	0.0%	0.0%
Total	$27.94	100.0%	$30.40	100.0%	(0.0%)

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

Table 3-78 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, gas or oil units.

Table 3-78 Components of PJM day-ahead, (adjusted), load-weighted, average LMP (Dollars per MWh): January 1 through March 31, 2016 and 2017

	2016 (Jan - Mar)		2017 (Jan - Mar)		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change Percent
DEC	$5.82	20.8%	$7.52	24.7%	3.9%
Gas	$3.55	12.7%	$6.40	21.1%	8.4%
Coal	$10.95	39.2%	$6.38	21.0%	(18.2%)
INC	$3.84	13.8%	$5.94	19.5%	5.8%
Markup	$0.00	0.0%	$1.56	5.1%	5.1%
Up to Congestion Transaction	$1.29	4.6%	$1.04	3.4%	(1.2%)
VOM	$1.39	5.0%	$0.81	2.7%	(2.3%)
NO_x	$0.37	1.3%	$0.28	0.9%	(0.4%)
Dispatchable Transaction	$0.42	1.5%	$0.26	0.9%	(0.6%)
CO_2	$0.04	0.1%	$0.09	0.3%	0.1%
SO_2	$0.07	0.2%	$0.04	0.1%	(0.1%)
Ten Percent Cost Adder	$0.02	0.1%	$0.04	0.1%	0.1%
Oil	$0.06	0.2%	$0.03	0.1%	(0.1%)
Other	$0.11	0.4%	$0.01	0.0%	(0.4%)
Constrained Off	$0.01	0.0%	$0.00	0.0%	(0.0%)
DASR LOC Adder	$0.02	0.1%	$0.00	0.0%	(0.1%)
DASR Offer Adder	$0.00	0.0%	$0.00	0.0%	(0.0%)
Wind	($0.01)	(0.1%)	($0.01)	(0.0%)	0.0%
NA	($0.00)	(0.0%)	$0.00	0.0%	0.0%
Total	$27.94	100.0%	$30.40	100.0%	(0.0%)

Price Convergence

The introduction of the PJM Day-Ahead Energy Market with virtuals as part of the design created the possibility that competition, exercised through the use of virtual offers and bids, could tend to cause prices in the Day-Ahead and Real-Time Energy Markets to converge more than would be the case without virtuals. 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 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 profit from 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.

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.

Table 3-79 shows the number of cleared UTC transactions, the number of profitable cleared UTCs, the number of cleared UTCs that were profitable at their source point and the number of cleared UTCs that were profitable at their sink point in the first three months of 2016 and 2017. In the first three months of 2017, 53.0 percent of all cleared UTC transactions were net profitable. Of cleared UTC transactions, 66.1 percent were profitable on the source side and 34.4 were profitable on the sink side but only 4.9 percent were profitable on both the source and sink side.

Table 3-79 Cleared UTC profitability by source and sink point: January 1 through March 31, 2016 and 2017[82]

Jan-Mar	Cleared UTCs	Profitable UTCs	UTC Profitable at Source Bus	UTC Profitable at Sink Bus	Profitable UTC	Profitable Source	Profitable Sink
2016	4,549,904	2,160,463	3,192,971	1,290,673	47.5%	70.2%	28.4%
2017	6,164,808	3,267,720	4,072,387	2,123,007	53.0%	66.1%	34.4%

Figure 3-47 shows total UTC daily gross profits and losses and net profits and losses in the first three months of 2017.

Figure 3-47 UTC daily gross profits and losses and net profits: January 1 through March 31, 2017[83]

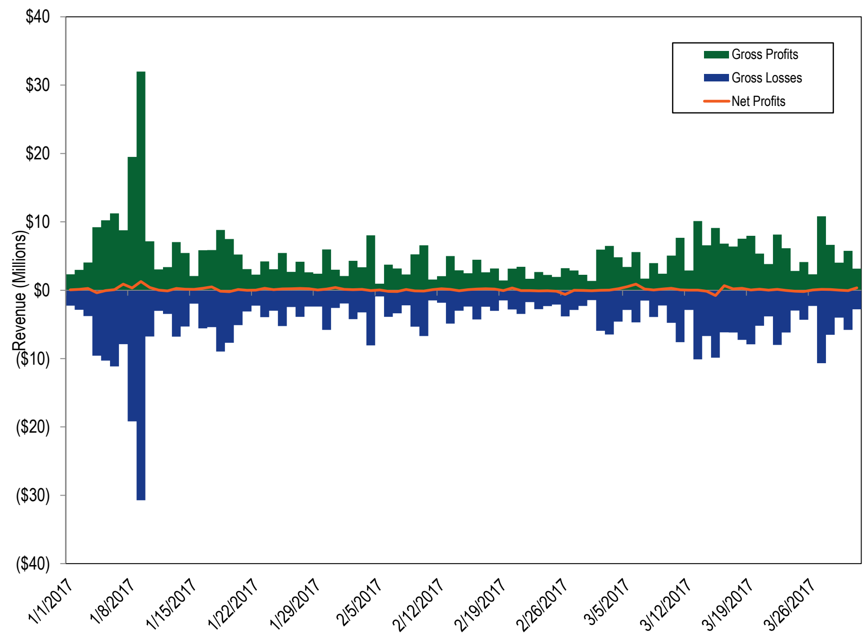


Figure 3-48 shows the cumulative UTC daily profits for the years 2013 through 2016. UTC profits during this period were primarily a result of significant unanticipated price differences between day ahead and real time LMPs. For example, the cumulative daily UTC profits in 2014 were greater than for the other three years as a result of profits from the significant and unanticipated day-ahead and real-time price differences that resulted from the polar vortex conditions in January 2014. Similarly, cumulative daily UTC profits increased during late February 2015 as a result of profits from the significant day-ahead and real-time prices differences that resulted from cold weather conditions. The cumulative daily UTC profits for 2016 are the lowest of these four years as a result of low and stable LMPs and stable prices during 2016.

82 Calculations exclude PJM administrative charges.

83 Calculations exclude PJM administrative charges.

Figure 3-48 Cumulative daily UTC profits: January 1, 2013 through March 31, 2017

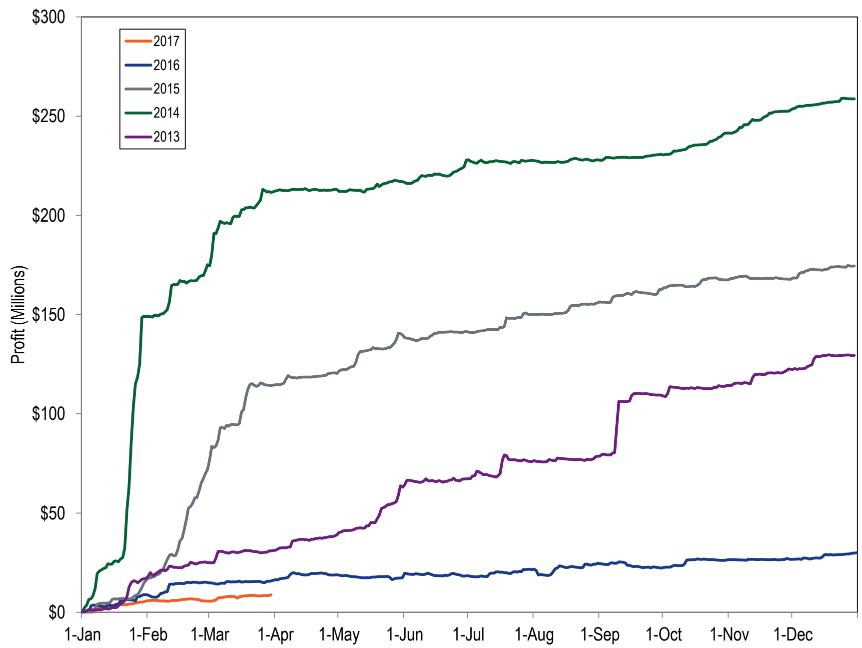


Table 3-80 shows UTC profits by month for 2013 through March 2017. May 2016, September 2016 and February 2017 were the only months in the past five years where the total monthly profits were negative.

There are incentives to use virtual transactions to profit from 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 3-50).

Analysis of the data from September 1, 2013, through September 30, 2015, 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 3-80 UTC profits by month: January 1, 2013 through March 31, 2017

	January	February	March	April	May	June	July	August	September	October	November	December	Total
2013	$17,048,654	$8,304,767	$5,629,392	$7,560,773	$25,219,947	$3,484,372	$8,781,526	$2,327,168	$31,160,618	$4,393,583	$8,730,701	$6,793,990	$129,435,490
2014	$148,973,434	$23,235,621	$39,448,716	$1,581,786	$3,851,636	$7,353,460	$3,179,356	$287,824	$2,727,763	$10,889,817	$11,042,443	$6,191,101	$258,762,955
2015	$16,132,319	$53,830,098	$44,309,656	$6,392,939	$19,793,475	$824,817	$8,879,275	$5,507,608	$6,957,012	$4,852,454	$392,876	$6,620,581	$174,493,110
2016	$8,874,363	$6,118,477	$1,119,457	$2,768,591	($1,333,563)	$841,706	$3,128,346	$3,200,573	($2,518,408)	$4,216,717	$254,684	$3,271,368	$29,942,312
2017	$5,716,757	($17,860)	$3,083,173										$8,782,071

Table 3-81 shows that the difference between the average real-time price and the average day-ahead price was -$1.30 per MWh in the first three months of 2016, and -$0.20 per MWh in the first three months of 2017. The difference between average peak real-time price and the average peak day-ahead price was -$0.96 per MWh in the first three months of 2016 and -$0.70 per MWh in the first three months of 2017.

Table 3-81 Day-ahead and real-time average LMP (Dollars per MWh): January 1 through March 31, 2016 and 2017[84]

	Jan-Mar 2016				Jan-Mar 2017			
	Day-Ahead	Real-Time	Difference	Percent of Real Time	Day-Ahead	Real-Time	Difference	Percent of Real Time
Average	$26.90	$25.60	($1.30)	(5.1%)	$29.59	$29.39	($0.20)	(0.7%)
Median	$25.11	$22.91	($2.20)	(9.6%)	$27.33	$25.71	($1.62)	(6.3%)
Standard deviation	$8.83	$12.99	$4.15	32.0%	$8.54	$12.28	$3.74	30.5%
Peak average	$29.85	$28.89	($0.96)	(3.3%)	$32.48	$31.77	($0.70)	(2.2%)
Peak median	$27.68	$24.72	($2.96)	(12.0%)	$30.39	$27.91	($2.47)	(8.9%)
Peak standard deviation	$8.00	$13.87	$5.88	42.3%	$8.54	$12.44	$3.90	31.4%
Off peak average	$24.28	$22.69	($1.59)	(7.0%)	$26.99	$27.24	$0.25	0.9%
Off peak median	$22.44	$20.87	($1.57)	(7.5%)	$24.42	$23.79	($0.63)	(2.6%)
Off peak standard deviation	$8.72	$11.39	$2.67	23.5%	$7.66	$11.74	$4.07	34.7%

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 3-82 shows the difference between the real-time and the day-ahead energy market prices for the first three months of 2001 through 2017.

Table 3-82 Day-ahead and real-time average LMP (Dollars per MWh): January 1 through March 31, 2001 through 2017

Jan-Mar	Day-Ahead	Real-Time	Difference	Percent of Real Time
2001	$36.45	$33.77	($2.68)	(7.3%)
2002	$22.43	$22.23	($0.20)	(0.9%)
2003	$51.20	$49.57	($1.63)	(3.2%)
2004	$45.84	$46.37	$0.52	1.1%
2005	$45.14	$46.51	$1.37	3.0%
2006	$51.23	$52.98	$1.75	3.4%
2007	$52.76	$55.34	$2.58	4.9%
2008	$66.10	$66.75	$0.65	1.0%
2009	$47.41	$47.29	($0.12)	(0.2%)
2010	$46.13	$44.13	($2.00)	(4.3%)
2011	$45.60	$44.76	($0.84)	(1.8%)
2012	$30.82	$30.38	($0.43)	(1.4%)
2013	$36.46	$36.33	($0.13)	(0.4%)
2014	$86.52	$84.04	($2.48)	(2.9%)
2015	$48.62	$47.39	($1.23)	(2.5%)
2016	$26.90	$25.60	($1.30)	(4.8%)
2017	$29.59	$29.39	($0.20)	(0.7%)

Table 3-83 provides frequency distributions of the differences between PJM real-time hourly LMP and PJM day-ahead hourly LMP for the first three months of 2007 through 2017.

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

Table 3-83 Frequency distribution by hours of PJM real-time LMP minus day-ahead LMP (Dollars per MWh): January 1 through March 31, 2007 through 2017

Jan-Mar	2007		2008		2009		2010		2011		2012		2013		2014	
LMP	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent
< ($1,000)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
($1,000) to ($750)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	2	0.09%
($750) to ($500)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	3	0.23%
($500) to ($450)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	1	0.28%
($450) to ($400)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	6	0.56%
($400) to ($350)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	5	0.79%
($350) to ($300)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	5	1.02%
($300) to ($250)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	6	1.30%
($250) to ($200)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	14	1.95%
($200) to ($150)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	14	2.59%
($150) to ($100)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	1	0.05%	0	0.00%	0	0.00%	45	4.68%
($100) to ($50)	14	0.65%	21	0.96%	1	0.05%	5	0.23%	17	0.83%	2	0.09%	0	0.00%	88	8.75%
($50) to $0	1,214	56.88%	1,309	60.93%	1,347	62.44%	1,569	72.90%	1,464	68.64%	1,566	71.83%	1,542	71.42%	1,242	66.28%
$0 to $50	847	96.11%	740	94.82%	788	98.93%	547	98.24%	619	97.31%	601	99.36%	587	98.61%	595	93.84%
$50 to $100	73	99.49%	97	99.27%	21	99.91%	33	99.77%	51	99.68%	12	99.91%	23	99.68%	55	96.39%
$100 to $150	7	99.81%	14	99.91%	2	100.00%	1	99.81%	6	99.95%	2	100.00%	3	99.81%	27	97.64%
$150 to $200	0	99.81%	1	99.95%	0	100.00%	4	100.00%	1	100.00%	0	100.00%	3	99.95%	16	98.38%
$200 to $250	1	99.86%	1	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	99.95%	9	98.80%
$250 to $300	1	99.91%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	1	100.00%	8	99.17%
$300 to $350	2	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	2	99.26%
$350 to $400	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	3	99.40%
$400 to $450	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	1	99.44%
$450 to $500	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	99.44%
$500 to $750	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	7	99.77%
$750 to $1,000	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	99.77%
$1,000 to $1,250	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	1	99.81%
>= $1,250	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	4	100.00%

Table 3-83 Frequency distribution by hours of PJM real-time LMP minus day-ahead LMP (Dollars per MWh): January 1 through March 31, 2007 through 2017 (continued)

Jan-Mar	2015		2016		2017	
LMP	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent
< ($1,000)	0	0.00%	0	0.00%	0	0.00%
($1,000) to ($750)	0	0.00%	0	0.00%	0	0.00%
($750) to ($500)	0	0.00%	0	0.00%	0	0.00%
($500) to ($450)	0	0.00%	0	0.00%	0	0.00%
($450) to ($400)	0	0.00%	0	0.00%	0	0.00%
($400) to ($350)	0	0.00%	0	0.00%	0	0.00%
($350) to ($300)	0	0.00%	0	0.00%	0	0.00%
($300) to ($250)	0	0.00%	0	0.00%	0	0.00%
($250) to ($200)	0	0.00%	0	0.00%	0	0.00%
($200) to ($150)	2	0.09%	0	0.00%	0	0.00%
($150) to ($100)	12	0.65%	0	0.00%	0	0.00%
($100) to ($50)	43	2.64%	0	0.00%	0	0.00%
($50) to $0	1,504	72.30%	1,657	75.90%	1,443	66.84%
$0 to $50	516	96.20%	514	99.45%	707	99.58%
$50 to $100	54	98.70%	8	99.82%	8	99.95%
$100 to $150	21	99.68%	4	100.00%	1	100.00%
$150 to $200	5	99.91%	0	100.00%	0	100.00%
$200 to $250	1	99.95%	0	100.00%	0	100.00%
$250 to $300	1	100.00%	0	100.00%	0	100.00%
$300 to $350	0	100.00%	0	100.00%	0	100.00%
$350 to $400	0	100.00%	0	100.00%	0	100.00%
$400 to $450	0	100.00%	0	100.00%	0	100.00%
$450 to $500	0	100.00%	0	100.00%	0	100.00%
$500 to $750	0	100.00%	0	100.00%	0	100.00%
$750 to $1,000	0	100.00%	0	100.00%	0	100.00%
$1,000 to $1,250	0	100.00%	0	100.00%	0	100.00%
>= $1,250	0	100.00%	0	100.00%	0	100.00%

Figure 3-49 shows the hourly differences between day-ahead and real-time hourly LMP in the first three months of 2017.

Figure 3-49 Real-time hourly LMP minus day-ahead hourly LMP: January 1 through March 31, 2017

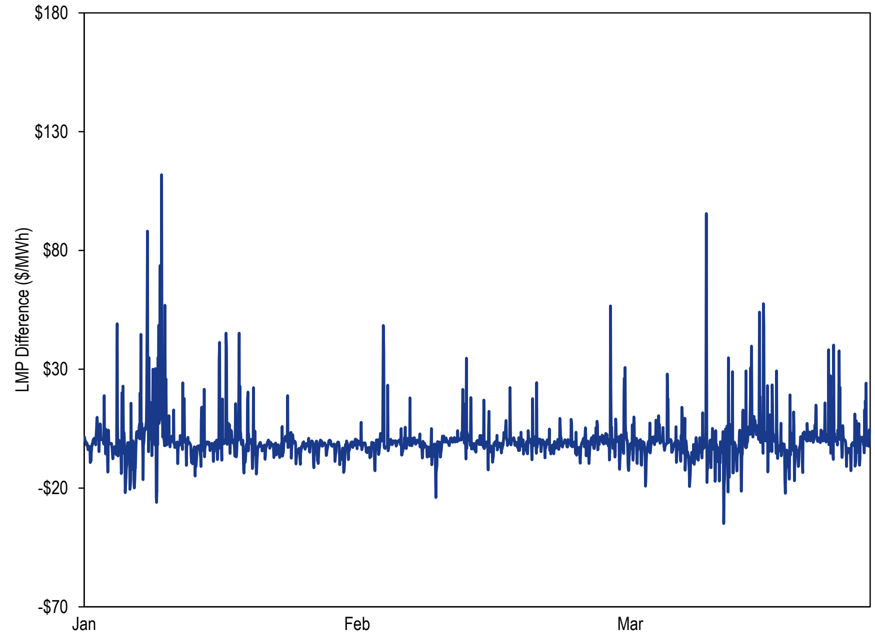


Figure 3-50 shows the monthly average of the differences between the day-ahead and real-time PJM average LMPs from January 2013, through March 2017.

Figure 3-50 Monthly average of real-time minus day-ahead LMP: January 1, 2013 through March 31, 2017

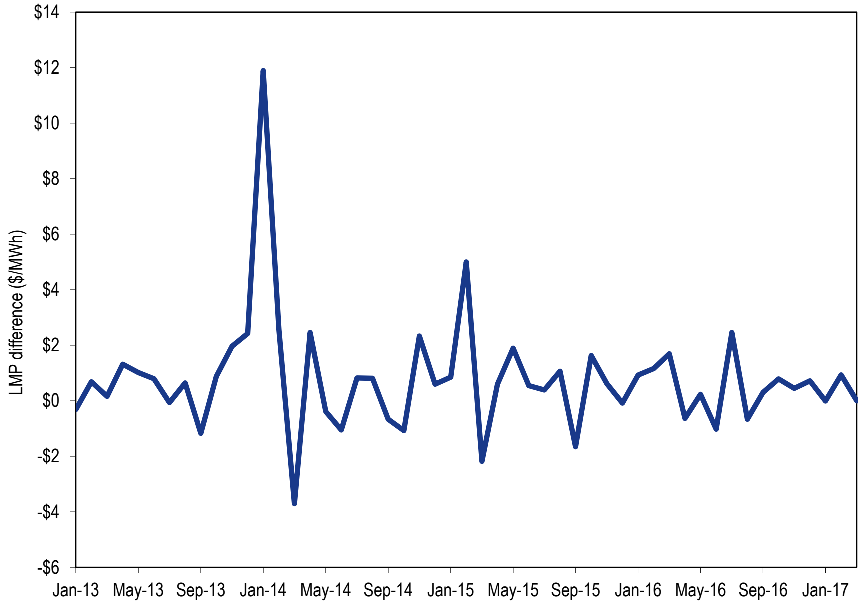


Figure 3-51 shows the monthly average of the absolute value of the differences between the day-ahead and real-time hourly, nodal LMPs from January 2013, through March 2017.

Figure 3-51 Monthly average of the absolute value of real-time minus day-ahead LMP by pnode: January 1, 2013 through March 31, 2017

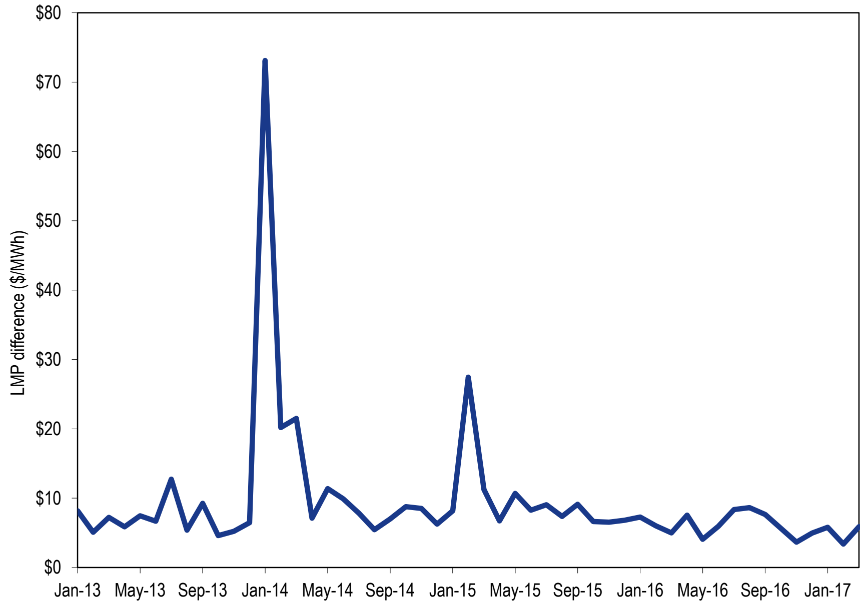
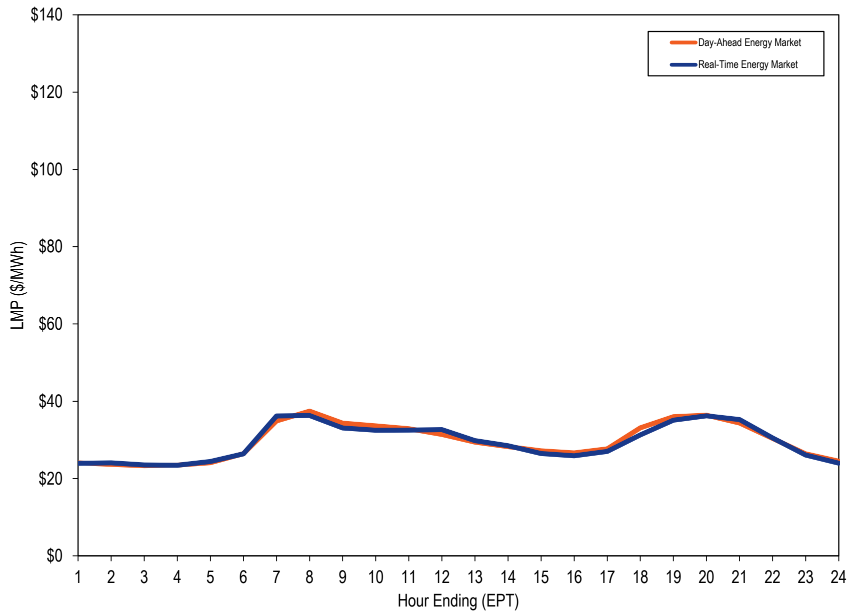


Figure 3-52 shows day-ahead and real-time LMP on an average hourly basis for the first three months of 2017.

Figure 3-52 PJM system hourly average LMP: January 1 through March 31, 2017



Scarcity

PJM's Energy Market experienced no shortage pricing events in the first three months of 2017. Table 3-84 shows a summary of the number of days emergency alerts, warnings and actions were declared in PJM in the first three months of 2016 and 2017.

Table 3-84 Summary of emergency events declared: January 1 through March 31, 2016 and 2017

	Number of days events declared	
Event Type	Jan - Mar, 2016	Jan - Mar, 2017
Cold Weather Alert	4	0
Hot Weather Alert	0	0
Maximum Emergency Generation Alert	0	0
Primary Reserve Alert	0	0
Voltage Reduction Alert	0	0
Primary Reserve Warning	0	0
Voltage Reduction Warning	0	0
Pre Emergency Mandatory Load Management Reduction Action	0	0
Emergency Mandatory Load Management Reduction Action (30, 60 or 120 minute lead time)	0	0
Maximum Emergency Action	0	0
Emergency Energy Bids Requested	0	0
Voltage Reduction Action	0	0
Shortage Pricing	0	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 did not declare any cold weather alerts in the first three months of 2017 compared to four days in the first three months of 2016.[85] 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 10 degrees Fahrenheit.

PJM did not declare any hot weather alerts in the first three months of 2017 and 2016.[86] The purpose of a hot weather alert is to prepare personnel and facilities for expected extreme hot and humid weather conditions, generally

85 See PJM. "Manual 13: Emergency Operations," Revision 61 (January 1, 2017), Section 3.3 Cold Weather Alert, p. 54.
86 See PJM. "Manual 13: Emergency Operations," Revision 61 (January 1, 2017), Section 3.4 Hot Weather Alert, p. 58.

when temperatures are forecast to exceed 90 degrees Fahrenheit with high humidity.

PJM did not declare any maximum emergency generation alert in the first three months of 2017 and 2016. 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.[87] 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 the first three months of 2017 and 2016. The purpose of a primary reserve alert is to alert members at least one day prior to the operating day that available primary reserves are anticipated to be short of the primary reserve requirement on the operating day. It is issued when the estimated primary reserves are less than the forecast primary reserve requirement.

PJM did not declare any voltage reduction alert in the first three months of 2017 and 2016. The purpose of a voltage reduction alert is to alert members at least one day prior to the operating day that a voltage reduction may be required on the operating day. It is issued when the estimated operating reserve is less than the forecast synchronized reserve requirement.

PJM did not declare any primary reserve warning in the first three months of 2017 and 2016. 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 noncritical plant load in the first three months of 2017 and 2016. The purpose of a voltage reduction warning and reduction of noncritical plant load is to warn members that available synchronized reserves are less than the synchronized reserve requirement and that a voltage reduction may be required. It can be issued for the RTO or for specific control zones.

PJM did not declare any emergency mandatory load management reductions in the first three months of 2017 and 2016. 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 did not declare any maximum emergency generation actions in the first three months of 2017 and 2016. 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 offers for emergency energy purchases in the first three months of 2017 and 2016.

PJM did not declare any voltage reduction actions in the first three months of 2017 and 2016. 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 nonsynchronized

87 See PJM. "Manual 13: Emergency Operations," Revision 61 (January 1, 2017), Section 2.3.1 Advance Notice Emergency Procedures: Alerts, p. 18.

reserve market clearing prices and locational marginal prices until the voltage reduction action has been terminated.

PJM declared nine synchronized reserve events in the first three months of 2017 compared to three synchronized reserve events in the first three months of 2016.[88] 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 3-85 provides a description of PJM declared emergency procedures.

88 See *2017 Quarterly State of the Market Report for PJM: January through March*, Section 10: Ancillary Service Markets for details on the spinning events.

Table 3-85 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.
Deploy All Resources Action	For emergency events that do not evolve over time, but rather develop rapidly and without prior warning, PJM issues this action to instruct all generation resources to be online immediately and to all load management resources to reduce load immediately.
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.

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.[89] 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 nonsynchronized reserve market clearing prices and the locational marginal price.

In the first three months of 2017, there were no shortage pricing events triggered in PJM.

Final Rule on Shortage Pricing and Settlement Intervals

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").[90] In particular, the price formation NOPR proposed (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.[91]

On June 16, 2016, the Commission issued a Final Rule in which it required each RTO/ISO to settle energy, operating reserves and intertie transactions using the same time intervals that it uses for to dispatch units or schedule these transactions (Order No. 825).[92] In PJM, the energy market dispatch and pricing interval is five minutes, and the order requires PJM to settle energy transactions on a five minute basis. In PJM, the synchronized reserve and regulation market dispatch and pricing interval is five minutes, and the order requires PJM to settle these reserves on a five minute basis. In PJM, intertie transactions are scheduled on fifteen minute intervals, and the order requires PJM to settle intertie transactions on a fifteen minute basis. However, the Commission allowed PJM to propose a shorter time interval for settling intertie transactions.[93]

The Commission also required each RTO/ISO to trigger shortage pricing for any dispatch and pricing interval in which a shortage of energy or operating reserves is indicated by the RTO/ISO's software.[94] In PJM, the rule would require PJM to trigger shortage pricing for any five minute interval when the Real-Time SCED (Security Constrained Economic Dispatch) indicates a shortage of synchronized reserves or primary reserves. Currently in PJM, if the dispatch tools (Intermediate-Term and Real-Time SCED) reflect a shortage of reserves (primary or synchronized) for a time period shorter than a defined threshold (30 minutes) 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. Currently, both Real-Time SCED and Intermediate-Term SCED have to consistently identify that a shortage of a particular reserve product exists for a period of at least 30 minutes to trigger the shortage pricing penalty factor for that reserve product. For example, if Real-Time SCED indicates a shortage of RTO wide primary reserve for an interval but the Intermediate-Term SCED forecasts that the reserve shortage does not extend beyond its first look ahead interval (15 minutes ahead of the Real-Time SCED

89 See OA Schedule 1 § 2.2(d).
90 152 FERC ¶ 61,218 (September 17, 2015).
91 *Id* at P 5.
92 155 FERC ¶ 61,276 (June 16, 2016).
93 *Id* at P 90.
94 *Id* at P 162.

interval), it is considered a transient shortage, and shortage pricing is not implemented. If Real-Time SCED indicates a shortage of RTO wide primary reserve for an interval and the Intermediate-Term SCED forecasts that the reserve shortage extends for at least two look ahead intervals (30 minutes ahead of the Real-Time SCED interval), shortage pricing is implemented. 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.[95]

PJM Compliance Filing on Shortage Pricing

On January 11, 2017, PJM filed proposed tariff revisions to comply with Order No. 825 and requested a simultaneous implementation date of February 1, 2018, for the settlement interval reforms and shortage pricing reforms.[96] In the January 11th Compliance Filing, PJM proposed to implement shortage pricing through the inclusion of the Reserve Penalty Factors in real time LMPs when the real time security constrained economic dispatch software determines that a primary reserve or synchronized reserve shortage exists on a five minute basis.[97]

Accuracy of Reserve Measurement

Under the new shortage pricing mechanism, the determination of shortage of synchronized and primary reserves by the real time SCED software is based on the measured and estimated levels of load, generation, interchange, demand response, and reserves. It also includes discretionary operator inputs to the ASO (Ancillary Service Optimizer) or SCED software. For the new shortage pricing mechanism to accurately reflect reserve shortage conditions, there needs to be accurate measurement of real-time reserves. That does not appear to be the case at present in PJM, but there does not appear to be any reason that PJM cannot implement that capability. Without very accurate measurement of reserves at minute by minute granularity, system operators cannot know with certainty that there is a shortage condition and therefore an appropriate trigger for five minute shortage pricing does not exist. The advantages of five minute shortage pricing are all implicitly based on the premise that the RTO knows accurately whether it is in a shortage condition. If PJM cannot demonstrate that it can accurately measure reserves at minute by minute granularity, it should not implement or continue five minute shortage pricing until it can demonstrate that capability.[98]

The Commission directed in the Final Rule that, to the extent an RTO/ISO needs to enhance its measurement capabilities to implement the shortage pricing requirement, it should propose to do so in its compliance filing.[99] PJM did not propose any enhancements to reserve measurement in the January 11th compliance filing.

The Market Monitor analyzed when shortage pricing would have been triggered in the first three months of 2017 and 2016 if the five minute shortage pricing rule had been in effect. There were two five minute intervals when both the MAD and the RTO synchronized reserves were less than the required levels in the first three months of 2017, compared to 15 such five minute intervals in the first three months of 2016. There were no five minute intervals when the MAD and RTO primary reserves were less than the required levels in the first three months of 2017 and 2016. Table 3-86 shows the number of intervals when five minute reserves were less than the required levels, the average shortage MW, the minimum shortage MW and the maximum shortage MW during the first three months of 2016 and 2017.

95 *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)

96 *See PJM Interconnection LLC*, Order No. 825 Compliance Filing, Docket No. ER17-775 (January 11, 2017) ("January 11th Compliance Filing").

97 PJM also plans to propose changes to the Operating Reserve Demand Curves used to trigger shortage pricing in a separate proceeding.

98 See Comments of the Independent Market Monitor for PJM, Docket No. RM15-24-000 (December 1, 2015) at 9.

99 155 FERC ¶ 61,276 at P 177 (June 16, 2016).

Table 3-86 Five minute reserve shortage statistics: January 1 through March 31, 2016 and 2017

	2016 (Jan - Mar)				2017 (Jan - Mar)			
Product	Number of Five Minute Shortage Intervals	Average of Shortage MW	Minimum Shortage MW	Maximum Shortage MW	Number of Five Minute Shortage Intervals	Average of Shortage MW	Minimum Shortage MW	Maximum Shortage MW
MAD Syncronized Reserve	15	51	9	186	2	52	21	83
RTO Synchronized Reserve	15	51	9	186	2	52	21	83
MAD Primary Reserve	0	NA	NA	NA	0	NA	NA	NA
RTO Primary Reserve	0	NA	NA	NA	0	NA	NA	NA

Table 3-87 shows the required synchronized reserves, the total synchronized reserves, and the shortage MW for the 2 five minute intervals when shortage pricing would have been triggered for synchronized reserve shortage in the first three months of 2017.

Table 3-87 Five minute intervals with synchronized reserve shortages: January 1 through March 31, 2017

Date and Time	Synchronized Reserve Requirement (MW)	Total Synchronized Reserves (MW)	Reserve Shortage (MW)
18-Feb-17 23:00	1,450	1,367	83
18-Feb-17 23:10	1,450	1,429	21

The accuracy of reserve measurement in PJM can be evaluated using historical data on performance during spinning events. The level of tier 1 biasing also reflects PJM dispatchers' estimate of the error in the measurement of tier 1 synchronized reserve. Both of these data sources provide insight into the accuracy of reserve measurement based on actual historical data.

Historical Performance During Spinning Events

Historical data on response from synchronized reserves during spinning events shows the accuracy of PJM reserve estimates. Synchronized reserves consist of tier 1 and tier 2 synchronized reserves that are procured to meet the RTO and Mid-Atlantic reserve requirements. Tier 1 synchronized reserve is comprised of all online resources following economic dispatch and able to ramp up from their current output in response to a synchronized reserve event.[100]

All resources that respond to spinning events are paid for their response. Table 3-88 shows the performance of tier 1 and tier 2 synchronized reserves during spinning events, declared in 2015 and 2016, that lasted at least 10 minutes. In 2015, tier 1 response MW shown in Table 3-88 were measured as the increase in MW from all resources as a response to the spinning event declaration, regardless of whether the units were part of the tier 1 MW estimate. Since the tier 1 response MW to spinning events included resources that were not part of the tier 1 MW estimate, the 2015 estimates for tier 1 response were greater than 100 percent. In 2016, PJM reports tier 1 response only from the units that were part of the estimated tier 1 MW.

Beginning in 2016, PJM started reporting the response to spinning events only from the units that were part of its tier 1 estimate MW. Table 3-88 shows that, in 2016, the tier 1 MW response percent was never greater than 85 percent, with an average tier 1 response of 75 percent.

If PJM is going to trigger shortage pricing based on shortage of synchronized reserves that is calculated based on current estimates, system operators will be relying on estimates of synchronized reserve MW that have historically been inaccurate.

100 See *2017 Quarterly State of the Market Report for PJM: January through March*, Section 10: Ancillary Service Markets at "Tier 1 Synchronized Reserve" for details on Tier 1 synchronized reserves.

Table 3-88 Performance of synchronized reserves during spinning events: March 3, 2015 through March 2017[101]

Spin Event (Date, Hour)	Duration (Minutes)	Tier 1 Estimate MW (Adjusted by DGP)	Tier 1 Response MW	Tier 2 Scheduled MW	Tier 2 Response MW	Tier 1 Response Percent	Tier 2 Response Percent
Mar 3, 2015 12	11	1,079.0	1,365.1	484.4	272.3	126.5%	56.2%
Mar 16, 2015 06	24	541.5	576.4	248.0	180.2	106.4%	72.7%
Mar 17, 2015 19	17	1,428.9	1,693.1	247.2	232.8	118.5%	94.2%
Mar 23, 2015 19	15	851.3	1,420.0	273.5	205.8	166.8%	75.2%
Jul 30, 2015 10	10	1,458.4	2,145.7	79.7	24.0	147.1%	30.1%
Jan 18, 2016 17	12	861.0	733.5	616.7	508.8	85.2%	82.5%
Feb 8, 2016 15	10	1,750.2	1,338.2	228.4	200.1	76.5%	87.6%
Apr 14, 2016 20	10	1,182.8	1,000.6	346.3	304.8	84.6%	88.0%
Jul 28, 2016 13	15	649.4	500.4	822.9	655.8	77.1%	79.7%
Nov 4, 2016 17	11	744.5	497.1	758.0	709.2	66.8%	93.6%
Dec 31, 2016 05	12	971.2	585.0	594.4	485.7	60.2%	81.7%
Mar 23, 2017 06	24	926.8	566.7	742.8	559.1	61.1%	75.3%

Tier 1 Synchronized Reserve Estimate Bias

The tier 1 synchronized reserve for a unit is measured as the lower of the available 10 minute ramp and the difference between the economic dispatch point and the economic maximum output. The total supply of tier 1 synchronized reserve MW available to the market solution is calculated as the sum of the individual units' tier 1 MW, with further adjustments. These adjustments include eliminating tier 1 MW from nuclear, wind, solar, energy storage, and hydro units, adjusting the available tier 1 MW from remaining units using a metric called Degree of Generator Performance (DGP) and using tier 1 estimate bias.[102] Tier 1 biasing occurs when PJM market operations manually modifies (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 nonsynchronized reserve to satisfy the synchronized reserve and primary reserve requirements. Tier 1 biasing reflects the operators' view on the available tier 1 MW in the system and a lack of confidence on the calculated estimates of tier 1 MW, thus forcing the market clearing engine to procure more or less synchronized reserves. Table 10-14 shows the average monthly biasing of tier 1 estimates in the Ancillary Service Optimizer (ASO), the tool used to procure reserves on an hourly basis, in 2015 and 2016.

The existence of tier MW biasing raises the possibility that under a five minute shortage pricing construct, shortage pricing penalty factors may be triggered or avoided not due to actual reserve levels, but by operators' discretionary decisions on the amount of available reserves. It is possible that the market engine's estimate of tier 1 MW, even after unit level adjustments such as DGP, may be enough to satisfy the reserve requirement, but an operator's biasing of the market engine's estimate may lead to triggering shortage pricing penalty factors. There are no rules in the PJM tariff or manuals regarding the use of tier 1 MW biasing. In a five minute shortage pricing construct, the need for explicit rules governing operator discretion regarding reserve estimates becomes critical. The IMM has recommended since 2012 that PJM explicitly define the rules for using tier 1 biasing and identify which rule permits it every time tier 1 synchronized reserve estimate biasing is used.

Generator Data used for Reserve Estimates

A potential source for the error in tier 1 MW is the use of economic dispatch point to calculate the available ramp limited MW in 10 minutes as opposed to the actual metered output from the generator for any 5 minute interval. The amount of tier 1 MW available from a resource may differ due to using the metered output from a unit versus the market clearing engine's estimate of the resource's output. PJM addressed this issue partially in 2015 by adjusting a resource's available 10 minute ramp with its DGP. The available tier 1 MW estimated by the market solution for each resource is adjusted by its DGP percent. PJM communicates to generation operators whose tier 1 MW is part of the market solution the latest estimate of units' tier 1 MW and units' current resource specific DGP.

101 Beginning January 2015, Degree of Generator Performance (DGP) was introduced as a metric to improve the accuracy of the tier 1 MW estimate used by the market solution.

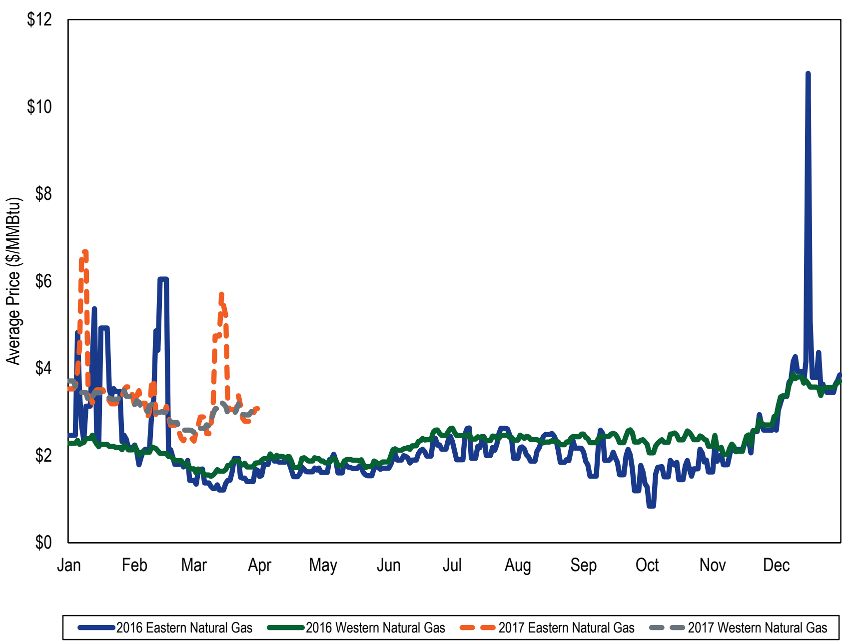
102 DGP measures how closely the unit has been following economic dispatch for the past 30 minutes.

PJM Cold Weather Operations 2017

Natural Gas Supply and Prices

As of March 31, 2017, gas fired generation was 35.9 percent (65,895.5 MW) of the total installed PJM capacity (183,593.6 MW).[103] 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 3-53 shows the average daily price of delivered natural gas for eastern and western parts of PJM service territory in 2017 and 2016.[104]

Figure 3-53 Average daily delivered price for natural gas: January 2016 through March 2017 ($/MMBtu)



103 *2017 Quarterly State of the Market Report for PJM: January through March*, Section 5: Capacity Market, at Installed Capacity.
104 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.

During the first three months of 2015, 2016 and 2017, a number of interstate gas pipelines that supply fuel for generators in the PJM service territory issued restriction notices limiting the availability of nonfirm transportation services. These notices include warnings of operational flow orders (OFO) and actual OFOs. OFOs may, depending on the nature of the transportation service purchased, permit the pipelines to 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 gas day, with penalties for deviating from the nominated quantities. Pipelines may also enforce strict balancing constraints which limit the ability of gas users, depending on the nature of the transportation service purchased, to deviate from the 24 hour ratable take and which may 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 short run marginal costs 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.

Uplift is an inherent part of the PJM market design. Uplift payments should nonetheless be limited to the efficient level. In wholesale power market design, a choice must be made between efficient prices and prices that fully compensate costs. Economists recognize that no single price achieves both goals in markets with nonconvex production costs, like the costs of producing electric power.[2] [3] In wholesale power markets like PJM, efficient prices equal the marginal cost of production by location. The dispatch of generators in accordance with these efficient price signals minimizes the total market cost of production. For generators with nonconvex costs, marginal cost prices may not cover the total cost of starting the generator and running at the efficient output level. Uplift payments cover the difference.

Overview

Energy Uplift Results

- **Energy Uplift Charges.** Total energy uplift charges decreased by $13.9 million, or 35.2 percent, in the first three months of 2017 compared to the first three months of 2016, from $39.5 million to $25.6 million.
- **Energy Uplift Charges Categories.** The decrease of $13.9 million in the first three months of 2017 is comprised of a $16.1 million decrease in day-ahead operating reserve charges, a $3.5 million decrease in balancing operating reserve charges and a $5.6 million increase in reactive services charges.
- **Average Effective Operating Reserve Rates in the Eastern Region.** Day-ahead load paid $0.025 per MWh, real-time load paid $0.028 per MWh, a DEC paid $0.227 per MWh and an INC and any load, generation or interchange transaction deviation paid $0.202 per MWh.
- **Average Effective Operating Reserve Rates in the Western Region.** Day-ahead load paid $0.025 per MWh, real-time load paid $0.024 per MWh, a DEC paid $0.218 per MWh and an INC and any load, generation or interchange transaction deviation paid $0.193 per MWh.
- **Reactive Services Rates.** The PENELEC, BGE and Pepco control zones had the three highest local voltage support rates: $0.232, $0.222 and $0.222 per MWh.

Characteristics of Credits

- **Types of units.** Coal units received 86.5 percent of all day-ahead generator credits. Combustion turbines received 75.6 percent of all balancing generator credits. Combustion turbines and diesels received 68.2 percent of the lost opportunity cost credits.
- **Concentration of Energy Uplift Credits.** The top 10 units receiving energy uplift credits received 44.7 percent of all credits. The top 10

1 Loss exists when gross energy and ancillary services market revenues are less than short run marginal costs, including all elements of the energy offer, which are startup, no load and incremental offers.

2 *See* Stoft, *Power System Economics: Designing Markets for Electricity*, New York: Wiley (2002) at 272; Mas-Colell, Whinston, and Green, *Microeconomic Theory*, New York: Oxford University Press (1995) at 570; and Quinzii, *Increasing Returns and Efficiency*, New York: Oxford University Press (1992).

3 The production of output is convex if the production function has constant or decreasing returns to scale, which result in constant or rising costs average costs with increases in output. Production is nonconvex with increasing returns to scale, which is the case when generating units have start or no load costs that are large relative to marginal costs. *See* Mas-Colell, Whinston, and Green at 132.

organizations received 83.3 percent of all credits. Concentration indexes for energy uplift categories classify them as highly concentrated. Day-ahead operating reserves HHI was 7331, balancing operating reserves HHI was 3764 and lost opportunity cost HHI was 5581.

- **Economic and Noneconomic Generation.** In the first three months of 2017, 85.5 percent of the day-ahead generation eligible for operating reserve credits was economic and 80.1 percent of the real-time generation eligible for operating reserve credits was economic.
- **Day-Ahead Unit Commitment for Reliability.** In the first three months of 2017, 1.2 percent of the total day-ahead generation MWh was scheduled as must run by PJM, of which 60.1 percent received energy uplift payments.

Geography of Charges and Credits

- In the first three months of 2017, 89.0 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, 4.4 percent by transactions at hubs and aggregates and 6.6 percent by interchange transactions at interfaces.
- Generators in the Eastern Region received 58.7 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.
- Generators in the Western Region received 39.7 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.
- External generators received 1.6 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.

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. First reported 2015. Status: Not adopted.)
- The MMU recommends that if PJM believes it appropriate to modify the LMP price setting logic, PJM initiate a stakeholder process to create transparent and consistent modifications to the rules and incorporate the modifications in the PJM tariff. (Priority: Medium. First Reported 2016. 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 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 four additional modifications to the energy lost opportunity cost calculations:
  - 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 for both the injection and the withdrawal sides of the UTC. (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 2012. Status: Not adopted. Stakeholder process.)
- The MMU recommends modifications to the calculation of lost opportunity costs credits paid to wind units. The lost opportunity costs credits paid to wind units should be based on the lesser of the desired output, the estimated output based on actual wind conditions and the capacity interconnection rights (CIRs). In addition, the MMU recommends that PJM allow and wind units submit CIRs that reflect the maximum output wind units want to inject into the transmission system at any time. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM revise Manual 11 attachment C consistent with the tariff to limit compensation to offered costs. The Manual 11 attachment C procedure should describe the steps market participants should take to change the availability of cost-based energy offers that have been submitted day ahead. The MMU recommends that PJM

eliminate the Manual 11 attachment C procedure with the implementation of hourly offers (ER16-372-000). (Priority: Medium. First reported 2016. 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 to make all market participants 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 2015.)
- 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: Partially adopted.)
- 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.)

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 incurred when LMP is greater than or equal to the incremental offer but does not cover start up and no load costs. Loss is defined to be receiving revenue less than the short run marginal costs incurred in order to generate energy. 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 short run 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.

Competitive market outcomes result from energy offers equal to short run marginal costs and that incorporate flexible operating parameters. But when PJM permits a unit to include inflexible operating parameters in its offer and pays uplift based on those inflexible parameters, there is an incentive for the unit to remain inflexible. The rules regarding operating parameters should be implemented in a way that creates incentives for flexible operations rather than inflexible operations. PJM has failed to hold coal, gas and oil steam turbines to the standard used for combined cycles, combustion turbines and diesels. The standard should be the maximum achievable flexibility, based on OEM standards. Applying a weaker standard to steam units effectively subsidizes inflexible units by paying them based on inflexible parameters that result from lack of investment and that could be made more flexible. The result both inflates uplift costs and suppresses energy prices.

In PJM, all energy payments to demand response resources are 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 have 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. Some uplift payments are the result of inflexible operating parameters included in offers by generating units. Operating parameters should reflect the flexibility of the benchmark new entrant unit in the PJM capacity market if the unit is to receive uplift payments from other market participants. 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 incremental, no load and startup costs.

Credits and Charges Categories

Energy uplift charges include day-ahead and balancing operating reserves, reactive services, synchronous condensing and black start services categories. Total energy uplift credits paid to PJM participants equal the total energy uplift charges paid by PJM participants. Table 4-1 and Table 4-2 show the categories of credits and charges and their relationship. These tables show how the charges are allocated.

Table 4-1 Day-ahead and balancing operating reserve credits and charges

Credits Received For:	Credits Category:		Charges Category:	Charges Paid By:	
		Day-Ahead			
Day-Ahead Import Transactions and Generation Resources	Day-Ahead Operating Reserve Transaction Day-Ahead Operating Reserve Generator	→	Day-Ahead Operating Reserve	Day-Ahead Load Day-Ahead Export Transactions Decrement Bids	in RTO Region
Economic Load Response Resources	Day-Ahead Operating Reserves for Load Response	→	Day-Ahead Operating Reserve for Load Response	Day-Ahead Load Day-Ahead Export Transactions Decrement Bids	in RTO Region
	Unallocated Negative Load Congestion Charges Unallocated Positive Generation Congestion Credits	→	Unallocated Congestion	Day-Ahead Load Day-Ahead Export Transactions Decrement Bids	in RTO Region
		Balancing			
Generation Resources	Balancing Operating Reserve Generator	→	Balancing Operating Reserve for Reliability	Real-Time Load plus Real-Time Export Transactions	in RTO, Eastern or Western Region
			Balancing Operating Reserve for Deviations	Deviations	
			Balancing Local Constraint	Applicable Requesting Party	
Canceled Resources Lost Opportunity Cost (LOC) Real-Time Import Transactions	Balancing Operating Reserve Startup Cancellation Balancing Operating Reserve LOC 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 Reactive Services Local Constraint	Zonal Real-Time Load 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 $13.9 million or 35.2 percent in the first three months of 2017 compared to the first three months of 2016. Table 4-3 shows total energy uplift charges in the first three months of 2016 and 2017.[4]

Table 4-3 Total energy uplift charges: January 1 through March 31, 2016 and 2017

	(Jan - Mar) 2016 Charges (Millions)	(Jan - Mar) 2017 Charges (Millions)	Change	Percent Change
Total Energy Uplift	$39.5	$25.6	($13.9)	(35.2%)
Energy Uplift as a Percent of Total PJM Billing	0.4%	0.3%	(0.2%)	(36.6%)

Table 4-4 compares energy uplift charges by category for the first three months of 2016 and 2017. The decrease of $13.9 million in the first three months of 2017 is comprised of a decrease of $16.1 million in day-ahead operating reserve charges and a decrease of $3.5 million in balancing operating reserve charges. These decreases were offset by an increase of $5.6 million in reactive services charges.

Table 4-4 Energy uplift charges by category: January 1 through March 31, 2016 and 2017

Category	(Jan - Mar) 2016 Charges (Millions)	(Jan - Mar) 2017 Charges (Millions)	Change (Millions)	Percent Change
Day-Ahead Operating Reserves	$21.3	$5.2	($16.1)	(75.4%)
Balancing Operating Reserves	$17.9	$14.4	($3.5)	(19.4%)
Reactive Services	$0.3	$5.9	$5.6	2,244.5%
Synchronous Condensing	$0.0	$0.0	$0.0	0.0%
Black Start Services	$0.1	$0.1	$0.0	1.2%
Total	$39.5	$25.6	($13.9)	(35.2%)

4 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 April 14, 2017.

Table 4-5 compares monthly energy uplift charges by category for 2016 and the first three months of 2017.

Table 4-5 Monthly energy uplift charges: January 1, 2016 through March 31, 2017

	2016 Charges (Millions)						2017 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	$7.4	$7.5	$0.0	$0.0	$0.0	$14.9	$2.6	$7.4	$1.25	$0.0	$0.0	$11.3
Feb	$7.6	$6.5	$0.0	$0.0	$0.0	$14.2	$2.0	$1.3	$3.3	$0.0	$0.0	$6.6
Mar	$6.4	$3.9	$0.2	$0.0	$0.0	$10.5	$0.6	$5.7	$1.4	$0.0	$0.0	$7.6
Apr	$3.0	$4.8	$0.2	$0.0	$0.0	$8.0						
May	$2.8	$3.3	$0.1	$0.0	$0.0	$6.3						
Jun	$4.6	$5.3	$0.1	$0.0	$0.1	$10.1						
Jul	$3.6	$10.9	$0.1	$0.0	$0.0	$14.6						
Aug	$2.4	$11.5	$0.0	$0.0	$0.0	$13.9						
Sep	$2.9	$6.9	$0.1	$0.0	$0.0	$9.9						
Oct	$3.6	$8.7	$0.3	$0.0	$0.0	$12.6						
Nov	$5.7	$2.8	$1.0	$0.0	$0.1	$9.5						
Dec	$7.3	$4.5	$0.4	$0.0	$0.0	$12.2						
Total (Jan - Mar)	$21.3	$17.9	$0.3	$0.0	$0.1	$39.5	$5.2	$14.4	$5.9	$0.0	$0.1	$25.6
Share (Jan - Mar)	54.0%	45.3%	0.6%	0.0%	0.1%	100.0%	20.5%	56.3%	22.9%	0.0%	0.2%	100.0%
Total	$57.3	$76.5	$2.5	$0.0	$0.3	$136.6	$5.2	$14.4	$5.9	$0.0	$0.1	$25.6
Share	42.0%	56.0%	1.8%	0.0%	0.2%	100.0%	20.5%	56.3%	22.9%	0.0%	0.2%	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.[5] Day-ahead operating reserve charges decreased by $16.1 million or 75.4 percent in the first three months of 2017 compared to the first three months of 2016.

Table 4-6 Day-ahead operating reserve charges: January 1 through March 31, 2016 and 2017

Type	(Jan - Mar) 2016 Charges (Millions)	(Jan - Mar) 2017 Charges (Millions)	Change (Millions)	(Jan - Mar) 2016 Share	(Jan - Mar) 2017 Share
Day-Ahead Operating Reserve Charges	$21.3	$5.2	($16.1)	100.0%	100.0%
Day-Ahead Operating Reserve Charges for Load Response	$0.0	$0.0	($0.0)	0.0%	0.0%
Unallocated Congestion Charges	$0.0	$0.0	$0.0	0.0%	0.0%
Total	$21.3	$5.2	($16.1)	100.0%	100.0%

5 See OA Schedule 1 § 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 10 times, totaling $26.9 million.

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 $3.5 million in the first three months of 2017 compared to the first three months of 2016.

Table 4-7 Balancing operating reserve charges: January 1 through March 31, 2016 and 2017

Type	(Jan - Mar) 2016 Charges (Millions)	(Jan - Mar) 2017 Charges (Millions)	Change (Millions)	(Jan - Mar) 2016 Share	(Jan - Mar) 2017 Share
Balancing Operating Reserve Reliability Charges	$5.0	$5.7	$0.6	28.2%	39.3%
Balancing Operating Reserve Deviation Charges	$12.8	$8.7	($4.1)	71.5%	60.5%
Balancing Operating Reserve Charges for Load Response	$0.0	$0.0	$0.0	0.0%	0.1%
Balancing Local Constraint Charges	$0.1	$0.0	($0.0)	0.3%	0.1%
Total	$17.9	$14.4	($3.5)	100.0%	100.0%

Table 4-8 shows the composition of the balancing operating reserve deviation charges. Balancing operating reserve deviation charges equal make whole credits paid to generators and import transactions, energy lost opportunity costs paid to generators and payments to resources canceled by PJM before coming online. In the first three months of 2017, 81.7 percent of balancing operating reserve deviation charges were for make whole credits paid to generators and import transactions, an increase of 19.8 percentage points compared to the share in the first three months of 2016.

Table 4-8 Balancing operating reserve deviation charges: January 1 through March 31, 2016 and 2017

Charge Attributable To	(Jan - Mar) 2016 Charges (Millions)	(Jan - Mar) 2017 Charges (Millions)	Change (Millions)	(Jan - Mar) 2016 Share	(Jan - Mar) 2017 Share
Make Whole Payments to Generators and Imports	$7.9	$7.1	($0.8)	62.0%	81.7%
Energy Lost Opportunity Cost	$4.9	$1.6	($3.3)	37.9%	18.2%
Canceled Resources	$0.0	$0.0	($0.0)	0.1%	0.0%
Total	$12.8	$8.7	($4.1)	100.0%	100.0%

Table 4-9 shows reactive services, synchronous condensing and black start services charges. Reactive services charges increased by $5.6 million in the first three months of 2017 compared to the first three months of 2016. Black start services charges and synchronous condensing charges remained at $0.1 million.

Table 4-9 Additional energy uplift charges: January 1 through March 31, 2016 and 2017

Type	(Jan - Mar) 2016 Charges (Millions)	(Jan - Mar) 2017 Charges (Millions)	Change (Millions)	(Jan - Mar) 2016 Share	(Jan - Mar) 2017 Share
Reactive Services Charges	$0.3	$5.9	$5.6	81.4%	99.0%
Synchronous Condensing Charges	$0.0	$0.0	$0.0	0.0%	0.0%
Black Start Services Charges	$0.1	$0.1	$0.0	18.6%	1.0%
Total	$0.3	$5.9	$5.6	100.0%	100.0%

Table 4-10 and Table 4-11 show the amount and percent shares of regional balancing charges in the first three months of 2016 and 2017. Regional balancing operating reserve charges consist of balancing operating reserve reliability and deviation charges. These charges are allocated regionally across PJM. The largest share of regional charges was paid by demand deviations. The regional balancing charges allocation table does not include charges attributed for resources controlling local constraints.

In the first three months of 2017, regional balancing operating reserve charges decreased by $3.4 million compared to the first three months of 2016. Balancing operating reserve reliability charges increased by $0.6 million or 12.4 percent and balancing operating reserve deviation charges decreased by $4.1 million or 31.8 percent.

Table 4-10 Regional balancing charges allocation (Millions): January 1 through March 31, 2016

Charge	Allocation	RTO		East		West		Total	
Reliability Charges	Real-Time Load	$3.2	17.7%	$1.7	9.3%	$0.1	0.6%	$4.9	27.7%
	Real-Time Exports	$0.1	0.3%	$0.1	0.3%	$0.0	0.0%	$0.1	0.6%
	Total	$3.2	18.0%	$1.7	9.6%	$0.1	0.6%	$5.0	28.3%
Deviation Charges	Demand	$5.3	29.8%	$1.9	10.4%	$0.1	0.6%	$7.3	40.8%
	Supply	$2.0	11.1%	$0.5	2.6%	$0.0	0.2%	$2.5	14.0%
	Generator	$2.2	12.3%	$0.8	4.4%	$0.0	0.2%	$3.0	16.9%
	Total	$9.5	53.3%	$3.1	17.4%	$0.2	1.1%	$12.8	71.7%
Total Regional Balancing Charges		$12.7	71.3%	$4.8	27.0%	$0.3	1.7%	$17.8	100%

Table 4-11 Regional balancing charges allocation (Millions): January 1 through March 31, 2017

Charge	Allocation	RTO		East		West		Total	
Reliability Charges	Real-Time Load	$5.0	34.7%	$0.4	3.1%	$0.0	0.3%	$5.5	38.1%
	Real-Time Exports	$0.2	1.2%	$0.0	0.1%	$0.0	0.0%	$0.2	1.3%
	Total	$5.2	35.8%	$0.5	3.2%	$0.0	0.3%	$5.7	39.4%
Deviation Charges	Demand	$4.6	32.3%	$0.1	1.0%	$0.0	0.0%	$4.8	33.3%
	Supply	$1.9	13.3%	$0.1	0.4%	$0.0	0.0%	$2.0	13.8%
	Generator	$1.9	13.2%	$0.0	0.3%	$0.0	0.0%	$2.0	13.6%
	Total	$8.5	58.9%	$0.2	1.7%	$0.0	0.1%	$8.7	60.6%
Total Regional Balancing Charges		$13.6	94.7%	$0.7	4.9%	$0.1	0.4%	$14.4	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. Table 4-1 shows how these charges are allocated.[6]

Figure 4-1 shows the daily day-ahead operating reserve rate for 2016 and the first three months of 2017. The average rate in the first three months of 2017 was $0.026 per MWh, $0.077 per MWh lower than the average in the first three months of 2016. The highest rate in the first three months of 2017 occurred on February 12, when the rate reached $0.172 per MWh, $0.230 per MWh lower than the $0.402 per MWh reached in the first three months of 2016, on February 16. Figure 4-1 also shows the daily day-ahead operating reserve rate including the congestion charges allocated to day-ahead operating reserves. There were no congestion charges allocated to day-ahead operating reserves in 2016 or in the first three months of 2017.

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

Figure 4-1 Daily day-ahead operating reserve rate ($/MWh): January 1, 2016 through March 31, 2017

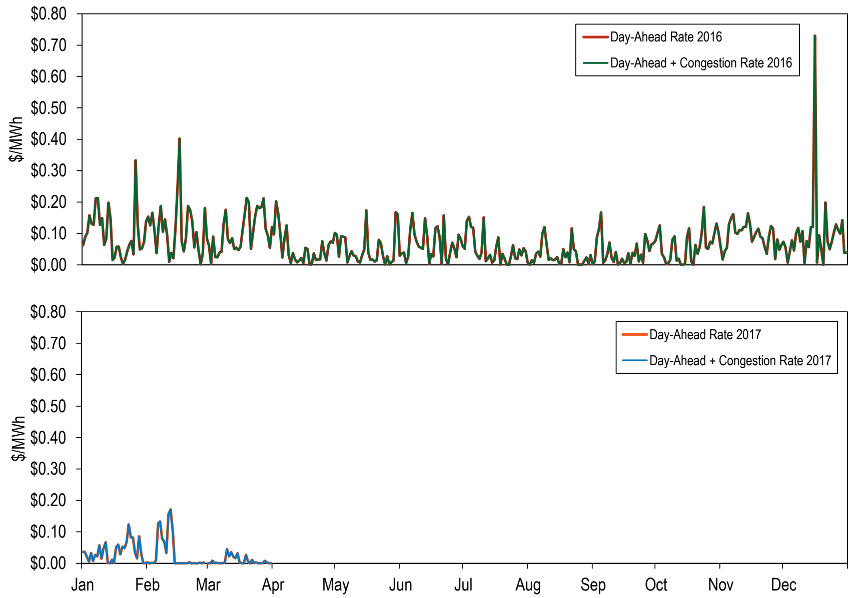


Figure 4-2 Daily balancing operating reserve reliability rates ($/MWh): January 1, 2016 through March 31, 2017

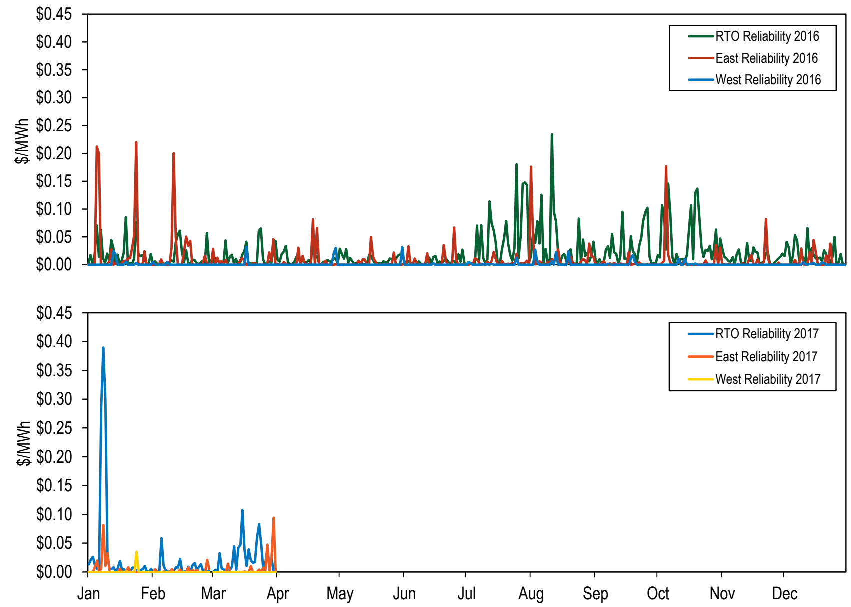


Figure 4-2 shows the RTO and the regional reliability rates for 2016 and the first three months of 2017. The average daily RTO reliability rate was $0.026 per MWh. The highest RTO reliability rate in the first three months of 2017 occurred on January 8, when the rate reached $0.390 per MWh, $0.304 per MWh higher than the $0.085 per MWh rate reached in the first three months of 2016, on January 19.

Figure 4-3 shows the RTO and regional deviation rates for 2016 and the first three months of 2017. The average daily RTO deviation rate was $0.180 per MWh. The highest daily rate in the first three months of 2017 occurred on January 9, when the RTO deviation rate reached $2.176 per MWh, $1.360 per MWh higher than the $0.816 per MWh rate reached in the first there months of 2016, on January 19.

Figure 4-3 Daily balancing operating reserve deviation rates ($/MWh): January 1, 2016 through March 31, 2017

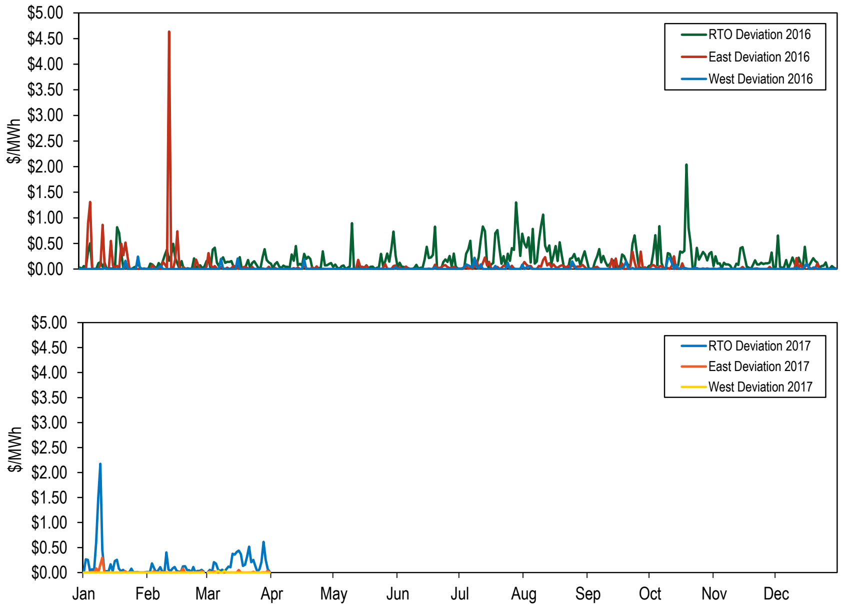


Figure 4-4 Daily lost opportunity cost and canceled resources rates ($/MWh): January 1, 2016 through March 31, 2017

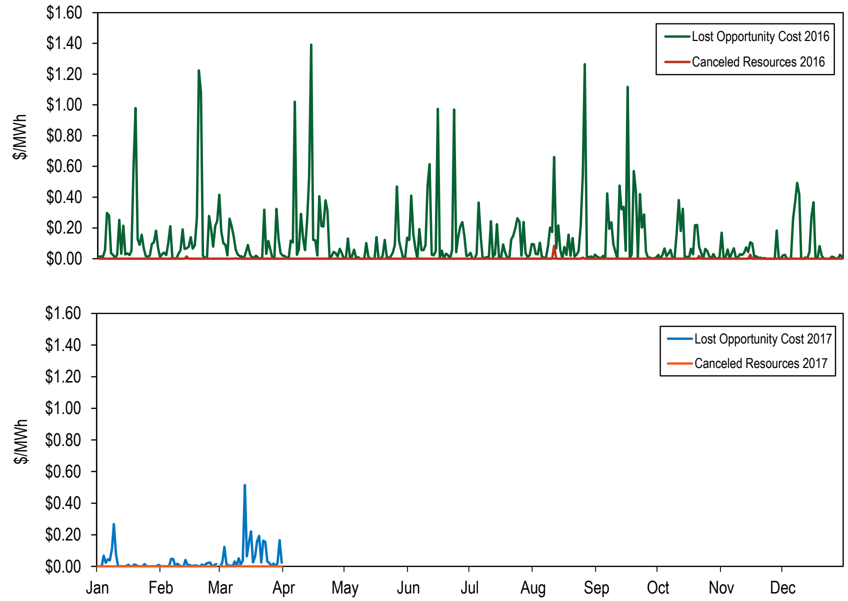


Figure 4-4 shows the daily lost opportunity cost rate and the daily canceled resources rate for 2016 and the first three months of 2017. The lost opportunity cost rate averaged $0.042 per MWh. The highest lost opportunity cost rate occurred on March 12, when it reached $0.515 per MWh, $0.710 per MWh lower than the $1.225 per MWh rate reached in the first three months of 2016, on February 19.

Table 4-12 shows the average rates for each region in each category in the first three months of 2016 and 2017.

Table 4-12 Operating reserve rates ($/MWh): January 1 through March 31, 2016 and 2017

Rate	(Jan - Mar) 2016 ($/MWh)	(Jan - Mar) 2017 ($/MWh)	Difference ($/MWh)	Percent Difference
Day-Ahead	0.103	0.026	(0.077)	(75.2%)
Day-Ahead with Unallocated Congestion	0.103	0.026	(0.077)	(75.2%)
RTO Reliability	0.016	0.026	0.010	62.8%
East Reliability	0.018	0.005	(0.013)	(72.4%)
West Reliability	0.001	0.000	(0.001)	(63.1%)
RTO Deviation	0.125	0.180	0.056	44.7%
East Deviation	0.156	0.012	(0.144)	(92.1%)
West Deviation	0.011	0.001	(0.011)	(93.9%)
Lost Opportunity Cost	0.130	0.042	(0.089)	(68.1%)
Canceled Resources	0.000	0.000	(0.000)	(58.8%)

Table 4-13 shows the operating reserve cost of a one MW transaction in the first three months of 2017. For example, a decrement bid in the Eastern Region (if not offset by other transactions) paid an average rate of $0.227 per MWh with a maximum rate of $2.663 per MWh, a minimum rate of $0.002 per MWh and a standard deviation of $0.356 per MWh. The rates in Table 4-13 include all operating reserve charges including RTO deviation charges. Table 4-13 illustrates both the average level of operating reserve charges by transaction types and the uncertainty reflected in the maximum, minimum and standard deviation levels.

Table 4-13 Operating reserve rates statistics ($/MWh): January 1 through March 31, 2017

		Rates Charged ($/MWh)			
Region	Transaction	Maximum	Average	Minimum	Standard Deviation
East	INC	2.606	0.202	0.000	0.355
	DEC	2.663	0.227	0.002	0.356
	DA Load	0.172	0.025	0.000	0.038
	RT Load	0.471	0.028	0.000	0.067
	Deviation	2.606	0.202	0.000	0.355
West	INC	2.443	0.193	0.000	0.336
	DEC	2.500	0.218	0.002	0.338
	DA Load	0.172	0.025	0.000	0.038
	RT Load	0.390	0.024	0.000	0.059
	Deviation	2.443	0.193	0.000	0.336

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 daily to real-time load across the entire RTO based on the real-time load ratio share of each network customer.

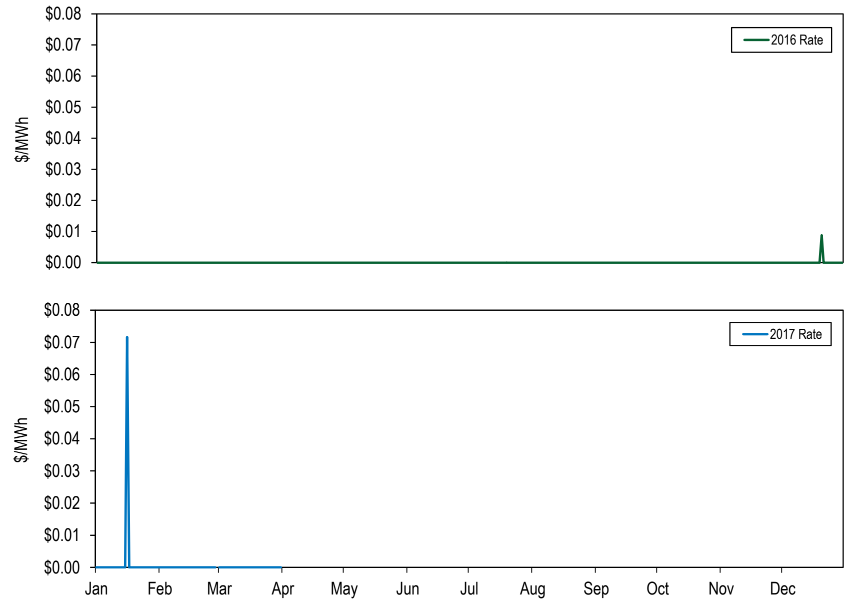
While reactive services rates are not posted by PJM, a local voltage support rate for each control zone can be calculated and a reactive transfer interface support rate can be calculated for the entire RTO. Table 4-14 shows the reactive services rates associated with local voltage support in the first three months of 2016 and 2017. Table 4-14 shows that in the first three months of 2017 the PENELEC Control Zone had the highest rate. Real-time load in the DPL Control Zone paid an average of $0.232 per MWh for reactive services associated with local voltage support, $0.229 or 9,659 percent higher than the average rate paid in the first three months of 2016.

Table 4-14 Local voltage support rates: January 1 through March 31, 2016 and 2017

Control Zone	(Jan - Mar) 2016 ($/MWh)	(Jan - Mar) 2017 ($/MWh)	Difference ($/MWh)	Percent Difference
AECO	0.000	0.000	0.000	NA
AEP	0.000	0.001	0.001	192.9%
AP	0.000	0.000	0.000	0.0%
ATSI	0.000	0.000	0.000	0.0%
BGE	0.000	0.222	0.222	NA
ComEd	0.000	0.050	0.050	106,825.8%
DAY	0.000	0.000	0.000	0.0%
DEOK	0.000	0.000	0.000	0.0%
DLCO	0.000	0.000	0.000	0.0%
Dominion	0.000	0.000	0.000	NA
DPL	0.049	0.014	(0.035)	(71.1%)
EKPC	0.000	0.000	0.000	0.0%
JCPL	0.000	0.000	0.000	NA
Met-Ed	0.000	0.002	0.002	NA
PECO	0.000	0.000	0.000	NA
PENELEC	0.002	0.232	0.229	9,659.0%
Pepco	0.000	0.222	0.222	NA
PPL	0.000	0.000	0.000	NA
PSEG	0.000	0.000	0.000	NA
RECO	0.000	0.000	0.000	NA

Figure 4-5 shows the daily RTO wide reactive transfer interface rate in 2016 and the first three months of 2017. RTO wide reactive charges were incurred only once in 2016 (December) and once in the first three months of 2017 (January). Those are the only instances in which PJM scheduled resources to provide reactive support to reactive interfaces and the resources required make whole payments.

Figure 4-5 Daily reactive transfer interface support rates ($/MWh): 2016 and 2017



Balancing Operating Reserve Determinants

Table 4-15 shows the determinants used to allocate the regional balancing operating reserve charges in the first three months of 2016 and 2017. Total real-time load and real-time exports were 4,364,577 MWh or 2.2 percent lower in the first three months of 2017 compared to the first three months of 2016. Total deviations summed across the demand, supply, and generator categories were 596,228 MWh or 1.6 percent higher in the first three months of 2017 compared to the first three months of 2016.

Table 4-15 Balancing operating reserve determinants (MWh): January 1 through March 31, 2016 and 2017

		Reliability Charge Determinants (MWh)			Deviation Charge Determinants (MWh)			
		Real-Time Load	Real-Time Exports	Reliability Total	Demand Deviations (MWh)	Supply Deviations (MWh)	Generator Deviations (MWh)	Deviations Total
(Jan - Mar) 2016	RTO	196,811,940	3,636,742	200,448,682	21,016,147	7,818,373	8,749,562	37,584,082
	East	92,212,662	2,393,889	94,606,551	10,735,953	4,268,586	5,033,123	20,037,663
	West	104,599,278	1,242,853	105,842,131	10,128,601	3,477,800	3,716,439	17,322,839
(Jan - Mar) 2017	RTO	189,125,027	6,959,078	196,084,105	21,397,923	9,527,913	7,254,475	38,180,311
	East	88,981,325	3,199,115	92,180,440	10,691,631	5,532,319	3,348,509	19,572,459
	West	100,143,702	3,759,963	103,903,665	10,608,325	3,877,189	3,905,967	18,391,480
Difference	RTO	(7,686,913)	3,322,336	(4,364,577)	381,776	1,709,539	(1,495,087)	596,228
	East	(3,231,336)	805,226	(2,426,111)	(44,322)	1,263,733	(1,684,615)	(465,204)
	West	(4,455,576)	2,517,110	(1,938,466)	479,724	399,389	189,528	1,068,641

Deviations fall into three categories, demand, supply and generator deviations. Table 4-16 shows the different categories by the type of transactions that incurred deviations. In the first three months of 2017, 35.1 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 64.9 percent of all RTO deviations were incurred by participants that deviated due to other transaction types or due to combinations of other transaction types.

Table 4-16 Deviations by transaction type: January 1 through March 31, 2017

Deviation Category	Transaction	Deviation (MWh) RTO	East	West	Share RTO	East	West
Demand	Bilateral Sales Only	232,750	189,935	42,815	0.6%	1.0%	0.2%
	DECs Only	4,302,256	1,877,138	2,327,151	11.3%	9.6%	12.7%
	Exports Only	1,353,888	607,012	746,876	3.5%	3.1%	4.1%
	Load Only	14,370,735	7,308,154	7,062,581	37.6%	37.3%	38.4%
	Combination with DECs	886,077	529,804	356,273	2.3%	2.7%	1.9%
	Combination without DECs	252,217	179,589	72,628	0.7%	0.9%	0.4%
Supply	Bilateral Purchases Only	139,718	96,885	42,833	0.4%	0.5%	0.2%
	Imports Only	1,174,118	898,717	275,401	3.1%	4.6%	1.5%
	INCs Only	6,894,515	3,756,326	3,019,785	18.1%	19.2%	16.4%
	Combination with INCs	1,301,185	765,088	536,097	3.4%	3.9%	2.9%
	Combination without INCs	18,376	15,303	3,073	0.0%	0.1%	0.0%
Generators		7,254,475	3,348,509	3,905,967	19.0%	17.1%	21.2%
Total		38,180,311	19,572,459	18,391,480	100.0%	100.0%	100.0%

Energy Uplift Credits

Table 4-17 shows the totals for each credit category in the first three months of 2016 and 2017. During the first three months of 2017, 55.9 percent of total energy uplift credits were in the balancing operating reserve category, an increase of 10.7 percentage points from 45.1 in the first three months of 2016.

Table 4-17 Energy uplift credits by category: January 1 through March 31, 2016 and 2017

Category	Type	(Jan - Mar) 2016 Credits (Millions)	(Jan - Mar) 2017 Credits (Millions)	Change	Percent Change	(Jan - Mar) 2016 Share	(Jan - Mar) 2017 Share
Day-Ahead	Generators	$21.3	$5.2	($16.1)	(75.4%)	54.1%	20.3%
	Imports	$0.0	$0.0	($0.0)	(100.0%)	0.0%	0.0%
	Load Response	$0.0	$0.0	($0.0)	(100.0%)	0.0%	0.0%
Balancing	Canceled Resources	$0.0	$0.0	($0.0)	(57.7%)	0.0%	0.0%
	Generators	$13.0	$12.8	($0.1)	(1.0%)	32.8%	49.6%
	Imports	$0.0	$0.0	($0.0)	(99.6%)	0.0%	0.0%
	Load Response	$0.0	$0.0	$0.0	11.1%	0.0%	0.0%
	Local Constraints Control	$0.1	$0.0	($0.0)	(63.3%)	0.1%	0.1%
	Lost Opportunity Cost	$4.8	$1.6	($3.2)	(66.7%)	12.1%	6.2%
Reactive Services	Day-Ahead	$0.0	$6.0	$6.0	NA	0.0%	23.2%
	Local Constraints Control	$0.0	$0.0	$0.0	NA	0.0%	0.0%
	Lost Opportunity Cost	$0.0	$0.0	$0.0	63.0%	0.0%	0.1%
	Reactive Services	$0.2	$0.1	($0.2)	(67.5%)	0.6%	0.3%
	Synchronous Condensing	$0.0	$0.0	$0.0	NA	0.0%	0.0%
Synchronous Condensing		$0.0	$0.0	$0.0	NA	0.0%	0.0%
Black Start Services	Day-Ahead	$0.0	$0.0	$0.0	NA	0.0%	0.0%
	Balancing	$0.0	$0.0	$0.0	NA	0.0%	0.0%
	Testing	$0.1	$0.1	$0.0	1.2%	0.1%	0.2%
Total		$39.4	$25.8	($13.6)	(34.5%)	100.0%	100.0%

Characteristics of Credits

Types of Units

Table 4-18 shows the distribution of total energy uplift credits by unit type in the first three months of 2016 and 2017. The decrease in energy uplift in the first three months of 2017 compared to the first three months of 2016 was primarily a result of lower credits paid to coal fired steam turbines. Credits to these units decreased by $9.1 million or 45.1 percent.

Table 4-18 Energy uplift credits by unit type: January 1 through March 31, 2016 and 2017

Unit Type	(Jan - Mar) 2016 Credits (Millions)	(Jan - Mar) 2017 Credits (Millions)	Change	Percent Change	(Jan - Mar) 2016 Share	(Jan - Mar) 2017 Share
Combined Cycle	$6.6	$2.6	($4.0)	(60.8%)	16.7%	10.0%
Combustion Turbine	$11.6	$10.9	($0.7)	(6.0%)	29.3%	42.1%
Diesel	$0.2	$0.1	($0.0)	(24.4%)	0.5%	0.6%
Hydro	$0.0	$0.0	$0.0	60.7%	0.0%	0.0%
Nuclear	$0.1	$0.0	($0.1)	(100.0%)	0.3%	0.0%
Solar	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%
Steam - Coal	$19.8	$10.7	($9.1)	(46.1%)	50.3%	41.4%
Steam - Other	$0.9	$1.2	$0.3	34.7%	2.2%	4.5%
Wind	$0.3	$0.4	$0.1	38.5%	0.7%	1.4%
Total	$39.4	$25.8	($13.6)	(34.5%)	100.0%	100.0%

Table 4-19 shows the distribution of energy uplift credits by category and by unit type in the first three months of 2017. Coal fired steam turbines received 86.5 percent of the day-ahead generator credits in the first three months of 2017, 6.9 percentage points higher than the share received in the first three months of 2016. Combustion turbines received 75.6 percent of the balancing generator credits in the first three months of 2017, 24.5 percentage points higher than the share received in the first three months of 2016. Combustion turbines and diesels received 68.2 percent of the lost opportunity cost credits in the first three months of 2017, 20.6 percentage points lower than the share received in the first three months of 2016.

Table 4-19 Energy uplift credits by unit type: January 1 through March 31, 2017

Unit Type	Day-Ahead Generator	Balancing Generator	Canceled Resources	Local Constraints Control	Lost Opportunity Cost	Reactive Services	Synchronous Condensing	Black Start Services
Combined Cycle	10.4%	14.2%	0.0%	0.0%	10.0%	0.7%	0.0%	9.3%
Combustion Turbine	0.5%	75.6%	0.0%	99.3%	64.3%	1.0%	0.0%	90.7%
Diesel	0.1%	0.5%	0.0%	0.0%	3.9%	0.3%	0.0%	0.0%
Hydro	0.0%	0.0%	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Solar	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Steam - Coal	86.5%	9.0%	0.0%	0.7%	2.6%	81.5%	0.0%	0.0%
Steam - Others	2.5%	0.2%	0.0%	0.0%	0.3%	16.6%	0.0%	0.0%
Wind	0.0%	0.5%	0.0%	0.0%	19.0%	0.0%	0.0%	0.0%
Total (Millions)	$5.2	$12.8	$0.0	$0.0	$1.6	$6.1	$0.0	$0.1

Table 4-19 also shows the distribution of reactive service credits and black start services credits by unit type. In the first three months of 2017, coal units received 81.5 of all reactive services credits.

Concentration of Energy Uplift Credits

There continues to be a high level of concentration in the units and companies receiving energy uplift credits. This concentration results from a combination of unit operating parameters, 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 44.7 percent of total energy uplift credits in the first three months of 2017, compared to 53.4 percent in the first three months of 2016. In the first three months of 2017, 170 units received 90 percent of all energy uplift credits, compared to 140 units in the first three months of 2016.

Figure 4-6 Cumulative share of energy uplift credits: January 1 through March 31, 2016 and 2017, by unit

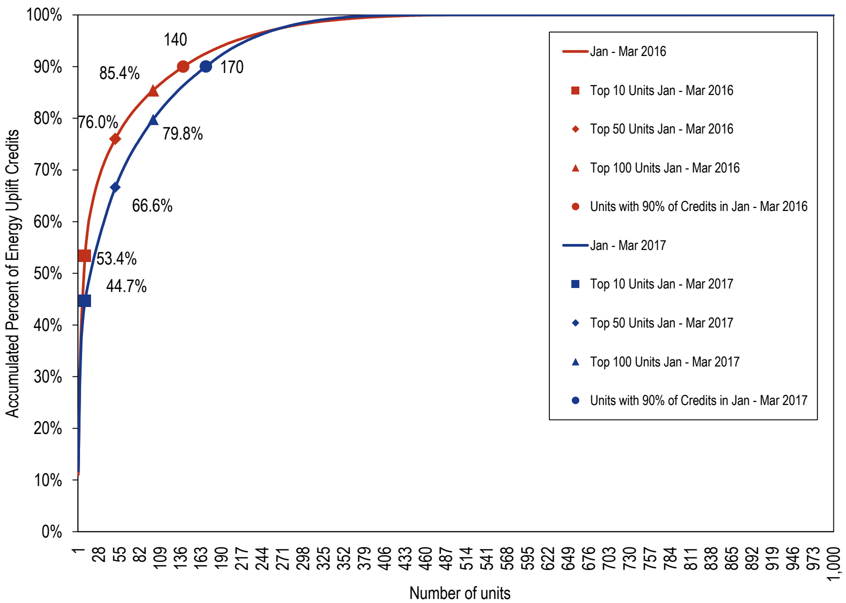


Table 4-20 shows the credits received by the top 10 units and top 10 organizations in each of the energy uplift categories paid to generators.

Table 4-20 Top 10 units and organizations energy uplift credits: January 1 through March 31, 2017

		Top 10 Units		Top 10 Organizations	
Category	Type	Credits (Millions)	Credits Share	Credits (Millions)	Credits Share
Day-Ahead	Generators	$4.6	86.9%	$5.2	98.5%
Balancing	Canceled Resources	$0.0	100.0%	$0.0	100.0%
	Generators	$2.4	18.7%	$9.8	76.4%
	Local Constraints Control	$0.0	100.0%	$0.0	100.0%
	Lost Opportunity Cost	$0.4	28.2%	$1.1	69.4%
Reactive Services		$5.9	96.5%	$6.1	100.0%
Synchronous Condensing		$0.0	0.0%	$0.0	0.0%
Black Start Services		$0.1	93.4%	$0.1	100.0%
Total		$11.5	44.7%	$21.5	83.3%

Table 4-21 shows balancing operating reserve credits received by the top 10 units identified for reliability or for deviations in each region. In the first three months of 2017, 66.1 percent of all credits paid to these units were allocated to deviations while the remaining 33.9 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: January 1 through March 31, 2017

	Reliability			Deviations			
	RTO	East	West	RTO	East	West	Total
Credits (Millions)	$0.7	$0.1	$0.0	$1.5	$0.1	$0.0	$2.4
Share	31.5%	2.4%	0.0%	61.1%	5.0%	0.0%	100.0%

In the first three months of 2017, concentration in all energy uplift credit categories was high.[7] [8] 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 7331, for balancing operating reserve credits to generators was 3764, for lost opportunity cost credits was 5581 and for reactive services credits was 8873.

7 See *2016 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).
8 Table 4-22 excludes local constraints control categories.

Table 4-22 Daily energy uplift credits HHI: January 1 through March 31, 2017

Category	Type	Average	Minimum	Maximum	Highest Market Share (One day)	Highest Market Share (All days)
Day-Ahead	Generators	7331	2229	10000	100.0%	44.4%
	Imports	NA	NA	NA	NA	NA
	Load Response	NA	NA	NA	NA	NA
Balancing	Canceled Resources	10000	10000	10000	100.0%	100.0%
	Generators	3764	1155	10000	100.0%	23.7%
	Imports	10000	10000	10000	100.0%	100.0%
	Load Response	9937	8935	10000	100.0%	97.2%
	Lost Opportunity Cost	5581	1481	10000	100.0%	14.8%
Reactive Services		8873	3866	10000	100.0%	57.0%
Synchronous Condensing		NA	NA	NA	NA	NA
Black Start Services		9849	7585	10000	100.0%	51.8%
Total		3943	904	9903	99.5%	24.1%

Economic and Noneconomic Generation[9]

Economic generation includes units scheduled day ahead or producing energy in real time at an incremental offer less than or equal to the LMP at the unit's bus. Noneconomic generation includes units that are scheduled or producing energy at an incremental offer higher than the LMP at the unit's bus. Units are paid day-ahead operating reserve credits based on their scheduled operation for the entire day. Balancing generator operating reserve credits are paid on a segmented basis for each period defined by the greater of the day-ahead schedule and minimum run time. Table 4-23 shows PJM's day-ahead and real-time total generation and the amount of generation eligible for operating reserve credits. In the Day-Ahead Energy Market only pool-scheduled resources are eligible for day-ahead operating reserve credits. In the Real-Time Energy Market only pool-scheduled resources that follow PJM's dispatch instructions are eligible for balancing operating reserve credits.

The MMU analyzed PJM's day-ahead and real-time generation eligible for operating reserve credits to determine the shares of economic and noneconomic generation. Each unit's hourly generation was determined to be economic or noneconomic based on the unit's hourly incremental offer, excluding the hourly no load cost and any applicable startup cost. A unit could be economic for every hour during a day or segment, but still receive operating reserve credits because the energy revenues did not cover the hourly no load costs and startup costs. A unit could be noneconomic for an hour or multiple hours and not receive operating reserve credits whenever the total energy revenues covered the total offer (including no load and startup costs) for the entire day or segment. In the first three months of 2017, 34.5 percent of the day-ahead generation was eligible for day-ahead operating reserve credits and 32.6 percent of the real-time generation was eligible for balancing operating reserve credits.[10]

Table 4-23 Day-ahead and real-time generation (GWh): January 1 through March 31, 2017

Energy Market	Total Generation	Generation Eligible for Operating Reserve Credits	Generation Eligible for Operating Reserve Credits Percent
Day-Ahead	199,981	68,943	34.5%
Real-Time	199,798	65,083	32.6%

Table 4-24 shows PJM's economic and noneconomic generation by hour eligible for operating reserve credits. In the first three months of 2017, 85.5 percent of the day-ahead generation eligible for operating reserve credits was economic and 80.1 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.

9 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.

10 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 4-24 Day-ahead and real-time economic and noneconomic generation from units eligible for operating reserve credits (GWh): January 1 through March 31, 2017

Energy Market	Economic Generation	Noneconomic Generation	Economic Generation Percent	Noneconomic Generation Percent
Day-Ahead	58,931	10,012	85.5%	14.5%
Real-Time	52,152	12,931	80.1%	19.9%

Noneconomic generation only leads to operating reserve credits when units' generation for the day or segment, scheduled or committed, is noneconomic, including no load and startup costs. Table 4-25 shows the generation receiving day-ahead and balancing operating reserve credits. In the first three months of 2017, 2.9 percent of the day-ahead generation eligible for operating reserve credits received credits and 1.8 percent of the real-time generation eligible for operating reserve credits received credits.

Table 4-25 Day-ahead and real-time generation receiving operating reserve credits (GWh): January 1 through March 31, 2017

Energy Market	Generation Eligible for Operating Reserve Credits	Generation Receiving Operating Reserve Credits	Generation Receiving Operating Reserve Credits Percent
Day-Ahead	68,943	2,019	2.9%
Real-Time	65,083	1,145	1.8%

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.[11] 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.[12] Units scheduled as must run by PJM may set LMP if raised above economic minimum and following the dispatch signal and are eligible for day-ahead operating reserve credits. Table 4-26 shows the total day-ahead generation and the subset of that generation scheduled as must run by PJM. In the first three months of 2017, 1.2 percent of the total day-ahead generation was scheduled as must run by PJM, 0.3 percentage points lower than the first three months of 2016.

Table 4-26 Day-ahead generation scheduled as must run by PJM (GWh): January 1, 2016 through March 31, 2017

	2016			2017		
	Total Day-Ahead Generation	Day-Ahead PJM Must Run Generation	Share	Total Day-Ahead Generation	Day-Ahead PJM Must Run Generation	Share
Jan	73,821	935	1.3%	71,967	1,071	1.5%
Feb	66,367	979	1.5%	61,356	725	1.2%
Mar	60,431	1,047	1.7%	66,657	523	0.8%
Apr	56,338	514	0.9%			
May	59,078	429	0.7%			
Jun	70,573	772	1.1%			
Jul	81,801	981	1.2%			
Aug	83,021	1,694	2.0%			
Sep	69,962	1,682	2.4%			
Oct	60,950	1,066	1.7%			
Nov	59,983	819	1.4%			
Dec	72,478	1,112	1.5%			
Total (Jan - Mar)	200,618	2,961	1.5%	199,981	2,318	1.2%
Total	814,803	12,031	1.5%	199,981	2,318	1.2%

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.

11 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>.

12 See PJM. "PJM Markets Gateway User Guide," Section Managing Unit Data (version April 29, 2016) p. 32, <http://www.pjm.com/~/media/etools/emkt/markets-gateway-user-guide.ashx>.

It is illogical and unnecessary to pay units day-ahead operating reserves because units do not incur any costs to run and any revenue shortfalls are addressed by balancing operating reserve payments.

Table 4-27 shows the total day-ahead generation scheduled as must run by PJM by category. In the first three months of 2017, 60.1 percent of the day-ahead generation scheduled as must run by PJM received operating reserve credits, 18.5 percent paid day-ahead operating reserve credits and 41.6 percent paid as reactive services. The remaining 39.9 percent of the day-ahead generation scheduled as must run by PJM did not need to be made whole.

Table 4-27 Day-ahead generation scheduled as must run by PJM by category (GWh): January 1 through March 31, 2017

	Reactive Services	Day-Ahead Operating Reserves	Economic	Total
Jan	338	256	477	1,071
Feb	411	172	141	725
Mar	215	2	306	523
Total (Jan - Mar)	964	430	925	2,318
Share	41.6%	18.5%	39.9%	100.0%

Total day-ahead operating reserve credits in the first three months of 2017 were $5.2 million, of which $4.0 million or 77.1 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 the first three months of 2017. Table 4-28 includes only day-ahead operating reserve charges and balancing operating reserve reliability and deviation charges since these categories are allocated regionally, while other charges, such as reactive services, synchronous condensing and black start services are allocated by control zone, and balancing local constraint charges are charged to the requesting party.

Charges are categorized by the location (control zone, hub, aggregate or interface) where they are allocated according to PJM's operating reserve rules. Credits are categorized by the location where the resources are located. The shares columns reflect the operating reserve credits and charges balance for each location. For example, transactions in the AEP Control Zone paid 14.4 percent of all operating reserve charges allocated regionally, and resources in the AEP Control Zone were paid 10.2 percent of the corresponding credits. The AEP Control Zone received less operating reserve credits than operating reserve charges paid and had 10.7 percent of the deficit. The deficit is the sum of the negative entries in the balance column. Transactions in the BGE Control Zone paid 4.3 percent of all operating reserve charges allocated regionally, and resources in the BGE Control Zone were paid 17.4 percent of the corresponding credits. The BGE Control Zone received more operating reserve credits than operating reserve charges paid and had 33.7 percent of the surplus. The surplus is the sum of the positive entries in the balance column. Table 4-28 also shows that 89.0 percent of all charges were allocated in control zones, 4.4 percent in hubs and aggregates and 6.6 percent in interfaces.

Table 4-28 Geography of regional charges and credits: January 1 through March 31, 2017

Location		Charges (Millions)	Credits (Millions)	Balance	Shares Total Charges	Shares Total Credits	Shares Deficit	Shares Surplus
Zones	AECO	$0.2	$0.2	($0.0)	1.1%	1.1%	0.0%	0.0%
	AEP	$2.8	$2.0	($0.8)	14.4%	10.2%	10.7%	0.0%
	AP	$1.1	$0.2	($0.9)	5.8%	1.1%	12.1%	0.0%
	ATSI	$1.4	$0.3	($1.1)	7.0%	1.4%	14.5%	0.0%
	BGE	$0.8	$3.4	$2.6	4.3%	17.4%	0.0%	33.7%
	ComEd	$1.9	$2.1	$0.2	9.9%	10.7%	0.0%	2.0%
	DAY	$0.4	$0.5	$0.1	1.8%	2.3%	0.0%	1.2%
	DEOK	$0.5	$0.4	($0.1)	2.8%	2.1%	1.6%	0.0%
	DLCO	$0.3	$0.0	($0.2)	1.3%	0.1%	3.0%	0.0%
	Dominion	$2.0	$4.1	$2.2	10.1%	21.0%	0.0%	28.2%
	DPL	$0.5	$0.5	$0.0	2.6%	2.7%	0.0%	0.4%
	EKPC	$0.3	$0.6	$0.3	1.8%	3.1%	0.0%	3.5%
	External	$0.0	$0.2	$0.2	0.0%	1.2%	0.0%	3.1%
	JCPL	$0.5	$0.3	($0.2)	2.4%	1.4%	2.5%	0.0%
	Met-Ed	$0.4	$0.0	($0.4)	2.0%	0.2%	4.7%	0.0%
	PECO	$0.9	$0.3	($0.6)	4.6%	1.4%	8.1%	0.0%
	PENELEC	$0.7	$0.3	($0.4)	3.5%	1.6%	4.9%	0.0%
	Pepco	$0.7	$2.5	$1.7	3.7%	12.5%	0.0%	22.5%
	PPL	$1.0	$0.3	($0.7)	5.3%	1.7%	9.3%	0.0%
	PSEG	$0.9	$1.3	$0.4	4.6%	6.7%	0.0%	5.5%
	RECO	$0.0	$0.0	($0.0)	0.2%	0.0%	0.6%	0.0%
	All Zones	$17.5	$19.7	$2.2	89.0%	100.0%	71.8%	100.0%
Hubs and Aggregates	AEP - Dayton	$0.1	$0.0	($0.1)	0.6%	0.0%	1.5%	0.0%
	Dominion	$0.0	$0.0	($0.0)	0.2%	0.0%	0.6%	0.0%
	Eastern	$0.0	$0.0	($0.0)	0.2%	0.0%	0.5%	0.0%
	New Jersey	$0.0	$0.0	($0.0)	0.2%	0.0%	0.4%	0.0%
	Ohio	$0.0	$0.0	($0.0)	0.0%	0.0%	0.1%	0.0%
	Western Interface	$0.0	$0.0	($0.0)	0.1%	0.0%	0.2%	0.0%
	Western	$0.6	$0.0	($0.6)	3.2%	0.0%	8.1%	0.0%
	RTEP B0328 Source	$0.0	$0.0	($0.0)	0.0%	0.0%	0.0%	0.0%
	All Hubs and Aggregates	$0.9	$0.0	($0.9)	4.4%	0.0%	11.4%	0.0%
Interfaces	CPLE Imp	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%	0.0%
	Hudson	$0.0	$0.0	($0.0)	0.0%	0.0%	0.0%	0.0%
	IMO	$0.1	$0.0	($0.1)	0.6%	0.0%	1.5%	0.0%
	Linden	$0.1	$0.0	($0.1)	0.3%	0.0%	0.7%	0.0%
	MISO	$0.4	$0.0	($0.4)	1.8%	0.0%	4.7%	0.0%
	Neptune	$0.1	$0.0	($0.1)	0.4%	0.0%	1.0%	0.0%
	NIPSCO	$0.0	$0.0	($0.0)	0.0%	0.0%	0.1%	0.0%
	Northwest	$0.0	$0.0	($0.0)	0.1%	0.0%	0.2%	0.0%
	NYIS	$0.2	$0.0	($0.2)	0.9%	0.0%	2.4%	0.0%
	OVEC	$0.0	$0.0	($0.0)	0.0%	0.0%	0.1%	0.0%
	South Exp	$0.1	$0.0	($0.1)	0.6%	0.0%	1.6%	0.0%
	South Imp	$0.4	$0.0	($0.4)	1.8%	0.0%	4.6%	0.0%
	All Interfaces	$1.3	$0.0	($1.3)	6.6%	0.0%	16.8%	0.0%
	Total	$19.7	$19.7	$0.0	100.0%	100.0%	100.0%	100.0%

Capacity Market

Each organization serving PJM load must meet its capacity obligations through the PJM Capacity Market, where load serving entities (LSEs) must pay the locational capacity price for their zone. LSEs can also construct generation and offer it into the capacity market, enter into bilateral contracts, develop demand resources and energy efficiency (EE) resources and offer them into the capacity market, or construct transmission upgrades and offer them into the capacity market.

The Market Monitoring Unit (MMU) analyzed market structure, participant conduct and market performance in the PJM Capacity Market for the first three months of 2017, 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.

Overview

RPM Capacity Market

Market Design

The Reliability Pricing Model (RPM) Capacity Market is a forward-looking, annual, locational market, with a must offer requirement for Existing Generation Capacity Resources and mandatory participation by load, with performance incentives, that includes clear market power mitigation rules and that permits the direct participation of demand-side resources.[4]

Under RPM, capacity obligations are annual. Base Residual Auctions (BRA) are held for Delivery Years that are three years in the future. Effective with the 2012/2013 Delivery Year, First, Second and Third Incremental Auctions (IA) are held for each Delivery Year.[5] Prior to the 2012/2013 Delivery Year, the Second Incremental Auction was conducted if PJM determined that an

1 The values stated in this report for the RTO and LDAs refer to the aggregate level including all nested LDAs unless otherwise specified. For example, RTO values include the entire PJM market and all LDAs. Rest of RTO values are RTO values net of nested LDA values.
2 In the 2008/2009 RPM Third Incremental Auction, 18 participants in the RTO market passed the TPS test.
3 In the 2012/2013 RPM Base Residual Auction, six participants included in the incremental supply of EMAAC passed the TPS test. In the 2014/2015 RPM Base Residual Auction, seven participants in the incremental supply in MAAC passed the TPS test.
4 The terms *PJM Region*, *RTO Region* and *RTO* are synonymous in this report and include all capacity within the PJM footprint.
5 See 126 FERC ¶ 61,275 (2009) at P 86.

unforced capacity resource shortage exceeded 100 MW of unforced capacity due to a load forecast increase. Effective January 31, 2010, First, Second, and Third Incremental Auctions are conducted 20, 10, and three months prior to the Delivery Year.[6] Also effective for the 2012/2013 Delivery Year, a Conditional Incremental Auction may be held if there is a need to procure additional capacity resulting from a delay in a planned large transmission upgrade that was modeled in the BRA for the relevant Delivery Year.[7]

The 2017/2018 RPM Third Incremental Auction was conducted in the first three months of 2017.

On June 9, 2015, FERC accepted changes to the PJM capacity market rules proposed in PJM's Capacity Performance (CP) filing.[8] 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 the 2016/2017 and 2017/2018 Delivery Years. 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.[9] 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. 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.

RPM prices are locational and may vary depending on transmission constraints.[10] 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 the first three months of 2017, PJM installed capacity increased 1,182.9 MW or 0.6 percent, from 182,410.7 MW on January 1 to 183,593.6 MW on March 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 March 31, 2017, 36.5 percent was coal; 35.9 percent was gas; 18.0 percent was nuclear; 3.6 percent was oil; 4.8 percent was hydroelectric; 0.6 percent was wind; 0.4 percent was solid waste; and 0.1 percent was solar.
- **Market Concentration.** In the 2016/2017 RPM Third Incremental Auction all participants in the total PJM market as well as the LDA RPM markets

6 See Order in Docket No. ER10-366-000 (January 22, 2010).
7 See 126 FERC ¶ 61,275 (2009) at P 88.
8 See Docket No. ER15-623-000 (December 12, 2014) and 151 FERC ¶ 61,208 (2015).
9 See "PJM Manual 18: PJM Capacity Market," Rev. 36 (December 22, 2017) at 8.

10 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.

failed the three pivotal supplier (TPS) test.[11] 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.[12 13 14]

- **Imports and Exports.** Of the 15.9 MW of imports in the 2016/2017 RPM Third Incremental Auction, 11.4 MW cleared. Of the cleared imports, 8.6 MW (75.4 percent) were from MISO.
- **Demand-Side and Energy Efficiency Resources.** Capacity in the RPM load management programs was 10,248.9 MW for June 1, 2016, as a result of cleared capacity for Demand Resources and Energy Efficiency Resources in RPM Auctions for the 2016/2017 Delivery Year (14,988.5 MW) less replacement capacity from sources other than Demand Resources and Energy Efficiency (4,739.6 MW).

Market Conduct

- **2017/2018 RPM Third Incremental Auction.** Of the 310 generation resources that submitted offers, the MMU calculated offer caps for nine generation resources (2.9 percent), of which five were based on the technology specific default (proxy) ACR values and four were unit-specific offer caps (1.3 percent).

Market Performance

- The 2017/2018 RPM Third Incremental Auction was conducted in the first three months of 2017. The weighted average capacity price for the 2017/2018 Delivery Year is $141.16 per MW-day, including all RPM Auctions for the 2017/2018 Delivery Year held through the first three months of 2017. The weighted average capacity price for the 2018/2019 Delivery Year is $177.38, including all RPM Auctions for the 2018/2019 Delivery Year held through the first three months of 2017. The weighted average capacity price for the 2019/2020 Delivery Year is $114.30, including all RPM Auctions for the 2019/2020 Delivery Year held through the first three months of 2017. RPM net excess increased 1,329.5 MW from 5,855.9 MW on June 1, 2015, to 7,185.4 MW on June 1, 2016.
- For the 2016/2017 Delivery Year, RPM annual charges to load are $7.7 billion.
- The delivery year weighted average capacity price was $121.84 per MW-day in 2016/2017 and $141.16 per MW-day in 2017/2018.

Generator Performance

- **Forced Outage Rates.** The average PJM EFORd for the first three months of 2017 was 6.2 percent, a decrease from 6.3 percent for the first three months of 2016.[15]
- **Generator Performance Factors.** The PJM aggregate equivalent availability factor for the first three months of 2017was 87.7 percent, an increase from 86.6 percent for the first three months of 2016.
- **Outages Deemed Outside Management Control (OMC).** In the first three months of 2017, 0.5 percent of forced outages were classified as OMC outages.

Recommendations[16]

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

11 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).

12 See PJM. OATT Attachment DD § 6.5.

13 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.

14 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).

15 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 was downloaded from the PJM GADS database on April 24, 2017. 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.

16 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.

capacity market rules. The status is reported as adopted if the recommendation was included in FERC's order approving PJM's Capacity Performance filing.[17]

- The MMU recommends the extension of minimum offer price rule (MOPR) to all existing and proposed units in order to protect competition in the capacity market from external subsidies. (Priority: High. First reported 2016. Status: Not adopted.)
- 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.[18] [19] (Priority: High. First reported 2013. Status: Not adopted. Pending before FERC.)
- The MMU recommends that the test for determining modeled Locational Deliverability Areas (LDAs) 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 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.[20] [21] 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.[22] (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 the following changes with respect to capacity imports into PJM:
  - The MMU recommends that all capacity imports be required to be deliverable to PJM load prior to the relevant delivery year to ensure that they are as close to full substitutes for internal, physical capacity

17 151 FERC ¶ 61,208 (June 9, 2015).

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

19 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2016," <http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Analysis_of_Replacement_Capacity_for_RPM_Commitments_06012007_to_06012016_20161227.pdf> (December 27, 2016).

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

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

22 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).

resources as possible. Pseudo ties alone are not adequate to ensure deliverability. (Priority: High. First reported 2016. Status: Not adopted.)

- — The MMU recommends that all costs incurred as a result of a pseudo tied unit be borne by the unit itself and included as appropriate in unit offers in the capacity market. (Priority: High. First reported 2016. Status: Not adopted.)

- The MMU recommends improvements to the performance incentive requirements of RPM:
  - — 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 2009. Status: Not adopted. Pending before FERC.)
  - — The MMU recommends that retroactive replacement capacity transactions not be permitted. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that treatment of costs in RMR filings be emphasized. Customers should bear all the incremental costs, including incremental investment costs, required by the RMR service that the unit owner would not have incurred if the unit owner had deactivated its unit as it proposed. Generation owners should bear all other costs. (Priority: Low. First reported 2010. Status: Not adopted.)
- The MMU recommends that the mitigation rules for Demand Resource and Energy Efficiency Resource offers be reevaluated and reviewed. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that Energy Efficiency Resources (EE) not be included on the supply side of the capacity market because PJM's load forecasts now account for future EE but did not when EE was first added to the capacity market. If EE is not included on the supply side, there is no reason to have an add back mechanism. If EE remains on the supply side, the implementation of the EE add back mechanism should be modified to ensure that market clearing prices are not affected. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that PJM reduce the number of incremental auctions to a single incremental auction held three months prior to the start of the delivery year and reevaluate the triggers for holding conditional incremental auctions. (Priority: Medium. First reported 2013. Modified Q1 2017. Status: Not adopted.)
- The MMU recommends that PJM release capacity in the incremental auction only in cases where the combination of quantities released and associated prices would increase the welfare of capacity market resource owners and load, including consideration of both capacity and energy market benefits in the determination of release quantities and prices. (Priority: Medium. New Recommendation. Status: Not adopted.)
- The MMU recommends that the notification requirement for deactivations be extended from 90 days prior to the date of deactivation to 12 months prior to the date of deactivation and that PJM and the MMU be provided 60 days rather than 30 days to complete their reliability and market power analyses. (Priority: Low. First reported 2012. Status: Partially adopted.)
- The MMU recommends clear, explicit and detailed rules that define the conditions under which PJM will and will not recall energy from PJM capacity resources and prohibit new energy exports from PJM capacity resources. The MMU recommends that those rules define the conditions under which PJM will purchase emergency energy while at the same time not recalling energy exports from PJM capacity resources. PJM has modified these rules, but they need additional clarification and operational details. (Priority: Low. First reported 2010. Status: Partially 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 2015.)
- 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 2012. Status: Adopted 2015.)

- The MMU recommends that all capacity imports have firm transmission to the PJM border acquired prior to offering in an RPM auction. (Priority: High. First reported 2014. Status: Adopted 2015.)
- 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 2015.)
- The MMU recommends that all resources importing capacity into PJM accept a must offer requirement. (Priority: High. First reported 2014. Status: Adopted 2015.)
- 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 2015.)
- 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 2015.)
- 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.[23] (Priority: Medium. First reported 2013. Status: Adopted 2015.)

Conclusion

The analysis of PJM Capacity Markets begins with market structure, which provides the framework for the actual behavior or conduct of market participants. The analysis examines participant behavior within that market structure. In a competitive market structure, market participants are constrained to behave competitively. The analysis examines market performance, measured by price and the relationship between price and marginal cost, that results from the interaction of market structure and participant behavior.

The MMU found serious market structure issues, measured by the three pivotal supplier test results, but no exercise of market power in the PJM Capacity Market in the first three months of 2017. Explicit market power mitigation rules in the RPM construct offset the underlying market structure issues in the PJM Capacity Market under RPM. The PJM capacity market results were competitive in the first three months of 2017.

The MMU has identified serious market design issues with RPM and the MMU has made specific recommendations to address those issues.[24] [25] [26] [27] [28] In 2016 and 2017, the MMU prepared a number of RPM-related reports and testimony, shown in Table 5-2. 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 CP Auctions which include more specific issues and suggestions for improvements.

The issue of external subsidies emerged more fully in 2016. The subsidies are not part of the PJM market design but nonetheless threaten the foundations of the PJM capacity market as well as the competitiveness of PJM markets overall.

The Ohio subsidy proceedings and the Illinois ZEC subsidy proceeding all originate from the fact that competitive markets result in the exit of uneconomic and uncompetitive generating units. Regardless of the specific rationales offered by unit owners, the proposed solution for all such generating units has been to provide out of market subsidies in order to

23 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).

24 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).

25 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).

26 See "Analysis of the 2018/2019 RPM Base Residual Auction Revised," <http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Analysis_of_the_20182019_RPM_Base_Residual_Auction_20160706.pdf> (July 6, 2016).

27 See "Analysis of the 2019/2020 RPM Base Residual Auction Revised," <http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Analysis_of_the_20192020_RPM_BRA_20160831-Revised.pdf> (August 31, 2016).

28 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2016," <http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Analysis_of_Replacement_Capacity_for_RPM_Commitments_06012007_to_06012016_20161227.pdf> (December 27, 2016).

retain such units. The proposed solution in all cases ignores the opportunity cost of subsidizing uneconomic units, which is the displacement of resources and technologies that would otherwise be economic. These subsidies are not accurately characterized as state subsidies. These subsidies were all requested by the owners of specific uneconomic generating units in order to improve the profitability of those specific units. These subsidies were not requested to accomplish broader social goals. Broader social goals can all be met with market based mechanisms available to all market participants on a competitive basis and without discrimination.

Subsidies are contagious. Competition in the markets could be replaced by competition to receive subsidies. Similar threats to competitive markets are being discussed by unit owners in other states and the potentially precedential nature of these actions enhances the urgency of creating an effective rule to maintain competitive markets by modifying market rules to address these subsidies. Fortunately, this can be accomplished quickly by expanding the coverage of an existing rule that already reflects stakeholder compromises.

PJM markets have no protection against this emergent threat. Accurate signals for entry and exit are necessary for well functioning and competitive markets. Competitive investors rely on accurate signals to make decisions. The current MOPR only addresses subsidies for new entry. The current subsidies demonstrate that the markets need protection against subsidized, noncompetitive offers from existing as well as new resources. The MOPR should be expanded to address subsidies for existing units, and this should be done expeditiously. This issue will not become moot unless and until the MOPR is reformed. Action is needed to correct the MOPR immediately. An existing unit MOPR is the best means to defend the PJM markets from the threat posed by subsidies intended to forestall retirement of financially distressed assets. The role of subsidies to renewables should also be clearly defined and be incorporated in this rule.

While the existing unit MOPR would protect markets in the short run, the underlying issues that have resulted in the pressure on markets should also be examined. Unit owners are seeking subsidies because gas prices are low resulting in low energy market margins and because flaws in the PJM capacity design have led to very substantial price suppression over the past 10 years.

To the extent that there are shared broader goals related to PJM markets, they should also be addressed, but this can happen with a slightly longer lead time. If a shared goal is to reduce carbon output, a price on carbon is the market based solution. If a shared goal is increased renewables in addition to their carbon attributes, a common approach to RECs would be a market based solution. Fuel diversity has also been mentioned as an issue. Current fuel diversity is higher than ever in PJM. If there is an issue, the real issue is fuel security and not fuel diversity. Significant reliance on specific fuels, including nuclear, coal and gas means that markets are at risk from a significant disruption in any one fuel. If fuel security for gas is a concern, a number of issues should be considered including the reliability of the pipelines, the compatibility of the gas pipeline and the merchant generator business models, the degree to which electric generators have truly firm gas service and the need for a gas RTO to help ensure reliability.

As a result of the fact that demand side resources have contributed to price suppression in PJM capacity markets, the place of demand side in PJM should be reexamined. There are ways to ensure and enhance the vibrancy of demand side without negatively affecting markets for generation. There are other price formation issues in the capacity market that should also be examined and addressed.

Table 5-2 RPM related MMU reports, January 2016 through March, 2017

Date	Name
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
February 1, 2016	IMM Post-Hearing Brief re AEP Ohio Case Nos. 14-1693 EL-RDR and 14-1694 EL-AAM http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Post_Hearing_Brief_Case_No_14-1693_and_14-1694_20160201.pdf
February 8, 2016	IMM Post-Hearing Reply Brief re AEP Ohio Case Nos. 14-1693-EL-RDR and 14-1694-EL-AAM http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Post_Hearing_Reply_Brief_Case_No_14-1693-14-1694_20160208.pdf
February 11, 2016	PJM IMM Joint Statement re Capacity Performance Docket Nos. ER15-623-000, -004 and EL15-29-000, and -003 http://www.monitoringanalytics.com/reports/Reports/2016/PJM_IMM_Joint_Statement_Docket_Nos_ER15-623-000_004_EL15-29-000_003_20160211.pdf
February 16, 2016	IMM Post-Hearing Brief re FE Ohio Case No. 14-1297-EL-SSO http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Post_Hearing_Brief_Case_No_14-1297_20160216.pdf
February 24, 2016	IMM Comments re DR CBL Testing http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Comments_Docket_Nos_ER16-873_20160223.pdf
February 25, 2016	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_20160225.pdf
February 26, 2016	IMM Post-Hearing Reply Brief re FE Ohio Case No. 14-1297-EL-SSO http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Post_Hearing_Reply_Brief_Case_No_14-1297-EL-SSO_20160226.pdf
March 22, 2016	IMM Answer re DR CBL Docket No. ER16-873-000 http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Answer_Docket_No_ER16-873-000_20160322.pdf
March 28, 2016	IMM Motion for Clarification or Rehearing re Net Revenue Docket No. EL14-94-000 http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Request_for_Rehearing_EL14-94-000_20160328.pdf
April 11, 2016	IMM Comments re Calpine MOPR Complaint Docket No. EL16-49-000 http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Comments_Docket_No_EL16-49-000_20160411.pdf
April 22, 2016	IMM Comments re Ramp Rate Capacity Performance Docket No. ER16-1336-000 http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Comments_Docket_No_ER16-1336_20160422.pdf
April 28, 2016	IMM Answer re Calpine Complaint Docket No. EL16-49-000 http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Answer_Docket_No_EL16-49-000_20160428.pdf
May 4, 2016	New Generation in the PJM Capacity Market: MW and Funding Sources for Delivery Years 2007/2008 through 2018/2019 http://www.monitoringanalytics.com/reports/Reports/2016/New_Generation_in_the_PJM_Capacity_Market_20160504.pdf
May 9, 2016	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2017/2018, 2018/2019 and 2019/2020 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/RPM_Must_Offer_Obligation_20160509.pdf
May 11, 2016	IMM Answer re Capacity Performance PAH Ramp Rate Docket No. ER16-1336-000 http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Answer_Docket_No_ER16-1336-000_20160511.pdf
June 13, 2016	IMM Answer and Motion for Leave to Answer re Calpine MOPR Complaint Docket No. EL16-49-000 http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Answer_Docket_No_EL16-49-000_20160613.pdf
June 24, 2016	IMM Answer to IMEA RFR Docket No. ER15-623-010, EL15-29-006 and EL15-41-002 http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Answer_Docket_Nos_ER15-623-010_EL15-29-006_EL15-41-002_20160624.pdf
July 6, 2016	Analysis of the 2018/2019 RPM Base Residual Auction Revised http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Analysis_of_the_20182019_RPM_Base_Residual_Auction_20160706.pdf
July 7, 2016	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2017/2018, 2018/2019 and 2019/2020 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/Messages/RPM_Must_Offer_Obligation_20160707.pdf
July 13, 2016	New Generation in the PJM Capacity Market: MW and Funding Sources for Delivery Years 2007/2008 through 2018/2019 ppt http://www.monitoringanalytics.com/reports/Presentations/2016/IMM_MIC_New_Generation_in_the_PJM_Capacity_Market_for_Delivery_Years_20072008_through_20182019_PPT_20160706.pdf
July 13, 2016	New Generation in the PJM Capacity Market: MW and Funding Sources for Delivery Years 2007/2008 through 2018/2019 http://www.monitoringanalytics.com/reports/Presentations/2016/IMM_MIC_New_Generation_in_the_PJM_Capacity_Market_for_Delivery_Years_20072008_through_20182019_20160706.pdf
August 26, 2016	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2017/2018, 2018/2019 and 2019/2020 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/Messages/RPM_Must_Offer_Obligations_20160826.pdf
August 31, 2016	Analysis of the 2019/2020 RPM Base Residual Auction http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Analysis_of_the_20192020_RPM_BRA_20160831-Revised.pdf
September 14, 2016	Capacity Release Proposal http://www.monitoringanalytics.com/reports/Presentations/2016/IMM_MIC_Capacity_Release_Proposal_20160914.pdf
November 22, 2016	IMM Complaint re Manual 18 Revisions Docket No. EL17-000 http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Complaint_Docket_No_EL17-_20161122.pdf
December 8, 2016	IMM Comments re CP Aggregate Rules Docket No. ER17-367-000 http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Comments_Docket_No_ER17-367-000_20161208.pdf
December 22, 2016	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2017/2018, 2018/2019 and 2019/2020 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/Messages/RPM_Must_Offer_Obligations_20161222.pdf
December 22, 2016	IMM Notice of Withdrawal re PJM Manual 18 Complaint Docket No. EL17-23-000 http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Notice_of_Withdrawal_Docket_No_EL17-23_20161222.pdf
December 27, 2016	IMM Analysis of Replacement Capacity for RPM Commitments: June 01, 2007 to June 01, 2016 http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Analysis_of_Replacement_Capacity_for_RPM_Commitments_06012007_to_06012016_20161227.pdf

Table 5-2 RPM related MMU reports, January 2016 through March, 2017 (continued)

Date	Name
December 30, 2016	IMM Motion to Lodge and for Commencement of Compliance Process re RPM Revisions Docket No. ER14-1461-000, -001 http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Motion_to_Lodge_Docket_No_ER14-1461_20161230.pdf
January 11, 2017	Replacement Capacity http://www.monitoringanalytics.com/reports/Presentations/2017/IMM_MIC_Replacement_Capacity_Report_20170111.pdf
January 24, 2017	Summary of BRA Analysis Results: 2013/2014 - 2019/2020 http://www.monitoringanalytics.com/reports/Reports/2017/IMM_BRA_Scenario_Results_Summary_20170124.pdf
January 30, 2017	IMM Answer re Amended Calpine MOPR Complaint Docket No. EL16-49-000 http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Answer_Docket_No_EL16-49_20170130.pdf
February 13, 2017	IMM Answer re Base Capacity Complaint Docket Nos. EL17-32 and EL17-36 http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Answer_Docket_Nos_EL17-32_EL17-36_20170213.pdf
February 24, 2017	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2017/2018, 2018/2019 and 2019/2020 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/Messages/RPM_Must_Offer_Obligation_20170224.pdf
March 1, 2017	Incremental Auction Review http://www.monitoringanalytics.com/reports/Presentations/2017/IMM_IASTF_Incremental_Auction_Review_20170301.pdf

Installed Capacity

On January 1, 2017, PJM installed capacity was 182,410.7 MW (Table 5-3).[29] Over the next three months, new generation, unit deactivations, facility reratings, plus import and export shifts resulted in PJM installed capacity of 183,593.6 MW on March 31, 2017, an increase of 1,182.9 MW or 0.6 percent from the January 1 level.[30] [31] The 1,182.9 MW increase was the result of capacity modifications (82.0 MW), new or reactivated generation (1,317.7 MW), and a decrease in exports (104.7 MW), offset by deactivations (209.0 MW) and derates (112.5 MW).

At the beginning of the new delivery year on June 1, 2016, PJM installed capacity was 182,061.4 MW, an increase of 2,194.4 MW or 1.2 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, 2016, as well as the expected installed capacity for the next three delivery years, based on the results of all auctions held through March 31, 2017.[32] On June 1, 2007, coal comprised 40.7 percent of the installed capacity, reached a maximum of 42.9 percent in 2012, decreased to 36.6 percent on June 1, 2016 and is projected to decrease to 29.0 percent by June 1, 2019. The share of gas increased from 29.1 percent in 2007 to 35.6 percent in 2016, and is projected to increase to 45.8 percent in 2019.

Table 5-3 PJM installed capacity (By fuel source): January 1, January 31, February 28, and March 31, 2017

	1-Jan-17		31-Jan-17		28-Feb-17		31-Mar-17	
	MW	Percent	MW	Percent	MW	Percent	MW	Percent
Coal	66,622.2	36.5%	66,622.2	36.5%	67,149.5	36.5%	66,940.5	36.5%
Gas	65,110.3	35.7%	65,084.5	35.7%	65,895.5	35.9%	65,895.5	35.9%
Hydroelectric	8,850.4	4.9%	8,850.4	4.9%	8,850.4	4.8%	8,850.4	4.8%
Nuclear	33,043.4	18.1%	33,043.4	18.1%	33,021.7	18.0%	33,103.7	18.0%
Oil	6,733.6	3.7%	6,733.6	3.7%	6,687.0	3.6%	6,687.0	3.6%
Solar	262.3	0.1%	268.0	0.1%	268.0	0.1%	268.0	0.1%
Solid waste	769.4	0.4%	769.4	0.4%	769.4	0.4%	769.4	0.4%
Wind	1,019.1	0.6%	1,074.2	0.6%	1,079.1	0.6%	1,079.1	0.6%
Total	182,410.7	100.0%	182,445.7	100.0%	183,720.6	100.0%	183,593.6	100.0%

29 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.

30 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.

31 Wind resources accounted for 1,079.1 MW, and solar resources accounted for 268.0 MW of installed capacity in PJM on March 31, 2017. PJM administratively reduces the capabilities of all wind generators to 13 percent and solar generators to 38 percent of nameplate capacity when determining the installed capacity because wind and solar resources cannot be assumed to be available on peak and cannot respond to dispatch requests. As data become available, unforced capability of wind and solar resources will be calculated using actual data. There are additional wind and solar resources not reflected in total capacity because they are energy only resources and do not participate in the PJM Capacity Market. See "PJM Manual 21: Rules and Procedures for Determination of Generating Capability," Revision 12 (January 1, 2017) at 19.

32 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.

Figure 5-1 Percent of PJM installed capacity (By fuel source): June 1, 2007 through June 1, 2019

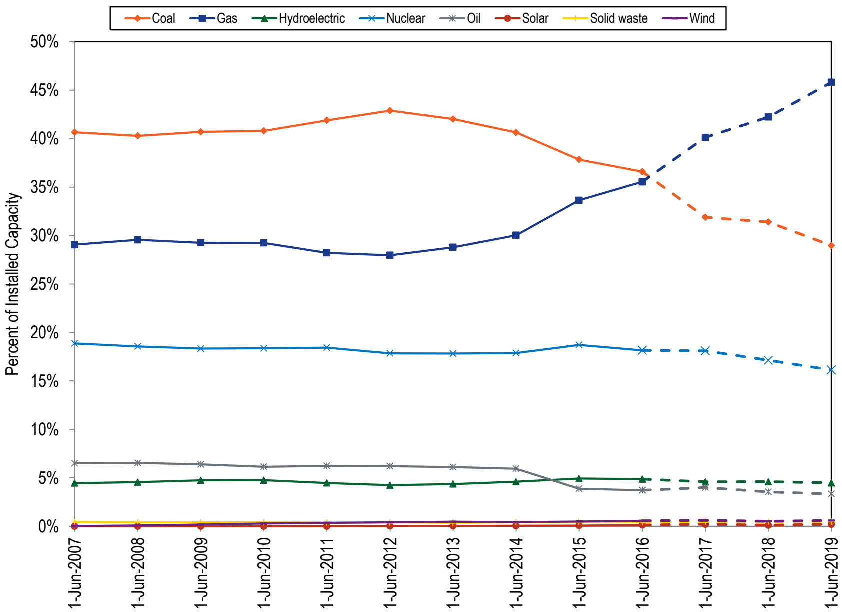


Figure 5-2 shows the fuel diversity index (FDI_c) for PJM installed capacity.[33] The FDI_c is defined as $1 - \sum_{i=1}^{N} s_i^2$

where s_i is the percent share of fuel type *i*. The minimum possible value for the FDI_c is zero, corresponding to all capacity from a single fuel type. The maximum possible value for the FDI_c is achieved when each fuel type has an equal share of capacity. For a capacity mix of eight fuel types, the maximum achievable index is 0.875. The fuel type categories used in the calculation of the FDI_c are the eight fuel sources in Table 5-3. The FDI_c is stable and does not exhibit any long-term trends. The only significant deviation occurred with the expansion of the PJM footprint. On April 1, 2002, PJM expanded with the addition of Allegheny Power System, which added about 12,000 MW of generation.[34] The reduction in the FDI_c resulted from an increase in coal capacity resources. A similar but more significant reduction occurred in 2004 with the expansion into the ComEd, AEP, and Dayton Power & Light control zones.[35] The FDI_c decreased on average 0.3 percent from the first three months of 2016 to the first three months of 2017. The decrease in FDI_c was a result of an increase in the capacity share of gas generators and corresponding small reductions in the share of nuclear, hydro, and coal. Figure 5-2 also includes the expected FDI_c through June 2019 based on the clearing of RPM auctions. The expected FDI_c is indicated in Figure 5-2 by the dashed orange line.

The FDI_c was used to measure the impact of potential retirements of resources that the MMU has identified as being at risk of retirement.[36] There were 96 resources with installed capacity totaling 14,500 MW identified as being at risk. The dashed green line in Figure 5-2 shows the FDI_c calculated assuming that the capacity from these 96 resources is replaced by gas generation. The FDI_c under these assumptions would decrease by 0.016 (2.4 percent) from the expected FDI_c for the period June 1, 2017, through June 1, 2019.

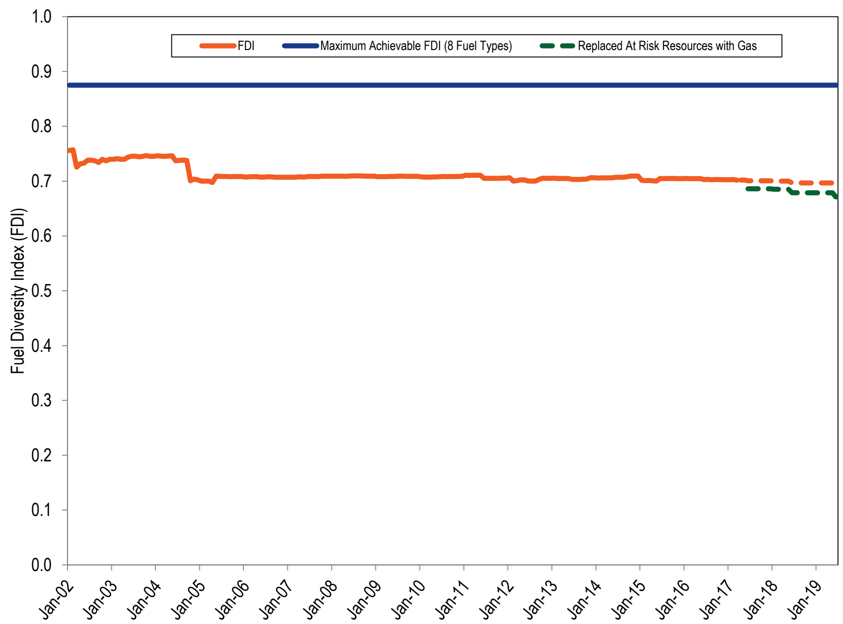
33 Monitoring Analytics developed the FDI to provide an objective metric of fuel diversity. The FDI metric is similar to the HHI used to measure market concentration. The FDI is calculated separately for energy output and for installed capacity.

34 On April 1, 2002, the PJM Region expanded with the addition of Allegheny Power System under a set of agreements known as "PJM-West." See page 4 in the *2002 State of the Market Report for PJM* for additional details.

35 See the *2016 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography" for an explanation of the expansion of the PJM footprint. The integration of the ComEd Control Area occurred in May 2004 and the integration of the AEP and Dayton control zones occurred in October 2004.

36 See the *2016 State of the Market Report for PJM*, Section 7, Units at Risk.

Figure 5-2 Fuel Diversity Index for PJM installed capacity (January 1, 2002 – June 1, 2019)



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.[37] In the first three months of 2017, the 2017/2018 RPM Third Incremental Auction was conducted.

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

Market Structure

Supply

Table 5-4 shows generation capacity changes since the implementation of the Reliability Pricing Model through the 2015/2016 Delivery Year. The 18,402.0 MW increase was the result of new generation capacity resources (15,284.9 MW), reactivated generation capacity resources (430.0 MW), uprates (5,510.3 MW), integration of external zones (18,109.0 MW), a net increase in capacity imports (5,998.3 MW), a net decrease in capacity exports (2,261.9 MW), offset by deactivations (26,122.3 MW) and derates (3,070.1 MW).

Table 5-4 Generation capacity changes: 2007/2008 to 2016/2017

	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	2,217.2	21.6	4,027.7	421.9	(1,570.5)
2014/2015	183,997.4	3,036.0	0.0	480.4	0.0	859.1	73.3	11,442.9	221.0	(7,361.7)
2015/2016	176,635.7	5,497.8	0.0	409.0	0.0	787.3	285.1	825.0	158.3	5,425.7
2016/2017	182,061.4									
Total		15,284.9	430.0	5,510.3	18,109.0	5,998.3	(2,261.9)	26,122.3	3,070.1	18,402.0

PJM Sell Offers

On November 9, 2016, PJM submitted tariff revisions to FERC requesting a change to the method for determining the PJM sell offer price in the 2017/2018 RPM Third Incremental Auction.[38] FERC partially accepted the PJM filing on January 6, 2017, agreeing with PJM that "it is just and reasonable for PJM's sell-back procedure to place a higher value on excess capacity than the current Incremental Auction procedure does."[39] However, rather than the offer price curve proposed by PJM, the Commission ordered PJM to release the capacity at a price effectively determined by the straight line connecting the price points of $0 per MW-day and the 2017/2018 BRA price.[40]

PJM sold 77.8 MW in PSEG North at 53.8 percent of the $215 per MW-day purchase price, and PJM sold the remaining 2,645.2 MW at 30.4 percent of the $120 per MW-day purchase price. PJM submitted sell offers for 8,586.6 MW in the 2017/2018 RPM Third Incremental Auction at prices conforming to the January 6, 2017 order.[41] Of the 8,586.6 MW of PJM Sell Offer submissions, 2,645.2 MW cleared. Of the 2,645.2 MW that cleared, 77.8 MW cleared in PSEG North at $115.76 per MW-day and the remaining 2,567.4 MW cleared at $36.49 per MW-day. The 2017/2018 RPM BRA clearing price was $215.00 per MW-day in PSEG North and $120 per MW-day in all other LDAs.

Demand

In the 2017/2018 RPM Third Incremental Auction, 4,019.1 MW cleared of the 13,786.3 MW of participant buy bids, and 78.2 MW cleared of the 78.2 MW of PJM buy bids for the RTO. Participant buy bids are submitted to cover commitment and compliance shortfalls or because participants wanted to purchase additional capacity. PJM buy bids are submitted due to reliability requirement adjustments and, for RPM Auction for Delivery Years prior to 2018/2019, deferred short term resource procurement.

The MMU analyzed market sectors in the PJM Capacity Market to determine how they met their load obligations. The PJM 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.

38 PJM Interconnection, L.L.C. Release of Capacity in 17/18 Third Scheduled Incremental Auction, Docket No. ER17-335-000 (November 9, 2017).
39 158 FERC ¶ 61,010 at P 22 (2017).
40 158 FERC ¶ 61,010 at P 24 (2017).
41 Ibid.

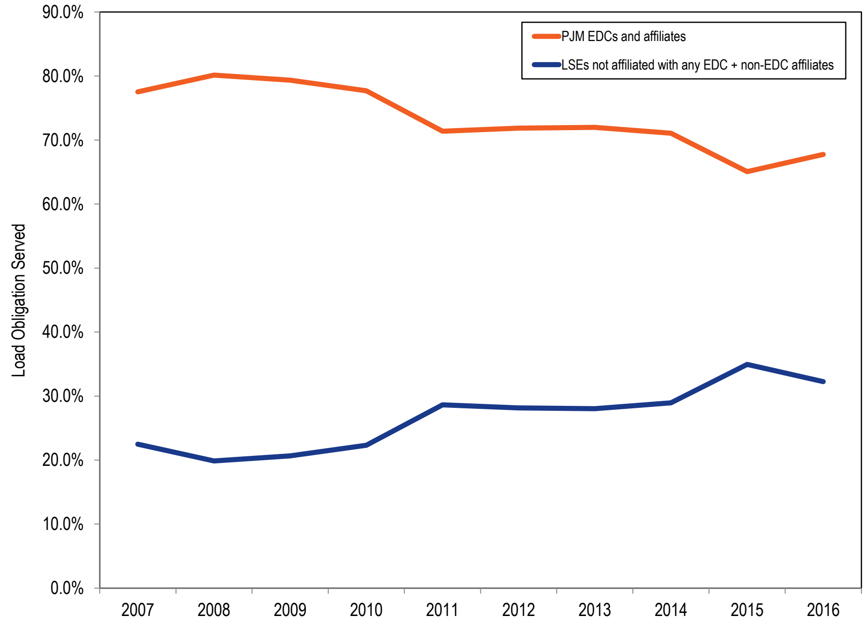
- **Non-PJM EDC Marketing Affiliate.** Affiliate companies of non-PJM EDCs that sell power and have load obligations in PJM, but do not own generating resources.
- **Non-EDC Generating Affiliate.** Affiliate companies of non-EDCs that own generating resources.
- **Non-EDC Marketing Affiliate.** Affiliate companies of non-EDCs that sell power and have load obligations in PJM, but do not own generating resources.

On June 1, 2016, PJM EDCs and their affiliates maintained a large market share of load obligations under RPM, together totaling 67.8 percent (Table 5-5), up from 65.1 percent on June 1, 2015. The combined market share of LSEs not affiliated with any EDC and of non-PJM EDC affiliates was 32.2 percent, down from 34.9 percent on June 1, 2015. 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, 2016 is shown in Figure 5-3. PJM EDCs' and their affiliates' share of load obligation has decreased from 77.5 percent on June 1, 2007, to 67.8 percent on June 1, 2016. The share of load obligation held by LSEs not affiliated with any EDC and non-PJM EDC affiliates increased from 22.5 percent on June 1, 2007, to 32.2 percent on June 1, 2016. Prior to the 2012/2013 Delivery Year, obligation was defined as cleared and make whole MW in the Base Residual Auction and the Second Incremental Auction plus ILR forecast obligations. Effective with the 2012/2013 Delivery Year, obligation is defined as the sum of the unforced capacity obligations satisfied through all RPM auctions for the delivery year.

Table 5-5 Capacity market load obligations served: June 1, 2016

	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	53,042.9	23,917.9	5,835.4	4,624.2	5,560.2	1,820.9	27,401.2	122,202.6
Percent of total obligation	43.4%	19.6%	4.8%	3.8%	4.5%	1.5%	22.4%	100.0%

Figure 5-3 Capacity market load obligation served: June 1, 2007 through June 1, 2016



Capacity Transfer Rights (CTRs)

Capacity Transfer Rights (CTRs) are used to return capacity market congestion revenues to load. Load pays for the transmission system through firm transmission charges and pays for congestion. Capacity market congestion revenues are the difference between the total dollars paid by load for capacity and the total dollars received by capacity market sellers. The MW of CTRs available for allocation to LSEs in an LDA is equal to the Unforced Capacity imported into the LDA, based on the results of the Base Residual Auction and Incremental Auctions, less any MW of CETL paid for directly by market participants in the form of Qualifying Transmission Upgrades (QTUs) cleared in an RPM Auction and Incremental Capacity Transfer Rights (ICTRs). There are two types of ICTRs, those allocated to a New Service Customer obligated to fund a transmission facility or upgrade and those associated with Incremental Rights-Eligible Required Transmission Enhancements.

For LDAs in which the RPM Auctions for a Delivery Year resulted in a positive average weighted Locational Price Adder, an LSE with CTRs corresponding to the LDA is entitled to a payment equal to the Locational Price Adder multiplied by the MW of the LSEs' CTRs.

In the 2019/2020 RPM Base Residual Auction, EMAAC had 4,242.2 MW of CTRs with a total value of $30,695,796, ComEd had 2,355.1 MW of CTRs with a total value of $88,584,307, and BGE had 4,720.3 MW of CTRs with a total value of $518,289. Additionally, EMAAC had 898.0 MW of ICTRs with a total annualized value of $6,497,766, and BGE had 371.7 MW with a total annualized value of $33,599.

Market Concentration

Auction Market Structure

As shown in Table 5-6, all participants in the total PJM market as well as the LDA RPM markets failed the three pivotal supplier (TPS) test in the 2017/2018 RPM Third Incremental Auction.[42] 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.[43] [44] [45] An overall offer cap was applied to all offers in the CP 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 5-6 presents the results of the TPS test. A generation owner or owners are pivotal if the capacity of the owners' generation facilities is needed to meet the demand for capacity. 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.

42 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.

43 See PJM. OATT Attachment DD § 6.5.

44 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.

45 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 5-6 RSI results: 2016/2017 through 2019/2020 RPM Auctions[46]

RPM Markets	$RSI_{1, 1.05}$	RSI_3	Total Participants	Failed RSI_3 Participants
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
2016/2017 Third Incremental Auction				
RTO	0.54	0.35	64	64
MAAC	0.00	0.00	0	0
PSEG	0.00	0.00	1	1
PSEG North	0.00	0.00	2	2
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
2017/2018 Second Incremental Auction				
RTO	0.65	0.32	30	30
PSEG	0.00	0.00	0	0
PSEG North	0.00	0.00	0	0
2017/2018 Third Incremental Auction				
RTO	0.70	0.42	63	63
PSEG	0.00	0.00	0	0
2018/2019 Base Residual Auction				
RTO	0.81	0.65	125	125

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

Table 5-6 RSI results: 2016/2017 through 2019/2020 RPM Auctions (continued)

RPM Markets	$RSI_{1, 1.05}$	RSI_3	Total Participants	Failed RSI_3 Participants
EMAAC	0.59	0.16	12	12
ComEd	1.11	0.02	4	4
2018/2019 First Incremental Auction				
RTO	0.51	0.23	32	32
EMAAC	-0.00	0.00	2	2
ComEd	0.00	0.00	1	1
2019/2020 Base Residual Auction				
RTO	0.81	0.66	131	131
EMAAC	0.79	0.23	6	6
ComEd	0.74	0.12	6	6
BGE	0.00	0.00	1	1

Locational Deliverability Areas (LDAs)

Under the PJM Tariff, PJM determines, in advance of each BRA, whether defined Locational Deliverability Areas (LDAs) will be modeled in the auction. Effective with the 2012/2013 Delivery Year, an LDA 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.[47] 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."[48] 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

47 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.

48 PJM. OATT Attachment DD § 5.10 (a) (ii).

Year, Sub-Annual and Limited Resource Constraints, replacing the Minimum Annual and a Minimum Extended Summer Resource Requirements, are established for each modeled LDA.[49] 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 5-4, Figure 5-5 and Figure 5-6.

Figure 5-4 Map of PJM Locational Deliverability Areas

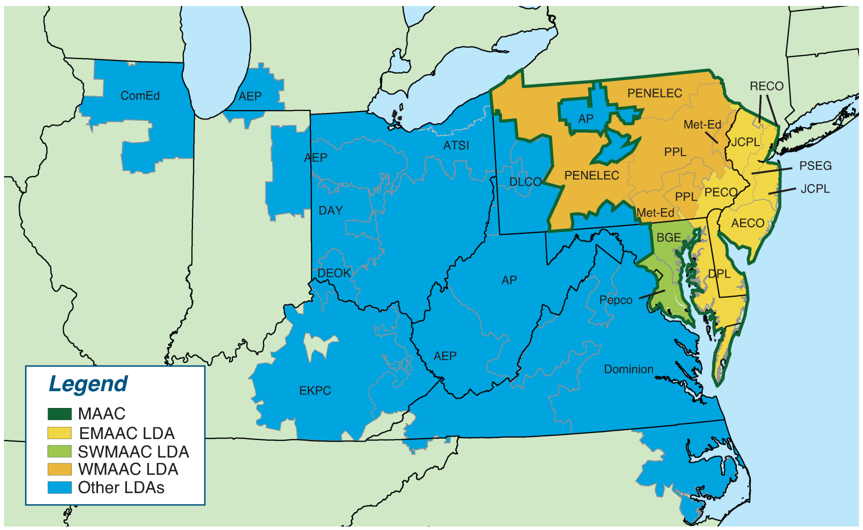


Figure 5-5 Map of PJM RPM EMAAC subzonal LDAs

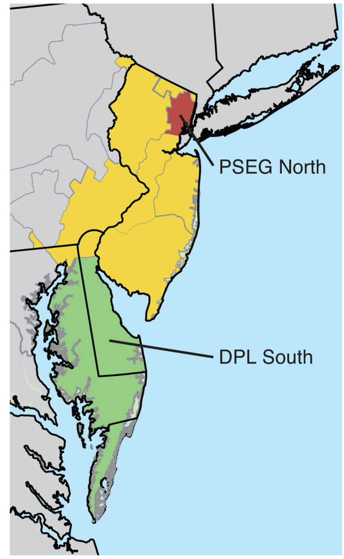
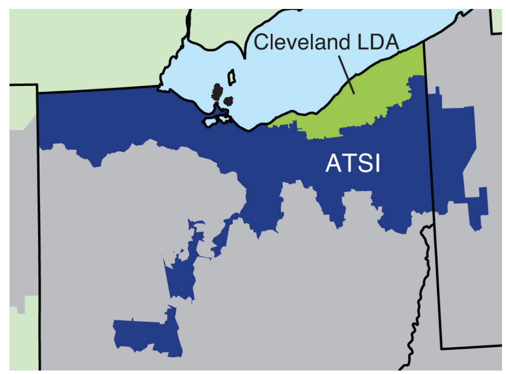


Figure 5-6 Map of PJM RPM ATSI subzonal LDA



49 146 FERC ¶ 61,052 (2014).

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.[50]

The PJM market rules should not create inappropriate barriers to either the import or export of capacity. The market rules in other balancing authorities should also not create inappropriate barriers to the import or export of capacity. The PJM market rules should ensure that the definition of capacity is enforced including physical deliverability, recallability and the obligation to make competitive offers into the PJM Day-Ahead Energy Market. Physical deliverability can only be assured by requiring that all imports are deliverable to PJM load to ensure that they are full substitutes for internal capacity resources. While pseudo ties were a step toward this goal, pseudo ties alone are not adequate to ensure deliverability. Pseudo ties create potential issues in the exporting area and do not ensure deliverability into the importing area. 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.[51] 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.

50 PJM. OATT Attachment DD § 5.6.6(b).
51 147 FERC ¶ 61,060 (2014).

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.[52]

Of the 15.9 MW of imports in the 2017/2018 RPM Third Incremental Auction, 11.4 MW cleared. Of the cleared imports, 8.6 MW (75.4 percent) were from MISO.As shown in Table 5-7, of the 4,343.4 MW of imports in the 2019/2020 RPM Base Residual Auction, 3,875.9 MW cleared. Of the cleared imports, 1,828.6 MW (47.2 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.[53] [54] 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 nonrecallability must be provided to assure PJM that the energy and capacity from the unit is not recallable to any other balancing authority.

52 151 FERC ¶ 61,208 (2015).
53 See "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Schedule 9 & 10.
54 See "PJM Manual 18: PJM Capacity Market," Revision 36 (December 22, 2016) at 54-55 & 78-79.

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.[55]

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. 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.[56] [57] 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.[58] 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.[59]

Exporting Capacity

Nonfirm 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.[60] The Capacity Market Seller must also identify the megawatt amount, export zone, and time period (in days) of the export.[61]

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.[62]

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.

55 OATT, Schedule 1, Section 1.10.1A.
56 See "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Section 1.69A.
57 See "PJM Manual 18: PJM Capacity Market," Revision 36 (December 22, 2016) at 57-58.
58 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).
59 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).
60 OATT Attachment DD § 6.6(g).
61 *Id.*
62 OATT Attachment M-Appendix § II.C.2.

Table 5-7 RPM imports: 2007/2008 through 2019/2020 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
2019/2020	2,067.3	1,828.6	2,276.1	2,047.3	4,343.4	3,875.9

Demand Resources

There are three basic demand products incorporated in the RPM market design:[63]

- **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.[64]

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:[65] [66]

- **Annual DR.** A 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.** A 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 only ten hours only during the hours of 10:00 a.m. to 10:00 p.m. EPT.
- **Limited DR.** A 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:[67] [68]

- **Base Capacity Demand Resource.** A 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.

63 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.
64 Letter Order in Docket No. ER10-366-000 (January 22, 2010).
65 134 FERC ¶ 61,066 (2011).
66 "Reliability Assurance Agreement among Load-Serving Entities in the PJM Region," Article 1.
67 151 FERC ¶ 61,208.
68 "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Article 1.

- **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.** A 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 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 5-8 and Table 5-10, capacity in the RPM load management programs was 10,248.9 MW for June 1, 2016, as a result of cleared capacity for Demand Resources and Energy Efficiency Resources in RPM Auctions for the 2016/2017 Delivery Year (14,988.5 MW) less replacement capacity (4,739.6 MW). Table 5-9 shows RPM commitments for DR and EE resources as the result of RPM Auctions prior to adjustments for replacement capacity transactions and certified ILR.

Table 5-8 RPM load management statistics by LDA: June 1, 2015 to June 1, 2019[69] [70] [71] [72]

	UCAP (MW)												
	RTO	MAAC	EMAAC	SWMAAC	DPL South	PSEG	PSEG North	Pepco	ATSI	ATSI Cleveland	ComEd	BGE	PPL
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	13,265.3	5,398.0	2,017.5	1,622.6	105.7	622.6	227.1	683.9	1,841.4	470.8			
EE cleared	1,723.2	418.0	86.4	262.6	2.0	27.9	10.8	136.5	226.9	58.6			
DR net replacements	(4,800.7)	(1,908.8)	(802.5)	(407.4)	(43.1)	(287.8)	(92.8)	(150.1)	(1,290.5)	(342.3)			
EE net replacements	61.1	111.0	27.1	94.5	(0.6)	6.3	3.3	17.9	(79.0)	(15.4)			
RPM load management @ 01-Jun-16	10,248.9	4,018.2	1,328.5	1,572.3	64.0	369.0	148.4	688.2	698.8	171.7			
DR cleared	11,870.7	4,584.5	1,630.9	1,464.1	86.3	402.8	157.1	658.3	1,256.0	323.5	1,602.9	805.8	811.9
EE cleared	1,922.3	547.7	180.0	291.5	5.6	55.2	18.5	155.4	192.3	41.4	747.6	136.1	43.2
DR net replacements	(2,283.7)	(398.4)	(227.6)	(30.2)	0.0	(53.2)	(25.0)	(13.4)	(438.7)	(151.0)	(339.8)	(16.8)	(78.3)
EE net replacements	(43.2)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(43.2)	(9.2)	0.0	0.0	0.0
RPM load management @ 01-Jun-17	11,466.1	4,733.8	1,583.3	1,725.4	91.9	404.8	150.6	800.3	966.4	204.7	2,010.7	925.1	776.8
DR cleared	11,200.6	4,302.1	1,690.7	1,183.1	86.8	389.9	139.2	523.1	958.6	287.2	1,895.2	660.0	716.2
EE cleared	1,579.8	443.3	170.7	225.2	3.5	44.4	10.9	125.1	67.6	13.9	753.8	100.1	28.9
DR net replacements	(232.4)	(81.4)	(68.9)	0.0	0.0	(10.9)	0.0	0.0	(16.0)	0.0	(95.0)	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	12,548.0	4,664.0	1,792.5	1,408.3	90.3	423.4	150.1	648.2	1,010.2	301.1	2,554.0	760.1	745.1
DR cleared	10,348.0	3,777.1	1,636.5	739.7	91.3	380.7	176.5	483.3	897.6	289.9	1,757.4	256.4	739.8
EE cleared	1,515.1	426.9	160.8	179.7	1.0	49.3	8.4	79.0	41.0	0.2	724.8	100.7	50.9
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-19	11,863.1	4,204.0	1,797.3	919.4	92.3	430.0	184.9	562.3	938.6	290.1	2,482.2	357.1	790.7

69 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.

70 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.

71 See PJM. OATT. Attachment DD § 5.14C. The reported DR cleared MW for the 2015/2016 and 2016/2017 Delivery Years reflect reductions in the level of committed MW due to the Demand Response Operational Resource Flexibility Transition Provision.

72 See PJM. OATT. Attachment DD § 5.14E. The reported DR cleared MW for the 2016/2017, 2017/2018, and 2018/2019 Delivery Years reflect reductions in the level of committed MW due to the Demand Response Legacy Direct Load Control Transition Provision.

Table 5-9 RPM load management cleared capacity and ILR: 2007/2008 through 2019/2020[73 74 75 76]

	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	12,737.6	13,265.3	1,656.9	1,723.2	0.0	0.0
2017/2018	11,430.4	11,870.7	1,852.7	1,922.3	0.0	0.0
2018/2019	10,292.1	11,200.6	1,452.2	1,579.8	0.0	0.0
2019/2020	9,510.3	10,348.0	1,393.7	1,515.1	0.0	0.0

73 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.

74 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.

75 See PJM. OATT. Attachment DD § 5.14C. The reported DR cleared MW for the 2015/2016 and 2016/2017 Delivery Years reflect reductions in the level of committed MW due to the Demand Response Operational Resource Flexibility Transition Provision.

76 See PJM. OATT. Attachment DD § 5.14E. The reported DR cleared MW for the 2016/2017, 2017/2018, and 2018/2019 Delivery Years reflect reductions in the level of committed MW due to the Demand Response Legacy Direct Load Control Transition Provision.

Table 5-10 RPM load management statistics: June 1, 2007 to June 1, 2019[77 78]

	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	14,394.5	14,988.5	(4,609.3)	(4,800.7)	58.7	61.1	9,843.9	10,248.9
01-Jun-17	13,283.1	13,793.0	(2,198.9)	(2,283.7)	(41.6)	(43.2)	11,042.6	11,466.1
01-Jun-18	11,744.3	12,780.4	(213.5)	(232.4)	0.0	0.0	11,530.8	12,548.0
01-Jun-19	10,904.0	11,863.1	0.0	0.0	0.0	0.0	10,904.0	11,863.1

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.[79 80 81] For Base Capacity, offer caps are defined as avoidable costs less PJM market revenues, or opportunity costs based on the potential sale of capacity in an external market. For Capacity Performance Resources, offer caps are defined as the applicable zonal net Cost of New Entry (CONE) times (B) where B is the average of the

77 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.

78 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.

79 See OATT Attachment DD § 6.5.

80 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.

81 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).

Balancing Ratios (B) during the Performance Assessment Hours in the three consecutive calendar years that precede the Base Residual Auction for such Delivery Year unless net avoidable costs exceed this level, or opportunity costs based on the potential sale of capacity in an external market. For RPM Third Incremental Auctions, capacity market sellers may elect, for Base Capacity offers, an offer cap equal to 1.1 times the BRA clearing price for the relevant LDA and delivery year or, for Capacity Performance offers, an offer cap equal to the greater of the net CONE for the relevant LDA and delivery year or 1.1 times the BRA clearing price for the relevant LDA and delivery year.

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.[82] 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. For Capacity Performance Resources, avoidable cost based offer caps are defined to be net of revenues from all other PJM markets and unit-specific bilateral contracts and expected bonus performance payments/non-performance charges.[83] Capacity resource owners could provide ACR data by providing their own unit-specific data or, for delivery years prior to 2020/2021, by selecting the default ACR values. The specific components of avoidable costs are defined in the PJM Tariff.[84]

Effective for the 2018/2019 and subsequent Delivery Years, the ACR definition includes two additional components, Avoidable Fuel Availability Expenses (AFAE) and Capacity Performance Quantifiable Risk (CPQR).[85] AFAE is available for Capacity Performance Resources. AFAE is defined to include expenses related to fuel availability and delivery. CPQR is available for Capacity Performance Resources and, for the 2018/2019 and 2019/2020 Delivery Years, Base Capacity Resources. CPQR is defined to be the quantifiable and reasonably supported cost of mitigating the risks of nonperformance associated with submission of an offer.

The opportunity cost option allows Capacity Market Sellers to offer based on 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.[86] 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.[87]

Effective May 3, 2013, the RPM Minimum Offer Price Rule (MOPR) was changed again.[88] 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 combined cycle (IGCC) technologies while excluding units primarily fueled with landfill gas or cogeneration units which are certified or self-certified as Qualifying Facilities

82 OATT Attachment DD § 6.8 (b).
83 For details on the competitive offer of a capacity performance resource, see "Analysis of the 2019/2020 RPM Base Residual Auction Revised," <http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Analysis_of_the_20192020_RPM_BRA_20160831-Revised.pdf> (August 31, 2016).
84 OATT Attachment DD § 6.8 (a).
85 151 FERC ¶ 61,208.
86 135 FERC ¶ 61,022 (2011).
87 135 FERC ¶ 61,022 (2011), *order on reh'g*, 137 FERC ¶ 61,145 (2011).
88 143 FERC ¶ 61,090 (2013).

(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.

2017/2018 RPM Third Incremental Auction

As shown in Table 5-11, 310 generation resources submitted offers in the 2017/2018 RPM Third Incremental Auction. The MMU calculated offer caps for nine generation resources (2.9 percent), of which five were based on the technology specific default (proxy) ACR values and four were unit-specific offer caps (1.3 percent of all generation resources), of which four offer caps included an APIR component. Of the 310 generation resources, 306 did not request unit specific offer caps, of which 205 generation resources elected the offer cap option of 1.1 times the BRA clearing price, five were based on the default ACRs, three Planned Generation Capacity Resources had uncapped offers (1.0 percent), and 93 generation resources were price takers (30.0 percent). Market power mitigation was applied to the sell offers of five generation resources.

Table 5-11 ACR statistics: 2017/2018 RPM Auctions

	2017/2018 Base Residual Auction		2017/2018 First Incremental Auction		2017/2018 Second Incremental Auction		2017/2018 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	369	30.7%	36	30.5%	15	15.8%	5	1.6%
Unit specific ACR (APIR)	122	10.1%	17	14.4%	18	18.9%	4	1.3%
Unit specific ACR (APIR and CPQR)	NA	NA	NA	NA	NA	NA	NA	NA
Unit specific ACR (non-APIR)	4	0.3%	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	5	0.4%	0	0.0%	2	2.1%	0	0.0%
Default ACR and opportunity cost	0	0.0%	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	205	66.1%
Uncapped planned uprate and default ACR	31	2.6%	0	0.0%	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	6	0.5%	2	1.7%	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	28	2.3%	6	5.1%	7	7.4%	3	1.0%
Existing generation resources as price takers	637	53.0%	57	48.3%	53	55.8%	93	30.0%
Total Generation Capacity Resources offered	1,202	100.0%	118	100.0%	95	100.0%	310	100.0%

Market Performance

Figure 5-7 shows cleared MW weighted average capacity market prices on a Delivery Year basis for the entire history of the PJM capacity markets. Table 5-12 shows RPM clearing prices for all RPM Auctions held through the first three months of 2017.

Figure 5-8 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 the first three months of 2017. A summary of these weighted average prices is given in Table 5-13.

Table 5-14 shows RPM revenue by resource type for all RPM Auctions held through the first three months of 2017 with $6.3 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 5-15 shows RPM revenue by calendar year for all RPM Auctions held through the first three months of 2017. In 2016, RPM revenue was $8.9 billion. In 2017, RPM revenue was $8.8 billion.

Table 5-16 shows the RPM annual charges to load. For the 2016/2017 Delivery Year, RPM annual charges to load are $7.7 billion. For the 2017/2018 Delivery Year, annual charges to load are $9.1 billion.

Table 5-12 Capacity prices: 2007/2008 through 2019/2020 RPM Auctions

		RPM Clearing Price ($ per MW-day)												
	Product Type	RTO	MAAC	APS	PPL	EMAAC	SWMAAC	DPL South	PSEG	PSEG North	Pepco	ATSI	ComEd	BGE
2007/2008 BRA		$40.80	$40.80	$40.80	$40.80	$197.67	$188.54	$197.67	$197.67	$197.67	$188.54		$40.80	$188.54
2008/2009 BRA		$111.92	$111.92	$111.92	$111.92	$148.80	$210.11	$148.80	$148.80	$148.80	$210.11		$111.92	$210.11
2008/2009 Third Incremental Auction		$10.00	$10.00	$10.00	$10.00	$10.00	$223.85	$10.00	$10.00	$10.00	$223.85		$10.00	$223.85
2009/2010 BRA		$102.04	$191.32	$191.32	$191.32	$191.32	$237.33	$191.32	$191.32	$191.32	$237.33		$102.04	$237.33
2009/2010 Third Incremental Auction		$40.00	$86.00	$86.00	$86.00	$86.00	$86.00	$86.00	$86.00	$86.00	$86.00		$40.00	$86.00
2010/2011 BRA		$174.29	$174.29	$174.29	$174.29	$174.29	$174.29	$186.12	$174.29	$174.29	$174.29		$174.29	$174.29
2010/2011 Third Incremental Auction		$50.00	$50.00	$50.00	$50.00	$50.00	$50.00	$50.00	$50.00	$50.00	$50.00		$50.00	$50.00
2011/2012 BRA		$110.00	$110.00	$110.00	$110.00	$110.00	$110.00	$110.00	$110.00	$110.00	$110.00		$110.00	$110.00
2011/2012 First Incremental Auction		$55.00	$55.00	$55.00	$55.00	$55.00	$55.00	$55.00	$55.00	$55.00	$55.00		$55.00	$55.00
2011/2012 ATSI FRR Integration Auction		$108.89	$108.89	$108.89	$108.89	$108.89	$108.89	$108.89	$108.89	$108.89	$108.89	$108.89	$108.89	$108.89
2011/2012 Third Incremental Auction		$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00
2012/2013 BRA		$16.46	$133.37	$16.46	$133.37	$139.73	$133.37	$222.30	$139.73	$185.00	$133.37		$16.46	$133.37
2012/2013 ATSI FRR Integration Auction		$20.46	$20.46	$20.46	$20.46	$20.46	$20.46	$20.46	$20.46	$20.46	$20.46	$20.46	$20.46	$20.46
2012/2013 First Incremental Auction		$16.46	$16.46	$16.46	$16.46	$153.67	$16.46	$153.67	$153.67	$153.67	$16.46	$16.46	$16.46	$16.46
2012/2013 Second Incremental Auction		$13.01	$13.01	$13.01	$13.01	$48.91	$13.01	$48.91	$48.91	$48.91	$13.01	$13.01	$13.01	$13.01
2012/2013 Third Incremental Auction		$2.51	$2.51	$2.51	$2.51	$2.51	$2.51	$2.51	$2.51	$2.51	$2.51	$2.51	$2.51	$2.51
2013/2014 BRA		$27.73	$226.15	$27.73	$226.15	$245.00	$226.15	$245.00	$245.00	$245.00	$247.14	$27.73	$27.73	$226.15
2013/2014 First Incremental Auction		$20.00	$20.00	$20.00	$20.00	$178.85	$54.82	$178.85	$178.85	$178.85	$54.82	$20.00	$20.00	$54.82
2013/2014 Second Incremental Auction		$7.01	$10.00	$7.01	$10.00	$40.00	$10.00	$40.00	$40.00	$40.00	$10.00	$7.01	$7.01	$10.00
2013/2014 Third Incremental Auction		$4.05	$30.00	$4.05	$30.00	$188.44	$30.00	$188.44	$188.44	$188.44	$30.00	$4.05	$4.05	$30.00
2014/2015 BRA	Limited	$125.47	$125.47	$125.47	$125.47	$125.47	$125.47	$125.47	$125.47	$213.97	$125.47	$125.47	$125.47	$125.47
2014/2015 BRA	Extended Summer	$125.99	$136.50	$125.99	$136.50	$136.50	$136.50	$136.50	$136.50	$225.00	$136.50	$125.99	$125.99	$136.50
2014/2015 BRA	Annual	$125.99	$136.50	$125.99	$136.50	$136.50	$136.50	$136.50	$136.50	$225.00	$136.50	$125.99	$125.99	$136.50
2014/2015 First Incremental Auction	Limited	$0.03	$5.23	$0.03	$5.23	$5.23	$5.23	$5.23	$5.23	$399.62	$5.23	$0.03	$0.03	$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	$410.95	$16.56	$5.54	$5.54	$16.56
2014/2015 First Incremental Auction	Annual	$5.54	$16.56	$5.54	$16.56	$16.56	$16.56	$16.56	$16.56	$410.95	$16.56	$5.54	$5.54	$16.56
2014/2015 Second Incremental Auction	Limited	$25.00	$56.94	$25.00	$56.94	$56.94	$56.94	$56.94	$56.94	$310.00	$56.94	$25.00	$25.00	$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	$310.00	$56.94	$25.00	$25.00	$56.94
2014/2015 Second Incremental Auction	Annual	$25.00	$56.94	$25.00	$56.94	$56.94	$56.94	$56.94	$56.94	$310.00	$56.94	$25.00	$25.00	$56.94
2014/2015 Third Incremental Auction	Limited	$25.51	$132.20	$25.51	$132.20	$132.20	$132.20	$132.20	$132.20	$256.76	$132.20	$25.51	$25.51	$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	$256.76	$132.20	$25.51	$25.51	$132.20
2014/2015 Third Incremental Auction	Annual	$25.51	$132.20	$25.51	$132.20	$132.20	$132.20	$132.20	$132.20	$256.76	$132.20	$25.51	$25.51	$132.20
2015/2016 BRA	Limited	$118.54	$150.00	$118.54	$150.00	$150.00	$150.00	$150.00	$150.00	$150.00	$150.00	$304.62	$118.54	$150.00
2015/2016 BRA	Extended Summer	$136.00	$167.46	$136.00	$167.46	$167.46	$167.46	$167.46	$167.46	$167.46	$167.46	$322.08	$136.00	$167.46
2015/2016 BRA	Annual	$136.00	$167.46	$136.00	$167.46	$167.46	$167.46	$167.46	$167.46	$167.46	$167.46	$357.00	$136.00	$167.46
2015/2016 First Incremental Auction	Limited	$43.00	$111.00	$43.00	$111.00	$111.00	$111.00	$111.00	$122.95	$122.95	$111.00	$168.37	$43.00	$111.00
2015/2016 First Incremental Auction	Extended Summer	$43.00	$111.00	$43.00	$111.00	$111.00	$111.00	$111.00	$122.95	$122.95	$111.00	$168.37	$43.00	$111.00
2015/2016 First Incremental Auction	Annual	$43.00	$111.00	$43.00	$111.00	$111.00	$111.00	$111.00	$122.95	$122.95	$111.00	$168.37	$43.00	$111.00

Table 5-12 Capacity prices: 2007/2008 through 2019/2020 RPM Auctions (continued)

		RPM Clearing Price ($ per MW-day)												
	Product Type	RTO	MAAC	APS	PPL	EMAAC	SWMAAC	DPL South	PSEG	PSEG North	Pepco	ATSI	ComEd	BGE
2015/2016 Second Incremental Auction	Limited	$123.56	$141.12	$123.56	$141.12	$141.12	$141.12	$141.12	$155.02	$155.02	$141.12	$204.10	$123.56	$141.12
2015/2016 Second Incremental Auction	Extended Summer	$136.00	$153.56	$136.00	$153.56	$153.56	$153.56	$153.56	$167.46	$167.46	$153.56	$216.54	$136.00	$153.56
2015/2016 Second Incremental Auction	Annual	$136.00	$153.56	$136.00	$153.56	$153.56	$153.56	$153.56	$167.46	$167.46	$153.56	$216.54	$136.00	$153.56
2015/2016 Third Incremental Auction	Limited	$100.76	$122.33	$100.76	$122.33	$122.33	$122.33	$122.33	$122.56	$122.56	$122.33	$100.76	$100.76	$122.33
2015/2016 Third Incremental Auction	Extended Summer	$163.20	$184.77	$163.20	$184.77	$184.77	$184.77	$184.77	$185.00	$185.00	$184.77	$163.20	$163.20	$184.77
2015/2016 Third Incremental Auction	Annual	$163.20	$184.77	$163.20	$184.77	$184.77	$184.77	$184.77	$185.00	$185.00	$184.77	$163.20	$163.20	$184.77
2016/2017 BRA	Limited	$59.37	$119.13	$59.37	$119.13	$119.13	$119.13	$119.13	$219.00	$219.00	$119.13	$94.45	$59.37	$119.13
2016/2017 BRA	Extended Summer	$59.37	$119.13	$59.37	$119.13	$119.13	$119.13	$119.13	$219.00	$219.00	$119.13	$114.23	$59.37	$119.13
2016/2017 BRA	Annual	$59.37	$119.13	$59.37	$119.13	$119.13	$119.13	$119.13	$219.00	$219.00	$119.13	$114.23	$59.37	$119.13
2016/2017 First Incremental Auction	Limited	$53.93	$89.35	$53.93	$89.35	$89.35	$89.35	$89.35	$214.44	$214.44	$89.35	$94.45	$53.93	$89.35
2016/2017 First Incremental Auction	Extended Summer	$60.00	$119.13	$60.00	$119.13	$119.13	$119.13	$119.13	$244.22	$244.22	$119.13	$100.52	$60.00	$119.13
2016/2017 First Incremental Auction	Annual	$60.00	$119.13	$60.00	$119.13	$119.13	$119.13	$119.13	$244.22	$244.22	$119.13	$100.52	$60.00	$119.13
2016/2017 Second Incremental Auction	Limited	$31.00	$71.00	$31.00	$71.00	$71.00	$71.00	$71.00	$99.01	$212.53	$71.00	$101.50	$31.00	$71.00
2016/2017 Second Incremental Auction	Extended Summer	$31.00	$71.00	$31.00	$71.00	$71.00	$71.00	$71.00	$99.01	$212.53	$71.00	$101.50	$31.00	$71.00
2016/2017 Second Incremental Auction	Annual	$31.00	$71.00	$31.00	$71.00	$71.00	$71.00	$71.00	$99.01	$212.53	$71.00	$101.50	$31.00	$71.00
2016/2017 Capacity Performance Transition Auction	Capacity Performance	$134.00	$134.00	$134.00	$134.00	$134.00	$134.00	$134.00	$134.00	$134.00	$134.00	$134.00	$134.00	$134.00
2016/2017 Third Incremental Auction	Limited	$5.02	$10.02	$5.02	$10.02	$10.02	$10.02	$10.02	$54.76	$184.97	$10.02	$5.02	$5.02	$10.02
2016/2017 Third Incremental Auction	Extended Summer	$5.02	$10.02	$5.02	$10.02	$10.02	$10.02	$10.02	$54.76	$184.97	$10.02	$5.02	$5.02	$10.02
2016/2017 Third Incremental Auction	Annual	$5.02	$10.02	$5.02	$10.02	$10.02	$10.02	$10.02	$54.76	$184.97	$10.02	$5.02	$5.02	$10.02
2017/2018 BRA	Limited	$106.02	$106.02	$106.02	$40.00	$106.02	$106.02	$106.02	$201.02	$201.02	$106.02	$106.02	$106.02	$106.02
2017/2018 BRA	Extended Summer	$120.00	$120.00	$120.00	$53.98	$120.00	$120.00	$120.00	$215.00	$215.00	$120.00	$120.00	$120.00	$120.00
2017/2018 BRA	Annual	$120.00	$120.00	$120.00	$120.00	$120.00	$120.00	$120.00	$215.00	$215.00	$120.00	$120.00	$120.00	$120.00
2017/2018 Capacity Performance Transition Auction	Capacity Performance	$151.50	$151.50	$151.50	$151.50	$151.50	$151.50	$151.50	$151.50	$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	$143.08	$84.00	$84.00	$84.00	$84.00
2017/2018 First Incremental Auction	Extended Summer	$84.00	$84.00	$84.00	$84.00	$84.00	$84.00	$84.00	$143.08	$143.08	$84.00	$84.00	$84.00	$84.00
2017/2018 First Incremental Auction	Annual	$84.00	$84.00	$84.00	$84.00	$84.00	$84.00	$84.00	$143.08	$143.08	$84.00	$84.00	$84.00	$84.00
2017/2018 Second Incremental Auction	Limited	$26.50	$26.50	$26.50	$26.50	$26.50	$26.50	$26.50	$120.43	$179.00	$26.50	$26.50	$26.50	$26.50
2017/2018 Second Incremental Auction	Extended Summer	$26.50	$26.50	$26.50	$26.50	$26.50	$26.50	$26.50	$120.43	$179.00	$26.50	$26.50	$26.50	$26.50
2017/2018 Second Incremental Auction	Annual	$26.50	$26.50	$26.50	$26.50	$26.50	$26.50	$26.50	$120.43	$179.00	$26.50	$26.50	$26.50	$26.50
2017/2018 Third Incremental Auction	Limited	$36.49	$36.49	$36.49	$36.49	$36.49	$36.49	$36.49	$115.76	$115.76	$36.49	$36.49	$36.49	$36.49
2017/2018 Third Incremental Auction	Extended Summer	$36.49	$36.49	$36.49	$36.49	$36.49	$36.49	$36.49	$115.76	$115.76	$36.49	$36.49	$36.49	$36.49
2017/2018 Third Incremental Auction	Annual	$36.49	$36.49	$36.49	$36.49	$36.49	$36.49	$36.49	$115.76	$115.76	$36.49	$36.49	$36.49	$36.49
2018/2019 BRA	Base Capacity	$149.98	$149.98	$149.98	$75.00	$210.63	$149.98	$210.63	$210.63	$210.63	$149.98	$149.98	$200.21	$149.98
2018/2019 BRA	Base Capacity DR/EE	$149.98	$149.98	$149.98	$75.00	$210.63	$59.95	$210.63	$210.63	$210.63	$41.09	$149.98	$200.21	$59.95
2018/2019 BRA	Capacity Performance	$164.77	$164.77	$164.77	$164.77	$225.42	$164.77	$225.42	$225.42	$225.42	$164.77	$164.77	$215.00	$164.77
2018/2019 First Incremental Auction	Base Capacity	$22.51	$22.51	$22.51	$22.51	$80.04	$22.51	$35.68	$80.04	$80.04	$22.51	$22.51	$25.36	$22.51
2018/2019 First Incremental Auction	Base Capacity DR/EE	$22.51	$22.51	$22.51	$22.51	$80.04	$22.51	$35.68	$80.04	$80.04	$22.51	$22.51	$25.36	$22.51
2018/2019 First Incremental Auction	Capacity Performance	$27.15	$27.15	$27.15	$27.15	$84.68	$27.15	$84.68	$84.68	$84.68	$27.15	$27.15	$30.00	$27.15
2019/2020 BRA	Base Capacity	$80.00	$80.00	$80.00	$80.00	$99.77	$80.00	$99.77	$99.77	$99.77	$80.00	$80.00	$182.77	$80.30
2019/2020 BRA	Base Capacity DR/EE	$80.00	$80.00	$80.00	$80.00	$99.77	$80.00	$99.77	$99.77	$99.77	$0.01	$80.00	$182.77	$80.30
2019/2020 BRA	Capacity Performance	$100.00	$100.00	$100.00	$100.00	$119.77	$100.00	$119.77	$119.77	$119.77	$100.00	$100.00	$202.77	$100.30

Table 5-13 Weighted average clearing prices by zone: 2016/2017 through 2019/2020

	Weighted Average Clearing Price ($ per MW-day)			
LDA	2016/2017	2017/2018	2018/2019	2019/2020
RTO				
AEP	$115.27	$139.94	$162.19	$96.60
AP	$115.27	$139.94	$162.19	$96.60
ATSI	$122.15	$138.22	$152.87	$97.03
Cleveland	$112.13	$138.43	$161.42	$97.44
ComEd	$115.27	$140.48	$209.55	$200.02
DAY	$115.27	$139.94	$162.19	$96.60
DEOK	$115.27	$139.94	$162.19	$96.60
DLCO	$115.27	$139.94	$162.19	$96.60
Dominion	$115.27	$139.94	$162.19	$96.60
EKPC	$115.27	$139.94	$162.19	$96.60
MAAC				
EMAAC				
AECO	$123.01	$137.20	$219.98	$114.57
DPL	$123.01	$137.20	$219.98	$114.57
DPL South	$119.87	$133.72	$219.21	$118.10
JCPL	$123.01	$137.20	$219.98	$114.57
PECO	$123.01	$137.20	$219.98	$114.57
PSEG	$220.70	$205.58	$220.71	$117.49
PSEG North	$218.25	$212.51	$223.42	$118.46
RECO	$123.01	$137.20	$219.98	$114.57
SWMAAC				
BGE	$120.96	$125.37	$143.38	$95.92
Pepco	$118.60	$133.34	$151.84	$92.25
WMAAC				
Met-Ed	$122.13	$139.32	$155.64	$98.04
PENELEC	$122.13	$139.32	$155.64	$98.04
PPL	$122.13	$136.20	$153.51	$97.03

Table 5-14 RPM revenue by type: 2007/2008 through 2019/2020[89] [90]

				Coal		Gas		Hydroelectric		Nuclear		Oil	
	Demand Resources	Energy Efficiency Resources	Imports	Existing	New/repower/ reactivated	Existing	New/repower/ reactivated	Existing	New/repower/ reactivated	Existing	New/repower/ reactivated	Existing	New/repower/ reactivated
2007/2008	$5,537,085	$0	$22,225,980	$1,019,060,206	$0	$1,624,111,360	$3,472,667	$209,490,444	$0	$996,085,233	$0	$340,362,114	$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	$1,322,601,837	$0	$378,756,365	$4,837,523
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	$1,517,723,628	$0	$450,523,876	$5,676,582
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	$1,799,258,125	$0	$446,000,462	$4,339,539
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	$1,079,386,338	$0	$266,483,502	$967,887
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	$762,719,550	$0	$248,611,128	$2,772,987
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	$1,346,223,419	$0	$386,561,718	$5,670,399
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	$1,464,950,862	$0	$323,630,668	$4,106,697
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	$1,850,033,226	$0	$401,718,239	$5,947,275
2016/2017	$466,952,356	$68,709,670	$244,091,507	$2,137,545,515	$72,217,195	$2,212,974,257	$667,098,133	$283,613,426	$13,927,638	$1,483,759,630	$0	$265,547,984	$4,030,823
2017/2018	$515,145,457	$86,147,605	$218,710,769	$2,452,687,763	$62,790,145	$2,546,591,742	$984,522,529	$346,676,968	$15,219,121	$1,694,447,711	$0	$280,738,408	$3,888,126
2018/2019	$635,787,176	$92,912,038	$262,439,441	$2,622,702,914	$76,339,006	$2,966,354,301	$1,440,327,407	$414,573,552	$15,344,022	$1,979,780,844	$0	$342,162,297	$2,922,855
2019/2020	$372,297,036	$79,809,657	$124,354,356	$1,589,569,993	$47,528,002	$1,942,148,285	$1,056,052,247	$247,708,445	$6,208,824	$1,262,041,327	$0	$187,212,812	$1,723,692

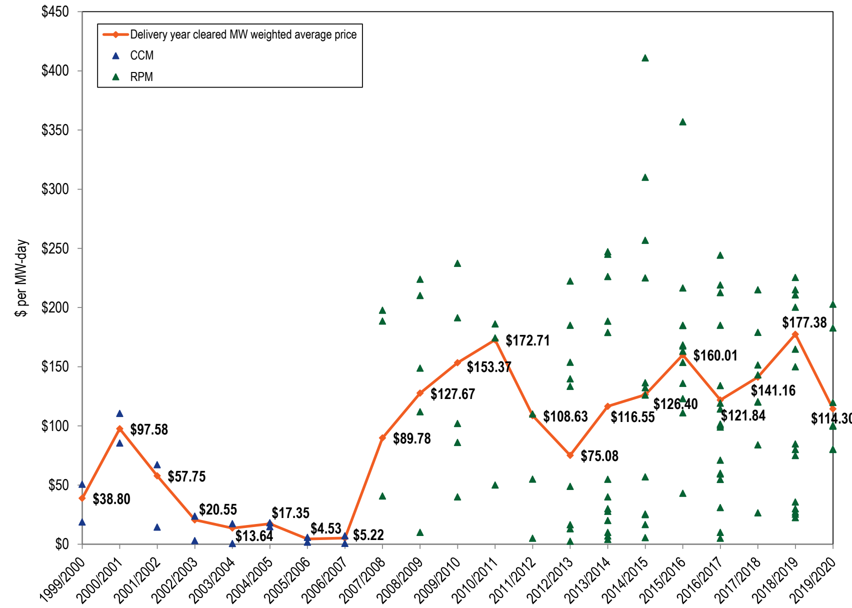
				Solar		Solid waste		Wind		
	Demand Resources	Energy Efficiency Resources	Imports	Existing	New/repower/ reactivated	Existing	New/repower/ reactivated	Existing	New/repower/ reactivated	Total revenue
2007/2008	$5,537,085	$0	$22,225,980	$0	$0	$31,512,230	$0	$430,065	$0	$4,252,287,381
2008/2009	$35,349,116	$0	$60,918,903	$0	$0	$35,011,991	$0	$1,180,153	$2,917,048	$6,087,147,586
2009/2010	$65,762,003	$0	$56,517,793	$0	$0	$42,758,762	$523,739	$2,011,156	$6,836,827	$7,503,218,157
2010/2011	$60,235,796	$0	$106,046,871	$0	$0	$40,731,606	$413,503	$1,819,413	$15,232,177	$8,449,652,496
2011/2012	$55,795,785	$139,812	$185,421,273	$0	$66,978	$25,636,836	$261,690	$1,072,929	$9,919,881	$5,335,087,023
2012/2013	$264,387,897	$11,408,552	$13,260,822	$0	$1,246,337	$26,840,670	$316,420	$812,644	$5,052,036	$3,871,714,635
2013/2014	$558,715,114	$21,598,174	$31,804,645	$0	$3,523,555	$43,943,130	$1,977,705	$1,373,205	$13,538,988	$6,799,778,047
2014/2015	$681,315,139	$42,308,549	$135,573,409	$0	$3,836,582	$34,281,137	$1,709,533	$1,524,551	$32,766,219	$7,437,267,646
2015/2016	$903,496,003	$66,652,986	$260,806,674	$0	$7,064,983	$35,862,368	$6,179,607	$1,829,269	$42,994,253	$10,161,726,902
2016/2017	$466,952,356	$68,709,670	$244,091,507	$0	$7,057,256	$32,648,789	$6,380,604	$1,144,873	$26,189,042	$7,993,888,695
2017/2018	$515,145,457	$86,147,605	$218,710,769	$0	$10,899,883	$34,771,100	$9,036,976	$1,529,251	$40,577,901	$9,304,381,453
2018/2019	$635,787,176	$92,912,038	$262,439,441	$0	$14,933,887	$37,917,294	$9,645,386	$1,166,553	$53,365,379	$10,968,674,353
2019/2020	$372,297,036	$79,809,657	$124,354,356	$0	$11,167,534	$21,032,486	$5,299,864	$752,496	$44,986,052	$6,999,893,108

89 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.
90 The results for the ATSI Integration Auctions are not included in this table.

Table 5-15 RPM revenue by calendar year: 2007 through 2020[91]

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	$137.69	176,742.6	366	$8,906,998,628
2017	$133.17	180,272.0	365	$8,762,232,394
2018	$162.39	173,437.4	365	$10,280,158,660
2019	$140.39	168,422.6	365	$8,630,559,230
2020	$114.30	167,329.5	152	$2,907,059,433

Figure 5-7 History of PJM capacity prices: 1999/2000 through 2019/2020[92]



91 The results for the ATSI Integration Auctions are not included in this table.

92 The 1999/2000-2006/2007 capacity prices are CCM combined market, weighted average prices. The 2007/2008-2019/2020 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 5-8 Map of RPM capacity prices: 2016/2017 through 2019/2020

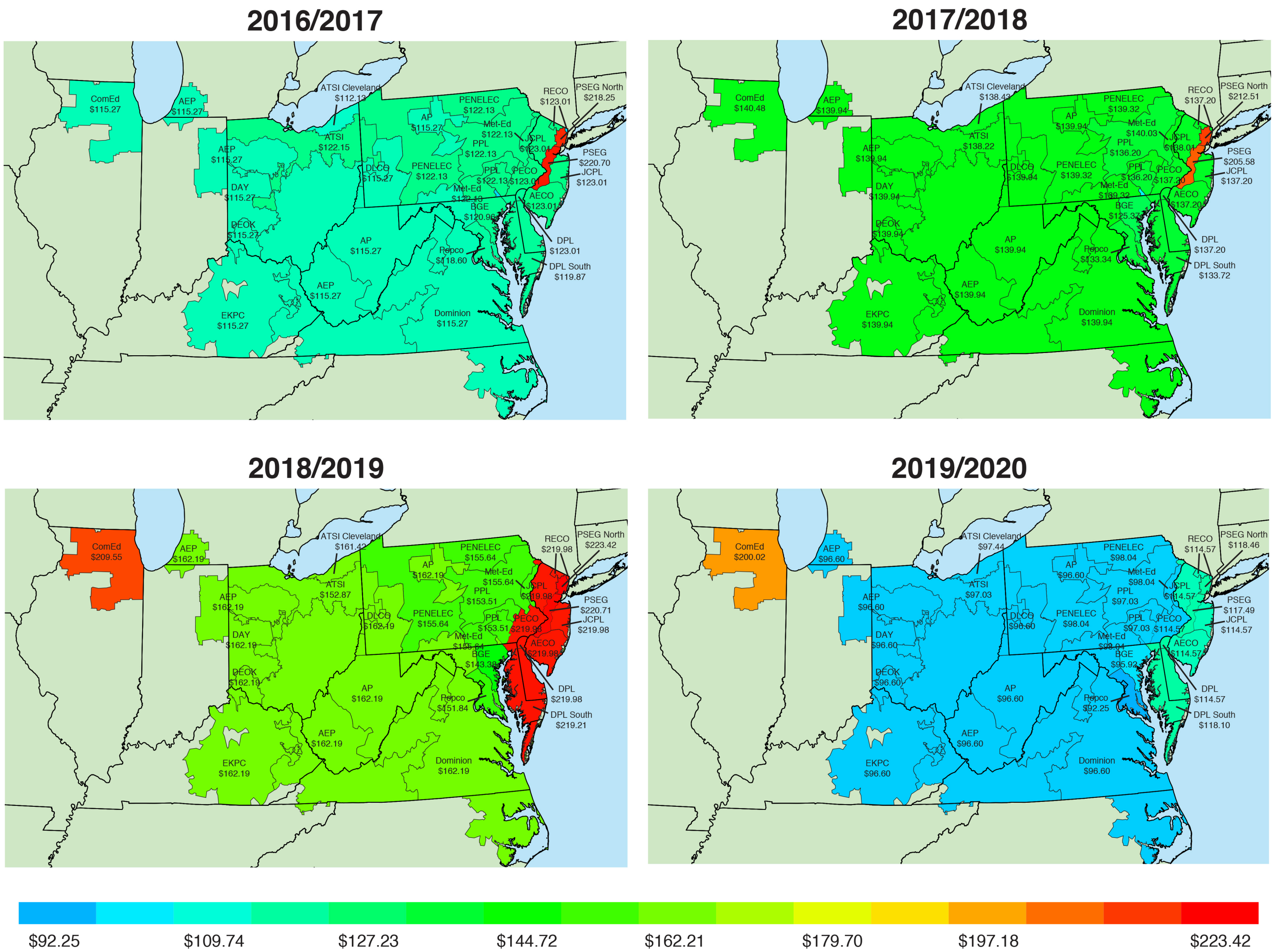


Table 5-16 RPM cost to load: 2015/2016 through 2019/2020 RPM Auctions[93 94 95]

	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	$101.62	81,169.7	$3,010,600,585
Rest of MAAC	$163.27	52,594.4	$3,134,361,252
PSEG	$224.70	11,042.7	$905,665,239
ATSI	$133.23	14,084.2	$684,910,081
Total		158,891.0	$7,735,537,157
2017/2018			
Rest of RTO	$153.61	94,874.5	$5,319,445,392
Rest of MAAC	$153.74	44,352.0	$2,488,734,815
PSEG	$208.59	10,932.0	$832,333,767
PPL	$151.86	7,935.5	$439,869,055
Total		158,094.0	$9,080,383,029
2018/2019			
Rest of RTO	$162.30	75,583.6	$4,477,496,562
Rest of MAAC	$216.11	42,763.4	$3,373,215,391
BGE	$155.91	7,897.7	$449,426,120
ComEd	$209.32	24,909.7	$1,903,172,638
Pepco	$154.63	7,416.8	$418,613,355
PPL	$152.87	8,445.3	$471,233,226
Total		167,016.4	$11,093,157,292
2019/2020			
Rest of RTO	$96.77	90,810.6	$3,216,399,297
Rest of EMAAC	$114.21	24,500.3	$1,024,120,622
BGE	$96.89	7,831.5	$277,722,332
ComEd	$189.99	25,326.5	$1,761,076,090
Pepco	$91.64	7,401.5	$248,261,480
PSEG	$114.46	11,435.5	$479,041,445
		167,305.9	$7,006,621,266

93 The RPM annual charges are calculated using the rounded, net load prices as posted in the PJM RPM Auction results.

94 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.

95 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 2017/2018, 2018/2019, and 2019/2020 Net Load Prices are not finalized. The 2017/2018, 2018/2019, and 2019/2020 obligation MW are not finalized.

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 for every hour during that period. In the first three months of 2017, nuclear units had a capacity factor of 94.6 percent, compared to 97.2 percent in the first three months of 2016; combined cycle units had a capacity factor of 57.5 percent in the first three months of 2017, compared to a capacity factor of 65.9 percent in the first three months of 2016; and steam units, which are primarily coal fired, had a capacity factor of 31.9 percent in the first three months of 2017, compared to 35.2 percent in the first three months of 2016. The decline in the capacity factor for coal units is the result of its higher operating costs compared to combined cycle and combustion turbine units in the first three months of 2017.

Table 5-17 PJM capacity factor (By unit type (GWh)): January through March, 2016 and 2017[96]

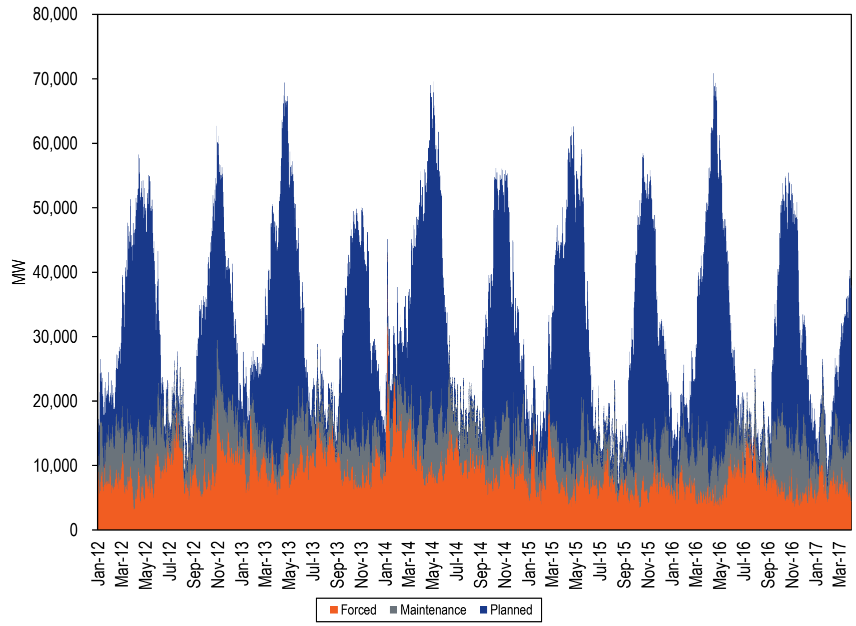
	2016 (Jan-Mar)		2017 (Jan-Mar)		
Unit Type	Generation (GWh)	Capacity Factor	Generation (GWh)	Capacity Factor	Change in 2017 from 2016
Battery	4.2	0.6%	9.1	1.3%	0.7%
Combined Cycle	44,355.3	65.9%	46,558.2	57.5%	(8.5%)
Combustion Turbine	2,061.3	3.3%	1,365.6	2.2%	(1.1%)
Diesel	130.8	13.5%	163.0	16.2%	2.7%
Diesel (Landfill gas)	355.5	43.2%	409.0	48.5%	5.3%
Fuel Cell	56.2	85.9%	56.1	86.6%	0.7%
Nuclear	71,578.3	97.2%	71,204.9	94.6%	(2.6%)
Pumped Storage Hydro	1,199.8	11.0%	1,095.9	10.2%	(0.8%)
Run of River Hydro	2,956.0	48.8%	2,468.0	41.2%	(7.6%)
Solar	173.9	14.4%	260.8	14.5%	0.2%
Steam	77,474.8	35.2%	71,768.2	31.9%	(3.3%)
Wind	5,802.6	38.2%	6,496.1	38.2%	(0.0%)
Total	206,148.7	44.9%	201,855.1	41.9%	(3.0%)

Generator Performance Factors

Generator outages fall into three categories: planned, maintenance, and forced. The MW on outage vary throughout the year. For example, the MW on planned outage are generally highest in the spring and fall, as shown in Figure 5-9, 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.

96 The capacity factors in this table are based on nameplate capacity values, and are calculated based on when the units come on line.

Figure 5-9 PJM outages (MW): 2012 through March 2017



Performance factors include the equivalent availability factor (EAF), the equivalent maintenance outage factor (EMOF), the equivalent planned outage factor (EPOF) and the equivalent forced outage factor (EFOF). These four factors add to 100 percent for any generating unit. The EAF is the proportion of hours in a year when a unit is available to generate at full capacity while the three outage factors include all the hours when a unit is unavailable. The EMOF is the proportion of hours in a year when a unit is unavailable because of maintenance outages and maintenance deratings. The EPOF is the proportion of hours in a year when a unit is unavailable because of planned outages and planned deratings. The EFOF is the proportion of hours in a year when a unit is unavailable because of forced outages and forced deratings.

The PJM aggregate EAF, EFOF, EPOF, and EMOF are shown in Figure 5-10. Metrics by unit type are shown in Table 5-18.

Figure 5-10 PJM equivalent outage and availability factors: 2007 to 2017

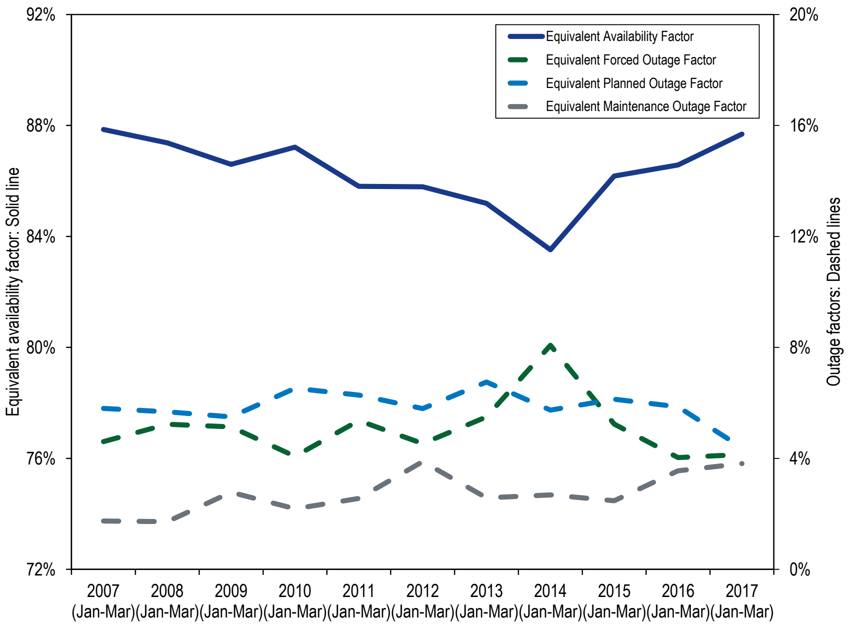


Table 5-18 EFOF, EPOF, EMOF and EAF by unit type: January 1 through March 31, 2007 through 2017

	Combined Cycle				Combustion Turbine				Diesel				Hydroelectric				Nuclear				Steam			
	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF
2007 (Jan-Mar)	1.1%	6.3%	1.4%	91.2%	6.1%	2.1%	2.7%	89.1%	8.0%	0.3%	1.6%	90.2%	1.3%	7.3%	2.0%	89.5%	0.4%	4.7%	0.4%	94.5%	6.9%	7.2%	2.1%	83.8%
2008 (Jan-Mar)	1.6%	3.2%	1.5%	93.7%	3.1%	3.5%	1.6%	91.8%	10.1%	0.2%	0.9%	88.8%	1.2%	8.7%	0.6%	89.5%	1.4%	6.9%	0.7%	91.0%	8.5%	6.2%	2.3%	83.0%
2009 (Jan-Mar)	3.3%	7.0%	3.0%	86.7%	1.4%	2.8%	1.8%	94.0%	6.6%	0.2%	1.7%	91.5%	1.5%	10.0%	1.2%	87.2%	3.8%	3.2%	1.0%	92.0%	7.5%	6.6%	3.8%	82.1%
2010 (Jan-Mar)	1.4%	6.1%	2.6%	89.9%	2.2%	1.8%	1.4%	94.6%	4.1%	0.7%	0.7%	94.5%	0.7%	10.1%	1.5%	87.7%	0.7%	6.7%	0.4%	92.3%	6.8%	7.8%	3.1%	82.3%
2011 (Jan-Mar)	2.6%	9.8%	1.8%	85.8%	1.5%	2.4%	1.6%	94.5%	2.5%	0.0%	3.6%	93.9%	1.7%	9.5%	0.9%	88.0%	1.5%	4.0%	0.7%	93.8%	9.1%	7.4%	3.9%	79.5%
2012 (Jan-Mar)	1.8%	6.9%	1.9%	89.4%	1.7%	2.1%	1.3%	94.9%	1.9%	0.0%	0.8%	97.3%	1.6%	4.8%	1.4%	92.1%	0.9%	5.3%	0.5%	93.3%	7.7%	7.0%	6.7%	78.6%
2013 (Jan-Mar)	4.6%	9.6%	2.9%	82.9%	5.6%	2.5%	0.9%	91.0%	3.7%	0.1%	1.1%	95.1%	0.5%	3.5%	2.3%	93.7%	0.5%	3.7%	0.3%	95.6%	8.1%	9.0%	4.0%	78.8%
2014 (Jan-Mar)	4.0%	9.7%	1.4%	84.9%	13.4%	2.9%	1.1%	82.6%	14.8%	0.0%	2.7%	82.4%	1.1%	9.3%	5.6%	84.1%	1.6%	5.8%	0.3%	92.3%	10.5%	5.4%	4.3%	79.7%
2015 (Jan-Mar)	2.8%	8.2%	1.7%	87.2%	3.6%	4.0%	1.1%	91.3%	9.9%	0.3%	1.9%	87.9%	2.0%	9.6%	1.4%	87.0%	1.4%	5.1%	0.5%	92.9%	8.4%	6.5%	4.1%	81.0%
2016 (Jan-Mar)	2.2%	4.7%	1.6%	91.5%	2.0%	2.4%	1.7%	93.8%	5.9%	0.0%	2.9%	91.3%	2.3%	5.0%	3.7%	89.0%	0.8%	4.8%	1.1%	93.3%	7.1%	8.2%	6.1%	78.6%
2017 (Jan-Mar)	2.1%	4.2%	1.4%	92.3%	0.9%	2.8%	1.7%	94.6%	3.5%	0.4%	1.3%	94.8%	2.3%	5.3%	3.7%	88.8%	0.4%	5.5%	0.5%	93.6%	8.6%	4.4%	7.5%	79.5%

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 either exclude some outages, XEFORd, or exclude some outages and exclude some time periods, EFORp. The other outage rate metrics will no longer be used under the capacity performance capacity market design.

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.[97] The EFORd metric includes all forced outages, regardless of the reason for those outages.

The average PJM EFORd for the first three months of 2017 was 6.2 percent, a decrease from 6.3 percent for the first three months of 2016. Figure 5-11 shows the average EFORd since 1999 for all units in PJM.[98]

97 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.

98 The universe of units in PJM changed as the PJM footprint expanded and as units retired from and entered PJM markets. See the *2016 State of the Market Report for PJM*, Appendix A: "PJM Geography" for details.

Figure 5-11 Trends in the PJM equivalent demand forced outage rate (EFORd): 1999 through 2017

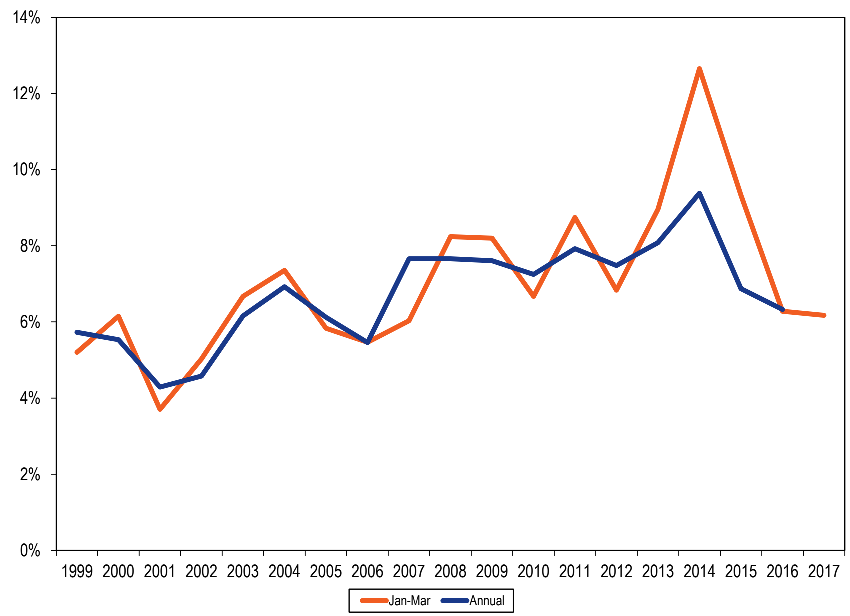


Table 5-19 shows the class average EFORd by unit type.

Table 5-19 PJM EFORd data for different unit types: January 1 through March 31, 2007 through 2017

	2007 (Jan-Mar)	2008 (Jan-Mar)	2009 (Jan-Mar)	2010 (Jan-Mar)	2011 (Jan-Mar)	2012 (Jan-Mar)	2013 (Jan-Mar)	2014 (Jan-Mar)	2015 (Jan-Mar)	2016 (Jan-Mar)	2017 (Jan-Mar)
Combined Cycle	6.3%	5.1%	4.9%	2.6%	3.5%	2.4%	5.1%	6.8%	4.9%	2.9%	2.4%
Combustion Turbine	20.7%	16.3%	12.7%	11.6%	11.4%	9.3%	20.2%	29.6%	18.6%	8.4%	5.8%
Diesel	9.0%	10.0%	8.1%	6.2%	5.1%	2.7%	3.8%	15.5%	11.0%	7.5%	4.8%
Hydroelectric	1.9%	2.9%	2.0%	1.0%	2.1%	2.7%	0.6%	1.5%	2.3%	3.3%	2.7%
Nuclear	0.4%	1.5%	3.8%	0.7%	1.6%	0.9%	0.5%	1.7%	1.5%	0.9%	0.5%
Steam	8.1%	10.7%	9.7%	8.7%	12.5%	9.7%	10.2%	13.6%	11.2%	9.4%	11.4%
Total	8.1%	8.8%	8.2%	6.7%	8.7%	6.8%	9.0%	12.7%	9.3%	6.3%	6.2%

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 capacity market design is implemented beginning with 2018/2019 Delivery Year 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.[99]

In 2006, NERC created specifications for certain types of outages deemed to be Outside Management Control (OMC).[100] 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.[101] 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.[102] That choice was made by PJM and can be modified without violating any NERC requirements.[103] 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.

99 "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Schedule 5.B.

100 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>.

101 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>.

102 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.

103 It is unclear whether there were member votes taken on this issue prior to PJM's implementation of its approach to OMC outages. It does not appear that PJM has consulted with members for the subsequent changes to its application of OMC outages.

Table 5-20 shows OMC forced outages by cause code, as classified by PJM. OMC forced outages accounted for 0.5 percent of all forced outages in the first three months of 2017. The largest contributor to OMC outages, transmission system problems other than catastrophes, was the cause of 27.3 percent of OMC outages and 0.1 percent of all forced outages.

Table 5-20 OMC outages: January 1 through March 31, 2017

OMC Cause Code	Percent of OMC Forced Outages	Percent of all Forced Outages
Transmission system problems other than catastrophes	27.3%	0.1%
Flood	13.9%	0.1%
Lack of fuel	11.8%	0.1%
Lack of water (hydro)	10.9%	0.1%
Transmission line	10.4%	0.1%
Miscellaneous regulatory	9.9%	0.0%
Switchyard circuit breakers	6.6%	0.0%
Switchyard transformers and associated cooling systems	4.0%	0.0%
Plant modifications strictly for compliance with new or changed regulatory requirements	4.0%	0.0%
Transmission equipment	0.6%	0.0%
Transmission equipment beyond the first substation	0.4%	0.0%
Switchyard system protection devices	0.2%	0.0%
Storms	0.1%	0.0%
Other fuel quality problems	0.0%	0.0%
Total	100.0%	0.5%

An outage is an outage, regardless of the cause. It is inappropriate that units on outage do not have to reflect that outage in their outage statistics, which affect their performance incentives and the level of unforced capacity and therefore capacity sold. No outages should be treated as OMC because when a unit is not available it is not available, regardless of the reason, and the data and payments to units should reflect that fact.[104]

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.

Performance Incentives

There are a number of performance incentives in the current (pre capacity performance) 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

104 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 market design is implemented beginning with 2018/2019 Delivery Year, 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 the first three months of 2017, 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 nonperformance 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.[105]

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.[106]

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.[107]

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.[108]

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.[109] The result is an exception, analogous to the lack of fuel exception, except much broader, which appears to have no logical basis.

105 OATT Attachment DD § 10(j).
106 "PJM Manual 18: PJM Capacity Market," Rev. 30 (December 17, 2015), Section 4.2.5.
107 "PJM Manual 18: PJM Capacity Market," Rev. 30 (December 17, 2015), Section 8.4.5.
108 "PJM Manual 18: PJM Capacity Market," Rev. 30 (December 17, 2015), Section 8.4.5.1.
109 OATT Attachment DD § 7.10(e).

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.[110]

There is a separate exception for wind and solar capacity resources which are exempt from this performance incentive.[111]

The peak hour availability charge does not apply if the unit unavailability resulted in another performance related charge or penalty.[112]

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.[113]

110 *Id*
111 *Id.*
112 *Id.*
113 "PJM Manual 18: PJM Capacity Market," Rev. 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.[114] On a system wide basis, the resultant lost equivalent availability from the forced outages is equal to the equivalent forced outage factor (EFOF).[115]

PJM EFOF was 4.1 percent in the first three months of 2017. This means there was 4.1 percent lost availability because of forced outages. Table 5-21 shows that forced outages for boiler tube leaks, at 20.7 percent of the systemwide EFOF, were the largest single contributor to EFOF.

114 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.
115 EFOF incorporates all outages regardless of their designation as OMC.

Table 5-21 Contribution to EFOF by unit type by cause: January 1 through March 31, 2017

	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Steam	System
Boiler Tube Leaks	7.5%	0.0%	0.0%	0.0%	0.0%	24.1%	20.7%
Electrical	30.7%	19.2%	7.4%	1.5%	0.0%	14.4%	15.3%
Feedwater System	0.5%	0.0%	0.0%	0.0%	2.3%	12.4%	10.4%
Boiler Air and Gas Systems	0.0%	0.0%	0.0%	0.0%	0.0%	8.6%	7.2%
Low Pressure Turbine	0.0%	0.0%	0.0%	0.0%	0.0%	8.3%	6.9%
Wet Scrubbers	0.0%	0.0%	0.0%	0.0%	0.0%	4.4%	3.7%
Valves	1.7%	0.0%	0.0%	0.0%	0.3%	4.2%	3.6%
Generator	22.7%	12.8%	12.2%	1.6%	0.0%	0.8%	3.1%
Reserve Shutdown	5.4%	5.4%	13.0%	24.0%	0.0%	1.9%	2.8%
Condensing System	0.4%	0.0%	0.0%	0.0%	7.2%	2.7%	2.4%
Miscellaneous (Generator)	5.0%	0.5%	3.8%	7.7%	52.4%	0.8%	2.3%
Boiler Fuel Supply from Bunkers to Boiler	0.6%	0.0%	0.0%	0.0%	0.0%	2.6%	2.2%
Exciter	2.5%	0.3%	0.0%	0.4%	0.0%	1.6%	1.5%
Auxiliary Systems	1.3%	15.6%	0.0%	0.2%	0.0%	0.8%	1.5%
Miscellaneous (Pollution Control Equipment)	0.0%	0.3%	0.0%	0.0%	0.0%	1.6%	1.3%
Boiler Piping System	1.4%	0.0%	0.0%	0.0%	0.0%	1.3%	1.2%
Cooling System	0.6%	0.0%	0.0%	0.0%	28.0%	0.4%	0.9%
Controls	0.6%	1.4%	0.8%	4.3%	0.0%	0.8%	0.9%
Boiler Fuel Supply to Bunker	0.0%	0.0%	0.0%	0.0%	0.0%	1.1%	0.9%
All Other Causes	19.0%	44.6%	62.8%	60.3%	9.7%	7.1%	11.0%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Table 5-22 Contributions to Economic Outages: January 1 through March 31, 2017

	Contribution to Economic Reasons
Lack of fuel (Non-OMC)	45.0%
Lack of fuel (OMC)	12.7%
Fuel conservation	11.9%
Lack of water (hydro)	11.7%
Ground water or other water supply problems	9.4%
Other economic problems	8.8%
Wet Fuel - Biomass	0.5%
Problems with primary fuel for units with secondary fuel operation	0.3%
Total	100.0%

Table 5-22 shows the categories which are included in the economic category.[116] Lack of fuel that is considered outside management control accounted for 12.7 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.”[117] 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.

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.

Until the capacity performance market design is fully implemented for the 2020/2021 Delivery Year, EFORp will be used in the calculation of nonperformance 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

116 The definitions of these outages are defined by NERC GADS.
117 The definitions of these outages are defined by NERC GADS.

next weekend.[118] It is reasonable to expect that units have some degree of control over when to take a forced outage, depending on the underlying cause of the forced outage. If units had no control over the timing of forced outages, outages during peak hours of the peak months would be expected to occur at roughly the same rate as outages during periods of demand throughout the rest of the year. With the exception of nuclear units, EFORp is lower than 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 5-23 shows the capacity-weighted class average of EFORd, XEFORd and EFORp.

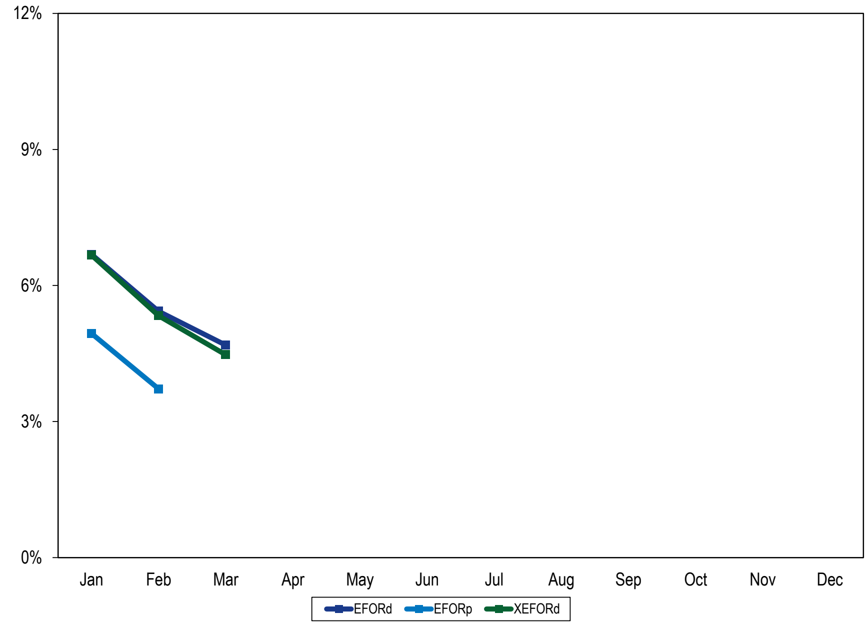
Table 5-23 PJM EFORd, XEFORd and EFORp data by unit type: January 1 through March 31, 2017[119]

	EFORd	XEFORd	EFORp	Difference EFORd and XEFORd	Difference EFORd and EFORp
Combined Cycle	2.4%	2.4%	1.5%	0.0%	0.9%
Combustion Turbine	5.8%	5.6%	0.8%	0.2%	5.0%
Diesel	4.8%	4.5%	2.3%	0.3%	2.5%
Hydroelectric	2.7%	2.6%	2.9%	0.1%	(0.2%)
Nuclear	0.5%	0.5%	0.9%	0.0%	(0.4%)
Steam	11.4%	11.0%	10.0%	0.4%	1.4%
Total	6.2%	6.0%	4.7%	0.2%	1.5%

Performance by Month

On a monthly basis, EFORp values were 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.

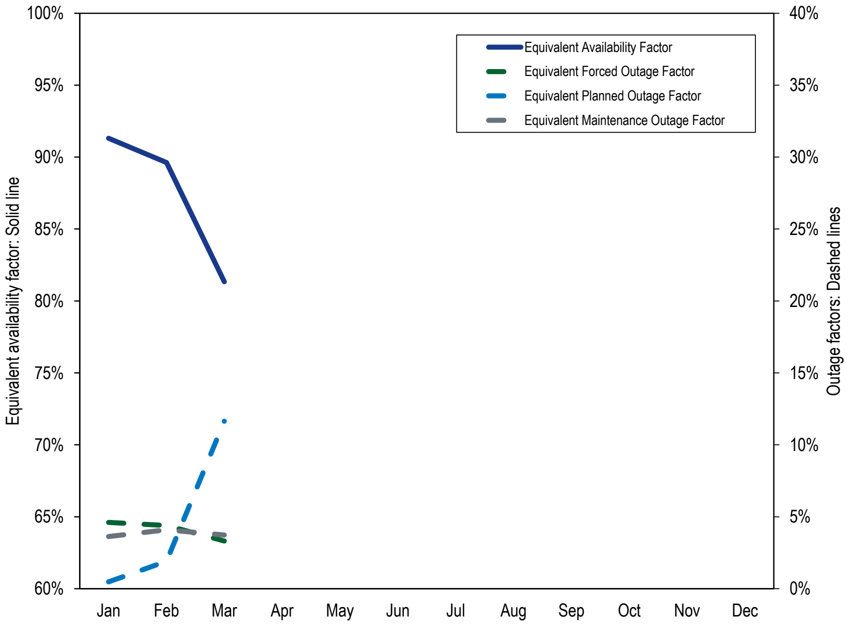
Figure 5-12 PJM EFORd, XEFORd and EFORp: January 1 through March 31, 2017



On a monthly basis, unit availability as measured by the equivalent availability factor is shown in Figure 5-13.

118 See "PJM Manual 22: Generator Resource Performance Indices," Rev. 16 (November 16, 2011), Definitions.
119 EFORp is only calculated for the peak months of January, February, June, July and August.

Figure 5-13 PJM monthly generator performance factors: January through March, 2017



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 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 and pre-emergency programs are part of the capacity market program which includes both capacity payments and associated energy revenues when the capacity is called on to respond.[1] In the first three months of 2017, the emergency program accounted for 98.7 percent of all revenue received by demand response providers, the economic program for 0.4 percent, synchronized reserve for 0.6 percent and the regulation market for 0.3 percent. Total emergency revenue decreased by $109.5 million, 48.7 percent, from $224.6 million in the first three months of 2016 to $115.1 million in the first three months of 2017. Capacity market revenue, which comprised 100.0 percent of the emergency demand response program in the first three months of 2017, decreased by $109.5 million, 48.7 percent, from $224.6 million in the first three months of 2016 to $115.1 million in the first three months of 2017.[2]

  Economic program revenue decreased by $0.3 million, from $0.7 million in the first three months of 2016 to $0.4 million in the first three months of 2017, a 38.4 percent decrease.[3] Synchronized reserve revenue decreased by $0.1 million, from $0.8 million in the first three months of 2016 to $0.70 million in the first three months of 2017, a 7.2 percent decrease. Regulation revenue increased by $0.2 million, from $0.2 million in the first three months of 2016 to $0.4 million in the first three months of 2017, a 126.6 percent increase.

  Total demand response revenue decreased by $109.6 million, from $226.2 million in the first three months of 2016 to $115.1 million in the first three months of 2017, a 48.5 percent decrease. Not all DR activities in the first three months of 2017 had been reported to PJM at the time of this report.

  Emergency and Economic 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.[4]

- **Demand Response Market Concentration.** The ownership of economic demand response was highly concentrated in the first three months of 2016 and 2017. The HHI for economic demand response reductions increased from 7699 in the first three months of 2016 to 9250 in the first three months of 2017. The ownership of emergency demand response was moderately concentrated in 2016. The HHI for emergency demand response registrations was 1469 for the 2016/2017 Delivery Year. In the 2016/2017 Delivery Year, the four largest companies contributed 66.6 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, but only if the subzone is defined at least one day before it is dispatched and only until PJM removes the definition of the subzone. 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 Throughout this document, emergency demand response refers to both emergency and pre-emergency demand response.
2 The total credits and MWh numbers for demand resources were calculated as of April 10, 2017 and may change as a result of continued PJM billing updates.
3 Economic credits are synonymous with revenue received for reductions under the economic load response program.
4 PJM: "Manual 28: Operating Agreement Accounting," Revision 75 (November 18, 2016), p 77.

Recommendations

The MMU recognizes that PJM incorporated some of the recommendations related to Demand Response in the Capacity Performance filing. The status of each recommendation reflects the status at March 31, 2017.

- 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 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 treated as an economic resource, responding to economic price signals like other capacity resources and not an emergency program responding only after an emergency is called, and not triggering the definition of a PJM emergency and not triggering a Performance Assessment Hour under the new PJM Capacity Market rules. (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.[5] (Priority: High. First reported 2013. Status: Not 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 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.[6] (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.)

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

6 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 June 29, 2016) ISO-NE requires that DR have an interval meter with five minute data reported to the ISO and each behind the meter generator is required to have a separate interval meter. After June 1, 2017, demand response resources in ISO-NE must also be registered at a single node.

- The MMU recommends that load management testing be initiated by PJM with limited warning to CSPs in order to more accurately 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. First reported 2015. 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 2015. Status: Not adopted.)
- The MMU recommends that PJM not remove any defined subzone and maintain a public record of all created and removed subzones. (Priority: Low. First reported 2016. 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. (Priority: High. First reported 2011. Status: Partially adopted.[7])
- 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 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 capping the baseline for measuring compliance under GLD, for the limited summer product, at the customers' PLC. (Priority: High. First reported 2010. Status: Adopted 2015.)
- 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, 2014.)

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

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.

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 (PAH) will be measured on an hourly basis.

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 MMU.

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. Pre-emergency demand response is defined to be dispatchable before an emergency event is declared.[8] 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.[9] 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 compensates CSPs for their participants' load reductions and CSPs in turn compensate 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.

8 147 FERC ¶ 61,103 (2014).

9 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.

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 benefits test (NBT) price threshold is exceeded. This approach replaced the payment of LMP minus the charges for wholesale power and transmission already included in customers' tariff rates.

Figure 6-1 shows all revenue from PJM demand response programs by market for the first three months of 2008 through 2017. 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.[10]

In the first three months of 2017, emergency and pre-emergency revenue, which includes capacity and emergency energy revenue, accounted for 98.7 percent of all revenue received by demand response providers, credits from the economic program were 0.4 percent, revenue from synchronized reserve was 0.6 percent and revenue from regulation was 0.3 percent.

Total emergency and pre-emergency revenue decreased by $109.5 million, or 48.7 percent, from $224.6 million in the first three months of 2016 to $115.1 million in the first three months of 2017. Of the total emergency revenue, capacity market revenue decreased by $109.5 million, or 48.7 percent, from $224.6 million in the first three months of 2016 to $115.1 million in the first three months of 2017. This was in part a result of lower capacity market prices in 2017. The capacity revenue in 2016 is from 2015/2016 RPM auction clearing prices and the capacity revenue in 2017 is from 2016/2017 RPM auction clearing prices. Weighted average capacity market prices decreased $38 per MW-day from $160 in the 2015/2016 Delivery Year to $122 in the 2016/2017 Delivery Year, a 23.9 percent decrease.[11] Total demand response revenue in the first three months of 2017 decreased by 48.5 percent from $226.2 million in the first three months of 2016 to $116.6 million in the first three months of 2017. Total demand response revenue includes economic, pre-emergency, emergency, synchronized reserve and regulation revenue.

Total revenue under the economic program decreased by $0.3 million from $0.7 million in the first three months of 2016 to $0.4 million in the first three months of 2017, a 38.4 percent decrease.

10 This includes both capacity market revenue and emergency energy revenue for capacity resources.

11 *2016 State of the Market Report for PJM*, Section 7: Net Revenues, Table 7-6.

Figure 6-1 Demand response revenue by market: January through March, 2008 through 2017

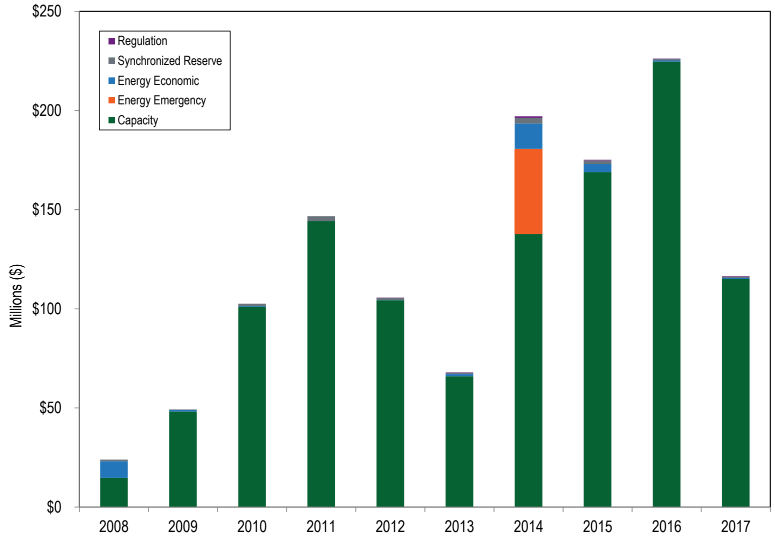


Table 6-2 shows registered sites and MW for the last day of each month for the period January 2010 through March 31, 2017. Registration is a prerequisite for CSPs to participate in the economic program. Both the average number of registrations for economic demand response and the average registered MW increased in the first three months of 2017 compared to the first three months of 2016. The average number of monthly registrations increased by 19 from 836 in the first three months of 2016 to 854 in the first three months of 2017. The average monthly registered MW increased by 30 MW, or 1.2 percent, from 2,557 MW in the first three months of 2016 to 2,586 MW in the first three months of 2017.

Several demand response resources are registered for both the economic and emergency demand response programs. There were 377 registrations and 3,876 nominated MW in the emergency program that were also registered in the economic program during the first three months of 2017.

Economic Program

Table 6-2 Economic program registrations on the last day of the month: January 1, 2010 through March 31, 2016

	2010		2011		2012		2013		2014		2015		2016		2017	
Month	Registrations	Registered MW	Registrations	Registered MW	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	838	2,557	871	2,603
Feb	1,842	2,624	1,612	2,435	1,995	2,384	843	2,327	1,174	2,330	1,076	2,956	835	2,557	842	2,579
Mar	1,845	2,623	1,612	2,519	1,996	2,356	788	2,284	1,185	2,692	1,075	2,949	834	2,556	850	2,577
Apr	1,849	2,587	1,611	2,534	189	1,318	970	2,346	1,194	2,827	1,076	2,938	832	2,556		
May	1,875	2,819	1,687	3,166	371	1,669	1,375	2,414	745	2,511	980	2,846	829	2,545		
Jun	813	1,608	1,143	1,912	803	2,347	1,302	2,144	928	2,943	871	2,614	518	2,500		
Jul	1,192	2,159	1,228	2,062	942	2,323	1,315	2,443	1,036	3,006	870	2,609	519	2,421		
Aug	1,616	2,398	1,987	2,194	1,013	2,373	1,299	2,527	1,080	3,033	869	2,609	805	2,569		
Sep	1,609	2,447	1,962	2,183	1,052	2,421	1,280	2,475	1,077	2,919	867	2,608	831	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	822	2,564		
Nov	1,605	2,444	1,988	2,255	824	2,267	1,192	2,307	1,063	2,995	851	2,566	820	2,564		
Dec	1,598	2,439	1,992	2,259	846	2,283	1,192	2,311	1,071	2,923	850	2,566	807	2,561		
Avg	1,609	2,432	1,606	2,382	1,150	2,175	1,113	2,364	1,067	2,732	974	2,788	774	2,547	854	2,586

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 peak economic MW dispatched by registration each month from January 2010 through March 2017. The monthly peak is the sum of each registration's monthly noncoincident peak dispatched MW and annual peak is the sum of each registration's annual noncoincident peak dispatched MW. The peak dispatched MW for all economic demand response registered resources decreased by 13 MW, from 147 MW in the first three months of 2016 to 134 MW in the first three months of 2017.[12]

Table 6-3 Sum of peak MW reductions for all registrations per month: January 1, 2010 through March 31, 2017

Sum of Peak MW Reductions for all Registrations per Month								
Month	2010	2011	2012	2013	2014	2015	2016	2017
Jan	183	132	110	193	446	169	139	123
Feb	121	89	101	119	307	336	128	82
Mar	115	81	72	127	369	198	120	27
Apr	111	80	108	133	146	143	118	
May	172	98	143	192	151	161	131	
Jun	209	561	954	433	483	833	121	
Jul	999	561	1,631	1,088	665	1,362	1,316	
Aug	794	161	952	497	358	272	249	
Sep	276	84	451	530	795	816	263	
Oct	118	81	242	168	214	136	150	
Nov	111	86	165	155	166	127	116	
Dec	114	88	98	168	155	122	147	
Annual	1,202	840	1,942	1,486	1,739	1,858	1,451	134

Emergency and Economic 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.[13] The zonal allocation is shown in Table 6-13.

12 As a result of the 60 day data lag from event date to settlement, not all settlements for February and March 2017 are incorporated in this report.

13 PJM: "Manual 28: Operating Agreement Accounting," Revision 75 (November 18, 2016), p 78.

Table 6-4 shows the total MW reductions made by participants in the economic program and the total credits paid for these reductions for the first three months of 2010 through 2017. The average credits per MWh paid increased by $0.23 per MWh, or 0.6 percent, from $41.93 per MWh in the first three months of 2016 to $42.17 per MWh in the first three months of 2017. The average real-time load weighted PJM LMP increased by $3.48 per MWh, or 13.0 percent, from $26.80 per MWh in the first three months of 2016 to $30.28 per MWh in the first three months of 2017. Curtailed energy for the economic program was 9,827 MWh in the first three months of 2017 and the total payments were $414,367.[14] Total credits paid for economic DR in the first three months of 2017 decreased by $258 thousand or 38.4 percent, compared to the first three months of 2016.

Table 6-4 Credits paid to the PJM economic program participants: January through March, 2010 through 2017

Year (Jan-Mar)	Total MWh	Total Credits	$/MWh
2010	8,139	$321,648	$39.52
2011	3,272	$240,304	$73.45
2012	1,030	$30,406	$29.52
2013	21,048	$1,083,755	$51.49
2014	58,195	$12,727,388	$218.70
2015	38,644	$4,175,116	$108.04
2016	16,038	$672,506	$41.93
2017	9,827	$414,367	$42.17

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 offer 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 the clearing price.

14 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.

Figure 6-2 shows monthly economic demand response credits and MWh, from January 2010 through March 2017. Energy prices increased in the first three months of 2017, resulting in higher payments to economic DR resources in the first three months of 2017 than in the first three months of 2016.

Figure 6-2 Economic program credits and MWh by month: January 1, 2010 through March 2017

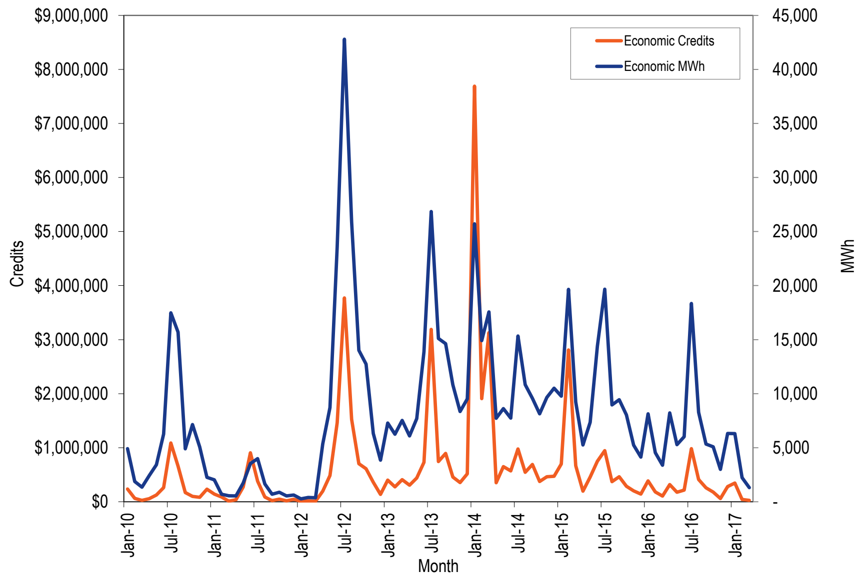


Table 6-5 shows performance for the first three months of 2016 and 2017 in the economic program by control zone. Total reductions under the economic program decreased by 6,211 MW from 16,038 MW in the first three months of 2016 to 9,827 MW in the first three months of 2017, a 38.7 percent decrease. Total revenue under the economic program decreased by $0.3 million from $0.7 million in the first three months of 2016 to $0.4 million in the first three months of 2017, a 38.4 percent decrease.

Table 6-5 PJM economic program participation by zone: January through March, 2016 and 2017

	Credits			MWh Reductions			Credits per MWh Reduction		
Zones	Jan-Mar 2016	Jan-Mar 2017	Percent Change	Jan-Mar 2016	Jan-Mar 2017	Percent Change	Jan-Mar 2016	Jan-Mar 2017	Percent Change
APS	$8,782		NA	252		NA	$34.84		
ATSI	$79,079		NA	2,287		NA	$34.58		
ComED	$6,805	$14,692	115.9%	218	501	129.7%	$31.18	$29.32	(6.0%)
Dominion	$376,529	$264,279	(29.8%)	7,744	3,794	(51.0%)	$48.62	$69.66	43.3%
JCPL	$308		NA	5		NA	$64.77		
Met-Ed		$382	NA		12	NA		$33.22	
PECO	($2,144)	$2,130	(199.3%)	9	19	116.6%	($242.59)	$111.21	(145.8%)
PENELEC	$69,028	$41,829	(39.4%)	2,213	1,705	(23.0%)	$31.20	$24.54	(21.3%)
PPL	$38		NA	1		NA	$26.50		
PSEG	$134,081	$91,054	(32.1%)	3,310	3,797	14.7%	$40.51	$23.98	(40.8%)
Total	$672,506	$414,367	(38.4%)	16,038	9,827	(38.7%)	$41.93	$42.17	0.6%

Table 6-6 shows total settlements submitted for the first three months of 2010 through 2017. A settlement is counted for every day on which a registration is dispatched in the economic program.

Table 6-6 Settlements submitted in the economic program: January through March, 2010 through 2017

Year	Jan-Mar 2010	Jan-Mar 2011	Jan-Mar 2012	Jan-Mar 2013	Jan-Mar 2014	Jan-Mar 2015	Jan-Mar 2016	Jan-Mar 2017
Number of Settlements	693	91	21	368	1,314	602	267	201

Table 6-7 shows the number of CSPs, and the number of participants in their portfolios, submitting settlements by year for the first three months of 2010 through 2017. There was one fewer active participant in the first three months of 2017 than in the first three months of 2016. All participants must be included in a CSP.

Table 6-7 Participants and CSPs submitting settlements in the economic program by year: January through March, 2010 through 2017

	(Jan-Mar) 2010		(Jan-Mar) 2011		(Jan-Mar) 2012		(Jan-Mar) 2013		(Jan-Mar) 2014		(Jan-Mar) 2015		(Jan-Mar) 2016		(Jan-Mar) 2017	
	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	Active CSPs	Active Participants
Total Distinct Active	5	90	5	25	4	9	9	49	12	115	11	47	6	17	6	16

The ownership of economic demand response was highly concentrated in the first three months of 2016 and 2017.[15] Table 6-8 shows the average hourly HHI for each month and the average hourly HHI for 2016 and the first three months of 2017. Table 6-8 also lists the share of reductions provided by, and the share of credits claimed by the four largest parent companies in each year. In the first three months of 2017, 99.8 percent of all economic DR reductions and 99.5 percent of economic DR revenue were attributable to the four largest parent companies. The HHI for economic demand response increased 1551 points, from 7699 in the first three months of 2016 to 9250 in the first three months of 2017.

Table 6-8 HHI and market concentration in the economic program: January 1, 2016 through March 31, 2017[16]

	HHI			Top Four Companies Share of Reduction			Top Four Companies Share of Credit		
Month	2016	2017	Percent Change	2016	2017	Change in Percent	2016	2017	Change in Percent
Jan	7435	8953	20.4%	97.5%	99.7%	2.2%	98.0%	99.6%	1.7%
Feb	7696	9256	20.3%	100.0%	100.0%	(0.0%)	100.0%	100.0%	(0.0%)
Mar	8587	9796	14.1%	98.9%			99.4%		
Apr	6753			100.0%			100.0%		
May	8155			97.9%			96.3%		
Jun	7685			100.0%			100.0%		
Jul	7412			96.0%			89.2%		
Aug	7684			93.5%			89.3%		
Sep	7815			93.8%			92.7%		
Oct	7708			100.0%			100.0%		
Nov	8836			100.0%			100.0%		
Dec	7550			93.4%			92.5%		
Total	7699	9250	20.1%	90.6%	99.8%	9.2%	90.3%	99.5%	9.2%

15 Parent companies may own one CSP or multiple CSPs. All HHI calculations in this section are at the parent company level.
16 March 2017 is omitted for the top four companies share of reductions and credits columns due to confidentiality requirements.

Table 6-9 shows average MWh reductions and credits by hour for the first three months of 2016 and 2017. In the first three months of 2016, 70 percent of reductions and 78 percent of credits occurred in hours ending 0900 to 2100, and in the first three months of 2017, 63 percent of reductions and 68 percent of credits occurred in hours ending 0900 to 2100.

Table 6-9 Hourly frequency distribution of economic program MWh reductions and credits: January through March, 2016 and 2017

	MWh Reductions			Program Credits		
Hour Ending (EPT)	2016	2017	Percent Change	2016	2017	Percent Change
1 through 8	3,775	1,282	(66%)	$209,417	$80,857	(61%)
9	2,381	802	(66%)	$95,480	$32,140	(66%)
10	1,464	741	(49%)	$56,919	$28,654	(50%)
11	935	624	(33%)	$32,611	$22,295	(32%)
12	773	563	(27%)	$25,876	$21,378	(17%)
13	633	534	(16%)	$20,782	$18,591	(11%)
14	604	509	(16%)	$19,030	$15,883	(17%)
15	580	506	(13%)	$16,908	$11,983	(29%)
16	544	484	(11%)	$15,788	$9,476	(40%)
17	554	549	(1%)	$17,061	$14,632	(14%)
18	705	715	1%	$35,175	$33,585	(5%)
19	1,015	799	(21%)	$48,162	$38,844	(19%)
20	1,043	826	(21%)	$42,044	$33,543	(20%)
21 through 24	1,032	894	(13%)	$37,256	$52,506	41%
Total	16,038	9,827	(39%)	$672,506	$414,367	(38%)

Table 6-10 shows the distribution of economic program MWh reductions and credits by ranges of real-time zonal, load-weighted, average LMP in the first three months of 2016 and 2017. In the first three months of 2017, 0.2 percent of MWh reductions and 0.5 percent of program credits occurred during hours when the applicable zonal LMP was higher than $175 per MWh.

Table 6-10 Frequency distribution of economic program zonal, load-weighted, average LMP (By hours): January through March, 2016 and 2017

	MWh Reductions			Program Credits		
LMP	Jan-Mar 2016	Jan-Mar 2017	Percent Change	Jan-Mar 2016	Jan-Mar 2017	Percent Change
$0 to $25	2,963	830	(72%)	$74	$5,057	6,689%
$25 to $50	9,724	5,694	(41%)	$60,139	$132,826	121%
$50 to $75	1,980	1,424	(28%)	$339,576	$85,291	(75%)
$75 to $100	589	1,133	92%	$118,195	$96,687	(18%)
$100 to $125	315	401	27%	$49,526	$41,846	(16%)
$125 to $150	159	135	(15%)	$29,763	$19,552	(34%)
$150 to $175	90	195	116%	$20,375	$30,975	52%
> $175	218	16	(93%)	$12,732	$2,133	(83%)
Total	16,038	9,827	(39%)	630,381	414,367	(34%)

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 2016 was calculated using generation offers from February 2015. 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.[17] The price at this point is the NBT threshold price.

The NBT test is a crude tool that is not based in market logic. The NBT threshold price is a monthly estimate calculated from a monthly supply curve that does not incorporate 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 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.

17 PJM. "Manual 11: Energy & Ancillary Services Market Operations," Revision 85 (November 1, 2016), p 146.

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.

Table 6-11 shows the NBT threshold price from April 2012, when FERC Order No. 745 was implemented in PJM, through March 2017.

Table 6-11 Net benefits test threshold prices: April 1, 2012 through March 31, 2017

	Net Benefits Test Threshold Price ($/MWh)					
Month	2012	2013	2014	2015	2016	2017
Jan		$25.72	$29.51	$29.63	$23.67	$32.60
Feb		$26.27	$30.44	$26.52	$26.71	$31.57
Mar		$25.60	$34.93	$24.99	$22.10	$30.56
Apr	$25.89	$26.96	$32.59	$24.92	$19.93	
May	$23.46	$27.73	$32.08	$23.79	$20.69	
Jun	$23.86	$28.44	$31.62	$23.80	$20.62	
Jul	$22.99	$29.42	$31.62	$23.03	$20.73	
Aug	$24.47	$28.58	$29.85	$23.17	$23.24	
Sep	$24.93	$28.80	$29.83	$21.69	$24.70	
Oct	$25.96	$29.13	$30.20	$21.48	$26.50	
Nov	$25.63	$31.63	$29.17	$22.28	$29.27	
Dec	$25.97	$28.82	$29.01	$22.31	$29.71	
Average	$24.80	$28.09	$30.91	$23.97	$23.99	$31.58

Table 6-12 shows the number of hours that at least one zone in PJM had day-ahead LMP or real-time LMP higher than the NBT threshold price. In the first three months of 2017, the highest zonal LMP in PJM was higher than the NBT threshold price 1,286 hours out of 2,159 hours, or 59.6 percent of all hours. Reductions occurred in 552 hours, or 42.9 percent, of those 1,286 hours in the first three months of 2017. The last three columns illustrate how often economic demand response activity occurred when LMPs exceeded NBT threshold prices for 2016 through March 2017.

Table 6-12 Hours with price higher than NBT and DR occurrences in those hours: January 1, 2016 through March 31, 2017

	Number of Hours		Number of Hours with LMP Higher than NBT			Percent of NBT Hours with DR		
Month	2016	2017	2016	2017	Percent Change	2016	2017	Percent Change
Jan	744	744	669	388	(42.0%)	48.6%	66.8%	18.2%
Feb	696	672	670	414	(38.2%)	66.1%	36.7%	(29.4%)
Mar	743	743	719	484	(32.7%)	53.0%	29.1%	(23.9%)
Apr	720		713			48.0%		
May	744		692			55.2%		
Jun	720		659			60.9%		
Jul	744		708			71.2%		
Aug	744		665			72.6%		
Sep	720		659			76.9%		
Oct	744		708			71.9%		
Nov	721		676			49.0%		
Dec	744		654			44.6%		
Total	8,784	2,159	8,192	1,286	(84.3%)	59.8%	42.9%	(16.9%)

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 paid in each zone and paid by exports. Real-time loads in AEP, Dominion, and exports paid the highest DR charges in the first three months of 2017.

Table 6-13 Zonal DR charge: January through March, 2017

Zone	January	February	March	Total
AECO	$4,353	$185	$265	$4,803
AEP	$51,987	$3,119	$3,280	$58,386
AP	$22,806	$1,427	$1,337	$25,571
ATSI	$26,970	$2,185	$2,109	$31,264
BGE	$16,686	$1,913	$1,065	$19,664
ComEd	$17,880	$1,886	$2,575	$22,342
DAY	$6,599	$582	$445	$7,626
DEOK	$9,185	$538	$623	$10,346
Dominion	$50,526	$2,908	$2,820	$56,254
DPL	$9,426	$3,023	$543	$12,992
DLCO	$5,238	$347	$355	$5,940
EKPC	$5,660	$279	$311	$6,249
JCPL	$10,110	$1,239	$779	$12,129
Met-Ed	$6,973	$559	$565	$8,097
PECO	$17,186	$692	$980	$18,858
PENELEC	$7,457	$828	$514	$8,799
Pepco	$14,718	$1,273	$914	$16,905
PPL	$19,570	$1,850	$1,612	$23,032
PSEG	$18,868	$2,784	$1,476	$23,128
RECO	$601	$89	$46	$736
Exports	$24,092	$14,579	$2,577	$41,248
Total	$346,890	$42,286	$25,191	$414,367

Table 6-14 shows the total zonal DR charge per MWh of real-time load and exports in the first three months of 2017. On a dollar per MWh basis, real-time load and exports in PSEG paid the highest charges for economic demand response in the first three months of 2017. The highest average zonal monthly per MWh charges for economic demand response occurred in January, when EKPC paid an average of $0.022/MWh.

Table 6-14 Zonal DR charge per MWh of load and exports: January through March, 2017

Zone	January	February	March	Zonal Average
AECO	$0.019	$0.005	$0.002	$0.009
AEP	$0.020	$0.005	$0.001	$0.009
AP	$0.019	$0.005	$0.001	$0.009
ATSI	$0.018	$0.005	$0.002	$0.008
BGE	$0.018	$0.006	$0.002	$0.009
ComEd	$0.013	$0.005	$0.002	$0.007
DAY	$0.018	$0.005	$0.001	$0.008
DEOK	$0.020	$0.005	$0.001	$0.009
Dominion	$0.019	$0.005	$0.001	$0.009
DPL	$0.019	$0.008	$0.002	$0.009
DLCO	$0.019	$0.005	$0.001	$0.009
EKPC	$0.022	$0.004	$0.001	$0.009
JCPL	$0.018	$0.009	$0.002	$0.009
Met-Ed	$0.018	$0.007	$0.002	$0.009
PECO	$0.019	$0.005	$0.001	$0.008
PENELEC	$0.018	$0.007	$0.002	$0.009
Pepco	$0.018	$0.005	$0.001	$0.008
PPL	$0.019	$0.008	$0.002	$0.009
PSEG	$0.018	$0.009	$0.002	$0.010
RECO	$0.017	$0.009	$0.002	$0.009
Exports	$0.009	$0.011	$0.002	$0.007
Monthly Average	$0.018	$0.006	$0.002	$0.009

Table 6-15 shows the monthly day-ahead and real-time DR charges and the per MWh DR charges in the first three months of 2016 and 2017. The day-ahead DR charges decreased by $176 thousand, or 73 percent, from $242 thousand in the first three months of 2016 to $66 thousand in the first three months of 2017. The real-time DR charges decreased $82 thousand, or 19 percent, from $430 thousand in the first three months of 2016 to $348 thousand in the first three months of 2017. The per MWh charge paid by all real-time load and exports for economic DR decreased $0.003/MWh, or 23.5 percent, from $0.011/MWh in the first three months of 2016 to $0.009/MWh in the first three months of 2017.

Table 6-15 Monthly day-ahead and real-time DR charge: January 1, 2016 through March 31, 2017

	Day-ahead DR Charge			Real-time DR Charge			Per MWh Charge ($/MWh)		
Month	2016	2017	Percent Change	2016	2017	Percent Change	2016	2017	Percent Change
Jan	$163,639	$35,392	(78.4%)	$222,281	$311,498	40.1%	$0.010	$0.018	80.5%
Feb	$64,230	$25,562	(60.2%)	$117,388	$16,723	(85.8%)	$0.022	$0.006	(71.3%)
Mar	$14,620	$5,180	(64.6%)	$90,349	$20,011	(77.9%)	$0.002	$0.002	(18.1%)
Apr	$94,264			$223,013			$0.009		
May	$64,456			$111,839			$0.010		
Jun	$71,162			$144,731			$0.004		
Jul	$310,567			$670,150			$0.063		
Aug	$98,494			$312,815			$0.010		
Sep	$58,644			$199,396			$0.014		
Oct	$39,644			$128,325			$0.003		
Nov	$5,836			$23,480			$0.001		
Dec	$7,582			$50,825			$0.002		
Total	$993,138	$66,134		$2,294,593	$348,232		$0.013	$0.009	
Jan-Mar	$242,488	$66,134	(72.7%)	$430,018	$348,232	(19.0%)	$0.011	$0.009	(23.5%)

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 2016/2017 Delivery Year. To participate as a limited demand resource, the provider must clear MW in an RPM auction. Emergency resources receive capacity revenue from the capacity market and also receive revenue 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.[18]

The ownership of Demand Resources was moderately concentrated in 2017. The HHI for Demand Resources was 1470 for the 2016/2017 Delivery Year. In 2017, the four largest companies contributed 66.6 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 was unconcentrated in one LDA in the 2016/2017 Delivery Year. The ownership of DR in five LDAs was moderately concentrated in the 2016/2017 Delivery Year. The ownership of DR in four LDAs was highly concentrated in the 2016/2017 Delivery Year.

Table 6-16 HHI value for LDAs by delivery year: 2016/2017 Delivery Year

Delivery Year	LDA	UCAP MW	HHI Value
2016/2017	ATSI	1,370.6	2757
	ATSI-CLEVELAND	470.8	3735
	DPL-SOUTH	105.7	2338
	EMAAC	1,289.2	2051
	MAAC	1,757.9	1891
	PEPCO	683.9	3735
	PS-NORTH	230.3	1599
	PSEG	404.1	1456
	RTO	6,423.6	1794
	SWMAAC	940.5	5125

Table 6-17 shows zonal monthly capacity market revenue to demand resources for the first three months of 2017. Capacity market revenue decreased in the first three months of 2017 by $109.5 million, or 48.7 percent, compared to the first three months of 2016, from $224.6 million to $115.1 million, as a result of lower RPM prices and fewer MW of DR cleared in RPM for the 2016/2017 delivery year.

18 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 Zonal monthly capacity revenue: January through March, 2017

Zone	January	February	March	Total
AECO	$638,888	$577,060	$638,888	$1,854,835
AEP, EKPC	$3,402,006	$3,072,780	$3,402,006	$9,876,792
AP	$1,666,929	$1,505,613	$1,666,929	$4,839,470
ATSI	$5,891,717	$5,321,551	$5,891,717	$17,104,984
BGE	$3,467,109	$3,131,582	$3,467,109	$10,065,800
ComEd	$3,079,815	$2,781,769	$3,079,815	$8,941,399
DAY	$463,438	$418,589	$463,438	$1,345,466
DEOK	$596,264	$538,561	$596,264	$1,731,088
DLCO	$2,475,103	$2,235,577	$2,475,103	$7,185,782
Dominion	$1,624,702	$1,467,472	$1,624,702	$4,716,876
DPL	$401,741	$362,863	$401,741	$1,166,344
JCPL	$824,053	$744,306	$824,053	$2,392,411
Met-Ed	$1,158,290	$1,046,198	$1,158,290	$3,362,778
PECO	$1,961,524	$1,771,699	$1,961,524	$5,694,748
PENELEC	$1,596,528	$1,442,025	$1,596,528	$4,635,080
Pepco	$2,458,692	$2,220,754	$2,458,692	$7,138,139
PPL	$3,690,484	$3,333,341	$3,690,484	$10,714,309
PSEG	$4,224,394	$3,815,581	$4,224,394	$12,264,368
RECO	$37,300	$33,690	$37,300	$108,290
Total	$39,658,975	$35,821,010	$39,658,975	$115,138,959

Table 6-18 shows the amount of energy efficiency (EE) resources in PJM for the 2012/2013 through 2016/2017 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 88.4 percent from 1,147.7 MW in the 2015/2016 delivery year to 2,162.5 MW in 2016/2017 Delivery Year.

Table 6-18 Energy efficiency resources by MW: 2012/2013 through 2016/2017 Delivery Year

	EE ICAP (MW)					EE UCAP (MW)				
	2012/2013	2013/2014	2014/2015	2015/2016	2016/2017	2012/2013	2013/2014	2014/2015	2015/2016	2016/2017
Total	643.4	871.0	1,035.4	1,147.7	2,162.5	666.1	904.2	1,077.7	1,189.6	2,249.7

FERC accepted PJM's proposed 30 minute lead time as a phased in approach on May 9, 2014, effective on June 1, 2015.[19] 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.[20] 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.[21] The exception requests must clearly state why the resource is unable to respond within 30 minutes based on the defined reasons for exception listed in Manual 18. Once a location is granted a longer lead time, the resource does not need to resubmit for a longer lead time each delivery year. Resources that request longer lead times without a physical constraint are rejected.

Table 6-19 shows the number of customer locations and nominated MW by product type and lead time for the 2016/2017 Delivery Year. PJM approved 2,673 locations, or 16.8 percent of all locations, which have 3,580 nominated MW capacity, or 38.3 percent of all nominated capacity, for exceptions to the 30 minutes lead time rule for the 2015/2016 Delivery Year.

19 See "Order Rejecting, in part, and Accepting, in part, Proposed Tariff Changes, Subject to Conditions," Docket No. ER14-822-001 (May 9, 2014).
20 See "PJM Interconnection, L.L.C.," Docket No. ER14-135-000 (October 20, 2014).
21 See "Manual 18: Capacity Market," Revision 35 (November 17, 2016), p. 62.

Table 6-19 Lead time by product type: 2016/2017 Delivery Year

Lead Type	Product Type	Locations	Nominated MW
Long Lead (120 Minutes)	Annual and Extended Summer	352	767
	Limited	2,005	2,391
Short Lead (60 Minutes)	Annual, Extended Summer and Limited	316	423
Quick Lead (30 Minutes)	Annual	245	395
	Extended Summer	658	453
	Limited	12,326	4,917
Total		15,902	9,346

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 measures 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. Limiting the GLD method to the minimum of the two calculations ensures reductions occur below the PLC, thus avoiding double counting of load reductions.[22] The Direct Load Control (DLC) method measures when the CSP turns on and turns off the direct load control switch to remotely trigger load reductions. DLC customers were not required to submit meter data to calculate load reductions. The direct load control method is no longer an eligible reduction method after May 31, 2016.[23]

Table 6-20 shows the MW registered by measurement and verification method and by load drop method for the 2016/2017 Delivery Year. For the 2016/2017 Delivery Year, 0.9 percent use the guaranteed load drop (GLD) measurement and verification method, 99.1 percent use the firm service level (FSL) method

22 135 FERC ¶ 61,212.
23 PJM. "Manual 18: PJM Capacity Market," Revision 36 (December 22, 2016), p. 63.

and 0.0 percent use direct load control (DLC). The direct load control method is no longer an eligible reduction method after May 31, 2016.[24]

Table 6-20 Reduction MW by each demand response method: 2016/2017 Delivery Year

Program Type	On-site Generation MW	HVAC MW	Refrigeration MW	Lighting MW	Manufacturing MW	Water Heating MW	Other, Batteries or Plug Load MW	Total	Percent by type
Firm Service Level	1,148.1	2,978.6	224.5	856.0	3,862.0	142.1	50.2	9,261.4	99.1%
Guaranteed Load Drop	16.2	26.4	1.5	9.1	31.2	0.1	0.0	84.4	0.9%
Non hourly metered sites (DLC)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
Total	1,164.2	3,004.9	226.0	865.1	3,893.2	142.2	50.2	9,345.8	100.0%
Percent by method	12.5%	32.2%	2.4%	9.3%	41.7%	1.5%	0.5%	100.0%	

Table 6-21 shows the fuel type used in the on-site generators identified in Table 6-20 for the 2016/2017 Delivery Year. Of the 12.5 percent of emergency demand response identified as using on site generation for the 2016/2017 Delivery Year, 75.5 percent of MW are diesel, 19.2 percent of MW are natural gas and 5.3 percent of MW are coal, gasoline, kerosene, oil, propane or waste products.

Table 6-21 On-site generation fuel type by MW: 2016/2017 Delivery Years

	2016/2017	
Fuel Type	MW	Percent
Coal, Gasoline, Kerosene, Oil, Propane, Waste Products	61.7	5.3%
Diesel	879.2	75.5%
Natural Gas	223.3	19.2%
Total	1,164.2	100.0%

Emergency and Pre-Emergency Event Reported Compliance

Table 6-22 shows the demand response cleared UCAP MW for PJM by Delivery Year. Total demand response cleared in PJM decreased by 2,188.4 MW, or 11.5 percent, from 15,453.7 MW in the 2015/2016 Delivery Year to 13,265.3 MW in the 2016/2017 Delivery Year. The DR percent of capacity decreased by 3.9 percent, from 8.9 percent in the 2015/2016 Delivery Year to 5.1 percent in the 2016/2017 Delivery Year.

24 PJM. "Manual 18: PJM Capacity Market," Revision 36 (December 22, 2016), p. 63.

Table 6-22 Demand response cleared MW UCAP for PJM: 2011/2012 through 2016/2017 Delivery Year

Delivery Year	DR Cleared MW UCAP	DR Percent of Capacity MW UCAP
2011/2012	1,826.6	1.4%
2012/2013	8,740.9	6.2%
2013/2014	10,779.6	6.7%
2014/2015	14,943.0	9.3%
2015/2016	15,453.7	8.9%
2016/2017	13,265.3	5.1%

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 effective February 16, 2017: AEP_CANTON, ATSI_CLE, DPL_SOUTH, PS_NORTH, ATSI_NEWCASOE, PPL_WESCO, ATSI_BLKRIVER, PENELEC_ERIC, APS_EAST, DOM_CHES, DOM_YORKTOWN.[25] PJM can remove a defined subzone at their discretion. There is no reason to remove a defined subzone, as the subzone may need to be dispatched again in the future. The METED_EAST, PENELEC_EAST, PPL_EAST and DOM_NORFOLK subzones were removed by PJM. More subzones may have been removed by PJM but PJM does not keep a record of created and removed subzones. The MMU recommends that PJM

25 See "Load Management Subzones," <http://www.pjm.com/~/media/markets-ops/demand-response/subzone-definition-workbook.ashx> (Accessed January 25, 2017).

not remove any defined subzones and maintain a public record of all created and removed subzones.

The subzone design and closed loops are related. 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.[26] 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. Of the 17 closed loop interface definitions, 11 (65 percent) were created for the purpose of allowing emergency DR to set price.[27]

Demand resources can be dispatched for voluntary compliance during any hour of any day, but dispatched resources are not measured for compliance outside 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.

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.[28]

Under the new capacity performance design of the PJM Capacity Market, compliance for potential penalties will be measured for DR only during performance assessment hours (PAH). When pre-emergency or emergency demand response is dispatched, a PAH is triggered for PJM.[29] As a result, PJM now classifies all demand response as an emergency resource.

The MMU recommends that demand response resources be treated as economic resources like all other capacity resources and therefore that the dispatch of demand response resources not automatically trigger a Performance Assessment Hour (PAH) for CP compliance.

PJM allows compliance to be measured across zones within a compliance aggregation area (CAA).[30] This changes the way CSPs dispatch resources when multiple electrically contiguous areas with the same RPM clearing prices are dispatched. The compliance rules determine how CSPs are paid and thus create incentives that CSPs will incorporate in their decisions about how to respond to PJM dispatch.[31] The multiple zone approach is 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

26 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).

27 See the *2016 State of the Market Report for PJM*, Volume II, Section 4, Energy Uplift, for additional information regarding all closed loop interfaces and the impacts to the PJM markets.

28 PJM "Manual 18: Capacity Market," Revision 34 (July 28, 2016), p 148.

29 PJM. OATT Definitions 2.23A.

30 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.

31 See "Manual 18: Capacity Market," Revision 36 (December 22, 2016) p. 166.

dispatch of demand resources would be consistent with the nodal dispatch of generation.

Load increases are not netted against load decreases for dispatched demand resources across hours or across registrations within hours for compliance purposes, but are treated as zero. This skews the compliance results towards higher compliance since poorly performing demand resources are not used in the compliance calculation. When load is above the peak load contribution during a demand response event, the load reduction is negative; it is a load increase rather than a decrease. PJM ignores such negative reduction values and instead replaces the negative values with a zero MW reduction value. The PJM Tariff and PJM Manuals do not limit the compliance calculation value to a zero MW reduction value.[32] The compliance values PJM reports for demand response events are different than the actual compliance values accounting for both increases and decreases in load from demand resources that are called on and paid under the program.

The MMU recommends that compliance rules be revised to include submittal of all necessary hourly load data, and that negative values be included when calculating event compliance across hours and registrations.

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."[33] The calculated CBL more accurately measures reductions for Demand Resources.

32 PJM. OATT Attachment K § PJM Emergency Load Response Program at Reporting and Compliance.

33 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 April 20, 2017).

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.[34]

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.

34 OATT Attachment K Section 8.9.

An extreme example makes clear the fundamental problems with the use of measurement and verification methods to define the level of power that would have been used but for the DR actions, and the payments to DR customers that result from these methods. The current rules for measurement and verification for demand resources make a bankrupt company, a customer that no longer exists due to closing of a facility or a permanently shut down company, or a company with a permanent reduction in peak load due to a partial closing of a facility, an acceptable demand response customer under some interpretations of the tariff, although it is the view of the MMU that such customers should not be permitted to be included as registered demand resources. Companies that remain in business, but with a substantially reduced load, can maintain their pre-bankruptcy FSL (firm service level to which the customer agrees to reduce in an event) commitment, which can be greater than or equal to the post-bankruptcy 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."[35] 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 the first three months of 2017, participants registered under the full option, which contains 99.6 percent of registrations, that were dispatched and reported 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.[36] The dispatch price is set by the CSP before the delivery year starts and cannot be changed during the delivery year. 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 and the 2016/2017 Delivery Year.[37] [38]

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.[39]

FERC Order 831 requires all energy offers above $1,000 per MWh to provide supporting documentation.[40] CSPs must provide documentation to verify the marginal costs of Demand Resources and Economic Resources for offers above $1,000 per MWh.

Table 6-23 shows the distribution of registrations and associated MW in the emergency full option across ranges of minimum dispatch prices for the 2016/2017 Delivery Year. The majority of participants, 58.7 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, 3.5 percent of participants have a dispatch price between $0 and $1 per MWh, and 94.7 percent of participants have a dispatch price above $1,000 per MWh. Energy offers are further increased by submitted shutdown costs, which, in the

35 OATT Attachment K Appendix Section 8.2.

36 OATT Attachment K Appendix Section 8.2.
37 139 FERC ¶ 61,057 (2012).
38 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.
39 PJM. "Manual 15: Cost Development Guidelines," Revision 28 (October 18, 2016), p. 59.
40 157 FERC ¶ 61,115 (2016).

2016/2017 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 $182.60 per location and $141.91 per MW.

Table 6-23 Distribution of registrations and associated MW in the emergency full option across ranges of minimum dispatch prices: 2016/2017 Delivery Year[41]

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	576	3.6%	322.9	3.5%	$1.74	$3.10
$1-$999	261	1.6%	198.7	2.1%	$54.39	$71.43
$1,000-$1,100	2,357	14.8%	3,032.9	32.5%	$182.60	$141.91
$1,101-$1,275	0	0.0%	0.0	0.0%	$0.00	$0.00
$1,276-$1,549	292	1.8%	300.8	3.2%	$55.04	$53.43
$1,550-$1,850	12,416	78.1%	5,490.7	58.7%	$41.75	$94.41
Total	15,902	100.0%	9,346.1	100.0%	$61.63	$104.86

41 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

- Energy net revenues are significantly affected by energy prices and fuel prices. Energy prices and fuel prices were higher in the first three months of 2017 than in the first three months of 2016. Gas prices increased more than LMP and CTs and CCs ran with lower margins as a result. Coal prices increased by less than LMP and CPs ran for more hours in the first three months of 2017 than in the first three months of 2016 and with higher margins.
- In the first three months of 2017, average energy market net revenues decreased by 66 percent for a new CT, 29 percent for a new CC, 68 percent for a new DS, and four percent for a new solar installation. Average energy market net revenues increased by 17 percent for a new CP, 17 percent for a new nuclear plant, and 16 percent for a new wind installation, as compared to the first three months of 2016.

Historical New Entrant CT and CC Revenue Adequacy

Total unit net revenues include energy and capacity revenues. Analysis of the total unit revenues of theoretical new entrant CTs and CCs for three representative locations shows that units that entered the PJM markets in 2007 have not covered their total costs, including the return on and of capital, on a cumulative basis through March 31, 2017. The analysis also shows that theoretical new entrant CTs and CCs that entered the PJM markets in 2012 have covered their total costs on a cumulative basis in the eastern PSEG and BGE zones but have not covered total costs in the western ComEd Zone. Energy market revenues were not sufficient to cover total costs in any scenario except the new entrant CC unit that went into operation in 2012 in BGE, which demonstrates the critical role of capacity market revenue in covering total costs.

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.

Unlike cost of service regulation, markets do not guarantee that units will cover their costs. New CT and CC units that began operation in 2007 have not covered their total costs from energy market and capacity market revenues through March 31, 2017 in the ComEd Zone, in the PSEG Zone and in the BGE Zone. New CT and CC units that began operation on June 1, 2012, have covered or more than covered their total costs in the PSEG Zone and the BGE Zone through March 31, 2017 and have not covered their total costs in the ComEd Zone through March 31, 2017.

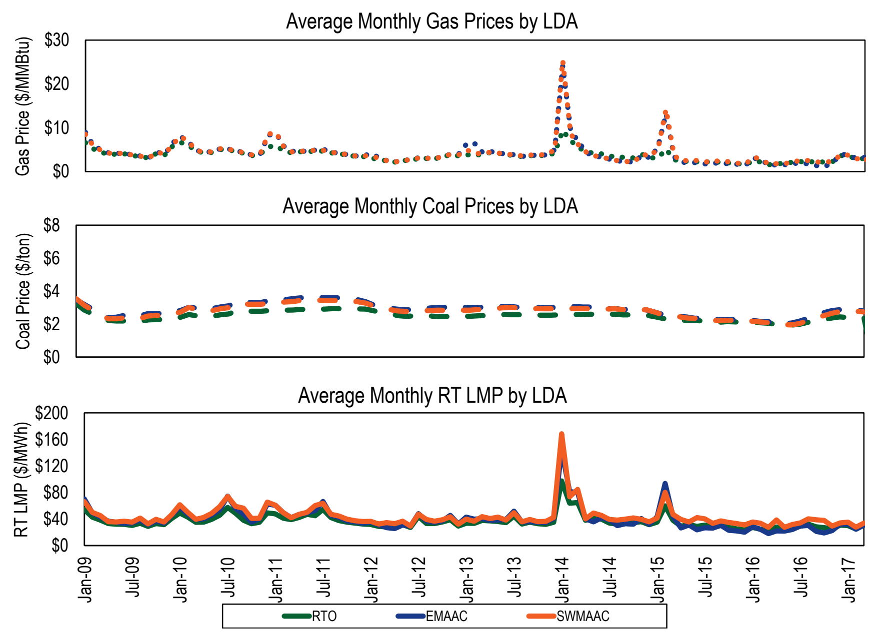
Net Revenue

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 13.0 percent higher in the first three months of 2017 than in the first three months of 2016, $30.28 per MWh versus $26.80 per MWh. Natural gas prices and coal prices increased in the first three months of 2017 over the first three months of 2016. The price of Northern Appalachian coal was 30.1 percent higher; the price of Central Appalachian coal was 34.6 percent higher; the price of Powder River Basin coal was 17.1 percent higher; the price of eastern natural gas was 36.0 percent higher; and the price of western natural gas was 64.6 percent higher (Figure 7-1).

Figure 7-1 Energy market net revenue factor trends: January 1, 2009 through March 31, 2017



Spark Spreads, Dark Spreads, and Quark Spreads

The spark, dark, or quark spread is defined as the difference 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 volatility is a result of fluctuations in LMP and the price of fuel. Spreads can be positive or negative.

Table 7-1 shows average peak hour spreads by year and Table 7-2 shows the associated standard deviation.

Table 7-1 Peak hour spreads ($/MWh): January 1, 2011 through March 31, 2017

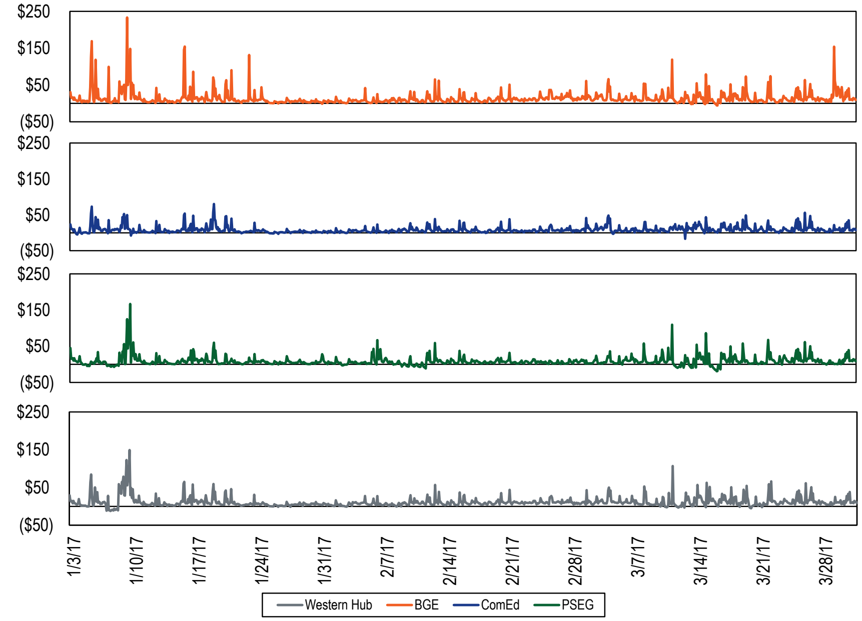
	BGE			ComEd			PSEG			Western Hub		
	Spark	Dark	Quark	Spark	Dark	Quark	Spark	Dark	Quark	Spark	Dark	Quark
2011	$26.27	$33.76	$48.66	$12.47	$33.68	$30.85	$22.99	$28.15	$47.70	$19.50	$26.15	$41.06
2012	$24.29	$24.21	$36.25	$16.17	$30.87	$27.23	$19.51	$17.57	$33.01	$19.94	$19.86	$31.91
2013	$19.59	$26.45	$40.79	$10.70	$31.64	$30.44	$13.65	$25.09	$42.13	$16.16	$22.34	$36.68
2014	$30.27	$51.11	$66.58	$11.14	$42.50	$43.23	$19.85	$43.01	$60.19	$23.23	$39.58	$55.05
2015	$25.86	$34.71	$44.42	$14.48	$27.68	$26.98	$13.53	$23.38	$34.31	$23.59	$25.29	$35.00
2016	$28.29	$28.11	$38.32	$14.22	$25.72	$26.58	$13.44	$10.80	$24.06	$21.47	$18.53	$28.75
2017 YTD	$13.95	$15.47	$31.65	$8.50	$22.64	$25.26	$8.86	$9.48	$27.92	$11.26	$11.81	$27.99

Table 7-2 Peak hour spread standard deviation ($/MWh): January 1, 2011 through March 31, 2017

	BGE			ComEd			PSEG			Western Hub		
	Spark	Dark	Quark	Spark	Dark	Quark	Spark	Dark	Quark	Spark	Dark	Quark
2011	$50.7	$51.1	$51.1	$26.3	$26.9	$26.9	$43.6	$45.3	$45.3	$37.2	$37.5	$37.4
2012	$33.7	$33.9	$33.7	$23.6	$23.7	$23.7	$29.6	$29.7	$29.7	$27.6	$28.0	$27.8
2013	$32.6	$33.3	$33.3	$18.2	$18.3	$18.2	$32.4	$30.4	$30.4	$25.3	$25.5	$25.5
2014	$88.1	$118.9	$118.9	$68.1	$68.3	$68.3	$78.3	$94.0	$94.3	$83.0	$86.7	$86.7
2015	$42.4	$44.9	$45.0	$20.8	$22.5	$22.5	$32.7	$40.9	$41.1	$31.3	$33.1	$33.4
2016	$32.8	$32.6	$32.6	$16.4	$16.6	$16.8	$17.0	$18.6	$18.4	$19.1	$18.5	$18.5
2017 YTD	$18.8	$20.3	$20.4	$9.5	$9.6	$9.7	$13.1	$15.7	$15.8	$13.5	$13.9	$14.0

Figure 7-2 shows the hourly spark spread for peak hours since January 1, 2017, for BGE, ComEd, PSEG, and Western Hub.

Figure 7-2 Hourly spark spread (gas) for peak hours ($/MWh): January 1 through March 31, 2017[1]



1 Spark spreads use a combined cycle heat rate of 7,000 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.

Figure 7-3 Hourly dark spread (coal) for peak hours ($/MWh): January 1 through March 31, 2017[2]

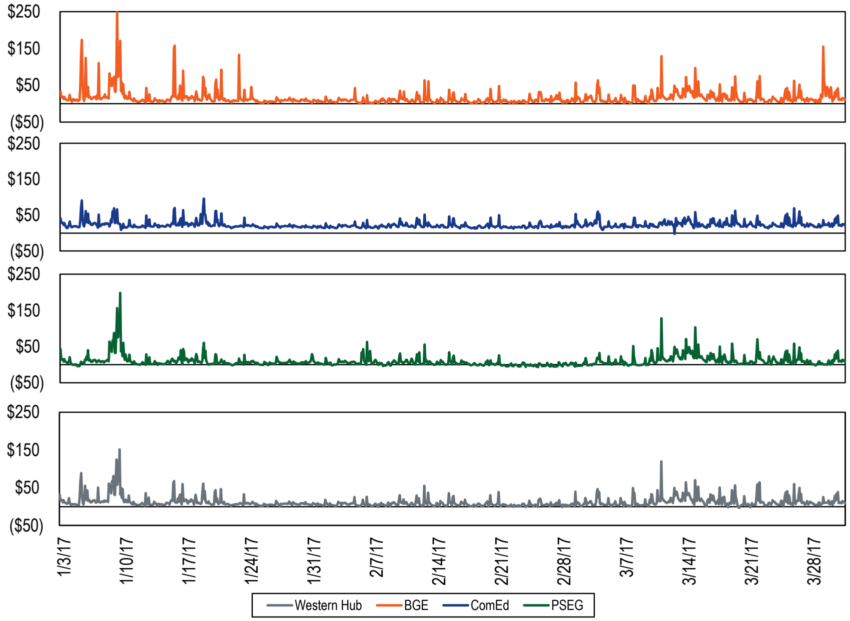
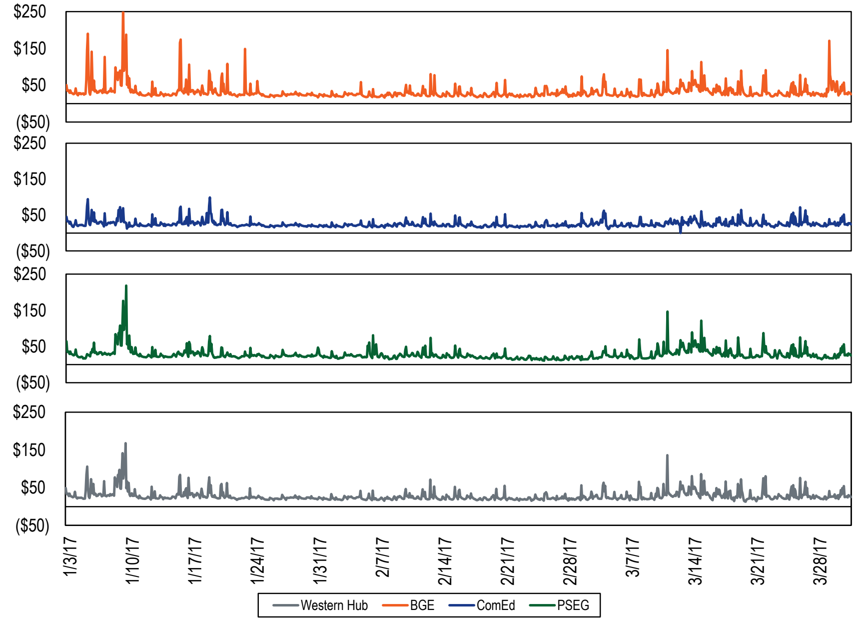


Figure 7-4 Hourly quark spread (uranium) for selected zones ($/MWh): January 1 through March 31, 2017[3]



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.

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.

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.

3 Quark spreads use a heat rate of 10,000 Btu/kWh, zonal hourly LMPs, and daily uranium prices.

- 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 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 installed 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] In addition, each CT, CC, CP, and DS plant was assumed to take a continuous 14 day planned annual outage in the fall season.

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 prices, adjusted for rail transportation costs.[11]

Short run marginal cost includes fuel costs, emissions costs, and VOM costs.[12 13] Average short run marginal costs are shown in Table 7-3.

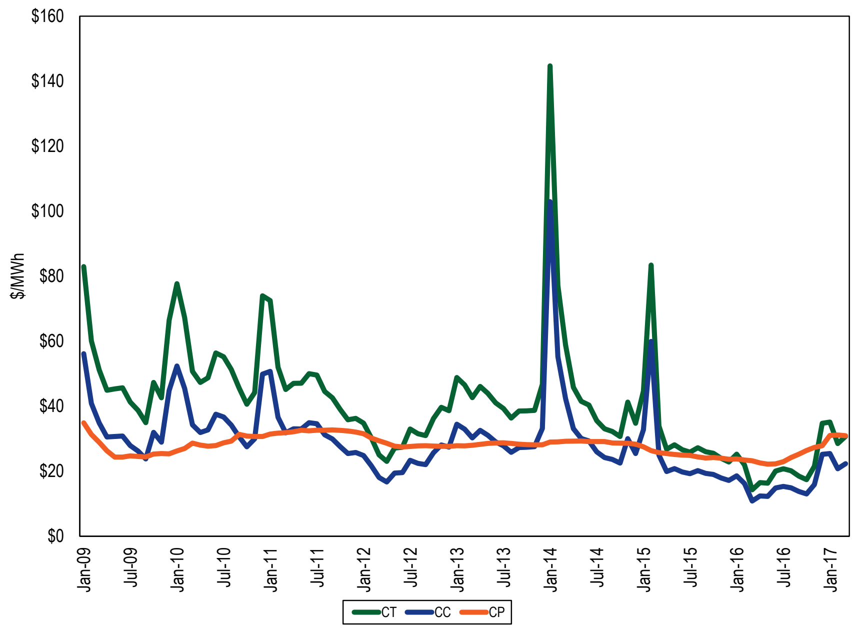
Table 7-3 Average short run marginal costs: January 1 through March 31, 2017

Unit Type	Short Run Marginal Costs ($/MWh)	Heat Rate (Btu/kWh)	VOM ($/MWh)
CT	$31.45	9,437	$0.25
CC	$22.84	6,679	$1.00
CP	$31.03	9,250	$4.00
DS	$137.69	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 1, 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).

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.
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.

Figure 7-5 Average short run marginal costs: January 1, 2009 through March 31, 2017



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.

Gas prices, coal prices, and energy prices are reflected in new entrant run hours. Table 7-4 shows the average run hours by a new entrant unit.

Table 7-4 Average run hours: January 1 through March 31, 2009 through 2017

	CT	CC	CP	DS	Nuclear	Wind	Solar
2009	215	1,286	2,136	34	2,136		
2010	79	971	2,136	14	2,136		
2011	469	1,665	2,136	17	2,136		
2012	1,298	2,104	2,160	3	2,160	1,782	269
2013	429	1,743	2,136	5	2,136	1,735	340
2014	875	1,721	2,136	165	2,136	1,822	255
2015	952	1,742	2,136	118	2,136	1,704	296
2016	1,282	1,984	663	23	2,160	1,782	376
2017	496	1,897	938	6	2,136	1,882	305

New Entrant Combustion Turbine

Energy market net revenue was calculated for a new CT plant economically dispatched by PJM. It was assumed that the CT plant had a minimum run time of two hours. The unit was first committed day ahead in profitable blocks of at least two 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 two hours, or any profitable hours bordering the profitable day ahead or real time block.

New entrant CT plant energy market net revenues were lower across all zones in the first three months of 2017 than in the first three months of 2016 (Table 7-5). The increase in gas prices caused average CT operating costs to be higher than the average LMP in January and February, resulting in fewer run hours. In addition, there were fewer high LMP hours in the first three months of 2017 than in 2016, which means that the CT had fewer hours to operate with high margins.

Table 7-5 Energy net revenue for a new entrant gas fired CT under economic dispatch: January 1 through March 31, 2009 through 2017 (Dollars per installed MW-year)[14]

Zone	2009	2010	2011	2012	2013	2014	2015	2016	2017	Change in 2017 from 2016
AECO	$2,728	$836	$9,202	$7,517	$3,214	$30,264	$13,722	$8,760	$1,980	(77%)
AEP	$1,901	$621	$3,123	$8,528	$3,199	$48,084	$19,634	$10,311	$4,191	(59%)
AP	$6,017	$2,409	$12,201	$11,591	$4,730	$65,810	$36,706	$14,737	$3,139	(79%)
ATSI	NA	NA	$0	$8,891	$3,653	$54,456	$19,993	$7,650	$4,097	(46%)
BGE	$3,358	$1,204	$5,747	$15,513	$5,058	$32,712	$9,300	$23,770	$5,501	(77%)
ComEd	$683	$194	$857	$3,157	$1,116	$19,735	$6,229	$3,151	$1,890	(40%)
DAY	$1,047	$331	$3,039	$9,388	$3,194	$47,524	$17,257	$7,009	$3,339	(52%)
DEOK	NA	NA	NA	$6,331	$2,085	$44,695	$24,316	$8,123	$3,208	(61%)
DLCO	$456	$2,513	$3,104	$9,158	$2,266	$41,566	$12,491	$12,102	$2,763	(77%)
Dominion	$5,632	$5,929	$5,031	$10,436	$6,543	$26,374	$11,232	$10,664	$2,760	(74%)
DPL	$3,661	$779	$5,614	$12,059	$2,838	$32,143	$13,114	$13,371	$5,008	(63%)
EKPC	NA	NA	NA	NA	$0	$45,421	$23,459	$7,950	$2,936	(63%)
JCPL	$2,577	$1,719	$10,060	$7,622	$5,970	$34,426	$15,452	$6,161	$2,532	(59%)
Met-Ed	$2,371	$710	$7,093	$6,542	$3,058	$28,211	$13,333	$6,375	$2,867	(55%)
PECO	$2,452	$881	$8,652	$6,738	$2,386	$28,475	$13,131	$5,351	$2,107	(61%)
PENELEC	$3,650	$1,326	$10,947	$10,488	$7,549	$79,708	$59,869	$15,466	$4,917	(68%)
Pepco	$3,268	$2,062	$5,965	$13,821	$5,302	$32,626	$7,748	$13,478	$3,686	(73%)
PPL	$2,204	$880	$10,269	$6,045	$2,517	$34,732	$13,827	$6,492	$2,495	(62%)
PSEG	$919	$328	$3,851	$4,562	$1,946	$17,568	$6,992	$3,000	$1,725	(42%)
RECO	$461	$298	$2,296	$3,872	$3,442	$18,173	$9,147	$3,347	$1,673	(50%)
PJM	$2,552	$1,354	$5,947	$8,540	$3,503	$38,135	$17,348	$9,363	$3,141	(66%)

14 The energy net revenues presented for the PJM area in this section represent the zonal average energy net revenues.

New Entrant Combined Cycle

Energy market net revenue was calculated for a new CC plant economically dispatched by PJM. It was assumed that the CC 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.[15] 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 CC plant energy market net revenues were lower in all but PSEG and RECO in the first three months of 2017 than in the first three months of 2016 (Table 7-6). In the first three months of 2017 the new CC plant had similar run hours as in the first three months of 2016. However, gas prices increased more than the LMP increased, resulting in lower margins and lower energy net revenues in 18 of 20 zones.

Table 7-6 Energy net revenue for a new entrant CC under economic dispatch: January 1 through March 31, 2009 through 2017 (Dollars per installed MW-year)[16]

Zone	2009	2010	2011	2012	2013	2014	2015	2016	2017	Change in 2017 from 2016
AECO	$12,504	$7,650	$23,944	$20,898	$13,647	$56,633	$29,158	$17,421	$11,972	(31%)
AEP	$5,215	$3,277	$13,838	$22,216	$15,740	$65,957	$32,327	$21,251	$15,421	(27%)
AP	$17,657	$8,782	$29,151	$25,351	$19,220	$88,769	$51,238	$24,600	$14,437	(41%)
ATSI	NA	NA	$0	$22,945	$17,203	$75,316	$33,610	$18,552	$14,864	(20%)
BGE	$13,494	$9,004	$17,981	$29,349	$19,030	$61,497	$18,447	$35,666	$19,870	(44%)
ComEd	$2,565	$456	$3,135	$13,158	$5,354	$24,423	$11,231	$11,374	$7,592	(33%)
DAY	$3,506	$1,934	$13,084	$23,184	$16,421	$65,549	$30,270	$18,393	$13,498	(27%)
DEOK	NA	NA	NA	$19,654	$12,964	$62,412	$37,950	$18,988	$12,718	(33%)
DLCO	$2,172	$4,036	$11,553	$22,591	$12,417	$55,522	$22,933	$20,753	$13,251	(36%)
Dominion	$19,787	$15,018	$18,479	$24,097	$18,064	$47,378	$20,917	$23,386	$13,939	(40%)
DPL	$13,710	$5,448	$19,168	$25,392	$14,206	$58,992	$26,208	$23,282	$15,500	(33%)
EKPC	NA	NA	NA	NA	$0	$62,362	$36,811	$18,200	$12,262	(33%)
JCPL	$12,929	$7,674	$25,248	$21,166	$17,261	$64,421	$31,063	$14,748	$13,543	(8%)
Met-Ed	$10,131	$6,078	$19,322	$19,502	$12,766	$54,369	$24,758	$14,805	$13,462	(9%)
PECO	$10,974	$6,713	$23,065	$19,889	$11,677	$54,796	$28,134	$13,639	$11,343	(17%)
PENELEC	$13,226	$6,336	$27,396	$24,519	$23,697	$106,773	$70,517	$24,858	$16,402	(34%)
Pepco	$12,033	$9,781	$17,384	$27,686	$19,412	$57,616	$15,827	$26,926	$16,016	(41%)
PPL	$9,837	$5,769	$21,396	$18,699	$11,602	$55,366	$26,697	$15,105	$12,834	(15%)
PSEG	$8,516	$5,996	$13,942	$14,952	$9,112	$38,580	$14,493	$7,819	$9,364	20%
RECO	$6,018	$4,820	$8,026	$13,976	$11,276	$40,300	$14,856	$8,247	$9,984	21%
PJM	$10,251	$6,398	$17,006	$21,538	$14,053	$59,852	$28,872	$18,901	$13,414	(29%)

15 All starts associated with combined cycle units are assumed to be hot starts.
16 The energy net revenues presented for the PJM area in this section represent the zonal average energy net revenues.

New Entrant Coal Plant

Energy market net revenue was calculated for a new CP plant economically dispatched by PJM. It was assumed that the CP 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. 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. 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 higher in all but five zones in the first three months of 2017 than in the first three months of 2016 (Table 7-7). The increase in LMP was greater than the increase in coal prices, resulting in more run hours, higher margins and higher net revenues in most zones.

Table 7-7 Energy net revenue for a new entrant CP: January 1 through March 31, 2009 through 2017 (Dollars per installed MW-year)[17]

Zone	2009	2010	2011	2012	2013	2014	2015	2016	2017	Change in 2017 from 2016
AECO	$43,215	$41,590	$36,063	$2,675	$13,783	$143,988	$58,708	$4,229	$3,243	(23%)
AEP	$16,803	$29,638	$21,699	$3,597	$16,892	$82,244	$27,081	$2,066	$4,367	111%
AP	$35,826	$40,552	$33,649	$5,402	$19,131	$102,926	$45,528	$3,016	$5,438	80%
ATSI	NA	NA	$0	$3,649	$17,503	$90,714	$29,110	$1,412	$5,288	274%
BGE	$46,577	$51,492	$40,197	$9,897	$23,506	$156,913	$62,899	$13,007	$6,181	(52%)
ComEd	$36,166	$40,706	$34,460	$25,552	$31,957	$87,058	$35,291	$1,091	$3,701	239%
DAY	$14,485	$27,375	$20,446	$1,419	$17,757	$82,450	$27,073	$1,184	$3,831	224%
DEOK	NA	NA	NA	$619	$14,454	$76,026	$23,975	$1,180	$3,058	159%
DLCO	$9,716	$23,675	$10,308	$1,926	$9,653	$66,530	$17,819	$1,841	$4,612	151%
Dominion	$41,068	$50,166	$36,153	$5,034	$20,582	$127,290	$58,725	$6,739	$4,639	(31%)
DPL	$47,268	$46,314	$42,948	$7,948	$19,736	$159,791	$72,097	$8,420	$5,104	(39%)
EKPC	NA	NA	NA	NA	$0	$75,988	$22,964	$1,851	$2,820	52%
JCPL	$43,327	$41,795	$36,913	$2,664	$16,833	$150,288	$59,850	$2,315	$3,924	69%
Met-Ed	$43,283	$44,209	$37,718	$3,371	$17,543	$143,912	$57,928	$2,458	$4,214	71%
PECO	$41,572	$40,698	$35,350	$2,336	$12,341	$141,628	$57,588	$2,200	$3,547	61%
PENELEC	$30,086	$33,010	$25,545	$2,745	$17,876	$107,488	$44,858	$1,892	$3,018	60%
Pepco	$42,835	$47,934	$33,287	$5,135	$19,073	$149,835	$57,241	$7,704	$5,138	(33%)
PPL	$39,552	$39,126	$33,557	$1,684	$12,376	$140,691	$56,463	$2,267	$3,636	60%
PSEG	$46,936	$43,883	$37,602	$3,241	$24,438	$163,942	$69,545	$3,131	$3,563	14%
RECO	$43,612	$40,865	$30,456	$2,816	$30,378	$161,280	$70,870	$2,962	$3,504	18%
PJM	$36,607	$40,178	$30,353	$4,827	$17,791	$120,549	$47,781	$3,548	$4,141	17%

17 The energy net revenues presented for the PJM area in this section represent the zonal average energy net revenues.

New Entrant Diesel

Energy market net revenue was calculated 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 the first three months of 2017 than in the first three months of 2016 (Table 7-8). There were relatively few hours in 2017 with high LMPs and positive margins because prices were higher but less volatile than in the first three months of 2016. In some zones there were no hours with positive margins.

Table 7-8 Energy market net revenue for a new entrant DS: January 1 through March 31, 2009 through 2017 (Dollars per installed MW-year)

Zone	2009	2010	2011	2012	2013	2014	2015	2016	2017	Change in 2017 from 2016
AECO	$1,555	$780	$928	$8	$262	$36,066	$11,926	$1,252	$73	(94%)
AEP	$100	$94	$9	$0	$99	$15,382	$3,059	$217	$0	NA
AP	$808	$224	$13	$0	$127	$20,072	$6,840	$316	$46	(85%)
ATSI	NA	NA	$0	$0	$97	$15,092	$2,727	$167	$50	(70%)
BGE	$2,596	$1,572	$975	$136	$592	$53,670	$11,187	$1,796	$745	(58%)
ComEd	$7	$73	$0	$0	$74	$12,076	$1,747	$92	$0	NA
DAY	$174	$92	$97	$0	$87	$15,130	$2,559	$200	$0	NA
DEOK	NA	NA	NA	$0	$74	$14,306	$2,105	$273	$0	NA
DLCO	$65	$1,547	$8	$0	$78	$13,813	$2,489	$174	$46	(74%)
Dominion	$2,696	$2,149	$1,062	$134	$468	$46,239	$10,055	$969	$323	(67%)
DPL	$2,442	$1,175	$898	$19	$290	$40,857	$14,788	$1,569	$673	(57%)
EKPC	NA	NA	NA	NA	$0	$15,363	$2,304	$171	$0	NA
JCPL	$1,348	$732	$1,192	$22	$453	$36,332	$12,736	$289	$155	(46%)
Met-Ed	$1,424	$758	$782	$4	$251	$35,247	$11,621	$265	$117	(56%)
PECO	$1,402	$755	$847	$9	$252	$35,496	$11,794	$255	$89	(65%)
PENELEC	$203	$109	$11	$0	$123	$17,773	$5,626	$168	$53	(69%)
Pepco	$2,925	$1,882	$1,215	$137	$667	$55,675	$10,096	$943	$345	(63%)
PPL	$1,297	$706	$920	$48	$255	$36,173	$12,432	$253	$127	(50%)
PSEG	$1,210	$672	$847	$9	$325	$35,956	$12,238	$316	$160	(49%)
RECO	$940	$530	$524	$0	$1,466	$33,335	$13,957	$310	$159	(49%)
PJM	$1,247	$815	$574	$28	$302	$29,203	$8,114	$500	$158	(68%)

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.[18]

New entrant nuclear plant energy market net revenues were higher in all but three zones in the first three months of 2017 than in the first three months of 2016 (Table 7-9). The increase in LMP resulted in higher margins and higher net revenues in most zones.

Table 7-9 Energy net revenue for a new entrant nuclear plant: January 1 through March 31, 2009 through 2017 (Dollars per installed MW-year)[19]

Zone	2009	2010	2011	2012	2013	2014	2015	2016	2017	Change in 2017 from 2016
AECO	$101,789	$91,719	$95,005	$49,465	$62,135	$209,062	$105,885	$33,950	$42,944	26%
AEP	$69,992	$68,828	$63,740	$45,781	$55,242	$130,923	$67,640	$38,437	$43,465	13%
AP	$85,930	$79,042	$76,989	$48,737	$58,231	$153,609	$86,634	$41,297	$45,402	10%
ATSI	NA	NA	$0	$46,380	$56,419	$140,042	$68,786	$38,237	$45,604	19%
BGE	$102,425	$98,153	$92,808	$57,792	$68,082	$219,233	$107,545	$59,830	$52,497	(12%)
ComEd	$57,229	$58,837	$54,172	$40,561	$48,679	$112,295	$54,074	$32,423	$39,564	22%
DAY	$66,782	$66,322	$63,005	$46,714	$55,805	$130,464	$65,467	$38,133	$44,311	16%
DEOK	NA	NA	NA	$43,474	$52,104	$123,359	$62,074	$37,014	$42,151	14%
DLCO	$60,313	$67,382	$59,001	$46,158	$52,319	$118,934	$57,909	$37,464	$44,016	17%
Dominion	$96,423	$96,719	$88,445	$51,477	$64,809	$186,500	$103,011	$48,565	$47,970	(1%)
DPL	$103,176	$92,441	$95,787	$53,757	$63,861	$222,427	$117,363	$47,167	$48,365	3%
EKPC	NA	NA	NA	NA	$0	$123,312	$60,945	$36,237	$41,659	15%
JCPL	$101,904	$91,945	$95,926	$49,706	$65,740	$216,025	$106,900	$31,139	$44,481	43%
Met-Ed	$98,776	$90,099	$90,065	$47,971	$61,337	$204,718	$101,495	$31,266	$44,324	42%
PECO	$99,985	$90,734	$94,229	$48,462	$60,336	$206,442	$104,527	$30,136	$42,354	41%
PENELEC	$84,307	$77,735	$76,824	$48,205	$61,776	$164,320	$87,695	$36,238	$43,667	20%
Pepco	$101,387	$98,734	$91,988	$56,101	$68,248	$215,636	$105,010	$52,225	$50,043	(4%)
PPL	$97,737	$88,977	$92,223	$47,319	$60,379	$205,302	$103,167	$31,552	$43,824	39%
PSEG	$103,610	$94,408	$98,713	$50,323	$77,497	$232,843	$114,967	$33,622	$45,219	34%
RECO	$99,961	$91,080	$90,901	$49,349	$84,198	$229,734	$116,341	$32,633	$45,554	40%
PJM	$90,102	$84,891	$78,879	$48,828	$58,860	$177,259	$89,872	$38,378	$44,871	17%

18 The class average forced outage rate was applied to total energy market net revenues.
19 The energy net revenues presented for the PJM area in this section represent the zonal average energy net revenues.

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 of operating wind units in the zone if 75 percent of existing wind units in the zone were generating at greater than or equal to 25 percent capacity factor in that hour.[20] The unit is credited with wind RECs for its generation and is assumed to have taken a 1603 payment instead of either the Investment Tax Credit (ITC) or Production Tax Credit (PTC).[21]

Wind energy market net revenues were higher in both zones in the first three months of 2017 than in the first three months of 2016 as a result of higher energy prices and higher margins (Table 7-10).

Table 7-10 Energy net revenue for a wind installation: January 1 through March 31, 2012 through 2017 (Dollars per installed MW-year)

Zone	2012	2013	2014	2015	2016	2017	Change in 2017 from 2016
ComEd	$23,562	$25,808	$43,705	$28,043	$21,027	$23,254	11%
PENELEC	$22,592	$30,532	$64,324	$42,418	$20,792	$25,299	22%

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 of operating solar units in the zone if 75 percent of existing solar units in the zone were generating at greater than or equal to 25 percent capacity factor in that hour. The unit is credited with SRECs for its generation and is assumed to have taken a 1603 payment instead of either the Investment Tax Credit (ITC) or Production Tax Credit (PTC).[22]

20 The condition that existing wind units in the zone were generating at greater than or equal to 25 percent capacity factor was not included in prior analyses of wind unit net revenues.

21 The 1603 payment is a direct payment of 30 percent of the project cost. REC related net revenues were overstated for the new entrant wind installation in the *2016 Quarterly State of the Market Report for PJM: January through June* and the *2016 Quarterly State of the Market Report for PJM: January through September* and were updated beginning with the *2016 State of the Market Report for PJM.*

22 The 1603 payment is a direct payment of 30 percent of the project cost. SREC related net revenues were overstated for the new entrant solar installation in the *2016 Quarterly State of the Market Report for PJM: January through June* and the *2016 Quarterly State of the Market Report for PJM: January through September* and have been updated as of the *2016 State of the Market Report for PJM.*

Solar energy market net revenues were slightly lower in the first three months of 2017 than in the first three months of 2016 as a result of fewer run hours (Table 7-11).

Table 7-11 PSEG energy net revenue for a solar installation: January 1 through March 31, 2012 through 2017 (Dollars per installed MW-year)

Zone	2012	2013	2014	2015	2016	2017	Change in 2017 from 2016
PSEG	$3,832	$10,800	$20,037	$14,764	$6,116	$5,854	(4%)

Historical New Entrant CT and CC Revenue Adequacy

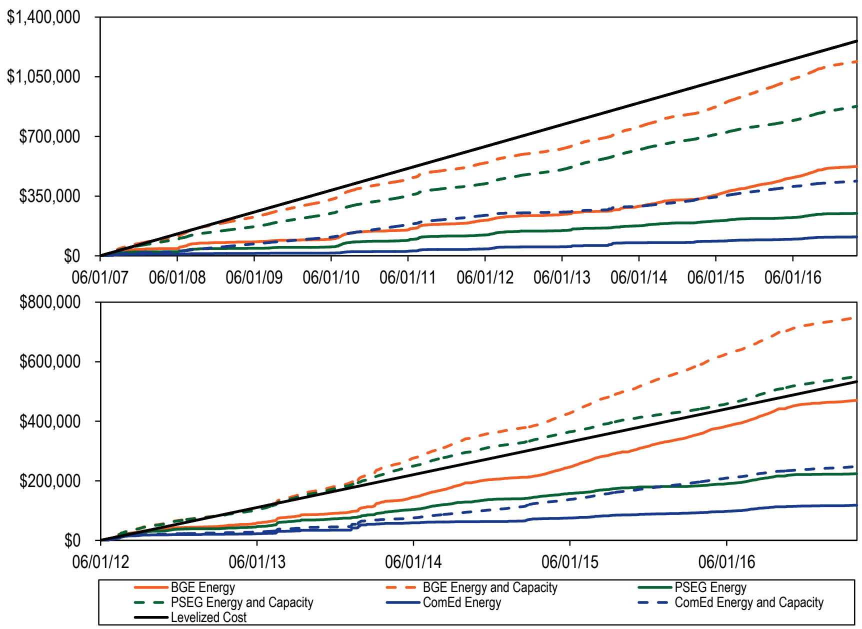
Total unit net revenues include energy and capacity revenues. Analysis of the total unit revenues of theoretical new entrant CTs and CCs for three representative locations shows that units that entered the PJM markets in 2007 have not covered their total costs, including the return on and of capital, on a cumulative basis through March 31, 2017. The analysis also shows that theoretical new entrant CTs and CCs that entered the PJM markets in 2012 have covered their total costs on a cumulative basis in the eastern PSEG and BGE zones, but have not covered total costs in the western ComEd Zone. Energy market revenues were not sufficient to cover total costs in any scenario except the new entrant CC unit that went into operation in 2012 in BGE, which demonstrates the critical role of capacity market revenue in covering total costs.

Under cost of service regulation, units are guaranteed that they will cover their total costs, assuming that the costs were determined to be reasonable. To the extent that units built in the PJM markets did not cover their total costs, investors were worse off and customers were better off than under cost of service regulation.

The summary figures compare net revenues for a new entrant CT and CC that began operation on June 1, 2007, at the start of the RPM capacity market, and new entrant CT and CC that began operation on June 1, 2012. In each figure, the solid black line shows the total net revenue required to cover total costs. The solid colored lines show net energy revenue by zone. The dashed colored lines show the sum of net energy and capacity revenue by zone.

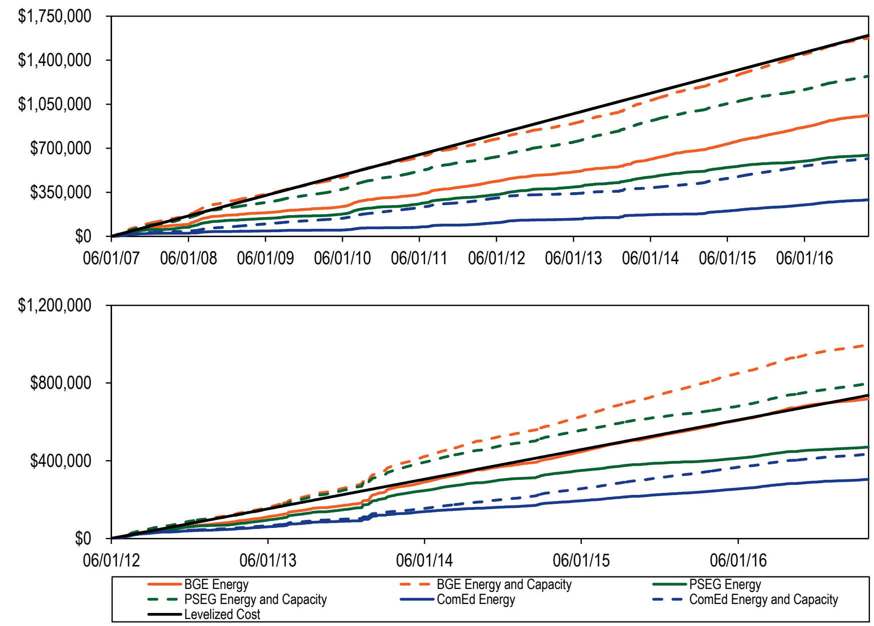
For the ComEd Zone, the PSEG Zone and the BGE Zone, Figure 7-6 compares cumulative energy market net revenues and energy market net revenues plus capacity market revenues to cumulative levelized costs for a new CT that began operation on June 1, 2007 and for a new CT that began operation on June 1, 2012. Cumulative energy market net revenues were less than cumulative total costs in all cases. Cumulative total market net revenues were less than the cumulative total costs of the 2007 new entrant CT unit for each year in each of the three zones. Cumulative total market net revenues were greater than the cumulative total costs of the 2012 new entrant CT unit in BGE and PSEG zones and less than total costs for the ComEd Zone.

Figure 7-6 Historical new entrant CT revenue adequacy: June 1, 2007 through March 31, 2017 and June 1, 2012 through March 31, 2017



For the ComEd Zone, the PSEG Zone and the BGE Zone, Figure 7-7 compares cumulative energy market net revenues and energy market net revenues plus capacity market revenues to cumulative levelized costs for a new CC that began operation on June 1, 2007 and for a new CC that began operation on June 1, 2012. Cumulative total market net revenues were less than the cumulative total costs of the 2007 new entrant CC unit for each year in each of the three zones. Cumulative total market net revenues through March 31, 2017, were greater than the cumulative total costs of the 2012 new entrant CC unit in BGE and PSEG zones and less than total costs for the ComEd Zone.

Figure 7-7 Historical new entrant CC revenue adequacy: June 1, 2007 through March 31, 2017 and June 1, 2012 through March 31, 2017



Assumptions used for this analysis are shown in Table 7-12.

Table 7-12 Assumptions for analysis of new entry

	2007 CT	2012 CT	2007 CC	2012 CC
Project Cost CT	$311,737,000	$319,167,000	$658,598,000	$665,995,000
Fixed O&M ($/MW-Year)	$14,475	$14,628	$20,016	$20,126
End of Life Value	$0	$0	$0	$0
Loan Term	20 years	20 years	20 years	20 years
Percent Equity (%)	50%	50%	50%	50%
Percent Debt (%)	50%	50%	50%	50%
Loan Interest Rate (%)	7%	7%	7%	7%
Federal Income Tax Rate (%)	35%	35%	35%	35%
State Income Tax Rate (%)	9%	9%	9%	9%
General Escalation (%)	2.5%	2.5%	2.5%	2.5%
Technology	GE Frame 7FA	GE Frame 7FA.05	GE Frame 7FA	GE Frame 7FA.05
ICAP (MW)	336	410	601	655
Depreciation MACRS 150% declining balance	15 years	15 years	20 years	20 years

Actual Net Revenue

The actual net revenue results for 2016 have been updated to include the results for nuclear plants.[23] [24] Table 7-13 shows the avoidable cost recovery from PJM energy and ancillary services markets by quartiles. In 2016, a substantial portion of units did not achieve full recovery of avoidable costs through energy markets alone. After including capacity revenues, net revenues from all markets cover avoidable costs for even the first quartile of most technology types, although this is not the case for every individual unit. The results for 2016 have been updated to include nuclear plants using operating costs of $27.15 per MWh for single unit sites and $18.74 per MWh for multiunit sites as avoidable costs.[25]

Table 7-13 Avoidable cost recovery by quartile: 2016

	Total Installed	Recovery of avoidable costs from energy and ancillary net revenue			Recovery of avoidable costs from all markets		
Technology	Capacity (ICAP)	First quartile	Median	Third quartile	First quartile	Median	Third quartile
CC - Combined Cycle	55,596	12%	288%	535%	256%	487%	706%
CT - Aero Derivative	6,173	10%	27%	42%	243%	322%	434%
CT - Industrial Frame	21,081	0%	13%	38%	400%	472%	532%
Coal Fired	61,317	6%	21%	52%	61%	85%	131%
Diesel	439	0%	56%	329%	426%	490%	696%
Hydro	9,725	127%	164%	233%	179%	277%	354%
Nuclear	31,661	61%	87%	104%	90%	119%	134%
Oil or Gas Steam	8,199	0%	0%	16%	163%	183%	214%
Pumped Storage	31,013	214%	260%	681%	250%	561%	715%

23 In prior reports the results did not include nuclear power plants in order not to reveal confidential data and because there was not good public data on nuclear unit avoidable costs.
24 The analysis of nuclear plants uses uniform fuel costs for all units.
25 Operating costs from: Nuclear Energy Institute (April, 2016) "*Nuclear Costs in Context*," <https://www.nei.org/CorporateSite/media/filefolder/Policy/Papers/Nuclear-Costs-in-Context.pdf?ext=.pdf>

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 Environmental Protection Agency (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.** The U.S. Environmental Protection Agency's (EPA) Mercury and Air Toxics Standards rule (MATS) 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 future of MATS is currently uncertain. The U.S. Supreme Court ruled in 2015 that EPA acted unreasonably when it deemed cost irrelevant to the decision to regulate power plants.[2] The EPA performed a cost review and made the required determination on cost in a supplemental finding.[3] In a case now pending before the U.S. Court of Appeals for the District of Columbia Circuit, the supplemental finding is under review.[4] On April 28, 2017, the Court granted EPA's request to postpone scheduled oral argument "to allow the new Administration adequate time to review the Supplemental Finding to determine whether it will be reconsidered."[5]
- **Air Quality Standards (NO_X and SO_2 Emissions).** The CAA requires each state to attain and maintain compliance with fine particulate matter (PM) and ozone national ambient air quality standards (NAAQS). The CAA also requires that each state prohibit emissions that significantly interfere with the ability of another state to meet NAAQS.[6] In January 2016, the EPA began the implementation of the Cross-State Air Pollution Rule (CSAPR) to address this issue through an interstate emissions trading regime.[7] As of January 1, 2017, CSAPR's Phase 2 emissions budgets and assurance provisions apply.
- **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.[8] On May 3, 2016, the Court issued a mandate to implement its May 1, 2015, order. The provisions that allowed RICE participating in emergency

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).
2 135 S. Ct. 2699, 2712 (2015).
3 *See 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; *see also* White Stallion Energy Center, LLC v EPA, Slip Op. No. 12-1100 (D.C. Cir. 2015) (per curiam).
4 *See* Case No. 16-1127, et al.
5 Respondent EPA's Motion to Continue Oral Argument, Case No. 16-1127, et al. (April 18, 2017) at 1.
6 CAA § 110(a)(2)(D)(i)(I).
7 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").
8 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).

demand response programs to operate for additional hours have been eliminated.[9] Zero hours are exempt.[10] As a result, the national emissions standards uniformly apply to all RICE.[11] All RICE are allowed to operate during emergencies, including declared Energy Emergency Alert Level 2 or five percent voltage/frequency deviations.[12]

- **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).[13] 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 of the rule that will prevent its taking effect until judicial review is completed.[14] The future of the Clean Power Plan is currently uncertain. The new administration is reviewing the Clean Power Plan and related rules and agency actions, and has indicated the possibility of suspension, revision or rescission of such rules and actions.[15] On April 28, 2017, the U.S. Court of Appeals for the District of Columbia Circuit issued an order granting a motion of the EPA to hold in abeyance for 60 days pending cases challenging the Clean Power Plan, and further directed the filing of briefs on whether these cases "should be remanded to the agency rather than held in abeyance."

- **Cooling Water Intakes.** An EPA rule implementing Section 316(b) of the Clean Water Act (CWA) requires that cooling water intake structures reflect the best technology available for minimizing adverse environmental impacts.[16] 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 rule sets nonbinding criteria for coal ash disposal facilities.

State Environmental Regulation

- **NJ High Electric Demand Day (HEDD) Rule.** A New Jersey rule that imposes operational restrictions and emissions control requirements on units responsible for significant NO_X emissions on high electric demand days (HEDD).[17] 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.[18]

- **Illinois Air Quality Standards (NO_X, SO_2 and Hg).** The State of Illinois has its own standards for NO_X, SO_2 and Hg (mercury) known as Multi-Pollutant Standards (MPS) and Combined Pollutants Standards (CPS) that are more stringent and take effect earlier than comparable Federal regulations, such as the EPA MATS rule.[19]

- **Regional Greenhouse Gas Initiative (RGGI).** The Regional Greenhouse Gas Initiative (RGGI) is a CO_2 emissions cap and trade agreement among Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont that applies to power generation facilities. The auction price in the March 8, 2017, auction for the 2015–2017 compliance period was \$3.00 per ton. The clearing price is equivalent to a price of \$3.31 per metric tonne, the unit used in other carbon markets. The price decreased from \$5.25 per ton from March 9, 2016, by \$2.25 per ton, or 42.9 percent, to \$3.00 per ton for March 8, 2017.

9 EPA, Memorandum, Peter Tsirigotis Guidance on Vacatur of RICE NESHAP and NSPS Provisions for Emergency Engines (April 15, 2016).
10 Id.
11 Id.
12 See 40 CFR §§ 60.4211(f)(2)(ii)–(iii), 60.4243(d)(2)(ii)–(iii), and 63.6640(f)(2)(ii)–(iii) (Declared Energy Emergency Alert Level 2 or 5 percent voltage/frequency deviations); 0 CFR §§ 60.4211(f)(1), 60.4243(d)(1), and 63.6640(f)(1) ("There is no time limit on the use of emergency stationary ICE in emergency situations."); 40 §§ CFR 60.4211(f)(3), 60.4243(d)(3), 63.6640(f)(3)–(4).
13 *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."
14 North Dakota v. EPA, et al., Order 15A793.
15 Executive Order: Promoting Energy Independence and Economic Growth, Sec. 4 (March 28, 2017), which can be accessed at: <https://www.whitehouse.gov/the-press-office/2017/03/28/presidential-executive-order-promoting-energy-independence-and-economi-1>.
16 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).
17 N.J.A.C. § 7:27–19.
18 CTs must have either water injection or selective catalytic reduction (SCR) controls; steam units must have either an SCR or selective noncatalytic reduction (SNCR).
19 35 Ill. Admin. Code §§ 225.233 (Multi-Pollutant Standard (MPS)), 224.295 (Combined Pollutant Standard: Emissions Standards for NO_X and SO_2 (CPS)).

State Renewable Portfolio Standards

Many states in PJM have enacted legislation to require that a defined percentage of retail suppliers' load be served by renewable resources, for which definitions vary. These are typically known as renewable portfolio standards, or RPS. As of March 31, 2017, Delaware, Illinois, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, and Washington, DC had renewable portfolio standards. Virginia and Indiana had voluntary renewable portfolio standards. Kentucky and Tennessee did not have renewable portfolio standards. West Virginia had a voluntary standard, but the state legislature repealed their renewable portfolio standard effective February 3, 2015.[20]

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. As a result of environmental regulations and agreements to limit emissions, many PJM units burning fossil fuels have installed emission control technology. On March 31, 2017, 92.8 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 93.5 percent of fossil fuel fired capacity in PJM had NO_X emission control technology.

Recommendations

- The MMU recommends that renewable energy credit markets based on state renewable portfolio standards be brought into PJM markets as they are an increasingly important component of the wholesale energy market. (Priority: Medium. First reported 2010. Status: Not adopted.)

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. The extension of the RPS concept to include nuclear power as a zero emissions source in order to provide subsidies to nuclear power will increase this impact. Renewable energy credit (REC) 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.[21]

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 same is true for nuclear power credits, ZECs (zero emissions credits). 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 in some cases the existence of these resources 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, clearing quantities and markets are not publicly available for all PJM states. RECs do not need to be consumed during the year of production which creates multiple prices for a REC based on the year of origination. 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. It would be preferable to have a single, transparent market for RECs operated by PJM that would meet the standards and requirements of all states in the PJM footprint including those with no RPS. This would provide better information for market participants about supply and demand and prices and contribute to a more efficient and competitive market and to better price formation. This could also facilitate entry by qualifying renewable resources by reducing the risks associated with lack of transparent market data. This would be a significant improvement even if some unusual or unique types of RECs remained outside this market.

20 See Enr. Com. Sub. For H. B. No. 2001.

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

PJM markets provide a flexible mechanism for incorporating the costs of environmental controls and meeting environmental requirements in a cost effective manner. Costs for environmental controls are part of bids for capacity resources in the PJM Capacity Market. The costs of 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. If there is a social decision to limit carbon output, a carbon price would be the most efficient way to implement that decision. It would also be an alternative to specific subsidies to individual nuclear power plants and instead provide a market signal to which any resource could respond. 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. The provision of subsidies to individual units creates a discriminatory regime that is not consistent with competition.

Federal Environmental Regulation

The U.S. Environmental Protection Agency (EPA) administers the Clean Air Act (CAA). The CAA regulates air emissions by providing for the establishment of acceptable levels of emissions of hazardous air pollutants. The EPA issues technology based standards for major sources and area sources of emissions.[22] [23] The EPA's 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.

22 42 U.S.C. § 7401 et seq. (2000).

23 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.

The EPA also administers the Clean Water Act (CWA), which regulates water pollution. The EPA implements the CWA through a permitting process, which regulates discharges from point sources that impact water quality and temperature in navigable waterways. In 2014, the EPA implemented new regulations for cooling water intakes under section 316(b) of the CWA.

Control of Mercury and Other Hazardous Air Pollutants

Section 112 of the CAA requires the EPA to promulgate emissions control standards, known as the National Emission Standards for Hazardous Air Pollutants (NESHAP), from both new and existing area and major sources.

On December 21, 2011, the U.S. Environmental Protection Agency (EPA) issued its Mercury and Air Toxics Standards rule (MATS), which applies the Clean Air Act (CAA) maximum achievable control technology (MACT) requirement to new or modified sources of emissions of mercury and arsenic, acid gas, nickel, selenium and cyanide.[24] The rule 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 required 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).[25]

The future of MATS is currently uncertain. On June 29, 2015, the U.S. Supreme Court remanded MATS to the U.S. Court of Appeals for the D.C. Circuit and ordered the EPA to consider cost earlier in the process when making the decision whether to regulate power plants under MATS.[26] The U.S. Supreme Court ruled in 2015 that EPA acted unreasonably when it deemed cost irrelevant to the decision to regulate power plants.[27] The remand did

24 National Emission Standards for Hazardous Air Pollutants From Coal and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil Fuel Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units, EPA Docket No. EPA-HQ-OAR-2009-0234, 77 Fed. Reg. 9304 (February 16, 2012); *aff'd*, White Stallion Energy Center, LLC v EPA, No. 12-1100 (D.C. Cir. April 15, 2014).

25 NSPS are promulgated under CAA § 111.

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

27 135 S. Ct. 2699, 2712 (2015).

not stay MATS and had no effect on the implementation of MATS. The EPA performed a cost review and made the required determination on cost in a supplemental finding.[28] On April 14, 2016, the EPA issued the required finding that "a consideration of cost does not cause us to change our determination that regulation of hazardous air pollutant (HAP) emissions from coal- and oil-fired EGUs is appropriate and necessary."[29] The rule has been effective since April 14, 2016, and remains effective. In a case now pending before the U.S. Court of Appeals for the District of Columbia Circuit, the supplemental finding is under review.[30] On April 28, 2017, the Court granted EPA's request to postpone scheduled oral argument "to allow the new Administration adequate time to review the Supplemental Finding to determine whether it will be reconsidered."[31]

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).[32] Standards for each pollutant are set and periodically revised, most recently for SO_2 in 2010, and SIPS are filed, approved and revised accordingly.

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) then in effect. On November 21, 2014, the EPA issued a rule requiring compliance with CSAPR's Phase 1 emissions budgets effective January 1, 2015, and CSAPR's Phase 2 emissions effective January 1, 2017.[33] The ruling and the EPA rules eliminated CAIR and replaced it with CSAPR.

In January, 2015, the EPA began implementation of the Cross-State Air Pollution Rule (CSAPR) 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 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. The CSPAR requires reductions 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 2008 8-Hour Ozone NAAQS.

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,

28 *See 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; *see also* White Stallion Energy Center, LLC v EPA, Slip Op. No. 12-1100 (D.C. Cir. 2015) (per curiam).

29 *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; see also White Stallion Energy Center, LLC v EPA, Slip Op. No. 12-1100 (D.C. Cir. 2015) (per curiam).

30 *See* Case No. 16-1127, et al.

31 Respondent EPA's Motion to Continue Oral Argument, Case No. 16-1127, et al. (April 18, 2017) at 1.

32 Nitric Oxides (NO_X), Sulfur Dioxide (SO_2), Ozone (O_3), Particulate Matter (PM), Carbon Monoxide (CO) and Lead (Pb).

33 *Rulemaking to Amend Dates in Federal Implementation Plans Addressing Interstate Transport of Ozone and Fine Particulate Matter*, EPA-HQ-OAR-2009-0491.

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); *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. 34830 (June 12, 2012).

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.

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.

If state emissions exceed the applicable assurance level, including the variability limit, a penalty is assessed and allocated to resources within the state in proportion to their responsibility for the excess. The penalty requires surrender of two additional allowances for each allowance needed to the cover the excess.

On September 7, 2016, the EPA issued a final rule updating the CSAPR ozone season NO_x emissions program to reflect the decrease to the ozone season NAAQS that occurred in 2008 (CSAPR Update).[40] 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.[41] The CSAPR Update increases the reductions required from upwind states to assist downwind states' ability to meet the lower 2008 standard.

The CSAPR Update also finalizes Federal Implementation Plans (FIPs) for each of the PJM states covered by CSAPR.[42] The EPA approves a FIP for states that fail to timely submit and obtain approval of their own implementation plan (SIPs).

Starting May 1, 2017, the CSAPR Update requires reduced summertime NO_x from power plants in certain PJM states: Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, Ohio, Pennsylvania, Tennessee, Virginia and West Virginia.[43] The EPA has removed North Carolina from the ozone season NO_x trading program.[44] Table 8-1 shows the revised 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.

Table 8-1 Current and proposed CSAPR ozone season NO_x budgets for electric generating units (before accounting for variability)[45]

State	2017 CSAPR Ozone Season NO_x Budget for Electric Generating Units (before accounting for variability) (Tons)	Assurance Level (Tons)
Illinois	14,601	17,667
Indiana	23,303	28,197
Kentucky	21,115	25,549
Maryland	3,828	4,632
Michigan	17,023	20,598
New Jersey	2,062	19,094
Ohio	19,522	23,622
Pennsylvania	17,952	21,722
Tennessee	7,736	9,361
Virginia	9,223	11,160
West Virginia	17,815	21,556

During the delay of CSAPR implementation, the EPA estimates that there "will be approximately 350,000 banked allowances entering the CSAPR NO_x ozone season trading program by the start of the 2017 ozone season control period."[46] The EPA is concerned that "[w]ithout imposing a limit on the transitioned vintage 2015 and 2016 banked allowances, the number of banked allowances would increase the risk of emissions exceeding the CSAPR Update emission budgets or assurance levels and would be large enough to let all affected sources emit up to the CSAPR Update assurance levels for five consecutive

40 *Cross-State Air Pollution Rule Update for the 2008 Ozone NAAQS*, EPA-HQ-OAR-2015-0500, 81 Fed. Reg. 74504 (–Oct. 26, 2016) ("CSAPR Update").
41 *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).
42 CSAPR Update at 74506 & n.9. PJM states that did not submit SIPs include Illinois, Maryland, Michigan, New Jersey, North Carolina, Pennsylvania, Tennessee, Virginia, and West Virginia; PJM states submitting SIPs but not obtaining approval include Indiana, Kentucky and Ohio. *Id.*

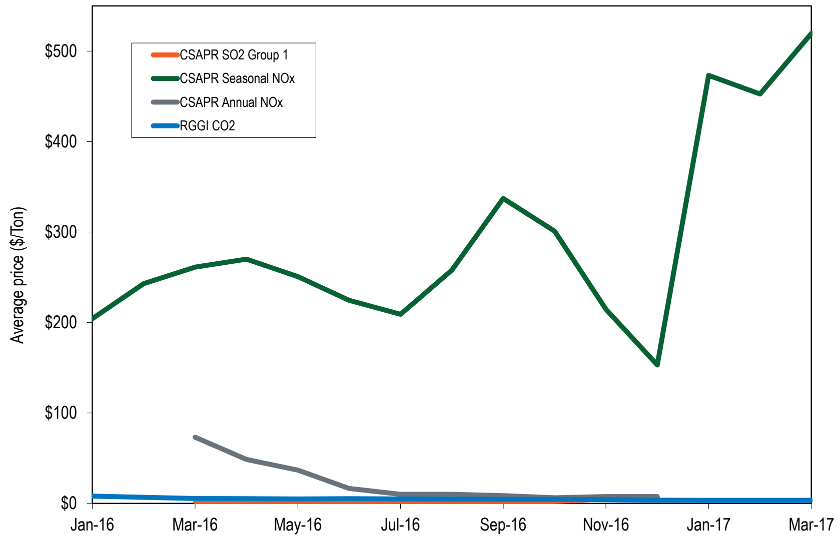
43 *Id.* at 74554.
44 *Id.* at 74507 n.13.
45 CSAPR Update at 74567.
46 *Id.* at 74588.

ozone seasons."[47] Accordingly, the EPA established a formulaic limit on the use of transitioned vintage 2015 and 2016 banked allowances.[48]

Figure 8-1 shows average, monthly settled prices for NO_X, CO_2 and SO_2 emissions allowances including CSAPR related allowances for 2016 through March 31, 2017. Figure 8-1 also shows the average, monthly settled price for the Regional Greenhouse Gas Initiative (RGGI) CO_2 allowances.

In the first three months of 2017, CSAPR annual NO_X prices were 94.5 percent lower than in the first three months of 2016. The CSAPR annual NO_X price was $73.18 in March 2016, and has decreased steadily since then. There were not any reported cleared purchases for January or February 2016 for CSAPR Annual NO_X. The CSAPR Seasonal NO_X price hit a peak of $519.57 in March 2017. The CSAPR Update resulted in fewer CSAPR Seasonal NO_X allowances.[49]

Figure 8-1 Spot monthly average emission price comparison: January 1, 2016 through March 31, 2017[50]



Emission Standards for Reciprocating Internal Combustion Engines

On January 14, 2013, the EPA signed a final rule amending its rules regulating emissions from a wide variety of stationary reciprocating internal combustion engines (RICE).[51] RICE include certain types of electrical generation facilities like diesel engines typically used for backup, emergency or supplemental power, including 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

47 *Id.*
48 *Id.* at 74560. The EPA states: "The one-time conversion of the 2015 and 2016 banked allowances will be made using a calculated ratio, or equation, to be applied in early 2017 once compliance reconciliation (or 'true-up')s for the 2016 ozone season program is completed." *Id.*
49 There were not any reported cleared purchases for January or February 2016 for CSAPR SO_2 or CSAPR Annual NO_X. There were not any reported cleared purchases for January through March 2017 for CSAPR SO_2.
50 Spot monthly average emission price information obtained through Evomarkets, <http://www.evomarkets.com>.
51 *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) ("2013 NESHAP RICE Rule"). In 2010, the EPA promulgated two rules with standards for hazardous air pollutant emissions from backup generators. The rules allowed backup generators to operate without emissions controls for fifteen hours each year as part of "demand response programs" during "emergency conditions that could lead to a potential electrical blackout." 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 ("2010 RICH NESHAP Rule").

Engines; and Standards of Performance for Stationary Compression Ignition Internal Combustion Engines (collectively RICE Rules).[52]

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).[53]

On May 22, 2012, the EPA proposed amendments to the 2010 RICE NESHAP Rule.[54] The proposed rule would have 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 rule would have increased the 2010 Rule's 15 hour per year run limit. The exempted emergency demand response programs included RPM demand resources.

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.[55] As a result, the national emissions standards uniformly apply to all RICE.[56] 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."[57] 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.[58]

On April 15, 2016, the EPA issued a letter explaining how it would implement the vacatur order.[59] The EPA explained upon issuance of the Court's mandate, "an engine may not operate in circumstances described in the vacated [portions of the 2013 NESHAP RICE Rule] for any number of hours power per year."[60] The EPA explained that such engines could, however, continue to operate for specified emergency and nonemergency reasons.[61]

On May 3, 2016, the Court issued a mandate to implement its May 1, 2015, order. Issuance of the mandate triggered implementation of the policy.

The MMU is currently taking steps to ensure resource portfolios remain in compliance. The MMU contacted all CSPs with Demand Resources using diesel fuel to ensure compliance is met among all PJM resources.

Regulation of Greenhouse Gas Emissions

The EPA regulates CO_2 as a pollutant using CAA provisions that apply to pollutants not subject to NAAQS.[62] [63]

The U.S. Court of Appeals for the Seventh Circuit has determined that a government agency can reasonably consider the global benefits of carbon emissions reduction against costs imposed in the U.S. by regulations in analyses known as the "Social Costs of Carbon."[64] The Court rejected claims raised by petitioners that raised concerns that the Social Cost of Carbon

52 *Id.*
53 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.*"
54 *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.
55 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).
56 *Id.*
57 DENREC v. EPA at 3, 20–21.
58 *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.
59 EPA, Memorandum, Peter Tsirigotis Guidance on Vacatur of RICE NESHAP and NSPS Provisions for Emergency Engines (April 15, 2016).
60 See 40 CFR §§ 60.4211(f)(2)(ii)–(iii), 60.4243(d)(2)(ii)–(iii), and 63.6640(f)(2)(ii)–(iii) (Declared Energy Emergency Alert Level 2 or 5 percent voltage/frequency deviations).
61 See 40 CFR §§ 60.4211(f)(1), 60.4243(d)(1), and 63.6640(f)(1) ("There is no time limit on the use of emergency stationary ICE in emergency situations."); 40 §§ CFR 60.4211(f)(3), 60.4243(d)(3), 63.6640(f)(3)–(4).
62 See CAA § 111.
63 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.
64 See Zero Zone, Inc., et al., v. U.S. Dept. of Energy, et al., Case Nos. 14-2147, et al., Slip Op. (August 8, 2016).

estimates were arbitrary, were not developed through transparent processes, and were based on inputs that were not peer-reviewed.[65] Although the decision applies only to the Department of Energy's regulations of manufacturers, it bolsters the ability of the EPA and state regulators to rely on social cost of carbon analyses.

On September 20, 2013, the EPA proposed national limits on the amount of CO_2 that new power plants would be allowed to emit.[66] [67] 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 (the Clean Power Plan).[68] 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 of the rule that will prevent its taking effect until judicial review is completed.[69]

The future of the Clean Power Plan is currently uncertain. The new administration is reviewing the Clean Power Plan and related rules and agency actions, and has indicated the possibility of suspension, revision or rescission of such rules and actions.[70] On April 28, 2017, the U.S. Court of Appeals for the District of Columbia Circuit issued an order granting a motion of the EPA to hold in abeyance for 60 days pending cases challenging the Clean Power Plan, and further directed the filing of briefs on whether these cases "should be remanded to the agency rather than held in abeyance."

65 *Id.*
66 *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>.
67 79 Fed. Reg. 1352 (January 8, 2014).
68 *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."
69 North Dakota v. EPA, et al., Order 15A793.
70 Executive Order: Promoting Energy Independence and Economic Growth, Sec. 4 (March 28, 2017), which can be accessed at: <https://www.whitehouse.gov/the-press-office/2017/03/28/presidential-executive-order-promoting-energy-independence-and-economi-1>.

Federal Regulation of Environmental Impacts on Water

Water cooling systems at steam electric power generating stations are subject to regulation under the Clean Water Act (CWA).

EPA regulations of discharges from steam electric power generating stations are set forth in the Generating Effluent Guidelines and Standards in 1974. These standards were amended most recently in 2015.

Section 301(a) of the CWA prohibits the point source discharge of pollutants to a water of the United States, unless authorized by permit.[71] Section 402 of the CWA establishes the required permitting process, known as the National Pollutant Discharge Elimination System (NPDES). NPDES permits limit discharges and include monitoring and reporting requirements. NPDES permits last five years before they must be renewed.

NPDES permits must satisfy the more stringent of a technology based standard, known at Best Technology Available (BTA), or water quality standards. NDPES permits include limits designed to prevent discharges that would cause or contribute to violations of water quality standards. Water quality standards include thermal limits.

PJM states are authorized to issue NPDES permits, with the exception of the District of Columbia. Pennsylvania, Delaware, Indiana and Illinois are partially authorized; the balance of PJM states are fully authorized.

The CWA regulates intakes in addition to discharges.

71 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. EPA issued a rule providing an expansive definition of "waters of the United States" in 2015 that the current administration has indicated an intent to review. See Executive Order: Restoring the Rule of Law, Federalism, and Economic Growth by Reviewing the "Waters of the United States" Rule (February 28, 2017) referring to "*Clean Water Rule: Definition of 'Waters of the United States*,'" 80 Fed. Reg. 37054 (June 29, 2015).

Section 316(b) of the CWA requires that cooling water intake structures reflect the BTA for minimizing adverse environmental impacts. The 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).[72]

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.

Federal Regulation of Coal Ash

The EPA administers the Resource Conservation and Recovery Act (RCRA), which governs the disposal of solid and hazardous waste.[73]

Solid waste is regulated under subtitle D, which encourages state management of nonhazardous industrial solid waste and sets nonbinding criteria for solid waste disposal facilities. Subtitle D prohibits open dumping. Subtitle D criteria are not directly enforced by the EPA. However, the owners of solid waste disposal facilities are exposed under the act to civil suits, and criteria set by the 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.

The EPA issued a rule under RCRA, the Coal Combustion Residuals rule (CCRR), which sets criteria for the disposal of coal combustion residues (CCRs), or coal ash, produced by electric utilities and independent power producers.[74] 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.

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 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 8-2 describes the criteria and anticipated implementation dates.

72 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).

73 42 U.S.C. §§ 6901 *et seq.*

74 *See Hazardous and Solid Waste Management System; Disposal of Coal Combustion Residuals From Electric Utilities*, 80 Fed. Reg. 21302 (April 17, 2015).

Table 8-2 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.	October 17, 2018
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

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.[75] 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.[76] NO_X emissions limits for coal units became effective December 15, 2012.[77] NO_X emissions limits for other unit types became effective May 1, 2015.[78] As of March 31, 2017, two Cedar Station units, three Middle Street units, three Missouri units, one Sherman Ave unit, three Burlington units, three Edison units, four Essex units, three Kearny units, one Mercer unit, one National Park unit, one Sewaren unit, eight Glen Gardner units and four Werner units identified as NJ HEDD units have retired.[79] In total 37 NJ HEDD units have retired and the remaining 41 NJ HEDD units are still operating after taking actions to comply with the HEDD regulations.

Table 8-3 shows the HEDD emissions limits applicable to each unit type.

75 N.J.A.C. § 7:27-19.
76 CTs must have either water injection or selective catalytic reduction (SCR) controls; steam units must have either an SCR or selective noncatalytic reduction (SNCR).
77 N.J.A.C. § 7:27-19.4.
78 N.J.A.C. § 7:27-19.5.
79 See Current New Jersey Turbines that are HEDD Units, <http://www.nj.gov/dep/workgroups/docs/apcrule_20110909turbinelist.pdf>.

Table 8-3 HEDD maximum NO_x emission rates[80]

Fuel and Unit Type	NOx 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).[81] 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.[82] 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.[83]

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.[84] RGGI generates revenues for the participating states which have spent approximately 57 percent of revenues to date on energy efficiency, 15 percent on clean and renewable energy, 8 percent on greenhouse gas abatements and 15 percent on direct bill assistance.[85]

Table 8-4 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 March 31, 2017, in short tons and metric tonnes. Prices for auctions held March 8, 2017, for the 2015–2017 compliance period were at $3.00 per allowance (equal to one ton of CO_2), above the current price floor of $2.05 for RGGI auctions.[86] The RGGI base budget for CO_2 will be reduced by 2.5 percent per year each year from 2015 through 2020. The price decreased from the last auction of $3.55 in December 2016. 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.

80 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.
81 35 Ill. Admin. Code §§ 225.233 (Multi-Pollutant Standard (MPS)), 224.295 (Combined Pollutant Standard: Emissions Standards for NO_X and SO_2 (CPS)).
82 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).
83 See *Id.*
84 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>.
85 *Investment of RGGI Proceeds Through 2014*, The Regional Greenhouse Gas Initiative, <http://rggi.org/docs/ProceedsReport/RGGI_Proceeds_FactSheet_2014.pdf>.
86 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 8-4 RGGI CO_2 allowance auction prices and quantities in short tons and metric tonnes: 2009-2011, 2012-2014 and 2015-2017 Compliance Periods[87]

	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
March 9, 2016	$5.25	14,838,732	14,838,732	$5.79	13,461,475	13,461,475
June 1, 2016	$4.53	15,089,652	15,089,652	$4.99	13,689,106	13,689,106
September 7, 2016	$4.54	14,911,315	14,911,315	$5.00	13,527,321	13,527,321
December 7, 2016	$3.55	14,791,315	14,791,315	$3.91	13,418,459	13,418,459
March 8, 2017	$3.00	14,371,300	14,371,300	$3.31	13,037,428	13,037,428

87 See Regional Greenhouse Gas Initiative, "Auction Results," <http://www.rggi.org/market/co2_auctions/results>.

Zero Emissions Credits (ZEC) Programs

On December 7, 2016, the State of Illinois enacted legislation that, among other things, provides subsidies, known as zero emission credits (ZECs), for certain existing nuclear-powered generation units that indicated they would otherwise retire.[88] The ZEC program provides that starting June 1, 2017, the Illinois Power Agency (IPA) must procure ZECs under ten year contracts with select Illinois nuclear power plants.[89]

IPA must procure ZECs equal to 16 percent of 2014 Illinois retail load.[90] The initial base ZEC price equals $16.50/MWh and increases $1.00/MWh annually commencing with the 2023/2024 Delivery Year.[91] The base price is reduced by the amount that "the market price index for the applicable delivery year exceeds the baseline market price index for the consecutive 12-month period ending May 31, 2016."[92]

The revenues provided by the ZEC legislation are expected to forestall the retirement of a specific PJM nuclear unit in Illinois, the Quad Cities Generating Station.[93]

On February 14, 2017, the Electric Power Supply Association (EPSA) and others filed a complaint in the U.S. District Court for the Northern District of Illinois Eastern Division.[94] State defendants have filed a motion to dismiss and EPSA et al. have filed a motion for a stay. On April 24, 2017, the MMU filed an amicus curiae brief opposing the motion to dismiss and supporting the motion for a stay.

88 See Illinois 99th Gen. Assemb., S.B. 2814 (Dec. 7, 2016), which can be accessed at: <http://www.ilga.gov/legislation/99/SB/09900SB2814lv.htm>. The Governor of Illinois signed the ZEC legislation, amending the Illinois Power Agency Act ("IPAA"), on December 7, 2016; see also ICC, et al., Potential Nuclear Power Plant Closings in Illinois (Jan. 5, 2015), which can be accessed at: <http://www.ilga.gov/reports/special/report_potential%20nuclear%20power%20plant%20closings%20in%20il.pdf>.

89 See IPAA § 1-75(d-5)(1).

90 See *id.*

91 See IPAA § 1-75(d-5)(1)(B).

92 See *id.*

93 See Ted Caddell, RTO Insider "Exelon's Crane Reports 'Monumental Year,'" (Feb. 8, 2017); Exelon, Press Release, "Exelon Announces Early Retirement of Clinton and Quad Cities Nuclear Plants" (June 2, 2016) (citing "lack of progress on Illinois energy legislation" as a key factor), which can be accessed at: <http://www.exeloncorp.com/newsroom/clinton-and-quad-cities-retirement>; Thomas Overton, Power, "Byron, Three Mile Island Nuclear Plants at Risk, Exelon Says" (June 6, 2016) (reporting Exelon statement that Byron is "economically challenged"), which can be accessed at: <http://www.powermag.com/byron-three-mile-island-nuclear-plants-at-risk-exelon-says/?printmode=1>

94 Case No. 17-cv-01164.

The ZEC legislation creates subsidies for existing units that create the same price suppressive effects as subsidies for new entry that are addressed by the Minimum Offer Price Rule.[95] The MMU has supported modification of the Minimum Offer Price (MOPR) Rules to apply to existing units receiving subsidies.[96] The MMU's proposed modification of the MOPR rules would, if in place, apply to nuclear units receiving subsidies. Such subsidies may otherwise result in noncompetitive offers in PJM markets that would be addressed on a unit specific basis.

A similar issue has arisen in New York, where the New York Public Service Commission (New York PSC) established a program requiring the purchase of ZEC credits from specific nuclear facilities in upstate New York. The constitutionality of the New York PSC's program has been challenged in a case pending before the U.S. District Court for the Southern District of New York.[97] On January 9, 2017, the MMU filed an amicus curiae brief supporting plaintiffs on the grounds that the ZEC subsidies interfere with the operation of wholesale power markets in New York and have price suppressive effects in the energy markets in PJM.[98]

State Renewable Portfolio Standards

Nine PJM jurisdictions have enacted legislation that requires 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. In PJM jurisdictions that have adopted an RPS, load serving entities are often required by law to meet defined shares of load using specific renewable and/or alternative energy sources commonly called "eligible technologies." Load serving entities may generally fulfil these obligations in one of two ways: they may use their own generation resources classified as eligible technologies to produce power or they may purchase renewable energy credits (RECs) that represent a known quantity of power produced with eligible technologies by other market participants or in other geographical locations. Load serving entities that fail to meet the percent goals set in their jurisdiction's RPS by generating power from eligible technologies or purchasing RECs are penalized with alternative compliance payments. As of March 31, 2017, Delaware, Illinois, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, and Washington, D.C. had renewable portfolio standards that are mandatory and include penalties in the form of alternative compliance payments for underperformance.

Two PJM jurisdictions have enacted voluntary renewable portfolio standards. Load serving entities in states with voluntary standards are not bound by law to participate and face no alternative compliance payments. Instead, incentives are offered to load serving entities to develop renewable generation or, to a more limited extent, purchase RECs. As of March 31, 2017, Virginia and Indiana had renewable portfolio standards that are voluntary and do not include penalties in the form of alternative compliance payments for underperformance.

In this section, voluntary standards will not be directly compared to RPS with enforceable compliance payments. Indiana's voluntary standard illustrates the issue. Although a voluntary standard including target shares was enacted by the Indiana legislature in 2011, no load serving entities have volunteered to participate in the program.[99]

Three PJM states have no renewable portfolio standards. Kentucky and Tennessee have enacted no renewable portfolio standards. West Virginia had a voluntary standard, but the state legislature repealed their renewable portfolio standard on January 27, 2015, effective February 3, 2015.[100]

Table 8-5 shows the percent of retail electric load that must be served by renewable and/or alternative energy resources under each PJM jurisdictions' RPS by year. Washington, DC will require 35 percent of load to be served by renewable resources in 2028, the highest standard of PJM jurisdictions. In October 2016, the Council of the District of Columbia passed legislation that expanded the District's RPS program and increased the percent of retail load in the District that must be served by clean energy resources to 50 percent by

95 OATT Attachment DD § 5.14(h).
96 See, e.g., Comments of the Independent Market Monitor for PJM, FERC Docket No. EL16-49-000 (April 11, 2016).
97 Coalition for Competitive Electricity, et al., v. Audrey Zibelman, et al., Case No. 1:16-cv-08164-VEC (USDC SDNY).
98 Brief of Amicus Curiae of Monitoring Analytics, LLC, acting in its capacity as the Independent Market Monitor for PJM, USDC SDNY Case No. 1:16-cv-08164-VEC (Jan. 9, 2017).
99 See the Indiana Utility Regulatory Commission's "2016 Annual Report." P 34 <http://www.in.gov/iurc/files/Annual%20Report%202016%20WEB%20version.pdf> (Accessed April 14, 2017).
100 See Enr. Com. Sub. For H. B. No. 2001.

2032.[101] On December 15, 2016, the Michigan State Senate approved Senate Bill 438 (S.B. 438) which increased the Michigan RPS percent requirements. The previous version of the bill required that 10 percent of retail electric load in Michigan be served by renewable and alternative energy resources in 2015 and subsequent years. S.B. 438 increased the percent of retail electric load to be served by renewable and alternative energy resources in Michigan to be 12.5 percent in 2019 and 2020 and 15 percent in 2021 and subsequent years.[102] In February 2017, the Maryland State House approved House Bill 1106 which increased the total RPS requirement from 20 percent by 2022 to 25 percent by 2020.

Table 8-5 Renewable standards of PJM jurisdictions: 2017 to 2028[103]

Jurisdiction with RPS	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Delaware	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	11.50%	13.00%	14.50%	16.00%	17.50%	19.00%	20.50%	22.00%	23.50%	25.00%	25.00%	25.00%
Maryland	15.60%	18.30%	20.40%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
Michigan	10.00%	10.00%	12.50%	12.50%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%
New Jersey	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%	10.00%	10.00%	10.00%	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%
Ohio	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	14.20%	14.70%	15.20%	15.70%	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%
Washington, D.C.	15.00%	16.50%	18.00%	20.00%	20.00%	20.00%	20.00%	23.00%	26.00%	29.00%	32.00%	35.00%
Jurisdiction with Voluntary Standard												
Indiana	4.00%	4.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	10.00%	10.00%	10.00%	10.00%
Virginia	7.00%	7.00%	7.00%	7.00%	7.00%	12.00%	12.00%	12.00%	15.00%	15.00%	15.00%	15.00%
Jurisdiction with No Standard												
Kentucky	No Renewable Portfolio Standard											
Tennessee	No Renewable Portfolio Standard											
West Virginia	No Renewable Portfolio Standard											

Each PJM jurisdiction with an RPS identifies the type of generation resources that may be used for compliance. These resources are often called eligible technologies. Some PJM jurisdictions with RPS group different eligible technologies into tiers based on the magnitude of their environmental impact. Of the nine PJM states with mandatory RPS, Maryland, New Jersey, Pennsylvania, and Washington, DC group the eligible technologies that must be used to comply with their RPS programs into Tier I and Tier II resources. Though there are minor differences across these four jurisdictions' definitions of Tier I resources, technologies that use solar photovoltaic, solar thermal, wind, ocean, tidal, biomass, low-impact hydro, and geothermal sources to produce electricity are classified as Tier I resources.

Delaware, Illinois, Michigan, North Carolina, and Ohio do not classify the resources eligible for their RPS standards by tiers. In Delaware, Illinois, North Carolina, and Ohio, eligible technologies are for the most part identical to Tier I resources. Michigan is the only state with an RPS that does not classify eligible technologies into tiers and also permits technologies that differ markedly from those classified as Tier I resources in states that do classify technologies. Michigan's RPS includes coal gasification, industrial cogeneration, and coal with carbon capture and storage as eligible technologies.

Table 8-6 shows the percent of retail electric load that must be served by Tier II resources under each PJM jurisdictions' RPS by year. Table 8-6 also shows specific technology requirements that PJM jurisdictions have added to their renewable portfolio standards. The standards shown in Table 8-6 are included in the total RPS requirements presented in Table 8-5. Illinois requires that a defined proportion of retail load be served by wind resources, increasing from 8.63 percent of load served in 2017 to 18.75 percent in 2026. Maryland, New Jersey, Pennsylvania and Washington, DC all have Tier II or "Class 2" standards, which allow specific technology types, such as waste coal units located in Pennsylvania, to qualify for renewable energy credits. By 2021, 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.

101 See B21-0650 – Renewable Portfolio Standard Expansion Amendment Act of 2016. <http://lims.dccouncil.us/Legislation/B21-0650> (Accessed January 18, 2017).

102 See Michigan Senate Bill 438 (2016) <http://www.legislature.mi.gov/(S(fcyinprlbqayp2e3i4hfromm))/mileg.aspx?page=getobject&objectname=2015-SB-0438> (Accessed April 17, 2017).

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

Table 8-6 Additional renewable standards of PJM jurisdictions: 2017 to 2028

Jurisdiction		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Illinois	Wind Requirement	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	0.12%	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%	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%
North Carolina	Swine Waste	0.07%	0.14%	0.14%	0.14%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%
North Carolina	Poultry Waste (in GWh)	900	900	900	900	900	900	900	900	900	900	900	900
Pennsylvania	Tier II Standard	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	1.50%	1.00%	0.50%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Table 8-7 Solar renewable standards by percent of electric load for PJM jurisdictions: 2017 to 2028

Jurisdiction with RPS	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Delaware	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	0.69%	0.78%	0.87%	0.96%	1.05%	1.14%	1.23%	1.32%	1.41%	1.50%	1.50%	1.50%
Maryland	1.15%	1.50%	1.95%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
Michigan	No Minimum Solar Requirement											
New Jersey	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%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%
Ohio	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	0.29%	0.34%	0.39%	0.44%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%
Washington, D.C.	0.98%	1.15%	1.35%	1.58%	1.85%	2.18%	2.50%	2.60%	2.85%	3.15%	3.45%	3.75%
Jurisdiction with Voluntary Standard												
Indiana	No Minimum Solar Requirement											
Virginia	No Minimum Solar Requirement											
Jurisdiction with No Standard												
Kentucky	No Renewable Portfolio Standard											
Tennessee	No Renewable Portfolio Standard											
West Virginia	No Renewable Portfolio Standard											

Some PJM jurisdictions have specific solar resource RPS requirements. These solar requirements are included in the total requirements shown in Table 8-5 but must be met by solar RECs (SRECs) only. Table 8-7 shows the percent of retail electric load that must be served by solar energy resources under each PJM jurisdictions' RPS by year. Delaware, Illinois, Maryland, New Jersey, North Carolina, Ohio, Pennsylvania, and Washington, DC have requirements for the proportion of load to be served by solar. Pennsylvania and Delaware allow only solar photovoltaic resources to fulfill their solar requirements. 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 2017, New Jersey has the most stringent solar standard in PJM, requiring that 3.0 percent of retail electricity sales within the state be served by solar resources. As Table 8-7 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.

Figure 8-2 and Figure 8-3 show the percent of retail electric load that must be served by Tier I resources and Tier 2 Resources in each PJM jurisdiction with a mandatory RPS. Figure 8-2 shows the percent of retail load that must be met with Tier I resources only. Because states that do not group eligible technologies into tiers generally classify eligible technologies in their RPS that are identical to Tier I resources, they are included in Figure 8-2. Figure 8-3 shows the percent of retail load that must be met with all eligible technologies, including Tier I, Tier II and alternative energy resources in all PJM jurisdictions with RPS. States with higher percent requirements for renewable and alternative energy resources are shaded darker. Jurisdictions with no standards or with only voluntary renewable standards are shaded gray. Pennsylvania's RPS illustrates the need to differentiate between percent requirements for Tier I and Tier II resources separately. Like all other PJM states with mandatory RPS, the Pennsylvania RPS identifies solar photovoltaic, solar thermal, wind, geothermal, biomass, and low-impact hydropower as Tier I resources. The Pennsylvania RPS identifies waste coal, demand side management, large-scale hydropower, integrated gasification combined cycle, clean coal and municipal solid waste as eligible Tier II resources. The 14.2 percent number in Figure 8-3 overstates the percent of retail electric load in Pennsylvania that must be served by renewable energy resources.

Figure 8-2 Map of retail electric load shares under RPS – Tier I resources only: 2017

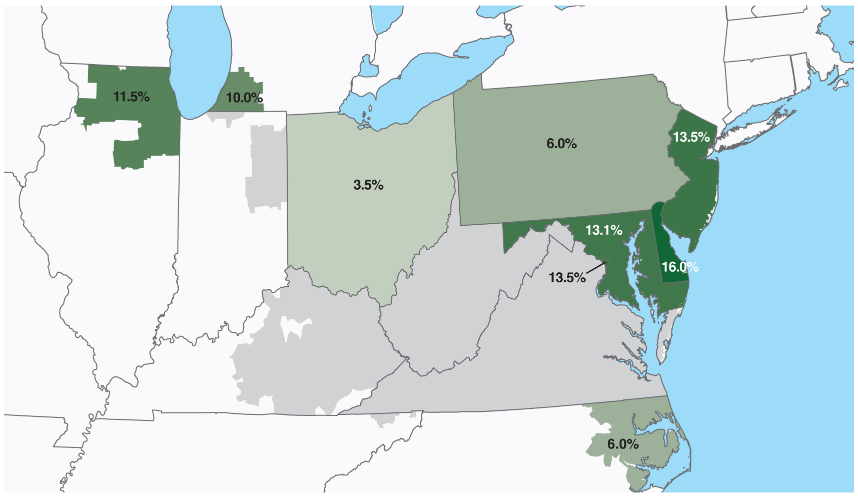
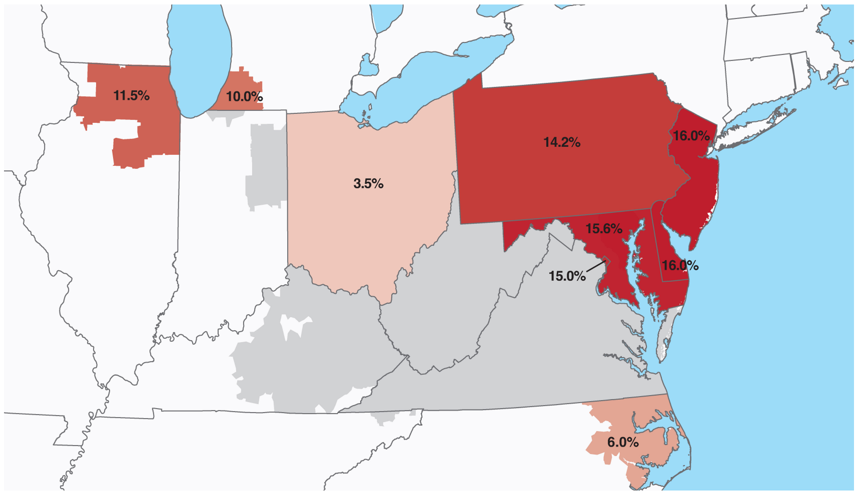


Figure 8-3 Map of retail electric load shares under RPS – Tier I and Tier II resources: 2017



Under the existing state renewable portfolio standards, approximately 8.4 percent of PJM load must be served by Tier I and Tier II renewable and alternative energy resources in 2017 and, if the proportion of load among states remains constant, 14.4 percent of PJM load must be served by renewable and alternative energy resources in 2028 under defined RPS rules. Approximately 6.3 percent of PJM load must be served by Tier I renewables in 2017 and, if the proportion of load among states remains constant, 9.0 percent of PJM load must be served by Tier I renewables in 2028 under defined RPS rules.

In jurisdictions with RPS, load serving entities must either generate power from eligible technologies identified in their jurisdictions' RPS or purchase RECs from resources classified as eligible technologies. Table 8-8 shows renewable resource generation by jurisdiction and resource type for the first three months of 2017. Wind output was 5,883.9 GWh of 9,156.2 Tier I GWh, or 64.3 percent, in the PJM footprint. As shown in Table 8-8, 14,291.6 GWh were generated by renewable resources, including both Tier II and Tier I renewable credits, of which, Tier I type resources accounted for 64.1 percent.

Total renewable generation was 7.3 percent of total generation in PJM for the first three months of 2017. Landfill gas, solid waste and waste coal were 4,653.9 GWh of renewable resource generation or 32.6 percent of the total Tier I and Tier II.

Table 8-8 Renewable resource generation by jurisdiction and renewable resource type (GWh): January 1 through March 31, 2017

	Tier I					Tier II				
Jurisdiction	Landfill Gas	Run-of-River Hydro	Solar	Wind	Total Tier I Credit	Pumped-Storage Hydro	Solid Waste	Waste Coal	Total Tier II Credit	Total Credit GWh
Delaware	9.8	0.0	0.0	0.0	9.8	0.0	0.0	0.0	0.0	9.8
Illinois	33.8	0.0	2.2	2,600.4	2,636.4	0.0	0.0	0.0	0.0	2,636.4
Indiana	13.0	11.0	2.8	1,313.6	1,340.3	0.0	0.0	0.0	0.0	1,340.3
Kentucky	0.0	123.5	0.0	0.0	123.5	0.0	0.0	0.0	0.0	123.5
Maryland	25.0	681.6	24.0	201.2	931.7	0.0	143.4	0.0	143.4	1,075.1
Michigan	6.6	18.8	1.0	0.0	26.4	0.0	0.0	0.0	0.0	26.4
New Jersey	69.8	4.1	106.4	3.9	184.2	93.0	354.1	0.0	447.1	631.3
North Carolina	0.0	104.3	90.2	121.5	316.0	0.0	0.0	0.0	0.0	316.0
Ohio	87.8	29.5	0.2	486.6	604.1	0.0	0.0	0.0	0.0	604.1
Pennsylvania	213.6	971.9	5.0	1,156.6	2,347.1	383.7	337.1	2,114.1	2,834.9	5,182.0
Tennessee	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Virginia	155.2	84.4	30.9	0.0	270.5	619.2	114.2	976.7	1,710.0	1,980.5
Washington, D.C.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
West Virginia	0.0	366.3	0.0	0.0	366.3	0.0	0.0	0.0	0.0	366.3
Total	614.4	2,395.2	262.7	5,883.9	9,156.2	1,095.9	948.7	3,090.8	5,135.4	14,291.6
Percent of Renewable Generation	4.3%	16.8%	1.8%	41.2%	64.1%	7.7%	6.6%	21.6%	35.9%	100.0%
Percent of Total Generation	0.3%	1.2%	0.1%	3.0%	4.7%	0.6%	0.5%	1.6%	2.6%	7.3%

Table 8-9 shows the capacity of renewable resources in PJM by jurisdiction, as defined by primary fuel type. This capacity includes coal and natural gas units that have a renewable fuel as an alternative fuel, and thus are able to earn renewable energy credits based on the fuel used to generate energy. For example, a coal generator that can also burn waste coal to generate power could list the alternative fuel as waste coal. A REC is only generated when using the fuel listed as Tier I or Tier II. New Jersey has the largest amount of solar capacity in PJM, 436.5 MW, or 45.0 percent of the total solar capacity. New Jersey's SREC prices were the highest in 2009 at $673 per REC, and in 2017 are at $227 per REC. Wind resources are located primarily in western PJM, in Illinois and Indiana, which include 4,448.7 MW, or 57.5 percent of the total wind capacity.

Table 8-9 PJM renewable capacity by jurisdiction (MW): March 31, 2017

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	59.3	0.0	0.0	0.0	0.0	9.0	0.0	0.0	2,846.4	2,914.7
Indiana	0.0	8.0	0.0	0.0	0.0	8.2	10.1	0.0	0.0	1,602.4	1,628.7
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	166.0	0.0	0.0	0.0	0.0	166.0
Maryland	0.0	25.1	0.0	69.0	0.0	494.4	93.5	128.2	0.0	190.0	1,000.2
Michigan	0.0	8.0	0.0	0.0	0.0	13.9	4.6	0.0	0.0	0.0	26.5
Missouri	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	146.0	146.0
New Jersey	0.0	77.7	0.0	0.0	453.0	11.5	436.5	162.0	0.0	4.5	1,145.1
North Carolina	0.0	0.0	0.0	0.0	0.0	352.5	291.2	0.0	0.0	208.0	851.7
Ohio	11,080.0	63.4	0.0	156.0	0.0	119.1	1.1	0.0	0.0	503.8	11,923.4
Pennsylvania	0.0	201.8	2,346.0	0.0	1,269.0	893.3	19.5	345.8	1,611.0	1,367.2	8,053.6
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	222.1	0.0	17.0	5,166.2	350.5	105.4	444.9	585.0	0.0	6,891.1
West Virginia	0.0	2.2	0.0	0.0	0.0	257.9	0.0	0.0	165.0	686.3	1,111.4
PJM Total	11,080.0	675.6	4,143.0	255.0	6,888.2	2,719.2	970.9	1,130.9	2,361.0	7,739.5	37,963.4

Table 8-10 shows renewable capacity registered in the PJM generation attribute tracking system (GATS). This includes solar capacity of 3,430.3 MW of which 1,498.5 MW is in New Jersey. These resources can earn renewable energy credits, and can be used to fulfill the renewable portfolio standards in PJM jurisdictions. Some of this capacity is located in jurisdictions outside PJM, but may qualify for specific renewable energy credits in some PJM jurisdictions. This includes both solar generation located inside PJM but not PJM units, and generation connected to other RTOs outside PJM.

Table 8-10 Renewable capacity by jurisdiction, non-PJM units registered in GATS (MW), on March 31, 2017[104]

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	81.7	0.0	2.1	86.0
Georgia	0.0	0.0	0.0	0.0	0.0	0.0	38.7	258.9	0.0	297.6
Illinois	0.0	21.4	91.9	0.0	0.6	0.0	44.7	0.0	300.5	459.0
Indiana	0.0	0.0	49.6	0.0	5.2	234.6	62.2	0.0	180.0	531.5
Iowa	0.0	0.0	0.0	0.0	0.0	0.0	3.2	0.0	186.7	189.8
Kentucky	600.0	86.2	20.2	0.0	0.4	0.0	16.4	93.0	0.0	816.2
Louisiana	0.0	0.0	0.0	0.0	0.0	0.0	0.0	63.0	0.0	63.0
Maryland	65.0	0.0	11.7	129.0	0.0	0.0	646.2	15.0	0.3	867.2
Michigan	55.0	1.3	3.2	0.0	0.0	0.0	3.0	31.0	0.0	93.5
Missouri	0.0	0.0	5.6	0.0	0.0	0.0	19.5	0.0	451.0	476.1
New Jersey	0.0	0.0	53.1	0.0	8.3	0.0	1,498.5	0.0	5.0	1,564.9
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	458.0	151.5	0.0	864.0
North Dakota	0.0	0.0	360.0	0.0	0.0	0.0	0.0	0.0	0.0	360.0
Ohio	0.0	1.0	33.6	92.6	16.4	32.4	166.2	109.3	35.1	486.6
Pennsylvania	109.7	31.7	45.2	91.0	15.2	5.0	255.4	68.6	3.3	625.0
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	12.1	0.0	0.5	0.0	99.4	287.6	0.0	417.7
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	0.0	0.0	0.0	0.0	0.0	3.5	0.0	0.0	3.5
District of Columbia	0.0	0.0	0.0	0.0	0.0	0.0	32.8	0.0	0.0	32.8
Total	829.7	756.9	700.4	312.6	64.5	272.0	3,430.3	1,267.7	1,164.0	8,798.1

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.[105] This decision is an important recognition of the integration of the RECs markets and the other PJM markets.

Delaware, North Carolina, Michigan and Virginia allow various types of renewable resources to earn multiple RECs per MWh, though typically one REC is equal to one MWh. For example, Delaware provided a three MWh REC for each MWh produced by in-state customer sited photovoltaic generation and fuel cells using renewable fuels that are installed on or before December 31, 2014.[106] 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.[107]

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 8-11 shows the REC tracking systems used by each state within the PJM footprint.

104 See PJM – EIS (Environmental Information Services), "Renewable Generators Registered in GATS," <https://gats.pjm-eis.com/gats2/PublicReports/RenewableGeneratorsRegisteredinGATS> (Accessed April 1, 2017).

105 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.").

106 See Delaware Renewable Portfolio Standard, <http://programs.dsireusa.org/system/program/detail/1231> (Accessed April 17, 2017).

107 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 and does not make unit data available to the MMU.

Table 8-11 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		
Maryland	PJM-GATS			
Michigan			MIRECS	
New Jersey	PJM-GATS			
North Carolina				NC-RETS
Ohio	PJM-GATS	M-RETS		
Pennsylvania	PJM-GATS			
Washington, D.C.	PJM-GATS			
Jurisdiction with Voluntary Standard				
Indiana	PJM-GATS	M-RETS		
Virginia	PJM-GATS			

All PJM states with renewable portfolio standards have specified geographical restrictions governing the source of RECs to satisfy states' standards. Table 8-12 describes these restrictions. Indiana, Illinois, Michigan, and Ohio all have provisions in their renewables standards that require all or a portion of RECs used to comply with states' standards to be generated by in-state resources. North Carolina has provisions that require RECs to be purchased from in-state resources but Dominion, the only utility located in both North Carolina and PJM, is exempt from these provisions.

Pennsylvania requires that RECs used for compliance with its RPS are produced from resources located within the PJM footprint. Virginia requires that every load serving entity that chooses to participate in its voluntary renewable energy standard purchase RECs from the control area or RTO in which it is located. Delaware requires that RECs used for compliance with its RPS are

Table 8-12 Geographic restrictions on REC purchases for renewable portfolio standard compliance in PJM states

State with RPS	RPS Contains In-state Provision	Geographical Requirements for RPS Compliance
Delaware	No	RECs must be purchased from resources located either within PJM or from resources outside of PJM that are directly deliverable into Delaware.
Illinois	Yes	All RECs must first be purchased from resources located within Illinois or resources located in a state directly adjoining Illinois. If there are insufficient RECs from Illinois and adjoining states to fulfill the RPS requirements, utilities may purchase RECs from anywhere.
Maryland	No	RECs must come from within PJM, 10-30 miles offshore the coast of Maryland or from a control area adjacent to PJM that is capable of delivering power into PJM.
Michigan	Yes	RECs must either come from resources located within Michigan or anywhere in the service territory of retail electric provider in Michigan that is not an alternative electric supplier. There are many exceptions to these requirements (see Michigan S.B. 213).
New Jersey	No	RECs must either be purchased from resources located within PJM or resources located in a control area synchronized with PJM.
North Carolina	Yes	Dominion, the only utility located in both the state of North Carolina and PJM, may purchase RECs from anywhere. Other utilities in North Carolina not located in PJM are subject to different REC requirements (see G.S. 62-113.8).
Ohio	Yes	All RECs must be generated from resources that are either located in the state of Ohio or have the capability to deliver power directly into Ohio. Any renewable facility located in state contiguous to Ohio has been deemed deliverable into the state of Ohio. If a renewable resource is located outside of this range, then it must demonstrate deliverabilty to the Public Utilities Commission of Ohio.
Pennsylvania	No	RECs must be purchased from resources located anywhere within PJM.
Washington, D.C.	No	RECs must be purchased from either a PJM state or a state adjacent with PJM. A PJM state is defined as any state with a portion of their geographical boundary within the footprint of PJM. An adjacent state is defined as a state that lies next to a PJM state, i.e. SC, GA, AL, AR, IA, NY, MO, MS, and WI.
State with Voluntary Standard		
Indiana	Yes	At least 50 percent of RECs must be purchased from resources located within Indiana.
Virginia	No	RECs must be purchased from the RTO or control area in which the participating utility is a member.

produced from resources located within the PJM footprint or resources located elsewhere if these resources can demonstrate that the power they produce is directly deliverable to Delaware. The District of Columbia, Maryland and New Jersey allow RECs to be purchased from resources located within PJM in addition to large areas that adjoin PJM for compliance with their standards

RECs do not need to be consumed during the year of production which creates multiple prices for a REC based on the year of origination. RECs typically have a shelf life of five years until they cannot be used to satisfy a state's RPS requirement. The REC price figures take the average price for each vintage of REC, regardless of when the REC is consumed. 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 8-4 shows the average solar REC (SREC) price by jurisdiction for 2009 through March 31, 2017. New solar generating units built in New Jersey to satisfy its RPS requirement lowered the SREC price. The average NJ SREC prices dropped from \$673 per SREC in 2009 to \$227 per SREC in the first three months of 2017. The limited supply of solar facilities in Washington, DC compared to the RPS requirement resulted in higher SREC prices. The average Washington, D.C. SREC price increased from \$197 per SREC in 2011 to \$433 per SREC in the first three months of 2017.[108]

Figure 8-4 Average SREC price by jurisdiction: January 1, 2009 through March 31, 2017

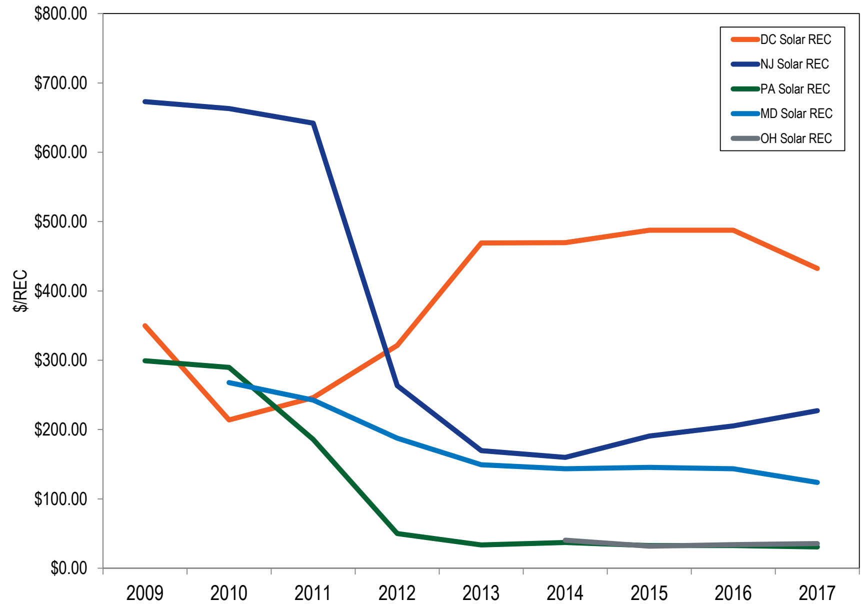
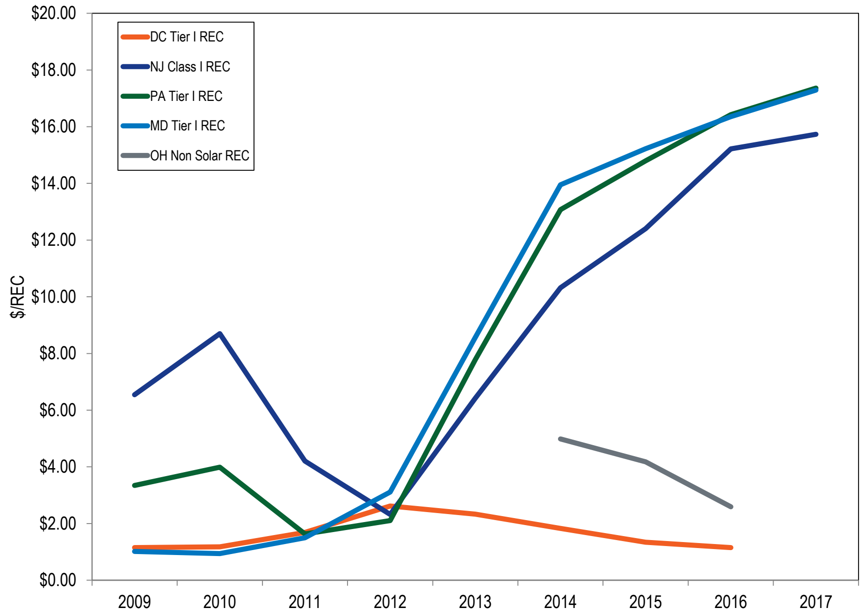


Figure 8-5 shows the average Tier I REC price by jurisdiction from 2009 through the first three months of 2017. Tier I REC prices are lower than SREC prices.[109]

108 Solar REC average price information obtained through Evomarkets, <http://www.evomarkets.com> (Accessed April 19, 2017).

109 Tier I REC price information obtained through Evomarkets, <http://www.evomarkets.com> (Accessed April 19, 2017). There were not any reported cleared purchases for January through March 2017 for OH Non Solar REC or DC Tier I RECs.

Figure 8-5 Average Tier I REC price by jurisdiction: January 1, 2009 through March 31, 2017



Tier II prices are lower than SREC and Tier I REC prices. Figure 8-6 shows the average Tier II REC price by jurisdiction for 2009 through the first three months of 2017. DC had the lowest Tier II REC prices at $1.15 per REC while New Jersey had the highest Tier II REC prices at $6.70per REC.[110]

Figure 8-6 Average Tier II REC price by jurisdiction: January 1, 2009 through March 31, 2017[111]

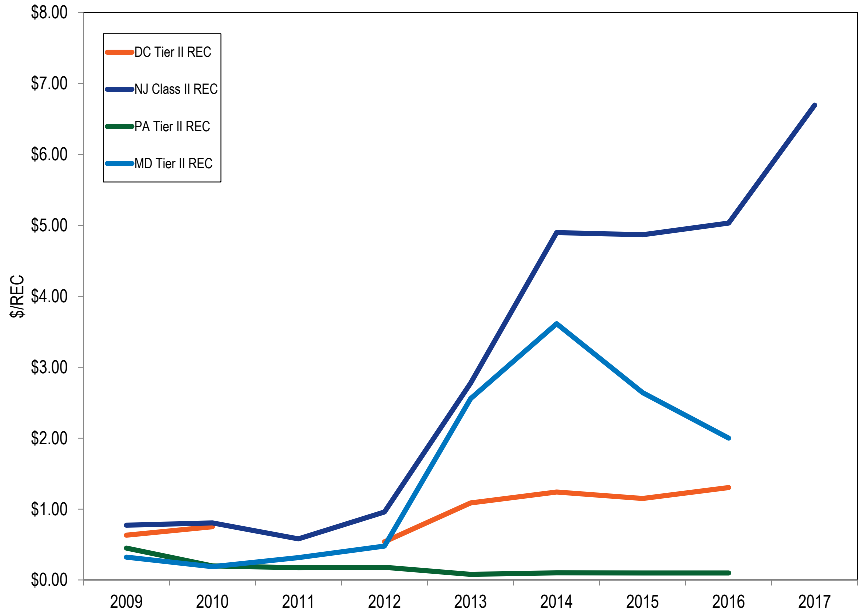


Table 8-13 shows the impact of a range of carbon prices on the cost per MWh of producing energy from three basic unit types.[112] [113] For example, if the price of carbon were $50 per ton, the short run marginal costs would increase by $27.60 per MWh for a new combustion turbine (CT) unit, $19.54 per MWh for a new combined cycle (CC) unit and $47.57 per MWh for a new coal plant (CP).

Table 8-13 also illustrates the effective cost of carbon included in the price of a REC or SREC. For example, the price of an SREC in New Jersey in the first three months of 2017 was $227 per MWh. The SREC price is paid in addition to the energy price paid at the time the solar energy is produced. If the MWh

110 Tier II REC price information obtained through Evomarkets <http://www.evomarkets.com> (Accessed April 19, 2017). There were not any reported cleared purchases for January 1, through March 31, 2017, for DC Tier II REC, PA Tier II REC or MD Tier II RECs.

111 Tier II REC price information obtained through Evomarkets <http://www.evomarkets.com> (Accessed April 19, 2017). There were not any reported cleared purchases for January 1, through March 31, 2017 for DC Tier II REC, PA Tier II REC or MD Tier II RECs.

112 Heat rates from: *2016 State of the Market Report for PJM*, Volume 2, Section 7: Net Revenue, p 283, Table 7-4.

113 Carbon emissions rates from: *Table A.3. Carbon Dioxide Uncontrolled Emission Factors*, Energy Information Administration, <https://www.eia.gov/electricity/annual/html/epa_a_03.html> (Accessed April 28, 2017).

produced by the solar resource resulted in avoiding the production of a MWh from a CT, the value of carbon reduction implied by the SREC price is a carbon price of $400 per ton. This result also assumes that the entire value of the SREC was based on reduced carbon emissions. The SREC price consistent with a carbon price of $50 per ton, assuming that a MWh from a CT is avoided, is $27.60 per MWh.

Table 8-13 Carbon price per MWh by unit type

	Carbon Price per MWh						
Unit Type	Carbon $5/ton	Carbon $10/ton	Carbon $15/ton	Carbon $50/ton	Carbon $100/ton	Carbon $200/ton	Carbon $400/ton
CT	$2.76	$5.52	$8.28	$27.60	$55.21	$110.41	$220.82
CC	$1.95	$3.91	$5.86	$19.54	$39.07	$78.14	$156.29
CP	$4.76	$9.51	$14.27	$47.57	$95.13	$190.26	$380.53

PJM jurisdictions have 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 $315.00 per MWh.[114] 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, the alternative compliance payment creates a cap on REC prices. Illinois requires that 50 percent of the state's renewable portfolio standard be met through alternative compliance payments. In Michigan and North Carolina, there are no pre-established values for alternative compliance payments. The public utility commissions in Michigan and North Carolina have the discretionary power to assess what a load serving entity must pay for any RPS shortfalls.

Table 8-14 shows the alternative compliance standards for RPS in PJM jurisdictions.

114 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 20, 2017).

Table 8-14 Renewable alternative compliance payments in PJM jurisdictions: March 31, 2017[115 116]

Jurisdiction with RPS	Standard Alternative Compliance ($/MWh)	Tier II Alternative Compliance ($/MWh)	Solar Alternative Compliance ($/MWh)
Delaware	$25.00		$400.00
Illinois	$1.89		
Maryland	$37.50	$15.00	$195.00
Michigan	No specific penalties		
New Jersey	$50.00		$315.00
North Carolina	No specific penalties: At the discretion of the NC Utility Commission		
Ohio	$49.75		$250.00
Pennsylvania	$45.00	$45.00	200% market value
Washington, D.C.	$50.00	$10.00	$500.00
Jurisdiction with Voluntary Standard			
Indiana	Voluntary standard - No Penalties		
Virginia	Voluntary standard - No Penalties		
Jurisdiction with No Standard			
Kentucky	No standard		
Tennessee	No standard		
West Virginia	No standard		

Load serving entities participating in mandatory RPS programs in PJM jurisdictions must submit compliance reports to the relevant jurisdiction's public utility commission. In their submitted compliance reports, load serving entities must indicate the quantity of MWh that they have generated using eligible renewable or alternative energy resources. They must also identify the quantity of RECs they may have purchased to make up for renewable energy generation shortfalls or to comply with RPS provisions requiring that they purchase RECs. The public utility commissions then release RPS compliance reports to the public. The RPS compliance reports are released with a lag of up to three years. It is therefore impossible to know the current level of RPS compliance in PJM jurisdictions. As of March 31, 2017, compliance reports for the year 2015 are available for Delaware, Illinois, Michigan, New Jersey, North Carolina, Pennsylvania, Washington, D.C.[117 118] The RPS compliance report for

115 See PJM – EIS (Environmental Management System). "Program Information," <http://www.pjm-eis.com/> (Accessed January 20, 2017).
116 See "Database of State Incentives for Renewables & Efficiency, "Policies & Incentives by State," <http://www.dsireusa.org/> (Accessed February 20, 2017).
117 RPS compliance reports are available on jurisdictions' public utilities commissions' websites.
118 The Lawrence Berkeley National Laboratory, a subsidiary of the US Department of Energy, actively keeps track of compliance reports and data on their website. See the report "U.S. Renewables Portfolio Standards: 2016 Annual Status Report (PDF)" and "RPS Compliance Data (XLSX)" available on their website. <https://emp.lbl.gov/projects/renewables-portfolio> (Accessed April 17, 2017).

the year 2014 is available for Ohio. The RPS compliance report for the year 2013 is available for Maryland.[119]

One jurisdiction where RPS compliance costs have raised concerns is the District of Columbia. According to the District of Columbia Public Service Commission's 2015 annual RPS compliance report, electric retailers have been able to meet the allotted standards for Tier I and II resources but have struggled to meet the standard for solar resources. Due to a combination of insufficient supply of eligible solar resources in the District and increasing percentages of load that must be served by solar resources, total solar alternative compliance payments in the District of Columbia have increased from $0.70 million in 2013 to $19.9 million in 2015.[120]

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.[121] 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.[122] Of the current 61,618.1 MW of coal capacity in PJM, 57,212.0 MW of capacity, 92.8 percent, has some form of FGD (flue-gas desulfurization) technology to reduce SO_2 emissions. Table 8-15 shows SO_2 emission controls by fossil fuel fired units in PJM.[123] [124] [125]

119 The Clean Energy States Alliance tracks all completed RPS compliance reports on their website: <http://cesa.org/projects/state-federal-rps-collaborative/state-rps-annual-reports-and-compliance-reports/#MD> (Accessed April 17, 2017).

120 See the Public Service Commission of the District of Columbia's "Report on the Renewable Energy Portfolio Standard for Compliance Year 2015." <http://www.dcpsc.org/getmedia/901b3c18-4859-435d-ae1a-ca296584c26b/aharris_542016_831_1_FC_-_945_-_2016_-_E_-_REPORT.aspx> (Accessed April 17, 2017)

121 See EPA. "National Ambient Air Quality Standards (NAAQS)," <https://www.epa.gov/criteria-air-pollutants/naaqs-table> (Accessed October 1, 2016).

122 Diesel oil includes number 1, number 2, and ultra-low sulfur diesel. See EPA. "Electronic Code of Federal Regulations, Title 40, Chapter 1, Subchapter C, Part 72, Subpart A Section 72.2" <http://www.ecfr.gov/cgi-bin/text-idx?SID=4f18612541a393473efb13acb879d470&c=true&node=se40.18.72_12&rgn=div8> (Accessed October 1, 2016).

123 See EPA. "Air Market Programs Data," <http://ampd.epa.gov/ampd/> (Accessed April 26, 2017).

124 Air Markets Programs Data is submitted quarterly. Generators have 60 days after the end of the quarter to submit data, and all data is considered preliminary and subject to change until it is finalized in June of the following year.

125 The total MW for each fuel type are less than the 183,593.6 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 April 26, 2017).

Table 8-15 SO_2 emission controls by fuel type (MW): March 31, 2017[126]

	SO_2 Controlled	No SO_2 Controls	Total	Percent Controlled
Coal	57,212.0	4,406.1	61,618.1	92.8%
Diesel Oil	0.0	5,949.6	5,949.6	0.0%
Natural Gas	0.0	54,692.3	54,692.3	0.0%
Other	325.0	4,920.7	5,245.7	6.2%
Total	57,537.0	69,968.7	127,505.7	45.1%

NO_X emission control technology is used by all fossil fuel fired unit types. Of current fossil fuel fired units in PJM, 119,225.0 MW, 93.5 percent, of 127,505.7 MW of capacity in PJM, have emission controls for NO_X. Table 8-16 shows NO_X emission controls by unit type in PJM. While most units in PJM have NO_X emission controls, many of these controls may need to be upgraded in order to meet each state's emission compliance standards based on whether a state is part of CSAPR, CAIR, Acid Rain Program (ARP) or a combination of the three. Future NO_X compliance standards will require select catalytic converters (SCRs) or selective non-catalytic reduction (SCNRs) for coal steam units, as well as SCRs or water injection technology for peaking combustion turbine units.[127]

Table 8-16 NO_X emission controls by fuel type (MW): As of March 31, 2017

	NO_x Controlled	No NO_x Controls	Total	Percent Controlled
Coal	60,678.8	939.3	61,618.1	98.5%
Diesel Oil	2,207.6	3,742.0	5,949.6	37.1%
Natural Gas	53,538.9	1,153.4	54,692.3	97.9%
Other	2,799.7	2,446.0	5,245.7	53.4%
Total	119,225.0	8,280.7	127,505.7	93.5%

Most coal units in PJM have particulate controls. Typically, technologies such as electrostatic precipitators (ESP) or fabric filters (baghouses) are used to reduce particulate matter from coal steam units.[128] Fabric filters work by allowing the flue gas to pass through a tightly woven fabric which filters out the particulates. Table 8-17 shows particulate emission controls by unit type in PJM. In PJM, 61,284.1 MW, 99.5 percent, of all coal steam unit MW,

126 The "other" category includes petroleum coke, wood, process gas, residual oil, other gas, and other oil. The EPA's "other" category does not have strict definitions for inclusion.

127 See EPA. "Mercury and Air Toxics Standards, Cleaner Power Plants" <https://www.epa.gov/mats/cleaner-power-plants#controls> (Accessed October 1, 2016).

128 See EPA, "Air Pollution Control Technology Fact Sheet," <https://www3.epa.gov/ttn/catc/dir1/ff-pulse.pdf> (Accessed October 1, 2016).

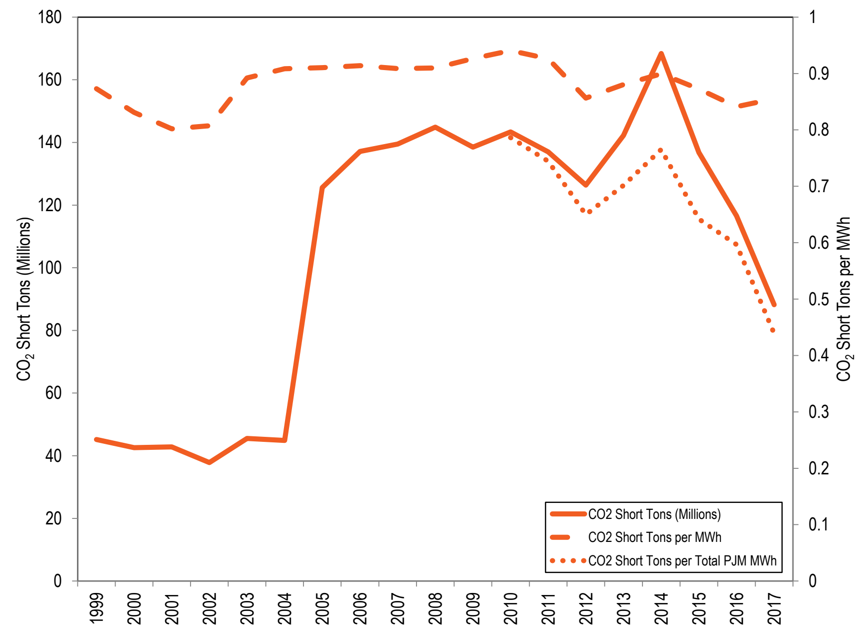
have some type of particulate emissions control technology, as of March 31, 2016. Most coal steam units in PJM have particulate emission controls in the form of ESPs, but many units have also installed baghouse technology, or a combination of an FGD and SCR to meet the state and federal emissions limits established by the MATS EPA regulations.[129] Currently, 143 of the 159 coal steam units have baghouse or FGD technology installed, representing 56,297 MW out of the 61,618.1 MW total coal capacity, or 91.4 percent.

Table 8-17 Particulate emission controls by fuel type (MW): As of March 31, 2017

	Particulate Controlled	No Particulate Controls	Total	Percent Controlled
Coal	61,284.1	334.0	61,618.1	99.5%
Diesel Oil	0.0	5,949.6	5,949.6	0.0%
Natural Gas	2,786.0	51,906.3	54,692.3	5.1%
Other	3,102.0	2,143.7	5,245.7	59.1%
Total	67,172.1	60,333.6	127,505.7	52.7%

Figure 8-7 shows the total CO_2 short ton emissions (in millions) and the CO_2 short ton emissions per MWh within PJM, for all CO_2 emitting units, for the first three months of each year from 1999 to 2017, as well as the CO_2 short ton emissions per MWh of total generation within PJM for the first three months of 2010 to 2017.[130] Since 1999 the amount of CO_2 produced per MWh was at a minimum of 0.80 short tons per MWh in the first three months of 2001, and a maximum of 0.94 short tons per MWh in the first three months of 2010. In the first three months of 2017, CO_2 emissions were 0.86 short tons per MWh. Total PJM generation increased from 195,329.0 GWh in the first three months of 2016 to 200,971.5 GWh in the first three months of 2017, while CO_2 produced decreased from 116.6 million tons in the first three months of 2016 to 88.2 million tons in the first three months of 2017.[131] The reduction in CO_2 emissions was primarily the result of a decrease in the use of coal for generation. Figure 8-8 shows the total on peak hour and off peak hour CO_2 short ton emissions (in millions) and the CO_2 short ton emissions per MWh within PJM, for all CO_2 emitting units, for the first three months of each year from 1999 to 2017. Since 1999 the amount of CO_2 produced per MWh during off peak hours was at a minimum of 0.82 short tons per MWh in the first three months of 2001, and a maximum of 0.95 short tons per MWh in the first three months of 2010. Since 1999 the amount of CO_2 produced per MWh during on peak hours was at a minimum of 0.82 short tons per MWh in the first three months of 2001, and a maximum of 0.93 short tons per MWh in the first three months of 2010. In the first three months of 2017, CO_2 emissions were 0.87 short tons per MWh and 0.85 short tons per MWh for off and on peak hours.

Figure 8-7 CO_2 emissions by year (millions of short tons), by PJM units: January 1, 1999 through March 31, 2017[132]



129 On April 14, 2016, the EPA issued a final finding regarding the Mercury and Air Toxics Standards. See EPA. "Regulatory Actions," <https://www.epa.gov/mats/regulatory-actions-final-mercury-and-air-toxics-standards-mats-power-plants> (Accessed October 1, 2016).

130 Unless otherwise noted, emissions are measured in short tons. A short ton is 2,000 pounds.

131 See *State of the Market Report for PJM: January through March*, Section 3: Energy Market, Table 3-8.

132 The emissions are calculated from the continuous emission monitoring system (CEMS) data from generators located within the PJM footprint.

Figure 8-8 CO_2 emissions during on and off peak hours by year (millions of short tons), by PJM units: January 1, 1999 through March 31, 2017[133]

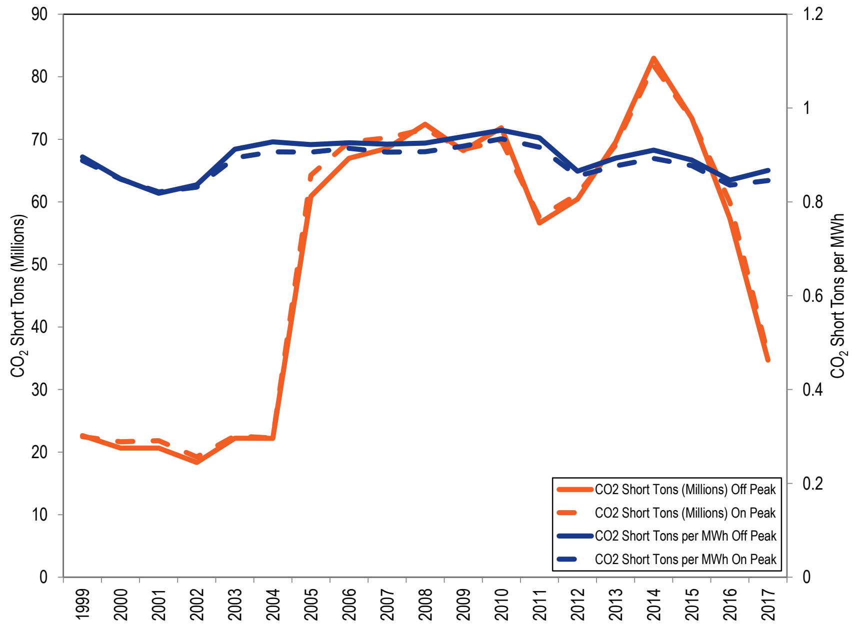


Figure 8-9 shows the total SO_2 and NO_X short ton emissions (in thousands) and the short ton emissions per MWh from emitting resources within PJM, for all SO_2 and NO_X emitting units, for the first three months of each year from 1999 to 2017, as well as the SO_2 and NO_X short ton emissions per MWh of total generation within PJM for the first three months of 2010 to 2017. Since 1999 the amount of SO_2 produced per MWh was at a minimum of 0.000633 short tons per MWh in the first three months of 2017, and a maximum of 0.006499 short tons per MWh in the first three months of 2004. Since 1999, the amount of NO_X produced per MWh was at a minimum of 0.000508 short tons per MWh in the first three months of 2017, and a maximum of 0.002202 short tons per MWh in the first three months of 2005. In the first three months of 2017, SO_2 emissions were 0.000633 short tons per MWh and NO_X emissions were 0.000508 short tons per MWh. The consistent decline in SO_2 and NO_X emissions starting in 2006 is the result of a decline in the use of coal from 2006 to 2017.

Figure 8-10 shows the total on peak hour and off peak hour SO_2 and NO_X short ton emissions (in thousands) and the short ton emissions per MWh from emitting resources within PJM, for all SO_2 and NO_X emitting units, for the first three months of each year from 1999 to 2017. Since 1999 the amount of SO_2 produced per MWh during off peak hours was at a minimum of 0.000670 short tons per MWh in the first three months of 2017, and a maximum of 0.006743 short tons per MWh in the first three months of 2004. Since 1999 the amount of SO_2 produced per MWh during on peak hours was at a minimum of 0.000709 short tons per MWh in the first three months of 2017, and a maximum of 0.006502 short tons per MWh in the first three months of 2004. Since 1999, the amount of NO_X produced per MWh during off peak hours was at a minimum of 0.000540 short tons per MWh in the first three months of 2017, and a maximum of 0.002193 short tons per MWh in the first three months of 2005. Since 1999, the amount of NO_X produced per MWh during on peak hours was at a minimum of 0.000512 short tons per MWh in the first three months of 2017, and a maximum of 0.002228 short tons per MWh in the first three months of 2005. In the first three months of 2017, SO_2 emissions were 0.000670 short tons per MWh and 0.000709 short tons per MWh for off and on peak hours. In the first three months of 2017, NO_X emissions were 0.000540 short tons per MWh and 0.000512 short tons per MWh for off and on peak hours.

133 The emissions are calculated from the continuous emission monitoring system (CEMS) data from generators located within the PJM footprint.

Figure 8-9 SO_2 and NO_x emissions by year (thousands of short tons), by PJM units: January 1, 1999 through March 31, 2017[134]

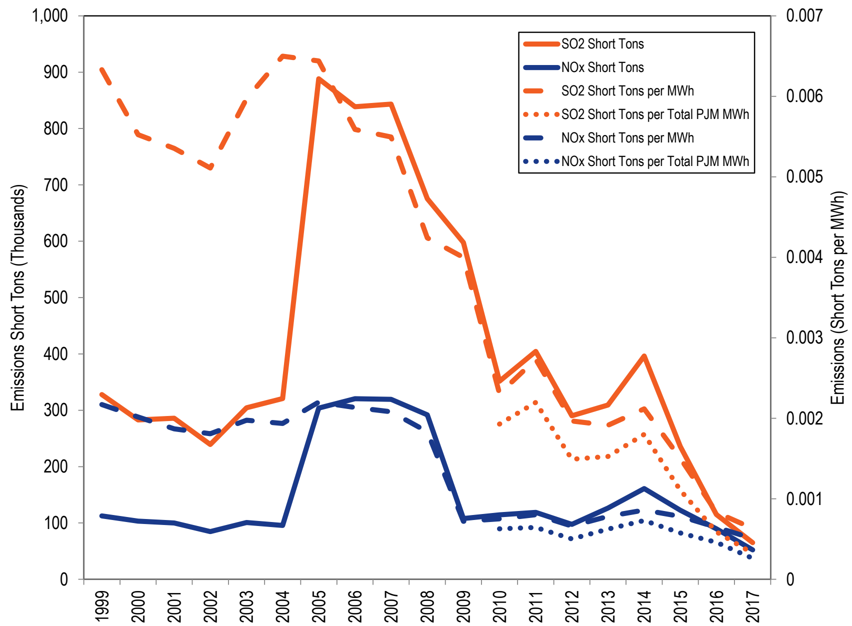
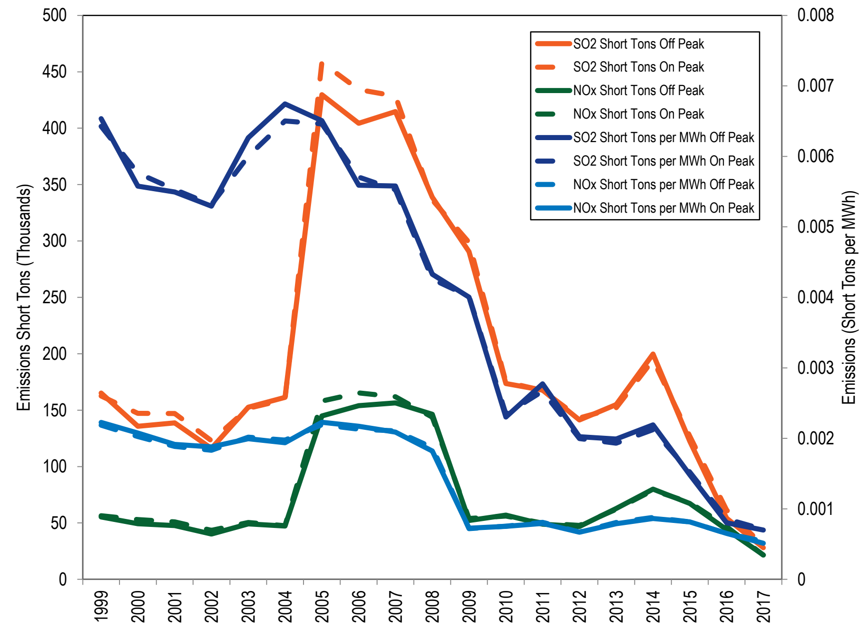


Figure 8-10 SO_2 and NO_x emissions during on and off peak hours by year (thousands of short tons), by PJM units: January through March, 1999 through 2017[135]



Wind and Solar Peak Hour Output

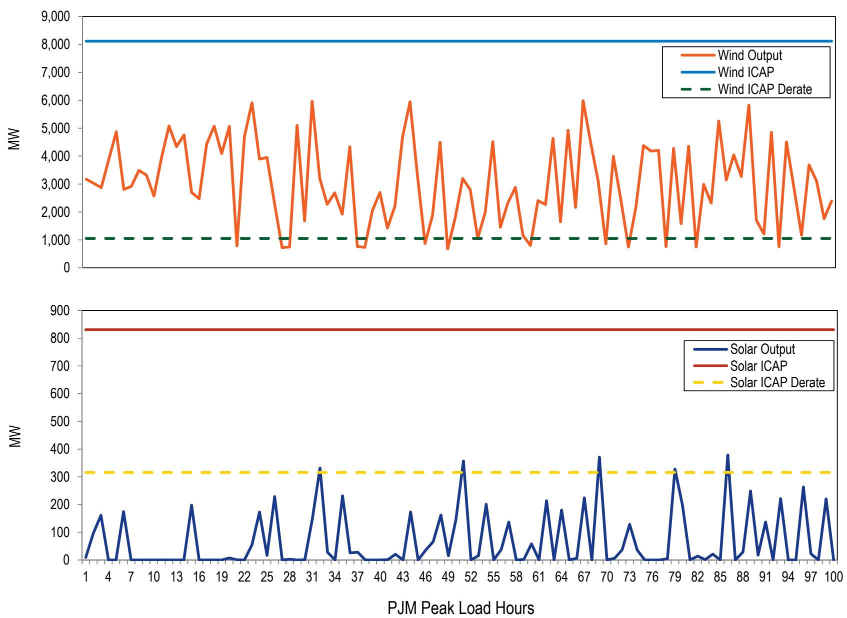
The capacity of solar and wind resources are derated for the PJM capacity market based on expected performance during high load hours. Figure 8-11 shows the wind and solar output during the top 100 load hours in PJM for the first three months of 2017. The top 100 load hours in PJM during the first three months of 2017 did not fall entirely within PJM defined peak load periods. There were 65 hours during PJM defined peak periods and 35 hours during PJM defined off peak periods. The hours are in descending order by load. The solid lines are the total ICAP of wind or solar PJM resources. The dashed lines are the total ICAP of wind and solar PJM resources derated to 13

134 The emissions are calculated from the continuous emission monitoring system (CEMS) data from generators located within the PJM footprint.

135 The emissions are calculated from the continuous emission monitoring system (CEMS) data from generators located within the PJM footprint.

and 38 percent. The actual output of the wind and solar resources during the top 100 peak load hours are above and below the derated values. Wind output was above the derated ICAP for 87 hours and below the derated ICAP for 13 hours of the top 100 peak load hours of the first three months of 2017. Wind output was above the derated ICAP 1939 hours and below the derated ICAP for 220 hours for the first three months of 2017. The wind capacity factor for the top 100 peak load hours of the first three months of 2017 is 37.2 percent. Solar output was above the derated ICAP for 5 hours and below the derated ICAP for 95 hours of the top 100 peak load hours of the first three months of 2017. Solar output was above the derated ICAP 376 hours and below the derated ICAP for 1783 hours for the first three months of 2017. The solar capacity factor for the top 100 peak load hours of the first three months of 2017 is 8.0 percent.

Figure 8-11 Wind and solar output during the top 100 peak load hours in PJM: January 1 through March 31, 2017



Wind Units

Table 8-18 shows the capacity factor of wind units in PJM. In the first three months of 2017, the capacity factor of wind units in PJM was 38.2 percent. Wind units that were capacity resources had a capacity factor of 39.3 percent and an installed capacity of 6,668 MW. Wind units that were classified as energy only had a capacity factor of 32.0 percent and an installed capacity of 1,214 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.[136]

Table 8-18 Capacity factor of wind units in PJM: January 1 through March 31, 2017[137]

Type of Resource	Capacity Factor	Installed Capacity (MW)
Energy-Only Resource	32.0%	1,214
Capacity Resource	39.3%	6,668
All Units	38.2%	7,882

Figure 8-12 shows the average hourly real-time generation of wind units in PJM, by month for the first three months of 2017. The hour with the highest average output, 3,664.6 MW, occurred in February, and the hour with the lowest average output, 2,418.6 MW, occurred in January. Wind output in PJM is generally higher in off-peak hours and lower in on-peak hours.

136 Wind resources are derated to 13 percent unless demonstrating higher availability during peak periods.
137 Capacity factor is calculated based on online date of the resource.

Figure 8-12 Average hourly real-time generation of wind units in PJM: January through March, 2017

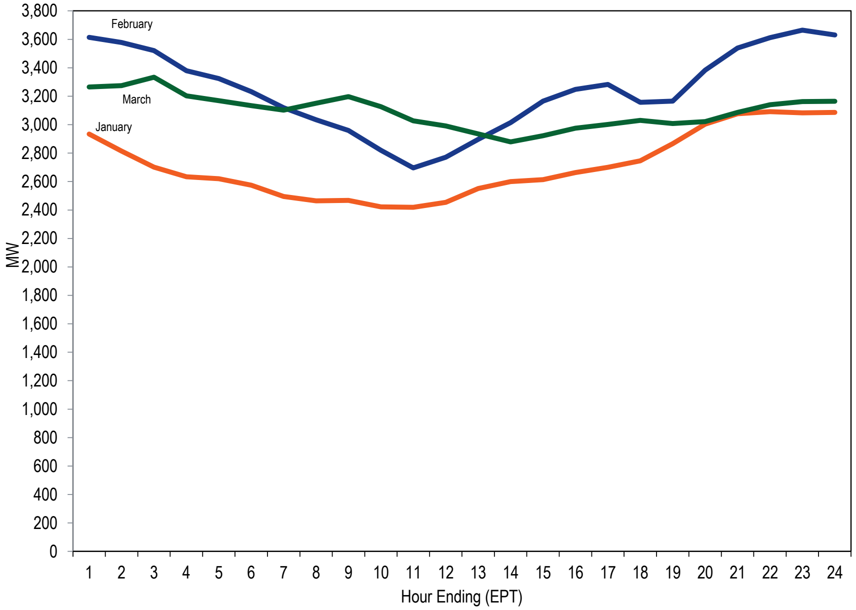


Table 8-19 shows the generation and capacity factor of wind units in each month of 2016 through March 2017.

Table 8-19 Capacity factor of wind units in PJM by month: January 1, 2016 through March 31, 2017

	2016		2017	
Month	Generation (MWh)	Capacity Factor	Generation (MWh)	Capacity Factor
January	2,095,618.0	40.5%	2,017,530.0	34.4%
February	1,925,470.3	39.8%	2,178,634.3	41.1%
March	1,781,561.4	34.5%	2,299,918.3	39.3%
April	1,587,976.6	31.7%		
May	1,230,631.9	23.6%		
June	1,029,071.2	19.7%		
July	691,689.6	12.8%		
August	603,498.4	11.2%		
September	1,017,658.6	19.5%		
October	1,647,392.1	30.5%		
November	1,851,353.3	34.7%		
December	2,254,119.4	39.4%		
Annual	17,716,040.8	28.1%	6,496,082.6	38.2%

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 noncapacity related wind energy at their discretion. Figure 8-13 shows the average hourly day-ahead generation offers of wind units in PJM, by month. The hourly day-ahead generation offers of wind units in PJM may vary.

Figure 8-13 Average hourly day-ahead generation of wind units in PJM: January 1 through March 31, 2017

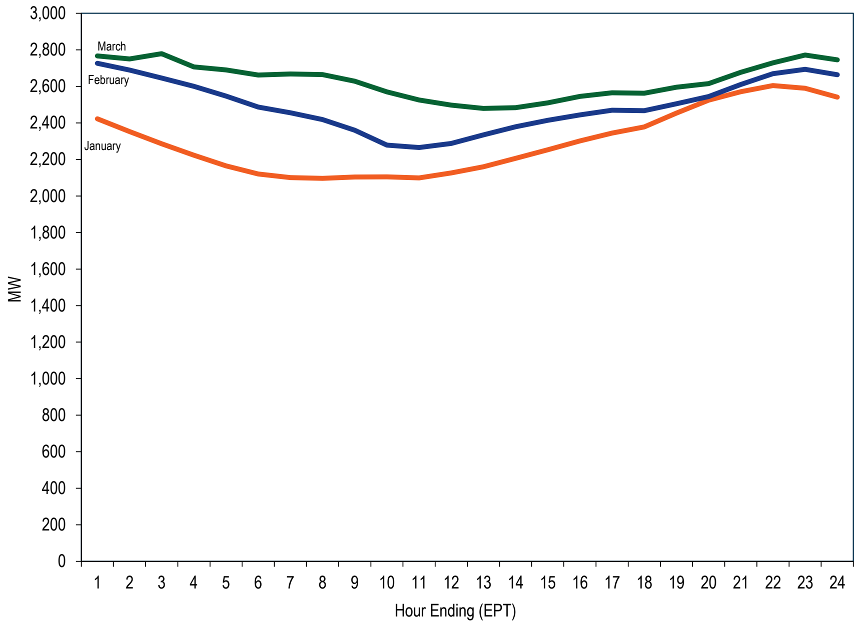
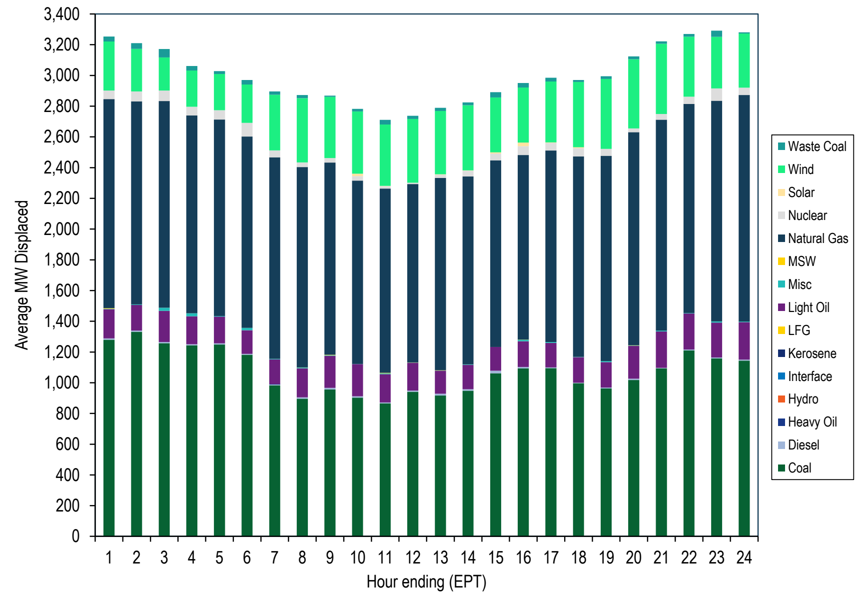


Figure 8-14 Marginal fuel at time of wind generation in PJM: January 1 through March 31, 2017



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 8-14 shows the hourly average proportion of marginal units by fuel type mapped to the hourly average MW of real-time wind generation in the first three months of 2017. This is not an exact measure of displacement because it is not based on a redispatch of the system without wind resources. When wind appears as the displaced fuel at times when wind resources were on the margin this means that there was no displacement for those hours.

Solar Units

Solar units in PJM may be in front of or behind the meter. The data reported include all PJM solar units that are in front of the meter. As shown in Table 8-10, there are 3,430.3 MW capacity of solar registered in GATS that are not PJM capacity or energy resources. Some behind the meter generation exists in clusters, such as community solar farms, and serves dedicated customers. Such customers may or may not be located at the same node on the transmission system as the solar farm. When behind the meter generation and its associated load are at separate nodes, loads should pay for the appropriate level of transmission service, and should not be permitted to escape their proper financial responsibility through badly designed rules, such as rules for netting.

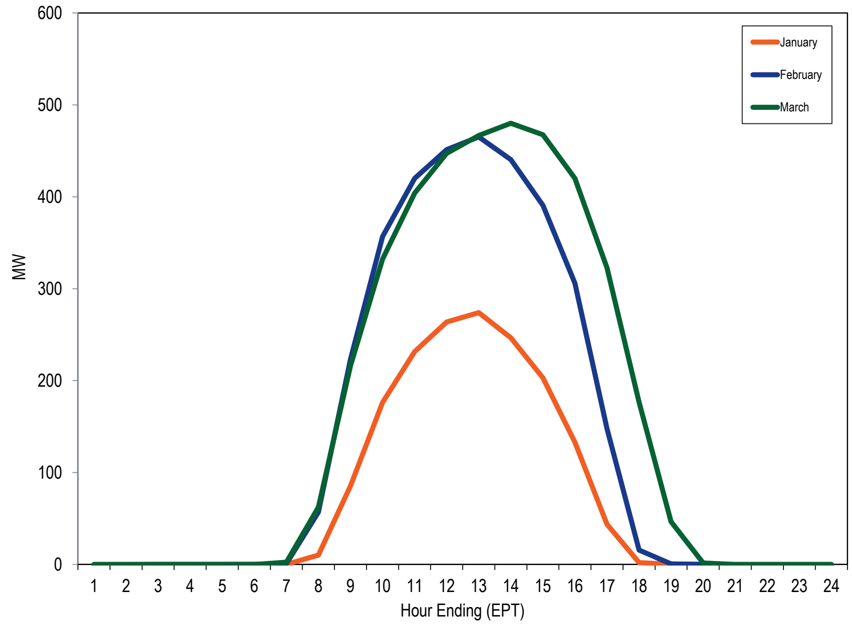
Table 8-20 shows the capacity factor of solar units in PJM. In the first three months of 2017, the capacity factor of solar units in PJM was 14.8 percent. Solar units that were capacity resources had a capacity factor of 14.0 percent and an installed capacity of 578 MW. Solar units that were classified as energy only had a capacity factor of 16.4 percent and an installed capacity of 283 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.[138]

Table 8-20 Capacity factor of wind units in PJM: January 1 through March 31, 2017

Type of Resource	Capacity Factor	Installed Capacity (MW)
Energy-Only Resource	16.4%	283
Capacity Resource	14.0%	578
All Units	14.8%	861

Solar output differs from month to month, based on seasonal variation and daylight hours during the month. Figure 8-15 shows the average hourly real-time generation of solar units in PJM, by month. Solar generation in PJM is highest during the hours of 11:00 through 13:00 EPT.

Figure 8-15 Average hourly real-time generation of solar units in PJM: January 1 through March 31, 2017



138 Solar resources are derated to 38 percent unless demonstrating higher availability during peak periods.

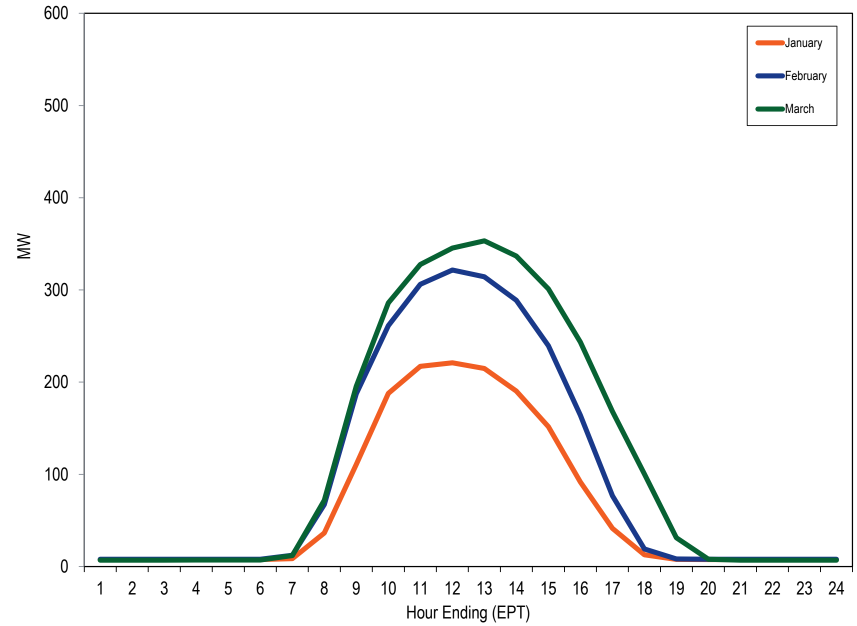
Table 8-21 shows the generation and capacity factor of solar units in each month of 2016 through March 2017.

Table 8-21 Capacity factor of solar units in PJM by month: January 1, 2016 through March 31, 2017

	2016		2017	
Month	Generation (MWh)	Capacity Factor	Generation (MWh)	Capacity Factor
January	38,858.7	10.8%	34,217.8	8.1%
February	43,770.8	12.6%	61,331.7	16.2%
March	73,745.6	19.1%	75,554.0	18.0%
April	85,867.1	22.8%		
May	77,453.7	19.8%		
June	101,147.1	26.0%		
July	101,146.3	25.1%		
August	99,167.5	24.5%		
September	74,093.9	18.7%		
October	67,357.0	16.4%		
November	57,259.6	14.4%		
December	38,424.5	9.4%		
Annual	858,291.9	18.4%	171,103.5	14.0%

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 8-16 shows the average hourly day-ahead generation offers of solar units in PJM, by month.[139]

Figure 8-16 Average hourly day-ahead generation of solar units in PJM: January 1 through March 31, 2017



139 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 nonmarket balancing authorities.

Overview

Interchange Transaction Activity

- **Aggregate Imports and Exports in the Real-Time Energy Market.** In the first three months of 2017, PJM was a monthly net exporter of energy in the Real-Time Energy Market in all months.[1] In the first three months of 2017, the real-time net interchange of -3,715.0 GWh was lower than the net interchange of 5,689.8 GWh in the first three months of 2016.
- **Aggregate Imports and Exports in the Day-Ahead Energy Market.** In the first three months of 2017, PJM was a monthly net exporter of energy in the Day-Ahead Energy Market in all months. In the first three months of 2017, the total day-ahead net interchange of -3,622.8 GWh was lower than net interchange of 1,369.2 GWh in the first three months of 2016.
- **Aggregate Imports and Exports in the Day-Ahead and the Real-Time Energy Market.** In the first three months of 2017, gross imports in the Day-Ahead Energy Market were 152.8 percent of gross imports in the Real-Time Energy Market (108.1 percent in the first three months of 2016). In the first three months of 2017, gross exports in the Day-Ahead Energy Market were 133.9 percent of the gross exports in the Real-Time Energy Market (174.3 percent in the first three months of 2016).
- **Interface Imports and Exports in the Real-Time Energy Market.** In the first three months of 2017, there were net scheduled exports at nine of PJM's 20 interfaces in the Real-Time Energy Market.
- **Interface Pricing Point Imports and Exports in the Real-Time Energy Market.** In the first three months of 2017, there were net scheduled exports at nine of PJM's 18 interface pricing points eligible for real-time transactions in the Real-Time Energy Market.[2]
- **Interface Imports and Exports in the Day-Ahead Energy Market.** In the first three months of 2017, there were net scheduled exports at 11 of PJM's 20 interfaces in the Day-Ahead Energy Market.
- **Interface Pricing Point Imports and Exports in the Day-Ahead Energy Market.** In the first three months of 2017, there were net scheduled exports at ten 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 the first three months of 2017, 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 the first three months of 2017, net scheduled interchange was -3,715 GWh and net actual interchange was -3,661 GWh, a difference of 54 GWh. In the first three months of 2016, the difference was 874 GWh. This difference is inadvertent interchange.
- **Loop Flows.** In the first three months of 2017, the Wisconsin Energy Corporation (WEC) interface had the largest loop flows of any interface with -301 GWh of net scheduled interchange and 2,598 GWh of net actual interchange, a difference of 2,899 GWh. In the first three months of 2017, the SouthIMP interface pricing point had the largest loop flows of any interface pricing point with 3,736 GWh of net scheduled interchange and 7,250 GWh of net actual interchange, a difference of 3,514 GWh.

Interactions with Bordering Areas

PJM Interface Pricing with Organized Markets

- **PJM and MISO Interface Prices.** In the first three months of 2017, 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 64.3 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 There is one interface pricing point eligible for day-ahead transaction scheduling only (NIPSCO).

- **PJM and New York ISO Interface Prices.** In the first three months of 2017, 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 50.4 percent of the hours.
- **Neptune Underwater Transmission Line to Long Island, New York.** In the first three months of 2017, 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 65.6 percent of the hours.
- **Linden Variable Frequency Transformer (VFT) Facility.** In the first three months of 2017, 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 61.7 percent of the hours.
- **Hudson DC Line.** In the first three months of 2017, 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 0.2 percent of the hours.[3]

Interchange Transaction Issues

- **PJM Transmission Loading Relief Procedures (TLRs).** PJM issued three TLRs of level 3a or higher in the first three months of 2017, compared to eight such TLRs issued in the first three months of 2016.
- **Up to congestion.** There was an increase in up to congestion volume starting in December 2015, coincident with the expiration of the fifteen month limit on the payment of prior uplift charges.[4] The average number of up to congestion bids submitted in the Day-Ahead Energy Market increased by 47.4 percent, from 134,610 bids per day in the first three months of 2016 to 198,362 bids per day in the first three months of 2017. The average cleared volume of up to congestion bids submitted in the Day-Ahead Energy Market increased by 16.0 percent, from 879,068 MWh per day in the first three months of 2016, to 1,019,907 MWh per day in the first three months of 2017.
- **45 Minute Schedule Duration Rule.** Effective May 19, 2014, PJM removed the 45 minute scheduling duration rule in response to FERC Order No. 764.[5] [6] PJM and the MMU issued a statement indicating ongoing concern about market participants' scheduling behavior, and a commitment to address any scheduling behavior that raises operational or market manipulation concerns.[7]

Recommendations

- The MMU recommends that PJM implement rules to prevent sham scheduling. The MMU recommends that PJM apply after the fact market settlement adjustments to identified sham scheduling segments to ensure that market participants cannot benefit from sham scheduling. (Priority: High. First reported 2012. Status: Not adopted. Stakeholder process.)
- 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 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 end the practice of maintaining outdated definitions of interface pricing points, 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: Medium. First reported 2013. Status: Not adopted.)

3 The Hudson line was out of service for all hours in the first three months of 2017. In the first three months of 2017, there were five hours with less than 1 MW of unscheduled flow across the Hudson line.
4 148 FERC ¶ 61,144 (2014). *Order Instituting Section 206 Proceeding and Establishing Procedures.* 16 U.S.C. § 824e.
5 *Integration of Variable Energy Resources*, Order No. 764, 139 FERC ¶ 61,246 (2012), *order on reh'g*, Order No. 764-A, 141 FERC ¶ 61231 (2012).
6 *See* Letter Order, Docket No. ER14-381-000 (June 30, 2014).
7 *See* joint statement of PJM and the MMU re Interchange Scheduling issued July 29, 2014, which can be accessed at: <http://www.monitoringanalytics.com/reports/Market_Messages/Messages/PJM_IMM_Statement_on_Interchange_Scheduling_20140729.pdf>.

- 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 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 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 nonfirm 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 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 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. First reported 2015. Status: Not adopted.)
- The MMU recommends that the emergency interchange cap be replaced with a market based solution. (Priority: Low. First reported 2015. 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 2014. Status: Adopted partially, 2015.)
- 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, 2013.)

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 nonmarket areas, all electricity transactions are part of a single energy market. Nonetheless, there are significant differences between market and nonmarket 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. Nonmarket areas do not include these features. The market areas are extremely transparent and the nonmarket 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 outcomes that would exist in an LMP market.

Interchange Transaction Activity

Charges and Credits Applied to Interchange Transactions

Interchange transactions are subject to various charges and credits. These charges and credits are dependent on whether the interchange transaction is submitted in the Real-Time or Day-Ahead Energy Market, the type of transaction, the transmission service used and whether the transaction is an import, export or wheel. Table 9-1 shows the billing line items that represent the charges and credits applied to real-time and day-ahead interchange transactions.[8]

8 For an explanation and current rate for each billing line item, see "*Customer Guide to PJM Billing*," (March 1, 2017) <http://www.pjm.com/~/media/markets-ops/settlements/custgd.ashx>.

Table 9-1 Charges and Credits Applied to Interchange Transactions

	Real-Time Transactions				Day-Ahead Transactions				
Billing Item	Import (Firm or Non Firm)	Import (Spot in)	Export	Wheel	Import (Firm or Non Firm)	Import (Spot in)	Export	Wheel	Up to Congestion
Firm or Non-Firm Point-to-Point Transmission Service	X		X[1]	X[1]	X		X[1]	X[1]	
Spot Import Service		X[2]				X[2]			
Day-ahead Spot Market Energy					X	X	X		
Balancing Spot Market Energy	X	X	X						
Day-ahead Transmission Congestion					X	X	X	X	X
Balancing Transmission Congestion	X	X	X	X					X
Day-ahead Transmission Losses					X	X	X	X	X
Balancing Transmission Losses	X	X	X	X					X
PJM Scheduling, System Control and Dispatch Service - Control Area Administration	X		X	X	X		X	X	
PJM Scheduling, System Control and Dispatch Service - Market Support	X	X	X		X	X	X		X
PJM Scheduling, System Control and Dispatch Service - Advanced Second Control Center	X	X	X	X	X	X	X	X	X
PJM Scheduling, System Control and Dispatch Service - Market Support Offset	X	X	X		X	X	X		X
PJM Settlement, Inc.	X	X	X		X	X	X		X
Market Monitoring Unit (MMU) Funding	X	X	X		X	X	X		X
FERC Annual Recovery	X		X	X	X		X	X	
Organization of PJM States, Inc. (OPSI) Funding	X		X	X	X		X	X	
Synchronous Condensing			X				X		
Transmission Owner Scheduling, System Control and Dispatch Service	X		X	X	X		X	X	
Reactive Supply and Voltage Control from Generation and Other Sources Service	X		X	X	X		X	X	
Day-ahead Operating Reserve					X	X	X		
Balancing Operating Reserve	X	X	X						
Black Start Service	X		X	X	X		X	X	
Marginal Loss Surplus Allocation (for those paying for transmission service only)			X				X		

1 No charge if Point of Delivery is MISO

2 No charge for spot in transmission

Aggregate Imports and Exports

In the first three months of 2017, PJM was a monthly net exporter of energy in the Real-Time Energy Market in all months (Figure 9-1).[9] In the first three months of 2017, the total real-time net interchange of -3,715.0 GWh was lower than the net interchange of 5,689.8 GWh in the first three months of 2016. The large difference in net interchange volumes from the first three months of 2016 to the first three months of 2017 was primarily a result of the requirement for external capacity resources to be pseudo tied into PJM. Prior to June 1, 2016, these units were dynamically scheduled into PJM or were block scheduled into PJM and were part of scheduled interchange as imports. Pseudo tied units are treated as internal generation and therefore do not affect interchange volume. The reduction of the import volume based on the switch to pseudo tie status contributed to the shift from importing to exporting interchange, as the previously scheduled imports became internal generation. In the first three months of 2017, the peak month for net exporting interchange was March, -1,608.2 GWh; in the first three months of 2016 there were no months with net exports. Gross monthly export volumes in the first three months of 2017 averaged 3,623.2 GWh compared to 2,406.2 GWh in the first three months of 2016, while gross monthly imports in the first three

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.

months of 2017 averaged 2,384.8 GWh compared to 4,302.8 GWh in the first three months of 2016.

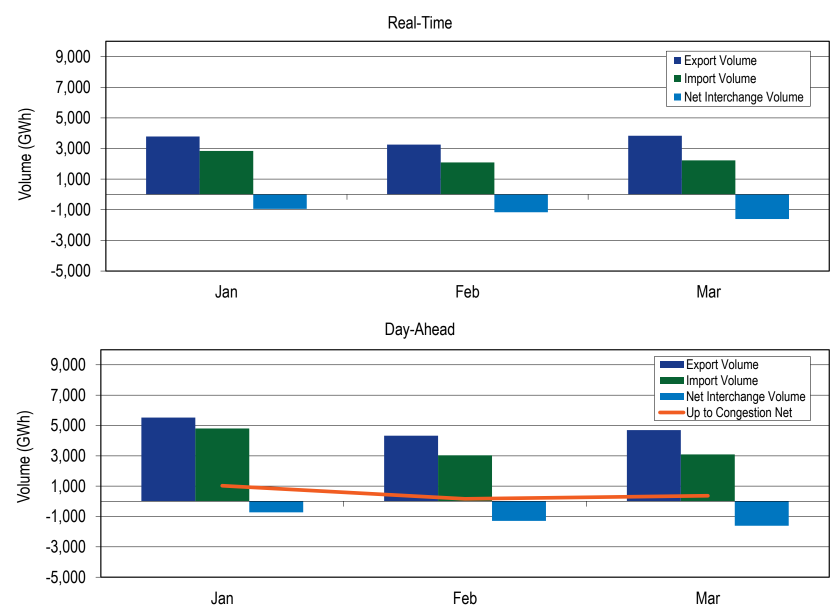
In the first three months of 2017, PJM was a monthly net exporter of energy in the Day-Ahead Energy Market in all months (Figure 9-1). In the first three months of 2017, the total day-ahead net interchange of -3,622.8 GWh was lower than the net interchange of 1,369.2 GWh in the first three months of 2016. The implementation of the pseudo-tied units on June 1, 2016, also impacted the day-ahead interchange totals. Prior to June 1, 2016, some external units were able to meet their day-ahead must offer requirements by submitting day-ahead energy schedules. When those external units became pseudo-tied units in PJM, they were required to offer into the Day-Ahead Energy Market through the Markets Gateway application. These offers replaced the day-ahead energy schedules that those units had submitted in the form of import transactions. The removal of these day-ahead transactions resulted in approximately 61.0 percent of the difference in the day-ahead net interchange totals in the first three months of 2017 compared to the first three months of 2016. In the first three months of 2017, the peak month for net exporting interchange was March, -1,606.7 GWh; in the first three months of 2016 there were no months with net exports. Gross monthly export volumes in the first three months of 2017 averaged 4,852.5 GWh compared to 4,193.4 GWh in the first three months of 2016, while gross monthly imports in the first three months of 2017 averaged 3,644.8 compared to 4,649.8 GWh in the first three months of 2016.

Figure 9-1 shows real-time and day-ahead import, export and net interchange volumes. The day-ahead totals include fixed, dispatchable and up to congestion transaction totals. The net interchange of up to congestion transactions are represented by the orange line.

In the first three months of 2017, gross imports in the Day-Ahead Energy Market were 152.8 percent of gross imports in the Real-Time Energy Market (108.1 percent in the first three months of 2016). In the first three months of 2017, gross exports in the Day-Ahead Energy Market were 133.9 percent of gross exports in the Real-Time Energy Market (174.3 percent in the first three months of 2016). In the first three months of 2017, net interchange was -3,622.8 GWh in the Day-Ahead Energy Market and -3,715.0 GWh in the Real-Time Energy Market compared to 1,369.2 GWh in the Day-Ahead Energy Market and 5,689.8 GWh in the Real-Time Energy Market in the first three months of 2016.

Transactions in the Day-Ahead Energy Market create financial obligations to deliver in the Real-Time Energy Market and to pay operating reserve charges based on differences between the transaction MW and price differences in the Day-Ahead and Real-Time Energy Markets.[10] In the first three months of 2017, 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.

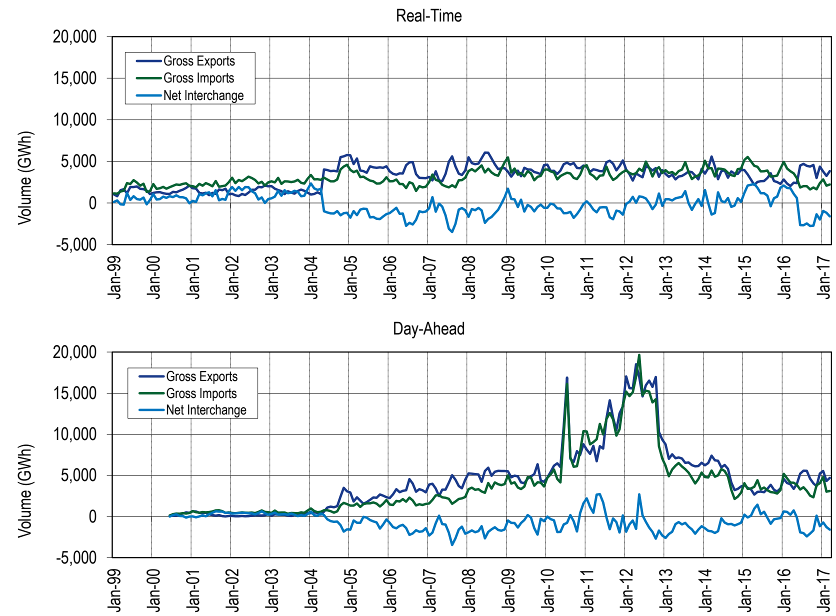
Figure 9-1 PJM real-time and day-ahead scheduled imports and exports: January 1 through March 31, 2017



10 Up to congestion transactions create financial obligations to deliver in real time, but do not pay operating reserve charges.

Figure 9-2 shows the real-time and day-ahead import and export volume for PJM from 1999 through March 31, 2017. 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 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. The requirement for external capacity resources to be pseudo tied into PJM has affected the real-time and day-ahead import volumes. Prior to June 1, 2016, these units were dynamically scheduled into PJM or were block scheduled into PJM and were part of scheduled interchange as imports. Pseudo tied units are treated as internal generation and therefore do not affect interchange volume. The reduction of the import volume based on the switch to pseudo tie status contributed to PJM remaining a primary net exporter in the Real-Time and Day-Ahead Energy Markets.

Figure 9-2 PJM real-time and day-ahead scheduled import and export transaction volume history: January 1, 1999 through March 31, 2017



Real-Time Interface Imports and Exports

In the Real-Time Energy Market, scheduled imports and exports are defined by the scheduled 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 9-17 includes a list of active interfaces in the first three months of 2017. Figure 9-3 shows the approximate geographic location of the interfaces. In the first three months of 2017, 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 9-2 through Table 9-4 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 the first three months of 2017 in Table 9-2, while gross scheduled imports and exports are shown in Table 9-3 and Table 9-4.

In the Real-Time Energy Market, in the first three months of 2017, there were net scheduled exports at nine of PJM's 20 interfaces. The top three net exporting interfaces in the Real-Time Energy Market accounted for 57.3 percent of the total net scheduled exports: PJM/Neptune (NEPT) with 19.5 percent, PJM/New York Independent System Operator (NYIS) with 19.2 percent and PJM/MidAmerican Energy Company (MEC) with 18.6 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 46.3 percent of the total net PJM scheduled exports in the Real-Time Energy Market. There were net scheduled exports in the Real-Time Energy Market at five of the ten separate interfaces that connect PJM to MISO. Those five exporting interfaces represented 52.9 percent of the total net PJM scheduled exports in the Real-Time Energy Market. Eight PJM interfaces had net scheduled imports, with the top three importing interfaces accounting for 80.1 percent of the total net scheduled imports: PJM/DUK (DUK) with 35.6 percent, PJM/Ameren-Illinois (AMIL) with 25.4 percent and PJM/Tennessee Valley Authority (TVA) with 19.1 percent of the net scheduled import volume.[11] 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 the first three months of 2017, there were net imports in the Real-Time Energy Market at four of the ten separate interfaces that connect PJM to MISO. Those four interfaces represented 29.9 percent of the total net PJM scheduled imports in the Real-Time Energy Market.

Table 9-2 Real-time scheduled net interchange volume by interface (GWh): January 1 through March 31, 2017

	Jan	Feb	Mar	Total
CPLE	(15.7)	27.0	(8.6)	2.7
CPLW	0.0	0.0	0.0	0.0
DUK	453.7	315.0	373.3	1,141.9
LGEE	225.2	95.7	169.3	490.1
MISO	(522.8)	(806.3)	(1,370.5)	(2,699.6)
ALTE	(39.0)	(349.6)	(429.9)	(818.5)
ALTW	0.4	0.5	0.0	0.9
AMIL	376.2	223.5	212.9	812.6
CIN	(319.6)	(282.3)	(560.3)	(1,162.2)
CWLP	0.0	0.0	0.0	0.0
IPL	(18.4)	(35.9)	(34.8)	(89.1)
MEC	(472.9)	(402.7)	(410.5)	(1,286.1)
MECS	100.4	(20.8)	56.0	135.5
NIPS	0.0	8.6	0.0	8.6
WEC	(149.9)	52.5	(203.8)	(301.3)
NYISO	(1,336.9)	(1,045.2)	(823.5)	(3,205.6)
HUDS	0.0	0.0	0.0	0.0
LIND	(222.2)	(157.9)	(147.5)	(527.6)
NEPT	(484.9)	(419.9)	(444.6)	(1,349.4)
NYIS	(629.8)	(467.4)	(231.5)	(1,328.7)
OVEC	(20.8)	(17.5)	(18.3)	(56.7)
TVA	273.9	268.0	70.2	612.1
Total	(943.5)	(1,163.3)	(1,608.2)	(3,715.0)

11 In the Real-Time Energy Market, three PJM interfaces had a net interchange of zero (PJM/Progress Energy Carolinas-West (CPLW), PJM/City Water Light & Power (CWLP) and PJM/Hudson (HUDS)).

Table 9-3 Real-time scheduled gross import volume by interface (GWh): January 1 through March 31, 2017

	Jan	Feb	Mar	Total
CPLE	7.2	39.3	5.9	52.4
CPLW	0.0	0.0	0.0	0.0
DUK	519.8	382.9	428.6	1,331.3
LGEE	225.2	99.6	171.7	496.4
MISO	992.0	562.9	793.9	2,348.8
ALTE	267.9	0.0	25.0	292.9
ALTW	0.4	0.5	0.0	0.9
AMIL	377.8	224.6	219.5	821.8
CIN	115.5	100.8	328.5	544.8
CWLP	0.0	0.0	0.0	0.0
IPL	30.7	13.0	39.0	82.7
MEC	26.7	31.5	40.4	98.6
MECS	173.0	27.8	141.5	342.3
NIPS	0.0	8.6	0.0	8.6
WEC	0.0	156.1	0.0	156.1
NYISO	788.6	694.5	674.5	2,157.6
HUDS	0.0	0.0	0.0	0.0
LIND	0.3	1.3	6.0	7.6
NEPT	0.0	0.0	0.0	0.0
NYIS	788.4	693.2	668.4	2,150.0
OVEC	0.0	0.0	0.0	0.0
TVA	305.5	311.7	150.9	768.1
Total	2,838.3	2,090.8	2,225.4	7,154.5

Table 9-4 Real-time scheduled gross export volume by interface (GWh): January 1 through March 31, 2017

	Jan	Feb	Mar	Total
CPLE	22.9	12.2	14.5	49.6
CPLW	0.0	0.0	0.0	0.0
DUK	66.2	67.9	55.3	189.3
LGEE	0.0	3.9	2.4	6.3
MISO	1,514.8	1,369.2	2,164.4	5,048.4
ALTE	306.9	349.6	454.9	1,111.4
ALTW	0.0	0.0	0.0	0.0
AMIL	1.6	1.1	6.6	9.3
CIN	435.1	383.1	888.8	1,707.0
CWLP	0.0	0.0	0.0	0.0
IPL	49.1	48.9	73.8	171.8
MEC	499.6	434.2	450.9	1,384.7
MECS	72.6	48.6	85.5	206.8
NIPS	0.0	0.0	0.0	0.0
WEC	149.9	103.6	203.8	457.4
NYISO	2,125.5	1,739.7	1,498.0	5,363.2
HUDS	0.0	0.0	0.0	0.0
LIND	222.4	159.2	153.5	535.1
NEPT	484.9	419.9	444.6	1,349.4
NYIS	1,418.2	1,160.6	899.9	3,478.7
OVEC	20.8	17.5	18.3	56.7
TVA	31.5	43.7	80.8	156.0
Total	3,781.8	3,254.1	3,833.6	10,869.5

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 path on which scheduled imports or exports will flow.[12] 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 path from a generation control area (GCA) to a load control area (LCA), this 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

12 There are multiple paths between any generation and load balancing authority. Market participants select the path based on transmission service availability and the transmission costs for moving energy from generation to load and interface prices.

PJM/MISO Interface based on the scheduled 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.[13]

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 the contract transmission path.[14] 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 9-18 presents the interface pricing points used in the first three months of 2017. 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.[15] 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 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.[16]

In the Real-Time Energy Market, in the first three months of 2017, there were net scheduled exports at nine of PJM's 18 interface pricing points eligible for real-time transactions.[17] The top three net exporting interface pricing points in the Real-Time Energy Market accounted for 88.4 percent of the total net scheduled exports: PJM/MISO with 57.0 percent, PJM/NEPTUNE with 15.8 percent and PJM/NYIS with 15.6 percent of the net scheduled export volume. The four separate interface pricing points that connect PJM to the NYISO

13 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.

14 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.

15 On June 1, 2015, PJM began using a dynamic weighting factor in the calculation for the Ontario Interface Pricing Point.

16 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.

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

(PJM/NYIS, PJM/NEPTUNE, PJM/HUDSONTP and PJM/LINDENVFT) together represented 37.6 percent of the total net PJM scheduled exports in the Real-Time Energy Market. Five PJM interface pricing points had net scheduled imports, with two importing interface pricing points accounting for 89.5 percent of the total net scheduled imports: PJM/SouthIMP with 77.4 percent and PJM/Ontario Independent Market Operator (IMO) with 12.0 percent of the net scheduled import volume.[18]

Table 9-5 Real-time scheduled net interchange volume by interface pricing point (GWh): January 1 through March 31, 2017

	Jan	Feb	Mar	Total
IMO	222.1	127.6	231.4	581.1
MISO	(1,466.3)	(1,322.5)	(2,082.4)	(4,871.2)
NORTHWEST	0.1	(0.2)	(0.1)	(0.2)
NYISO	(1,336.9)	(1,045.2)	(825.9)	(3,208.0)
HUDSONTP	0.0	0.0	0.0	0.0
LINDENVFT	(222.2)	(157.9)	(147.5)	(527.6)
NEPTUNE	(484.9)	(419.9)	(444.6)	(1,349.4)
NYIS	(629.8)	(467.4)	(233.8)	(1,331.0)
OVEC	(20.8)	(17.5)	(18.3)	(56.7)
Southern Imports	1,780.5	1,222.6	1,240.1	4,243.2
CPLEIMP	5.9	2.0	4.4	12.2
DUKIMP	11.1	6.0	35.2	52.3
NCMPAIMP	173.4	151.6	118.1	443.1
SOUTHEAST	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0
SOUTHIMP	1,590.2	1,063.0	1,082.4	3,735.6
Southern Exports	(122.1)	(128.0)	(153.0)	(403.2)
CPLEEXP	(14.0)	(1.9)	(9.0)	(25.0)
DUKEXP	(28.3)	(40.7)	(7.4)	(76.5)
NCMPAEXP	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0
SOUTHEXP	(79.8)	(85.4)	(136.6)	(301.7)
Total	(943.5)	(1,163.3)	(1,608.2)	(3,715.0)

Table 9-6 Real-time scheduled gross import volume by interface pricing point (GWh): January 1 through March 31, 2017

	Jan	Feb	Mar	Total
IMO	222.3	127.6	231.6	581.5
MISO	46.7	46.1	81.7	174.6
NORTHWEST	0.1	0.0	0.0	0.1
NYISO	788.6	694.5	672.0	2,155.1
HUDSONTP	0.0	0.0	0.0	0.0
LINDENVFT	0.3	1.3	6.0	7.6
NEPTUNE	0.0	0.0	0.0	0.0
NYIS	788.4	693.2	666.0	2,147.6
OVEC	0.0	0.0	0.0	0.0
Southern Imports	1,780.5	1,222.6	1,240.1	4,243.2
CPLEIMP	5.9	2.0	4.4	12.2
DUKIMP	11.1	6.0	35.2	52.3
NCMPAIMP	173.4	151.6	118.1	443.1
SOUTHEAST	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0
SOUTHIMP	1,590.2	1,063.0	1,082.4	3,735.6
Southern Exports	0.0	0.0	0.0	0.0
CPLEEXP	0.0	0.0	0.0	0.0
DUKEXP	0.0	0.0	0.0	0.0
NCMPAEXP	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0
SOUTHEXP	0.0	0.0	0.0	0.0
Total	2,838.3	2,090.8	2,225.4	7,154.5

18 In the Real-Time Energy Market, four PJM interface pricing points had a net interchange of zero (HUDSONTP, NCMPAEXP, Southeast and Southwest).

Table 9-7 Real-time scheduled gross export volume by interface pricing point (GWh): January 1 through March 31, 2017

	Jan	Feb	Mar	Total
IMO	0.3	0.1	0.1	0.4
MISO	1,513.0	1,368.6	2,164.2	5,045.8
NORTHWEST	0.0	0.2	0.1	0.3
NYISO	2,125.5	1,739.7	1,497.9	5,363.1
HUDSONTP	0.0	0.0	0.0	0.0
LINDENVFT	222.4	159.2	153.5	535.1
NEPTUNE	484.9	419.9	444.6	1,349.4
NYIS	1,418.2	1,160.6	899.8	3,478.6
OVEC	20.8	17.5	18.3	56.7
Southern Imports	0.0	0.0	0.0	0.0
CPLEIMP	0.0	0.0	0.0	0.0
DUKIMP	0.0	0.0	0.0	0.0
NCMPAIMP	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0
SOUTHIMP	0.0	0.0	0.0	0.0
Southern Exports	122.1	128.0	153.0	403.2
CPLEEXP	14.0	1.9	9.0	25.0
DUKEXP	28.3	40.7	7.4	76.5
NCMPAEXP	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0
SOUTHEXP	79.8	85.4	136.6	301.7
Total	3,781.8	3,254.1	3,833.6	10,869.5

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 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.[19] 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.[20]

In the Day-Ahead Energy Market, transaction sources and sinks are determined solely by market participants. In Table 9-8, Table 9-9, and Table 9-10, 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 nonmarket 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

19 Effective September 17, 2010, up to congestion transactions no longer required a willing to pay congestion transmission reservation.

20 See the *2010 State of the Market Report for PJM*, Volume II, Section 4, "Interchange Transactions," for details.

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 9-8 through Table 9-10 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 the first three months of 2017 in Table 9-8, while gross scheduled imports and exports are shown in Table 9-9 and Table 9-10.

In the Day-Ahead Energy Market, in the first three months of 2017, there were net scheduled exports at 11 of PJM's 20 interfaces. The top three net exporting interfaces in the Day-Ahead Energy Market accounted for 67.4 percent of the total net scheduled exports: PJM/New York Independent System Operator (NYIS) with 23.2 percent, PJM/MidAmerican Energy Company (MEC) with 22.2 percent and PJM/Neptune (NEPT) with 22.0 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 46.5 percent of the total net PJM scheduled exports in the Day-Ahead Energy Market. In the first three months of 2017, there were net exports in the Day-Ahead Energy Market at seven of the ten separate interfaces that connect PJM to MISO. Those seven interfaces represented 53.4 percent of the total net PJM exports in the Day-Ahead Energy Market. Three PJM interfaces had net scheduled imports, with the top importing interface, PJM/DUK, accounting for 99.0 percent of the net import volume. The four interfaces that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT, PJM/HUDS and PJM/Linden (LIND)) together had net scheduled exports in the Day-Ahead Energy Market. In the first three months of 2017, there were net imports in the Day-Ahead Energy Market at none of the ten separate interfaces that connect PJM to MISO.[21]

Table 9-8 Day-ahead scheduled net interchange volume by interface (GWh): January 1 through March 31, 2017

	Jan	Feb	Mar	Total
CPLE	(11.2)	7.5	(3.2)	(6.9)
CPLW	0.0	0.0	0.0	0.0
DUK	330.8	281.6	312.4	924.8
LGEE	0.0	0.3	0.0	0.3
MISO	(934.0)	(867.5)	(1,469.1)	(3,270.6)
ALTE	(225.7)	(280.7)	(378.9)	(885.4)
ALTW	0.0	0.0	0.0	0.0
AMIL	0.0	0.0	(5.8)	(5.8)
CIN	(129.5)	(93.6)	(459.9)	(682.9)
CWLP	0.0	0.0	0.0	0.0
IPL	0.0	(2.3)	(13.0)	(15.3)
MEC	(496.4)	(433.1)	(428.2)	(1,357.7)
MECS	8.1	(18.7)	(66.9)	(77.4)
NIPS	0.0	0.0	0.0	0.0
WEC	(90.5)	(39.2)	(116.4)	(246.2)
NYISO	(1,181.0)	(894.0)	(768.1)	(2,843.1)
HUDS	0.0	0.0	0.0	0.0
LIND	(33.1)	(21.7)	(20.1)	(74.9)
NEPT	(489.6)	(412.1)	(445.4)	(1,347.1)
NYIS	(658.3)	(460.2)	(302.6)	(1,421.1)
OVEC	0.0	0.0	0.0	0.0
TVA	38.4	19.7	(48.6)	9.5
Total without Up To Congestion	(1,757.1)	(1,452.4)	(1,976.5)	(5,186.0)
Up To Congestion	1,032.7	160.6	369.8	1,563.1
Total	(724.4)	(1,291.8)	(1,606.7)	(3,622.8)

21 In the Day-Ahead Energy Market, six PJM interfaces had a net interchange of zero (PJM/Progress Energy Carolinas-West (CPLW), PJM/Western Alliant Energy (ALTW), PJM/City Water Light & Power (CWLP), PJM/Northern Indiana Public Service Company (NIPS), PJM/Hudson (HUDS) and PJM/Ohio Valley Electric Cooperative (OVEC)).

Table 9-9 Day-Ahead scheduled gross import volume by interface (GWh): January 1 through March 31, 2017

	Jan	Feb	Mar	Total
CPLE	5.4	17.8	5.2	28.3
CPLW	0.0	0.0	0.0	0.0
DUK	342.3	281.6	322.6	946.5
LGEE	0.0	0.3	0.0	0.3
MISO	54.3	11.3	15.2	80.8
ALTE	0.0	0.0	0.0	0.0
ALTW	0.0	0.0	0.0	0.0
AMIL	0.0	0.0	0.0	0.0
CIN	2.6	0.0	0.0	2.6
CWLP	0.0	0.0	0.0	0.0
IPL	0.0	0.0	0.0	0.0
MEC	0.0	0.0	0.0	0.0
MECS	51.6	11.3	15.2	78.1
NIPS	0.0	0.0	0.0	0.0
WEC	0.0	0.0	0.0	0.0
NYISO	645.8	571.7	496.6	1,714.2
HUDS	0.0	0.0	0.0	0.0
LIND	0.0	0.2	0.5	0.7
NEPT	0.0	0.0	0.0	0.0
NYIS	645.8	571.5	496.1	1,713.5
OVEC	0.0	0.0	0.0	0.0
TVA	41.9	43.8	0.9	86.6
Total without Up To Congestion	1,089.7	926.4	840.6	2,856.7
Up To Congestion	3,714.6	2,109.4	2,253.9	8,077.9
Total	4,804.3	3,035.8	3,094.4	10,934.5

Table 9-10 Day-Ahead scheduled gross export volume by interface (GWh): January 1 through March 31, 2017

	Jan	Feb	Mar	Total
CPLE	16.6	10.3	8.3	35.2
CPLW	0.0	0.0	0.0	0.0
DUK	11.5	0.0	10.2	21.7
LGEE	0.0	0.0	0.0	0.0
MISO	988.3	878.8	1,484.3	3,351.4
ALTE	225.7	280.7	378.9	885.4
ALTW	0.0	0.0	0.0	0.0
AMIL	0.0	0.0	5.8	5.8
CIN	132.1	93.6	459.9	685.5
CWLP	0.0	0.0	0.0	0.0
IPL	0.0	2.3	13.0	15.3
MEC	496.4	433.1	428.2	1,357.7
MECS	43.6	29.9	82.1	155.6
NIPS	0.0	0.0	0.0	0.0
WEC	90.5	39.2	116.4	246.2
NYISO	1,826.9	1,465.7	1,264.7	4,557.3
HUDS	0.0	0.0	0.0	0.0
LIND	33.1	21.9	20.6	75.6
NEPT	489.6	412.1	445.4	1,347.1
NYIS	1,304.2	1,031.7	798.7	3,134.6
OVEC	0.0	0.0	0.0	0.0
TVA	3.5	24.1	49.5	77.1
Total without Up To Congestion	2,846.8	2,378.9	2,817.0	8,042.7
Up To Congestion	2,681.9	1,948.8	1,884.1	6,514.7
Total	5,528.6	4,327.6	4,701.1	14,557.4

Day-Ahead Interface Pricing Point Imports and Exports

Table 9-11 through Table 9-16 show the day-ahead scheduled interchange totals at the interface pricing points. In the first three months of 2017, up to congestion transactions accounted for 73.9 percent of all scheduled import MW transactions and 44.8 percent of all scheduled export MW transactions in the Day-Ahead Energy Market. The day-ahead net scheduled interchange in the first three months of 2017, including up to congestion transactions, is shown by interface pricing point in Table 9-11. Scheduled up to congestion transactions by interface pricing point in the first three months of 2017 are shown in Table 9-12. Day-ahead gross scheduled imports and exports, including up to congestion transactions, are shown in Table 9-13 and Table 9-15, while gross scheduled import and export up to congestion transactions are show in Table 9-14 and Table 9-16.

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.

After NIPSCO integrated into MISO on May 1, 2004, PJM kept the NIPSCO interface pricing point for the purpose of facilitating the long term day-ahead positions created at the NIPSCO Interface prior to the integration. However, the NIPSCO interface pricing point remains an eligible interface pricing point in the PJM Day-Ahead Energy Market today, and is available for all market participants to use as the pricing point for day-ahead imports, exports and wheels, INCs, DECs and up to congestion transactions. The NIPSCO interface pricing point continues to also be used as an eligible source or sink for new FTRs.

In the first three months of 2017, the day-ahead net scheduled interchange at the NIPSCO interface pricing point was -1,585.0 GWh (Table 9-11). Table 9-12 shows that all -1,585.0 GWh of day-ahead net scheduled interchange submitted at the NIPSCO interface pricing point were made up of up to congestion transactions. 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.

Maintaining outdated definitions of interface pricing points is unnecessary, inconsistent with the tariff and creates artificial opportunities for gaming by virtual transactions and FTRs. The MMU recommends that PJM end the practice of maintaining outdated definitions of interface pricing points, 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 the first three months of 2017, there were net scheduled exports at ten of PJM's 19 interface pricing points eligible for day-ahead transactions. The top three net exporting interface pricing points in the Day-Ahead Energy Market accounted for 53.1 percent of the total net scheduled exports: PJM/NIPSCO with 20.4 percent, PJM/MISO with 16.6 percent and PJM/NEPTUNE with 16.2 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 32.3 percent of the total net PJM scheduled exports in the Day-Ahead Energy Market (the PJM/HUDSONTP Interface Pricing Point had net scheduled imports). Seven PJM interface pricing points had net scheduled imports, with three importing interface pricing points accounting for 83.0 percent of the total net scheduled imports: PJM/Ohio Valley Electric Corporation (OVEC) with 31.4 percent, PJM/Southeast with 28.8 percent and

PJM/SOUTHIMP with 22.8 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) together had net scheduled exports in the Day-Ahead Energy Market. However, the PJM/HUDSONTP interface pricing points had net scheduled imports that represented 3.8 percent of the total PJM net scheduled imports in the Day-Ahead Energy Market.[22]

In the Day-Ahead Energy Market, in the first three months of 2017, 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 79.0 percent of the total net up to congestion scheduled exports: PJM/NIPSCO with 56.2 percent and PJM/Southwest with 22.8 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) together had net scheduled import up to congestion transactions in the Day-Ahead Energy Market (the PJM/LINDENVFT interface pricing point had net scheduled exports representing 2.0 percent of the net export up to congestion volume). Eight PJM interface pricing points had net scheduled up to congestion imports, with the top three importing interface pricing points accounting for 73.7 percent of the total net up to congestion imports: PJM/OVEC with 29.8 percent, PJM/Southeast with 27.3 percent and PJM/MISO with 16.7 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 12.4 percent of the total net scheduled up to congestion exports in the Day-Ahead Energy Market.[23]

Table 9-11 Day-ahead scheduled net interchange volume by interface pricing point (GWh): January 1 through March 31, 2017

	Jan	Feb	Mar	Total
IMO	134.8	(25.0)	(202.5)	(92.7)
MISO	(100.3)	(259.5)	(931.6)	(1,291.4)
NIPSCO	(950.4)	(289.9)	(344.8)	(1,585.0)
NORTHWEST	(370.1)	(455.6)	(326.7)	(1,152.4)
NYISO	(838.4)	(756.8)	(759.1)	(2,354.3)
HUDSONTP	191.8	24.8	(57.5)	159.1
LINDENVFT	(58.5)	(43.6)	(28.0)	(130.1)
NEPTUNE	(482.9)	(387.4)	(386.8)	(1,257.1)
NYIS	(488.9)	(350.5)	(286.8)	(1,126.2)
OVEC	742.4	64.9	497.4	1,304.7
Southern Imports	1,418.8	988.4	996.3	3,403.5
CPLEIMP	5.4	3.2	5.2	13.7
DUKIMP	8.2	26.9	19.6	54.8
NCMPAIMP	175.1	152.1	149.9	477.1
SOUTHEAST	424.7	377.5	439.6	1,241.8
SOUTHWEST	376.6	125.7	164.6	666.9
SOUTHIMP	428.8	303.1	217.5	949.3
Southern Exports	(761.1)	(558.4)	(535.7)	(1,855.2)
CPLEEXP	(15.8)	(9.8)	(7.7)	(33.3)
DUKEXP	0.0	0.0	0.0	0.0
NCMPAEXP	0.0	0.0	0.0	0.0
SOUTHEAST	(13.3)	(21.9)	(9.7)	(45.0)
SOUTHWEST	(576.6)	(401.3)	(332.9)	(1,310.8)
SOUTHEXP	(155.4)	(125.4)	(185.4)	(466.1)
Total	(724.4)	(1,291.8)	(1,606.7)	(3,622.8)

22 In the Day-Ahead Energy Market, two PJM interface pricing points (PJM/DUKEXP and PJM/NCMPAEXP) had net interchange of zero.
23 In the Day-Ahead Energy Market, six PJM interface pricing points (PJM/CPLEIMP, PJM/DUKIMP, PJM/NCMPAIMP, PJM/CPLEEXP, PJM/DUKEXP and PJM/NCMPAEXP) had up to congestion net interchange of zero.

Table 9-12 Up to congestion scheduled net interchange volume by interface pricing point (GWh): January 1 through March 31, 2017

	Jan	Feb	Mar	Total
IMO	83.2	(36.3)	(217.7)	(170.9)
MISO	404.5	198.9	127.9	731.2
NIPSCO	(950.4)	(289.9)	(344.8)	(1,585.0)
NORTHWEST	110.7	(35.1)	98.1	173.7
NYISO	342.6	137.2	9.0	488.8
HUDSONTP	191.8	24.8	(57.5)	159.1
LINDENVFT	(25.4)	(22.0)	(7.9)	(55.3)
NEPTUNE	6.8	24.7	58.6	90.0
NYIS	169.4	109.7	15.8	294.9
OVEC	742.4	64.9	497.4	1,304.7
Southern Imports	1,029.2	645.0	667.6	2,341.8
CPLEIMP	0.0	0.0	0.0	0.0
DUKIMP	0.0	0.0	0.0	0.0
NCMPAIMP	0.0	0.0	0.0	0.0
SOUTHEAST	424.7	377.5	439.6	1,241.8
SOUTHWEST	376.6	125.7	164.6	666.9
SOUTHIMP	227.9	141.8	63.4	433.2
Southern Exports	(729.5)	(524.0)	(467.7)	(1,721.2)
CPLEEXP	0.0	0.0	0.0	0.0
DUKEXP	0.0	0.0	0.0	0.0
NCMPAEXP	0.0	0.0	0.0	0.0
SOUTHEAST	(13.3)	(21.9)	(9.7)	(45.0)
SOUTHWEST	(576.6)	(401.3)	(332.9)	(1,310.8)
SOUTHEXP	(139.5)	(100.8)	(125.0)	(365.4)
Total Interfaces	1,032.7	160.6	369.8	1,563.1
INTERNAL	28,699.9	24,147.9	24,822.8	77,670.6
Total	29,732.6	24,308.5	25,192.6	79,233.8

Table 9-13 Day-ahead scheduled gross import volume by interface pricing point (GWh): January 1 through March 31, 2017

	Jan	Feb	Mar	Total
IMO	213.7	67.9	56.5	338.0
MISO	753.3	402.1	343.1	1,498.5
NIPSCO	60.1	158.5	137.7	356.2
NORTHWEST	398.3	184.1	261.1	843.6
NYISO	1,156.1	863.3	651.2	2,670.5
HUDSONTP	231.3	106.6	12.7	350.7
LINDENVFT	17.4	13.7	21.7	52.8
NEPTUNE	36.2	39.1	64.9	140.2
NYIS	871.2	703.8	551.8	2,126.9
OVEC	804.0	371.6	648.6	1,824.1
Southern Imports	1,418.8	988.4	996.3	3,403.5
CPLEIMP	5.4	3.2	5.2	13.7
DUKIMP	8.2	26.9	19.6	54.8
NCMPAIMP	175.1	152.1	149.9	477.1
SOUTHEAST	424.7	377.5	439.6	1,241.8
SOUTHWEST	376.6	125.7	164.6	666.9
SOUTHIMP	428.8	303.1	217.5	949.3
Southern Exports	0.0	0.0	0.0	0.0
CPLEEXP	0.0	0.0	0.0	0.0
DUKEXP	0.0	0.0	0.0	0.0
NCMPAEXP	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0
SOUTHEXP	0.0	0.0	0.0	0.0
Total	4,804.3	3,035.8	3,094.4	10,934.5

Table 9-14 Up to congestion scheduled gross import volume by interface pricing point (GWh): January 1 through March 31, 2017

	Jan	Feb	Mar	Total
IMO	162.1	56.6	41.2	259.9
MISO	750.7	402.1	343.1	1,495.9
NIPSCO	60.1	158.5	137.7	356.2
NORTHWEST	398.3	184.1	261.1	843.6
NYISO	510.2	291.6	154.5	956.3
HUDSONTP	231.3	106.6	12.7	350.7
LINDENVFT	17.4	13.5	21.2	52.1
NEPTUNE	36.2	39.1	64.9	140.2
NYIS	225.4	132.3	55.7	413.4
OVEC	804.0	371.6	648.6	1,824.1
Southern Imports	1,029.2	645.0	667.6	2,341.8
CPLEIMP	0.0	0.0	0.0	0.0
DUKIMP	0.0	0.0	0.0	0.0
NCMPAIMP	0.0	0.0	0.0	0.0
SOUTHEAST	424.7	377.5	439.6	1,241.8
SOUTHWEST	376.6	125.7	164.6	666.9
SOUTHIMP	227.9	141.8	63.4	433.2
Southern Exports	0.0	0.0	0.0	0.0
CPLEEXP	0.0	0.0	0.0	0.0
DUKEXP	0.0	0.0	0.0	0.0
NCMPAEXP	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0
SOUTHEXP	0.0	0.0	0.0	0.0
Total Interfaces	3,714.6	2,109.4	2,253.9	8,077.9

Table 9-15 Day-ahead scheduled gross export volume by interface pricing point (GWh): January 1 through March 31, 2017

	Jan	Feb	Mar	Total
IMO	78.9	92.8	259.0	430.8
MISO	853.6	661.6	1,274.7	2,789.9
NIPSCO	1,010.4	448.4	482.5	1,941.3
NORTHWEST	768.5	639.7	587.9	1,996.0
NYISO	1,994.5	1,620.1	1,410.3	5,024.8
HUDSONTP	39.5	81.8	70.2	191.5
LINDENVFT	75.9	57.3	49.7	182.9
NEPTUNE	519.0	426.6	451.7	1,397.3
NYIS	1,360.1	1,054.4	838.6	3,253.1
OVEC	61.6	306.7	151.2	519.5
Southern Imports	0.0	0.0	0.0	0.0
CPLEIMP	0.0	0.0	0.0	0.0
DUKIMP	0.0	0.0	0.0	0.0
NCMPAIMP	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0
SOUTHIMP	0.0	0.0	0.0	0.0
Southern Exports	761.1	558.4	535.7	1,855.2
CPLEEXP	15.8	9.8	7.7	33.3
DUKEXP	0.0	0.0	0.0	0.0
NCMPAEXP	0.0	0.0	0.0	0.0
SOUTHEAST	13.3	21.9	9.7	45.0
SOUTHWEST	576.6	401.3	332.9	1,310.8
SOUTHEXP	155.4	125.4	185.4	466.1
Total	5,528.6	4,327.6	4,701.1	14,557.4

Table 9-16 Up to congestion scheduled gross export volume by interface pricing point (GWh): January 1 through March 31, 2017

	Jan	Feb	Mar	Total
IMO	78.9	92.8	259.0	430.8
MISO	346.2	203.3	215.2	764.6
NIPSCO	1,010.4	448.4	482.5	1,941.3
NORTHWEST	287.6	219.2	163.1	669.9
NYISO	167.6	154.4	145.5	467.5
HUDSONTP	39.5	81.8	70.2	191.5
LINDENVFT	42.8	35.5	29.1	107.3
NEPTUNE	29.4	14.5	6.4	50.2
NYIS	56.0	22.6	39.9	118.5
OVEC	61.6	306.7	151.2	519.5
Southern Imports	0.0	0.0	0.0	0.0
CPLEIMP	0.0	0.0	0.0	0.0
DUKIMP	0.0	0.0	0.0	0.0
NCMPAIMP	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0
SOUTHIMP	0.0	0.0	0.0	0.0
Southern Exports	729.5	524.0	467.7	1,721.2
CPLEEXP	0.0	0.0	0.0	0.0
DUKEXP	0.0	0.0	0.0	0.0
NCMPAEXP	0.0	0.0	0.0	0.0
SOUTHEAST	13.3	21.9	9.7	45.0
SOUTHWEST	576.6	401.3	332.9	1,310.8
SOUTHEXP	139.5	100.8	125.0	365.4
Total Interfaces	2,681.9	1,948.8	1,884.1	6,514.7

Table 9-17 Active real-time and day-ahead scheduling interfaces: January 1 through March 31, 2017[24]

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

24 On July 2, 2012, Duke Energy Corp. (DUK) completed a merger with Progress Energy Inc. (CPLE and CPLW). As of March 31, 2017, DUK, CPLE and CPLW continued to operate as separate balancing authorities, and are still defined as distinct interfaces in the PJM energy market.

Figure 9-3 PJM's footprint and its external day-ahead and real-time scheduling interfaces

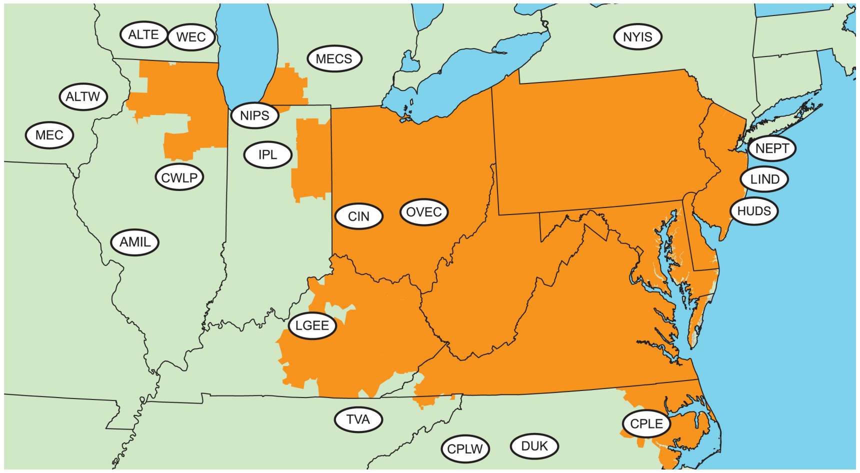


Table 9-18 Active day-ahead and real-time scheduled interface pricing points: January 1 through March 31, 2017[25]

	Jan	Feb	Mar
CPLEEXP	Active	Active	Active
CPLEIMP	Active	Active	Active
DUKEXP	Active	Active	Active
DUKIMP	Active	Active	Active
HUDSONTP	Active	Active	Active
LINDENVFT	Active	Active	Active
MISO	Active	Active	Active
NCMPAEXP	Active	Active	Active
NCMPAIMP	Active	Active	Active
NEPTUNE	Active	Active	Active
NIPSCO	Active	Active	Active
Northwest	Active	Active	Active
NYIS	Active	Active	Active
Ontario IESO	Active	Active	Active
OVEC	Active	Active	Active
Southeast	Active	Active	Active
SOUTHEXP	Active	Active	Active
SOUTHIMP	Active	Active	Active
Southwest	Active	Active	Active

25 The NIPSCO interface pricing point is valid only in the Day-Ahead Energy Market.

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.[26]

Loop flow results, 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 nonmarket balancing authorities, and thus incur additional transmission costs. PJM's interface pricing method recognizes that transactions sourcing in SPP and sinking in

26 See the *2012 State of the Market Report for PJM*, Volume II, Section 8, "Interchange Transactions," for a more detailed discussion.

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 the first three months of 2017, there were net scheduled flows of 1,593 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 the first three months of 2017, net scheduled interchange was -3,715 GWh and net actual interchange was -3,661 GWh, a difference of 54 GWh. In the first three months of 2016, net scheduled interchange was 5,690 GWh and net actual interchange was 6,564 GWh, a difference of 874 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.[27]

Table 9-19 shows that in the first three months of 2017, the Wisconsin Energy Corporation (WEC) interface had the largest loop flows of any interface with -301 GWh of net scheduled interchange and 2,598 GWh of net actual interchange, a difference of 2,899 GWh.

27 See PJM. "Manual 12: Balancing Operations," Revision 36 (February 1, 2017).

Table 9-19 Net scheduled and actual PJM flows by interface (GWh): January 1 through March 31, 2017

	Actual	Net Scheduled	Difference (GWh)
CPLE	1,677	3	1,674
CPLW	(296)	0	(296)
DUK	334	1,142	(808)
LGEE	989	490	498
MISO	(5,761)	(2,700)	(3,061)
ALTE	(1,522)	(818)	(703)
ALTW	(472)	1	(473)
AMIL	372	813	(441)
CIN	(2,738)	(1,162)	(1,576)
CWLP	(42)	0	(42)
IPL	(204)	(89)	(115)
MEC	(716)	(1,286)	570
MECS	(1,458)	136	(1,593)
NIPS	(1,580)	9	(1,589)
WEC	2,598	(301)	2,899
NYISO	(3,260)	(3,206)	(54)
HUDS	0	0	0
LIND	(528)	(528)	0
NEPT	(1,349)	(1,349)	0
NYIS	(1,383)	(1,329)	(54)
OVEC	543	(57)	600
TVA	2,113	612	1,501
Total	(3,661)	(3,715)	54

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.[28] 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

28 The terms balancing authority and control area are used interchangeably in this section. The NERC Tag applications maintained the terminology of generation control area (GCA) and load control area (LCA) after the implementation of the NERC functional model. The NERC functional model classifies the balancing authority as a reliability service function, with, among other things, the responsibility for balancing generation, demand and interchange balance. See "Reliability Functional Model," <http://www.nerc.com/files/Functional_Model_V4_CLEAN_2008Dec01.pdf>. (August 2008)

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 9-20 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 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 (7,250 GWh) and the total southern export actual flows (-2,433 GWh) for 4,817 GWh of net imports. The net scheduled flows from the southern region are determined by summing the total southern import scheduled flows (4,243 GWh) and the total southern export scheduled flows (-403 GWh) for 3,840 GWh of net imports. In the first three months of 2017, the loop flows at the southern region were the difference between the southern region net scheduled flows (3,840 GW) and the southern region net actual flows (4,817 GWh) for a total of 977 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 9-20 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 9-20 Net scheduled and actual PJM flows by interface pricing point (GWh): January 1 through March 31, 2017

	Actual	Net Scheduled	Difference (GWh)
IMO	0	581	(581)
MISO	(5,761)	(4,871)	(890)
NORTHWEST	0	(0)	0
NYISO	(3,260)	(3,208)	(52)
HUDSONTP	0	0	0
LINDENVFT	(528)	(528)	(0)
NEPTUNE	(1,349)	(1,349)	0
NYIS	(1,383)	(1,331)	(52)
OVEC	543	(57)	600
Southern Imports	7,250	4,243	3,006
CPLEIMP	0	12	(12)
DUKIMP	0	52	(52)
NCMPAIMP	0	443	(443)
SOUTHEAST	0	0	0
SOUTHWEST	0	0	0
SOUTHIMP	7,250	3,736	3,514
Southern Exports	(2,433)	(403)	(2,030)
CPLEEXP	0	(25)	25
DUKEXP	0	(76)	76
NCMPAEXP	0	0	0
SOUTHEAST	0	0	0
SOUTHWEST	0	0	0
SOUTHEXP	(2,433)	(302)	(2,131)
Total	(3,661)	(3,715)	54

Table 9-21 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 9-23 shows that 579 of the 581 GWh (99.7 percent) of gross scheduled transactions that were mapped to the IMO interface pricing point were scheduled as imports through MISO, and 2 of the 581 GWh (0.3 percent) were scheduled as imports through the NYISO.

Table 9-21 shows that in the first three months of 2017, the SouthIMP interface pricing point had the largest loop flows of any interface pricing point with 3,736 GWh of net scheduled interchange and 7,250 GWh of net actual interchange, a difference of 3,514 GWh.

Table 9-21 Net scheduled and actual PJM flows by interface pricing point (GWh) (Adjusted for IMO Scheduled Interfaces): January 1 through March 31, 2017

	Actual	Net Scheduled	Difference (GWh)
MISO	(5,761)	(4,292)	(1,468)
NORTHWEST	0	(0)	0
NYISO	(3,260)	(3,206)	(54)
HUDSONTP	0	0	0
LINDENVFT	(528)	(528)	(0)
NEPTUNE	(1,349)	(1,349)	0
NYIS	(1,383)	(1,329)	(54)
OVEC	543	(57)	600
Southern Imports	7,250	4,243	3,006
CPLEIMP	0	12	(12)
DUKIMP	0	52	(52)
NCMPAIMP	0	443	(443)
SOUTHEAST	0	0	0
SOUTHWEST	0	0	0
SOUTHIMP	7,250	3,736	3,514
Southern Exports	(2,433)	(403)	(2,030)
CPLEEXP	0	(25)	25
DUKEXP	0	(76)	76
NCMPAEXP	0	0	0
SOUTHEAST	0	0	0
SOUTHWEST	0	0	0
SOUTHEXP	(2,433)	(302)	(2,131)
Total	(3,661)	(3,715)	54

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 loop flow would be reduced.

The MMU also recommends that PJM implement a validation method for submitted transactions that would require market participants to submit transactions on paths that reflect the expected actual power flow in order to reduce unscheduled loop flows.

Table 9-22 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 paths at each of PJM's interfaces. For example, Table 9-22 shows that in the first three months of 2017, 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 (271 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 were assigned the MISO interface pricing point (-1,655 GWh).

Table 9-22 Net scheduled and actual PJM flows by interface and interface pricing point (GWh): January 1 through March 31, 2017

Interface	Interface Pricing Point	Actual	Net Scheduled	Difference (GWh)	Interface	Interface Pricing Point	Actual	Net Scheduled	Difference (GWh)
ALTE		(1,522)	(818)	(703)	HUDS		0	0	0
	IMO	0	25	(25)		HUDSONTP	0	0	0
	MISO	(1,522)	(1,111)	(410)	IPL		(204)	(89)	(115)
	SOUTHIMP	0	268	(268)		IMO	0	67	(67)
ALTW		(472)	1	(473)		MISO	(204)	(162)	(42)
	IMO	0	1	(1)		SOUTHIMP	0	7	(7)
	MISO	(472)	0	(472)	LGEE		989	490	498
AMIL		372	813	(441)		SOUTHEXP	(1,547)	(6)	(1,541)
	MISO	372	(1)	373		SOUTHIMP	2,536	496	2,039
	SOUTHIMP	0	813	(813)	LIND		(528)	(528)	0
CIN		(2,738)	(1,162)	(1,576)		LINDENVFT	(528)	(528)	0
	IMO	0	271	(271)	MEC		(716)	(1,286)	570
	MISO	(2,738)	(1,655)	(1,083)		MISO	(716)	(1,288)	572
	NORTHWEST	0	(0)	0		SOUTHIMP	0	2	(2)
	SOUTHEXP	0	(1)	1	MECS		(1,458)	136	(1,593)
	SOUTHIMP	0	223	(223)		IMO	0	216	(216)
CPLE		1,677	3	1,674		MISO	(1,458)	(205)	(1,253)
	CPLEEXP	0	(25)	25		SOUTHEXP	0	(1)	1
	CPLEIMP	0	12	(12)		SOUTHIMP	0	126	(126)
	NCMPAIMP	0	29	(29)	NEPT		(1,349)	(1,349)	0
	SOUTHEXP	(291)	(25)	(267)		NEPTUNE	(1,349)	(1,349)	0
	SOUTHIMP	1,968	11	1,957	NIPS		(1,580)	9	(1,589)
CPLW		(296)	0	(296)		MISO	(1,580)	9	(1,589)
	SOUTHEXP	(309)	0	(309)		SOUTHIMP	0	0	(0)
	SOUTHIMP	13	0	13	NYIS		(1,383)	(1,329)	(54)
CWLP		(42)	0	(42)		IMO	0	2	(2)
	MISO	(42)	0	(42)		NYIS	(1,383)	(1,331)	(52)
DUK		334	1,142	(808)	OVEC		543	(57)	600
	DUKEXP	0	(76)	76		OVEC	543	(57)	600
	DUKIMP	0	52	(52)	TVA		2,113	612	1,501
	NCMPAIMP	0	414	(414)		SOUTHEXP	(122)	(156)	34
	SOUTHEXP	(163)	(113)	(50)		SOUTHIMP	2,235	768	1,467
	SOUTHIMP	498	865	(367)	WEC		2,598	(301)	2,899
						MISO	2,598	(457)	3,056
						SOUTHIMP	0	156	(156)
					Grand Total		(3,661)	(3,715)	54

Table 9-23 shows the net scheduled and actual PJM flows by interface pricing point and interface. The grouping is reversed from Table 9-22. Table 9-23 shows the interfaces where transactions were scheduled which received the individual interface pricing points. For example, Table 9-23 shows that in the first three months of 2017, 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 MISO interface pricing point, had a path that entered the PJM energy market at the NIPS Interface (9 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 MISO interface pricing point, had a path that exited the PJM energy market at the CIN Interface (-1,655 GWh).

Table 9-23 Net scheduled and actual PJM flows by interface pricing point and interface (GWh): January 1 through March 31, 2017

Interface Pricing Point	Interface	Actual	Net Scheduled	Difference (GWh)	Interface Pricing Point	Interface	Actual	Net Scheduled	Difference (GWh)
CPLEEXP		0	(25)	25	NEPTUNE		(1,349)	(1,349)	0
	CPLE	0	(25)	25		NEPT	(1,349)	(1,349)	0
CPLEIMP		0	12	(12)	NORTHWEST		0	(0)	0
	CPLE	0	12	(12)		CIN	0	(0)	0
DUKEXP		0	(76)	76	NYIS		(1,383)	(1,331)	(52)
	DUK	0	(76)	76		NYIS	(1,383)	(1,331)	(52)
DUKIMP		0	52	(52)	OVEC		543	(57)	600
	DUK	0	52	(52)		OVEC	543	(57)	600
HUDSONTP		0	0	0	SOUTHEXP		(2,433)	(302)	(2,131)
	HUDS	0	0	0		CIN	0	(1)	1
IMO		0	581	(581)		CPLE	(291)	(25)	(267)
	ALTE	0	25	(25)		CPLW	(309)	0	(309)
	ALTW	0	1	(1)		DUK	(163)	(113)	(50)
	CIN	0	271	(271)		LGEE	(1,547)	(6)	(1,541)
	IPL	0	67	(67)		MECS	0	(1)	1
	MECS	0	216	(216)		TVA	(122)	(156)	34
	NYIS	0	2	(2)	SOUTHIMP		7,250	3,736	3,514
LINDENVFT		(528)	(528)	0		ALTE	0	268	(268)
	LIND	(528)	(528)	0		AMIL	0	813	(813)
MISO		(5,761)	(4,871)	(890)		CIN	0	223	(223)
	ALTE	(1,522)	(1,111)	(410)		CPLE	1,968	11	1,957
	ALTW	(472)	0	(472)		CPLW	13	0	13
	AMIL	372	(1)	373		DUK	498	865	(367)
	CIN	(2,738)	(1,655)	(1,083)		IPL	0	7	(7)
	CWLP	(42)	0	(42)		LGEE	2,536	496	2,039
	IPL	(204)	(162)	(42)		MEC	0	2	(2)
	MEC	(716)	(1,288)	572		MECS	0	126	(126)
	MECS	(1,458)	(205)	(1,253)		NIPS	0	0	(0)
	NIPS	(1,580)	9	(1,589)		TVA	2,235	768	1,467
	WEC	2,598	(457)	3,056		WEC	0	156	(156)
NCMPAIMP		0	443	(443)	Grand Total		(3,661)	(3,715)	54
	CPLE	0	29	(29)					
	DUK	0	414	(414)					

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 nonmarket 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 nonmarket 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 (nonmarket 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.[29]

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.[30]

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

29 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.

30 141 FERC ¶ 61,235 (2012). *Availability of E-Tag Information to Commission Staff.*

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.

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 nonmarket areas are not. For example, PJM posts real-time load via its eDATA application. Most nonmarket 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.

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.[31] [32]

PJM modified the definition of the PJM/MISO interface price effective June 1, 2014. PJM's new MISO interface pricing point includes 10 equally weighted buses that are close to the PJM/MISO border. The 10 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. MISO is currently planning to modify their MISO/PJM interface definition to match PJM's PJM/MISO interface definition, effective June 1, 2017.

31 See "LMP Aggregate Definitions," (March 9, 2017) <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>.
32 Based on information obtained from MISO's extranet <http://extranet.midwestiso.org> (Accessed April 11, 2017).

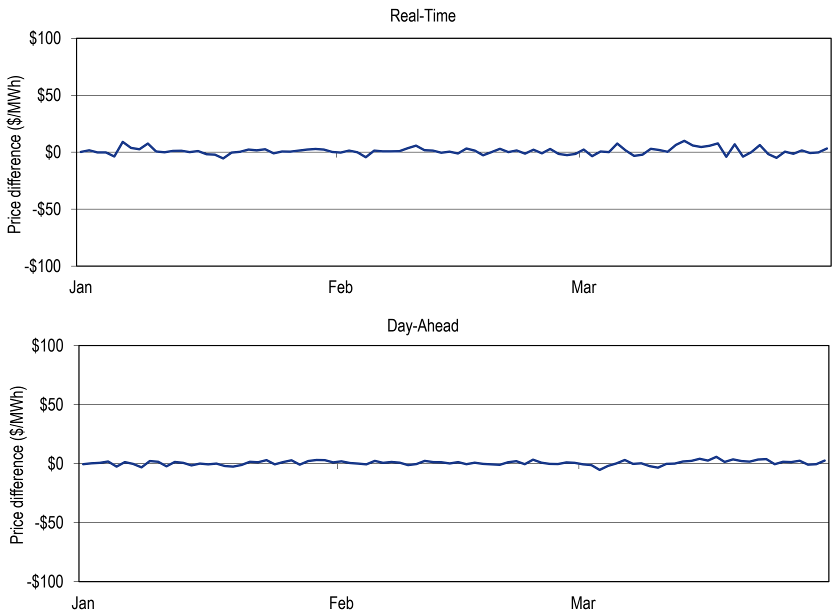
Real-Time and Day-Ahead PJM/MISO Interface Prices

In the first three months of 2017, the direction of flow was consistent with price differentials in 64.3 percent of the hours. Table 9-24 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 shows the underlying hourly variability in prices. 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 (Table 9-28).

Table 9-24 PJM and MISO flow based hours and average hourly price differences: January 1 through March 31, 2017

LMP Difference	Flow Direction	Number of Hours	Average Hourly Price Difference
MISO/PJM LMP > PJM/MISO LMP	Total Hours	1,390	$4.44
	Consistent Flow (PJM to MISO)	1,386	$4.43
	Inconsistent Flow (MISO to PJM)	4	$9.76
	No Flow	0	$0.00
PJM/MISO LMP > MISO/PJM LMP	Total Hours	769	$5.15
	Consistent Flow (MISO to PJM)	2	$0.65
	Inconsistent Flow (PJM to MISO)	767	$5.16
	No Flow	0	$0.00

Figure 9-4 Real-time and day-ahead daily hourly average price difference (MISO/PJM Interface minus PJM/MISO Interface): January 1 through March 31, 2017



Distribution and Prices of Hourly Flows at the PJM/MISO Interface

In the first three months of 2017, the direction of hourly energy flows was consistent with PJM and MISO interface price differentials in 1,388 hours (64.3 percent of all hours), and was inconsistent with price differentials in 771 hours (35.7 percent of all hours). Table 9-25 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 771 hours where flows were in a direction inconsistent with price differences, 537 of those hours (69.6 percent) had a price difference greater than or equal to $1.00 and 204 of those hours (26.5 percent) had a price difference greater than or equal to $5.00. The largest price difference with such flows was $66.65. Of the 1,388 hours where flows were consistent with price differences, 1,044 of those hours (75.2 percent) had a price difference greater than or equal to $1.00 and 284 of all such hours (20.5 percent) had a price difference greater than or equal to $5.00. The largest price difference with such flows was $171.04.

Table 9-25 Distribution of hourly flows that are consistent and inconsistent with price differences between PJM and MISO: January 1 through March 31, 2017

Price Difference Range (Greater Than or Equal To)	Inconsistent Hours	Percent of Inconsistent Hours	Consistent Hours	Percent of Consistent Hours
$0.00	771	100.0%	1,388	100.0%
$1.00	537	69.6%	1,044	75.2%
$5.00	204	26.5%	284	20.5%
$10.00	107	13.9%	136	9.8%
$15.00	73	9.5%	80	5.8%
$20.00	51	6.6%	53	3.8%
$25.00	36	4.7%	35	2.5%
$50.00	6	0.8%	9	0.6%
$75.00	0	0.0%	3	0.2%
$100.00	0	0.0%	1	0.1%
$200.00	0	0.0%	0	0.0%
$300.00	0	0.0%	0	0.0%
$400.00	0	0.0%	0	0.0%
$500.00	0	0.0%	0	0.0%

PJM and NYISO Interface Prices

If interface prices were defined in a comparable manner by PJM and the NYISO, if identical rules governed external transactions in PJM and the NYISO, if time lags were not built into the rules governing such transactions and if no risks were associated with such transactions, then prices at the interfaces would be expected to be very close and the level of transactions would be expected to be related to any price differentials. The fact that none of these conditions exists is important in explaining the observed relationship between interface prices and inter-RTO/ISO power flows, and those price differentials.[33]

PJM and NYISO each calculate an interface LMP using network models including distribution factor impacts. PJM currently uses two buses within

33 See the *2012 State of the Market Report for PJM*, Volume II, Section 8, "Interchange Transactions," for a more detailed discussion.

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.

The existing definition interface definition was created to reflect the impact of the ConEd wheeling arrangement. On April 28, 2016, Con Edison announced its intent to terminate the wheeling agreement effective May 1, 2017. The end of the wheeling agreement means that the expected actual power flows will change and therefore the definition of the interface price needs to change. Effective May 1, 2017, PJM will replace the old PJM/NYIS interface price definition. The new PJM/NYIS interface price will be based on four buses within NYISO. These buses were chosen based on the assumption that, in the absence of the wheeling arrangement, 68 percent of the scheduled energy will flow across the PJM/NYISO border on the Branchburg to Ramapo PAR controlled tie, and the remaining 32 percent will enter the NYISO on free flowing A/C tie lines.

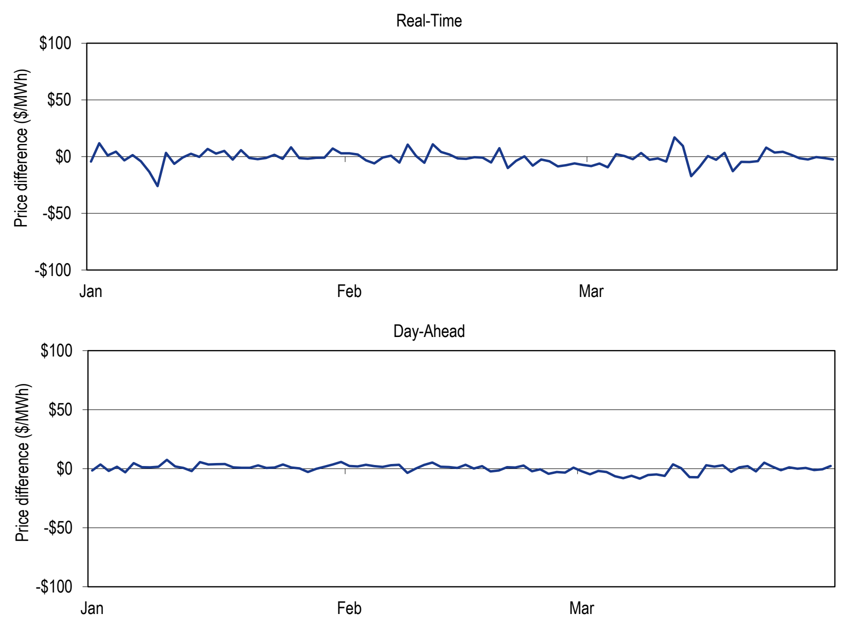
Real-Time and Day-Ahead PJM/NYISO Interface Prices

In the first three months of 2017, 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 50.4 percent of the hours in 2016. Table 9-26 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. Figure 9-5 shows the underlying hourly variability in prices. 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 (Table 9-28).

Table 9-26 PJM and NYISO flow based hours and average hourly price differences: January 1 through March 31, 2017[34]

LMP Difference	Flow Direction	Number of Hours	Average Hourly Price Difference
NYIS/PJM proxy bus LBMP > PJM/NYIS LMP	Total Hours	860	$9.80
	Consistent Flow (PJM to NYIS)	795	$9.13
	Inconsistent Flow (NYIS to PJM)	65	$17.97
	No Flow	0	$0.00
PJM/NYIS LMP > NYIS/PJM proxy bus LBMP	Total Hours	1,299	$8.33
	Consistent Flow (NYIS to PJM)	294	$8.41
	Inconsistent Flow (PJM to NYIS)	1,005	$8.31
	No Flow	0	$0.00

Figure 9-5 Real-time and day-ahead daily hourly average price difference (NY/PJM proxy - PJM/NYIS Interface): January 1 through March 31, 2017



34 The NYISO Locational Based Marginal Price (LBMP) is the equivalent term to PJM's Locational Marginal Price (LMP).

Distribution and Prices of Hourly Flows at the PJM/NYISO Interface

In the first three months of 2017, the direction of hourly energy flows was consistent with PJM/NYISO and NYISO/PJM price differences in 1,089 hours (50.4 percent of all hours), and was inconsistent with price differences in 1,070 hours (49.6 percent of all hours). Table 9-27 shows the distribution of hourly energy flows between PJM and NYISO based on the price differences between the PJM/NYISO and NYISO/PJM prices. Of the 1,070 hours where flows where flows were in a direction inconsistent with price differences, 945 of those hours (88.3 percent) had a price difference greater than or equal to $1.00 and 537 of all those hours (50.2 percent) had a price difference greater than or equal to $5.00. The largest price difference with such flows was $152.30. Of the 1,089 hours where flows were consistent with price differences, 931 of those hours (85.5 percent) had a price difference greater than or equal to $1.00 and 451 of all such hours (41.4 percent) had a price difference greater than or equal to $5.00. The largest price difference with such flows was $271.25.

Table 9-27 Distribution of hourly flows that are consistent and inconsistent with price differences between PJM and NYISO: January 1 through March 31, 2017

Price Difference Range (Greater Than or Equal To)	Inconsistent Hours	Percent of Inconsistent Hours	Consistent Hours	Percent of Consistent Hours
$0.00	1,070	100.0%	1,089	100.0%
$1.00	945	88.3%	931	85.5%
$5.00	537	50.2%	451	41.4%
$10.00	261	24.4%	230	21.1%
$15.00	158	14.8%	130	11.9%
$20.00	104	9.7%	97	8.9%
$25.00	80	7.5%	79	7.3%
$50.00	18	1.7%	33	3.0%
$75.00	6	0.6%	14	1.3%
$100.00	3	0.3%	11	1.0%
$200.00	0	0.0%	2	0.2%
$300.00	0	0.0%	0	0.0%
$400.00	0	0.0%	0	0.0%
$500.00	0	0.0%	0	0.0%

Summary of Interface Prices between PJM and Organized Markets

Some measures of the real-time and day-ahead PJM interface pricing with MISO and with the NYISO are summarized and compared in Table 9-28, including average prices and measures of variability.

Table 9-28 PJM, NYISO and MISO real-time and day-ahead border price averages: January 1 through March 31, 2017

		Real-Time		Day-Ahead	
	Description	NYISO	MISO	NYISO	MISO
Average Hourly Price	PJM Price at ISO Border	$29.36	$26.01	$29.70	$26.51
	ISO Price at PJM Border	$28.85	$27.04	$29.94	$27.11
	Difference at Border (PJM-ISO)	$0.51	($1.03)	($0.24)	($0.60)
	Average Absolute Value of Hourly Difference at Border	$8.92	$4.69	$3.36	$2.17
	Sign Changes per Day	5.9	6.6	2.9	4.2
Standard Deviation	PJM Price at ISO Border	$13.81	$9.19	$9.58	$6.12
	ISO Price at PJM Border	$20.44	$9.67	$10.04	$5.67
	Difference at Border (PJM-ISO)	$18.16	$9.92	$4.40	$2.89

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 65.6 percent of the hours in the first three months of 2017. Table 9-29 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 9-29 PJM and NYISO flow based hours and average hourly price differences (Neptune): January 1 through March 31, 2017

LMP Difference	Flow Direction	Number of Hours	Average Hourly Price Difference
NYIS/Neptune Bus LBMP > PJM/NEPT LMP	Total Hours	1,417	$12.29
	Consistent Flow (PJM to NYIS)	1,417	$12.29
	Inconsistent Flow (NYIS to PJM)	0	$0.00
	No Flow	0	$0.00
PJM/NEPT LMP > NYIS/Neptune Bus LBMP	Total Hours	742	$8.52
	Consistent Flow (NYIS to PJM)	0	$0.00
	Inconsistent Flow (PJM to NYIS)	742	$8.52
	No Flow	0	$0.00

To move power from PJM to NYISO using the Neptune Line, two PJM transmission service reservations are required. A transmission service reservation is required from the PJM Transmission System to the Neptune HVDC Line ("Out Service") and another transmission service reservation is required on the Neptune HVDC line ("Neptune Service").[35] The PJM Out Service is covered by normal PJM OASIS business operations.[36] The Neptune Service falls under the provisions for controllable merchant facilities, Schedule 14 of the PJM Tariff. The Neptune Service is also acquired on the PJM OASIS.

Table 9-30 Percent of scheduled interchange across the Neptune line by primary rights holder: July 1, 2007 through March 31, 2017

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
January	NA	100.00%	100.00%	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%	100.00%	100.00%
March	NA	100.00%	100.00%	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%	100.00%	
May	NA	100.00%	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%	100.00%	
July	100.00%	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%	100.00%	
September	100.00%	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%	100.00%	
November	100.00%	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%	100.00%	

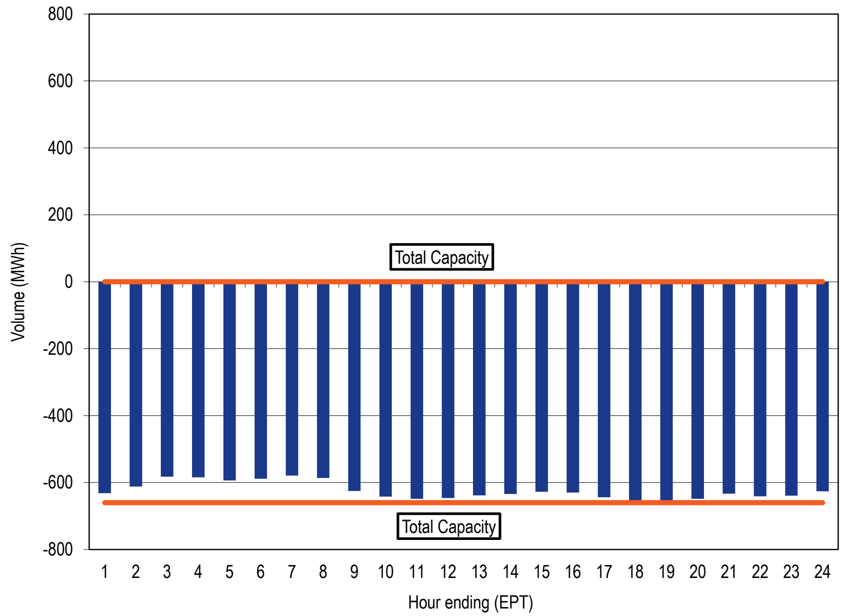
Neptune Service is owned by a primary rights holder, and any nonfirm service that is not used (as defined by a schedule on a NERC Tag) may be released either voluntarily by the primary rights holder or by default by PJM. The primary rights holder may elect to voluntarily release monthly, weekly, daily or hourly firm or nonfirm 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 nonfirm 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 March 31, 2017, the rate for the nonfirm 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 9-30 shows the percent of scheduled interchange across the Neptune Line by the primary rights holder since commercial operations began in July, 2007. Table 9-30 shows that in the first three months of 2017, the primary rights holder was responsible for 100 percent of the scheduled interchange across the Neptune Line in all months. Figure 9-6 shows the hourly average flow across the Neptune Line for the first three months of 2017.

35 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>.

36 See OASIS "Regional Transmission and Energy Scheduling Practices," (March 31, 2016) <http://www.pjm.com/~/media/etools/oasis/regional-practices-clean-pdf.ashx>.

Figure 9-6 Neptune hourly average flow: January 1 through March 31, 2017



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 61.7 percent of the hours in the first three months of 2017. Table 9-31 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 9-31 PJM and NYISO flow based hours and average hourly price differences (Linden): January 1 through March 31, 2017

LMP Difference	Flow Direction	Number of Hours	Average Hourly Price Difference
NYIS/Linden Bus LBMP > PJM/LIND LMP	Total Hours	1,332	$10.84
	Consistent Flow (PJM to NYIS)	1,332	$10.84
	Inconsistent Flow (NYIS to PJM)	0	$0.00
	No Flow	0	$0.00
PJM/LIND LMP > NYIS/Linden Bus LBMP	Total Hours	827	$8.33
	Consistent Flow (NYIS to PJM)	0	$0.00
	Inconsistent Flow (PJM to NYIS)	827	$8.33
	No Flow	0	$0.00

To move power from PJM to NYISO on the Linden VFT Line, two PJM transmission service reservations are required. A transmission service reservation is required from the PJM Transmission System to the Linden VFT ("Out Service") and another transmission service reservation is required on the Linden VFT ("Linden VFT Service").[37] The PJM Out Service is covered by normal PJM OASIS business operations.[38] The Linden VFT Service falls under the provisions for controllable merchant facilities, Schedule 16 and Schedule 16-A of the PJM Tariff. The Linden VFT Service is also acquired on the PJM OASIS.

Linden VFT Service is owned by a primary rights holder, and any nonfirm 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 nonfirm 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 nonfirm 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 March 31, 2017, the rate for the nonfirm service released by default was $6.00 per MWh. The primary rights holder remains obligated to pay for the

37 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>.

38 See OASIS "Regional Transmission and Energy Scheduling Practices," (March 31, 2016) <http://www.pjm.com/~/media/etools/oasis/regional-practices-clean-doc.ashx>.

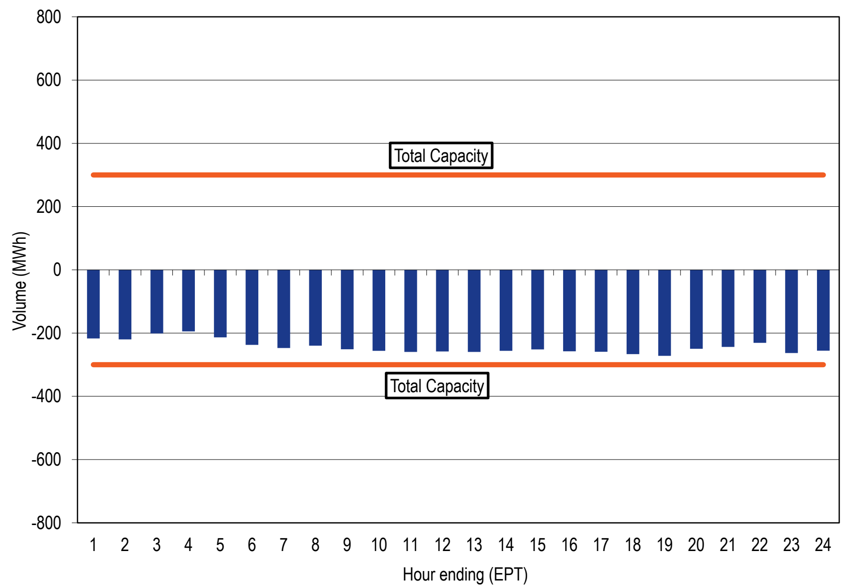
released service unless a second transmission customer acquires the released service.

Table 9-32 shows the percent of scheduled interchange across the Linden VFT Line by the primary rights holder since commercial operations began in November, 2009. Table 9-32 shows that in the first three months of 2017, the primary rights holder was responsible for 100 percent of the scheduled interchange across the Linden VFT Line. Figure 9-7 shows the hourly average flow across the Linden VFT Line for the first three months of 2017.

Table 9-32 Percent of scheduled interchange across the Linden VFT Line by primary rights holder: November 1, 2009 through March 31, 2017

	2009	2010	2011	2012	2013	2014	2015	2016	2017
January	NA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	70.53%	100.00%
February	NA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	94.95%	100.00%
March	NA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	96.46%	100.00%
April	NA	99.97%	100.00%	100.00%	100.00%	99.98%	100.00%	49.32%	
May	NA	100.00%	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%	100.00%	
July	NA	100.00%	100.00%	100.00%	100.00%	29.56%	100.00%	100.00%	
August	NA	100.00%	100.00%	100.00%	100.00%	82.46%	100.00%	100.00%	
September	NA	100.00%	100.00%	100.00%	100.00%	81.68%	100.00%	100.00%	
October	NA	100.00%	100.00%	100.00%	100.00%	100.00%	35.05%	100.00%	
November	100.00%	100.00%	100.00%	100.00%	99.86%	100.00%	61.45%	100.00%	
December	100.00%	100.00%	100.00%	98.22%	100.00%	100.00%	84.57%	100.00%	

Figure 9-7 Linden hourly average flow: January 1 through March 31, 2017[39]



Hudson Direct Current (DC) Merchant Transmission Line

The Hudson direct current (DC) Line is a bidirectional merchant 230 kV transmission line, with a capacity of 673 MW, providing a direct connection between PJM (Public Service Electric and Gas Company's (PSE&G) Bergen 230 kV Switching Station located in Ridgefield, New Jersey) and NYISO (Consolidated Edison's (ConEd) W. 49th Street 345 kV Substation in New York City). The connection is a submarine cable system. While the Hudson DC Line is a bidirectional line, power flows are only from PJM to New York because the Hudson Transmission Partners, LLC have only requested withdrawal rights (320 MW of firm withdrawal rights, and 353 MW of nonfirm withdrawal rights). The flows were consistent with price differentials in 0.2 percent of the hours in the first three months of 2017. Table 9-33 shows the number of hours

39 The Linden VFT Line is a bidirectional facility. The "Total Capacity" lines represent the maximum amount of interchange possible in either direction. These lines were included to maintain a consistent scale, for comparison purposes, with the Neptune DC Tie Line.

and average hourly price differences between the PJM/HUDS Interface and the NYIS/Hudson bus based on LMP differences and flow direction.

Table 9-33 PJM and NYISO flow based hours and average hourly price differences (Hudson): January 1 through March 31, 2017[40]

LMP Difference	Flow Direction	Number of Hours	Average Hourly Price Difference
NYIS/Hudson Bus LBMP > PJM/HUDS LMP	Total Hours	1,316	$10.86
	Consistent Flow (PJM to NYIS)	5	$18.55
	Inconsistent Flow (NYIS to PJM)	0	$0.00
	No Flow	1,311	$10.83
PJM/HUDS LMP > NYIS/Hudson Bus LBMP	Total Hours	843	$8.29
	Consistent Flow (NYIS to PJM)	0	$0.00
	Inconsistent Flow (PJM to NYIS)	0	$0.00
	No Flow	841	$8.29

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").[41] The PJM Out Service is covered by normal PJM OASIS business operations.[42] 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 nonfirm 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 nonfirm 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 nonfirm 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 March 31, 2017, the rate for the nonfirm 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.

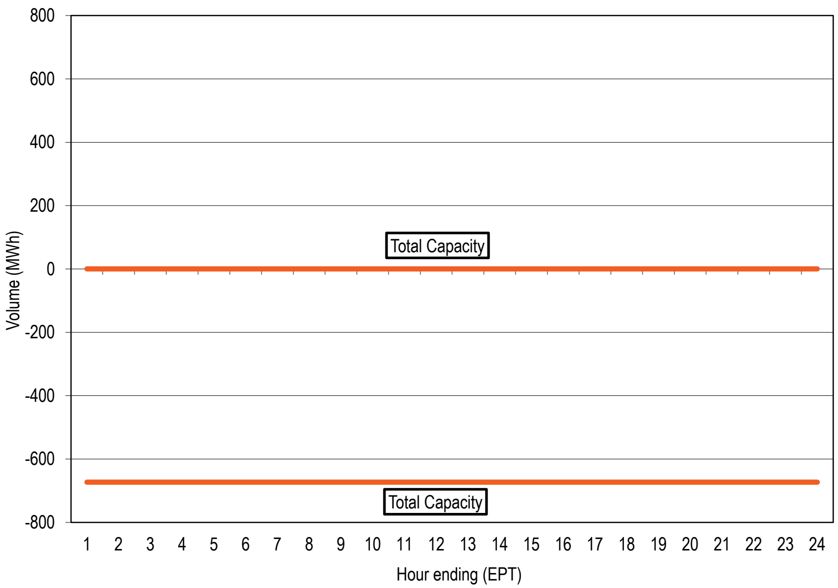
Table 9-34 shows the percent of scheduled interchange across the Hudson Line by the primary rights holder since commercial operations began in May, 2013. Table 9-34 shows that in the first three months of 2017, there was no scheduled interchange across the Hudson Line. Figure 9-8 shows the hourly average flow across the Hudson Line for the first three months of 2017.

Table 9-34 Percent of scheduled interchange across the Hudson Line by primary rights holder: May 1, 2013 through March 31, 2017

	2013	2014	2015	2016	2017
January	NA	51.22%	16.27%	100.00%	NA
February	NA	49.00%	14.67%	NA	NA
March	NA	40.40%	71.88%	NA	NA
April	NA	100.00%	100.00%	NA	
May	100.00%	26.87%	100.00%	100.00%	
June	100.00%	5.89%	59.72%	100.00%	
July	100.00%	18.51%	84.34%	NA	
August	100.00%	75.17%	65.48%	NA	
September	100.00%	75.31%	78.73%	NA	
October	100.00%	99.71%	18.65%	100.00%	
November	85.57%	99.60%	24.67%	100.00%	
December	28.32%	1.68%	100.00%	NA	

40 The Hudson line was out of service for all hours in the first three months of 2017. In the first three months of 2017, there were five hours with less than 1 MW of unscheduled flow across the Hudson line.
41 See OASIS "PJM Business Practices for Hudson Transmission Service,"<http://www.pjm.com/~/media/etools/oasis/merch-trans-facilities/htp-Business-practices.ashx>.
42 See OASIS "Regional Transmission and Energy Scheduling Practices," (March 31, 2016) <http://www.pjm.com/~/media/etools/oasis/regional-practices-clean-doc.ashx>.

Figure 9-8 Hudson hourly average flow: January 1 through March 31, 2017



Interchange Activity During High Load Hours

The PJM metered system peak load during the first three months of 2017 was 124,210 MW in the HE 0800 on January 9, 2017. PJM did not declare any emergency alerts, warnings or actions in that hour. PJM did not make any emergency energy purchases or sales in that hour. During the month of January 2017, PJM was a net scheduled exporter of energy in 618 of the 744 hours (83.1 percent of all hours). During those 618 hours, the average hourly scheduled exports were 1,645 MW (representing 1.8 percent of the average hourly load of 91,579 MW in January 2017). With the exception of HE 2400, PJM was a net importer of energy in all hours on January 9, 2017, with average hourly scheduled imports of 685 MW.

Operating Agreements with Bordering Areas

To improve reliability and reduce potential 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 9-35 shows a summary of the elements included in each of the operating agreements PJM has with its bordering areas.

Table 9-35 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[43]

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.[44]

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 10 buses along the PJM/MISO border to calculate the PJM/MISO interface pricing point LMP while MISO uses all

43 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>.
44 See "PJM/MISO Joint and Common Market Initiative," <http://www.pjm.com/committees-and-groups/stakeholder-meetings/pjm-miso-joint-common.aspx>.

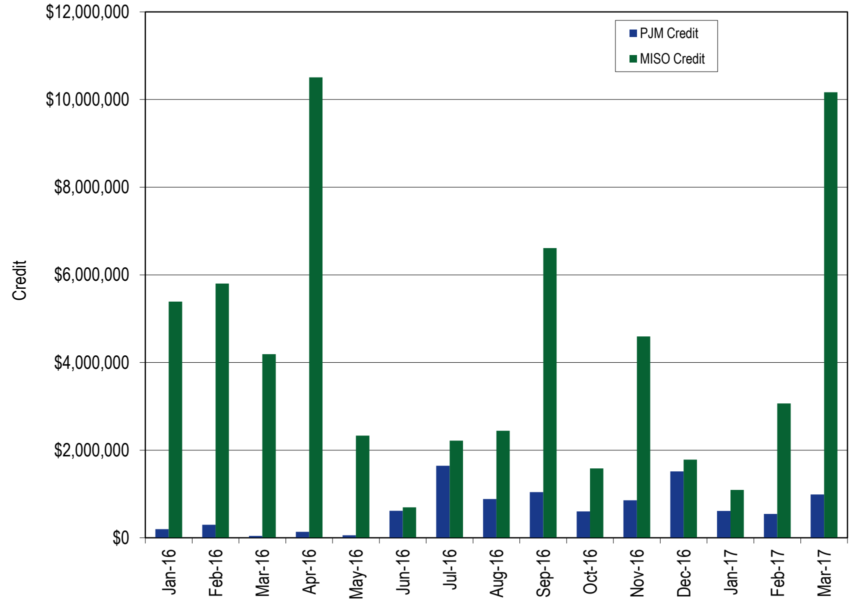
of the PJM generator buses in its model of the PJM system in its calculation of the MISO/PJM interface pricing point.[45] MISO is currently planning to modify their MISO/PJM interface definition to match PJM's PJM/MISO interface definition on June 1, 2017.[46]

Coordinated flowgates (CF) are flowgates that are monitored and/or controlled by PJM or MISO, on which only one has a significant impact (defined as a greater than five percent impact based on transmission distribution factors and/or generation to load distribution factors). A reciprocal coordinated flowgate (RCF) is a CF that is monitored and controlled by 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, 2017, PJM had 150 flowgates eligible for M2M (Market to Market) coordination. In the first three months of 2017, PJM added 13 flowgates and deleted 12 flowgates, leaving 151 flowgates eligible for M2M coordination as of March 31, 2017. As of January 1, 2017, MISO had 261 flowgates eligible for M2M coordination. In the first three months of 2017, MISO added 35 flowgates and deleted 26 flowgates, leaving 270 flowgates eligible for M2M coordination as of March 31, 2017.

The firm flow entitlement (FFE) represents the amount of historic 2004 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 nonmonitoring 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 nonmonitoring RTO for congestion relief provided by the non-monitoring RTO based on the difference between the nonmonitoring RTO's market flow and their FFE. In the first three months of 2017, 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 9-9 shows credits for coordinated congestion management between PJM and MISO.

Figure 9-9 Credits for coordinated congestion management: January 1, 2016 through March 31, 2017[47]



45 See the *2012 State of the Market Report for PJM*, Volume II, Section 8, "Interchange Transactions," for a more detailed discussion.

46 See "Joint and Common Market: MISO-PJM Interface Pricing Update," (November 15, 2016) <http://www.pjm.com/~/media/committees-groups/stakeholder-meetings/pjm-miso-joint-common/20161115/20161115-item-03a-interface-pricing-post-implementation.ashx>.

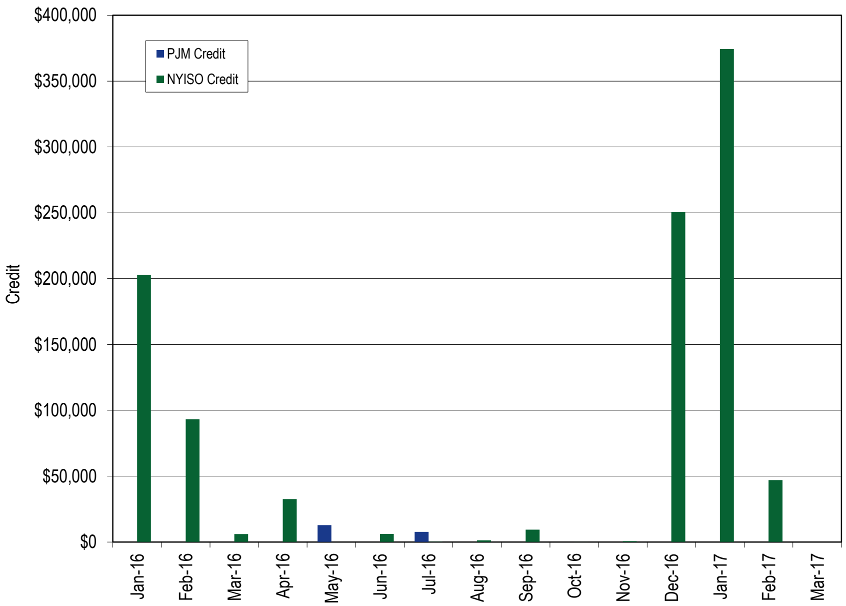
47 The totals represented in this figure represent the settlements as of the time of this report and may not include adjustments or resettlements.

PJM and 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.

In the first three months of 2017, 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 9-10 shows credits for coordinated congestion management between PJM and NYISO.

Figure 9-10 Credits for coordinated congestion management (flowgates): January 1, 2016 through March 31, 2017[49]



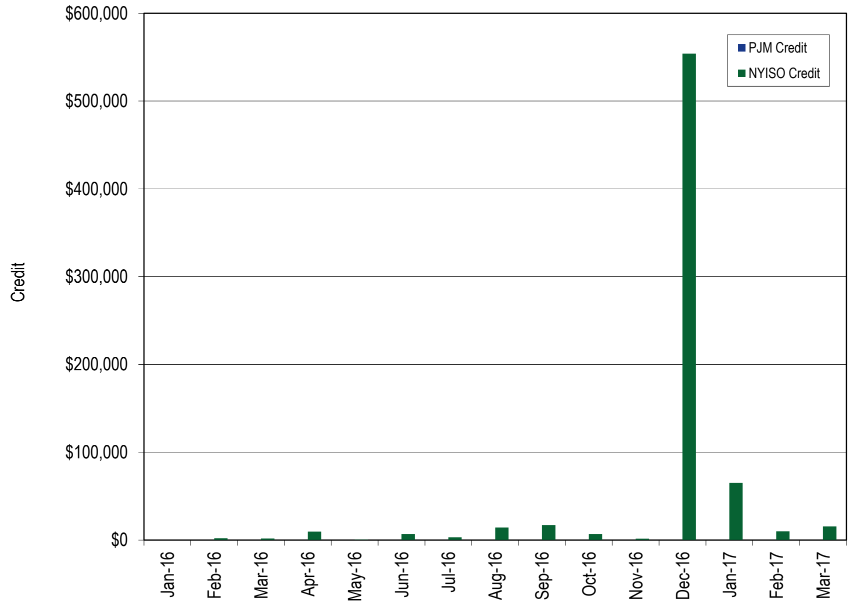
48 See "New York Independent System Operator, Inc., Joint Operating Agreement with PJM Interconnection, L.L.C.," (May 26, 2016) <http://www.pjm.com/~/media/documents/agreements/nyiso-joa.ashx>.

49 The totals represented in this figure represent the settlements as of the time of this report and may not include adjustments or resettlements.

The M2M coordination process focuses on real-time market coordination to manage transmission limitations that occur on M2M flowgates in a 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 an 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 the first three months of 2017, PAR settlements resulted in monthly payments from PJM to NYISO. Figure 9-11 shows the Ramapo PAR credits for coordinated congestion management between PJM and NYISO.

50 See "New York Independent System Operator, Inc., Joint Operating Agreement with PJM Interconnection, L.L.C.," (May 26, 2016) <http://www.pjm.com/~/media/documents/agreements/nyiso-joa.ashx>.

Figure 9-11 Credits for coordinated congestion management (Ramapo PARs): January 1, 2016 through March 31, 2017[51]



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 transactions under the Transmission Line Loading Relief (TLR) procedure to achieve the same relief. The agreement remained in effect in the first three months of 2017.

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

51 The totals represented in this figure represent the settlements as of the time of this report and may not include adjustments or resettlements.
52 See "Joint Reliability Coordination Agreement Among and Between PJM Interconnection, L.L.C., and Tennessee Valley Authority," (October 15, 2014) <http://www.pjm.com/~/media/documents/agreements/joint-reliability-coordination-agreement-miso-pjm-tva.ashx>.
53 See "Amended and Restated Joint Operating Agreement Among and Between PJM Interconnection, L.L.C., and Duke Energy Progress Inc.," (December 3, 2014) <http://www.pjm.com/media/documents/merged-tariffs/progress-joa.pdf>.
54 See *PJM Interconnection, L.L.C and Progress Energy Carolinas, Inc.* Docket No. ER10-713-000 (February 2, 2010).

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 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.

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.

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

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.

congestion management protocol needs to be revised. The existing JOA does not apply to the merged company and should be terminated.

Article 14 of the JOA provides details of the PJM/DEP congestion management agreement (CMA). The purpose of the CMA is to allow "DEP to quickly respond to the LMP values sent by PJM to DEP. This quick response will help manage the congestion on the PJM transmission system by maintaining flows within established limits and stabilizing PJM LMP values, and will help reduce the need to use the TLR process to relieve the congestion by maintaining power flows within established reliability limits." Congestion is managed by using a dynamic schedule between CPLE and PJM. DEP responds to the dynamic pricing signal sent by PJM by increasing generation, which creates energy flow in the direction from CPLE to PJM or by decreasing generation, which creates energy flow in the direction from PJM to CPLE. The dynamic schedule calls for more DEP generation when the DEP marginal cost of online generation is less than the CPLE LMP, and it calls for less DEP generation when the DEP marginal cost exceeds the CPLE LMP. The economic energy flow on the dynamic schedule reduces congestion.

The amount of congestion relief is limited by the amount of energy that can flow on the dynamic schedule. Several factors determine this limit, including: the physical limitations of DEP's units; ATC limits on the transmission path between CPLE and PJM; the actual confirmed transmission acquired in advance by DEP. Section 14.4.1 of the JOA states that:

> The transmission service used on the DEP transmission system to support the process described in this Article will be a non-firm point to point reservation from DEP to PJM made by DEP. The Dynamic Schedule will be limited to the point to point reservation. The transmission service used on the PJM transmission system will be network secondary service.

In the first three months of 2017, DEP acquired the required transmission service in only 139 of the 2,159 hours (6.4 percent of all hours), with an average capacity of approximately 129 MW. At most, DEP could have increased their generation to help manage constraints via a sale of power to PJM 6.4 percent of the time in the first three months of 2017, and the maximum redispatch would have been only 129 MW, on average.

A CMA that can only be used in 6.4 percent of all hours is not an effective approach to congestion management. 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 the first three months of 2017.

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 the first three months of 2017.

60 See "PJM-VACAR South RC Agreement," (November 7, 2014) <http://www.pjm.com/~/media/documents/agreements/executed-pjm-vacar-rc-agreement.ashx>.
61 See "Balancing Authority Operations Coordination Agreement between Wisconsin Electric Power Company and PJM Interconnection, LLC," (July 20, 2013) <http://www.pjm.com/~/media/documents/agreements/balancing-authority-operations-coordination-agreement.ashx>.

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 the first three months of 2017.

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 9-36 shows the real-time LMP calculated per the PJM/PEC JOA and the high/low pricing method used by Duke and NCMPA for the first three months of 2017. The values shown in Table 9-36 are the average LMP over only the hours in the first three months of 2017, where interchange transactions settled at those pricing points. The difference between the LMP under these agreements and PJM's SouthIMP LMP ranged from -$0.73 with Duke to -$0.14 with NCMPA.[64] This means that under the specific interface pricing agreements, Duke would receive, on average, $0.27 less for importing energy into PJM than if they were to receive the SouthIMP pricing point. In the first three months of 2017, market participants received $106,941 less for importing energy using these pricing points than they would have if they were to have received the SouthIMP pricing point. The difference between the LMP under these agreements and PJM's SouthEXP LMP ranged from $0.59 with DUKE to $3.18 with PEC. This means that under the specific interface pricing agreements, PEC would pay, on average, $3.18 more for exporting energy from PJM than they would have if they were to pay the SouthEXP pricing point. In the first three months of 2017, market participants paid $155,641 more for exporting energy using these pricing points than they would have if they were to have paid the SouthEXP pricing point.

Table 9-36 Real-time average hourly LMP comparison for Duke, PEC and NCMPA: January 1 through March 31, 2017

	Import LMP	Export LMP	SOUTHIMP	SOUTHEXP	Difference IMP LMP - SOUTHIMP	Difference EXP LMP - SOUTHEXP
Duke	$34.54	$26.20	$35.27	$25.61	($0.73)	$0.59
PEC	$25.84	$38.48	$25.99	$35.30	($0.15)	$3.18
NCMPA	$27.50	NA	$27.63	NA	($0.14)	NA

Table 9-37 shows the day-ahead LMP calculated per the PJM/PEC JOA and the high/low pricing method used by Duke and NCMPA for the first three months of 2017. The values shown in Table 9-37 are the average LMP over only the hours in the first three months of 2017, where interchange transactions settled at those pricing points. The difference between the LMP under these agreements and PJM's SouthIMP LMP ranged from $0.09 with Duke to $0.62 with PEC. This means that under the specific interface pricing agreements, PEC would receive, on average, $0.62 more for importing energy into PJM than if they were to receive the SouthIMP pricing point. In the first three months of 2017, market participants received $71,624 more for importing energy using these pricing points than they would have if they were to have received the SouthIMP pricing point. The difference between the LMP under these agreements and PJM's SouthEXP LMP was $2.86 at the PEC interface (in the first three months of 2017, neither Duke nor NCMPA had day ahead transactions settle at their respective export pricing points). This means that under the specific interface pricing agreements, PEC would pay, on average, $2.86 more for exporting energy from PJM than if they were to pay the SouthEXP pricing point. In the first three months of 2017, market participants

62 See "Northeastern ISO/RTO Planning Coordination Protocol," (December 8, 2004) <http://www.pjm.com/~/media/documents/agreements/northeastern-iso-rto-planning-coordination-protocol.ashx>.
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.

paid $95,715 more for exporting energy using these pricing points than they would have if they were to have paid the SouthEXP pricing point.

Table 9-37 Day-ahead average hourly LMP comparison for Duke, PEC and NCMPA: January 1 through March 31, 2017

	Import LMP	Export LMP	SOUTHIMP	SOUTHEXP	Difference IMP LMP - SOUTHIMP	Difference EXP LMP - SOUTHEXP
Duke	$31.37	NA	$31.28	NA	$0.09	NA
PEC	$28.65	$36.32	$28.03	$33.46	$0.62	$2.86
NCMPA	$28.87	NA	$28.74	NA	$0.13	NA

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 (Duke Energy Progress) is engaged in congestion management with PJM while the other part of the entity (Duke) 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.

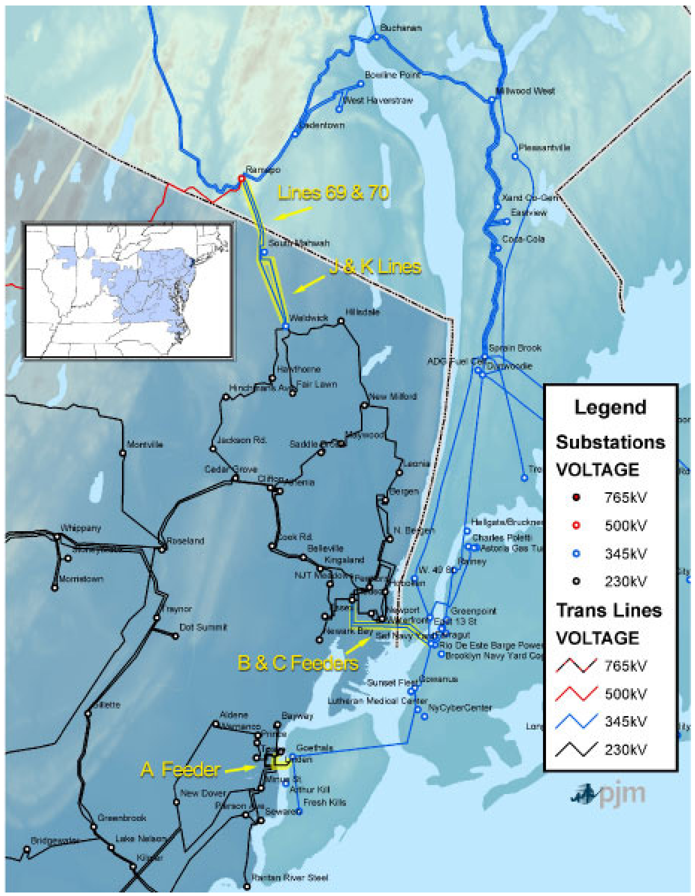
The Con Edison protocol models a fixed MW level flowing from NYISO to PJM over the JK (Ramapo - Waldwick) interface, and from PJM to NYISO over the ABC (Hudson - Farragut and Linden - Goethals) interface (See Figure 9-12).

On April 28, 2016, Con Edison announced its intent to terminate its 1,000 MW long-term firm point-to-point transmission service, effective May 1, 2017. Upon termination of the transmission reservation, the Con Edison protocol would also be terminated. On October 4, 2016, the NYISO and PJM issued a draft white paper to begin discussions for developing alternative designs for using the ABC and JK interfaces upon expiration of the Con Edison protocol effective May, 1, 2017.[71] The draft white paper proposal includes modifications to the existing PJM-NY AC Proxy Bus definition to include the JK and ABC lines and the inclusion of the JK and ABC lines in the market-to-market PAR coordination process. The proposal also includes provisions for determining

65 See the *2017 Quarterly State of the Market Report for PJM: January through March*, Section 4 – "Energy Market Uplift" 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 See "*Con Ed/PSEG Wheel Replacement Proposal*," (December 19, 2016) which can be accessed at: <http://www.pjm.com/~/media/library/reports-notices/special-reports/20161004-coned-pseg-wheel-replacement-proposal.ashx>.

the target flows over the JK and ABC interfaces. The proposed target flows will be based on a static interchange percentage and will continue to include a percentage of the Rockland Electric Company (RECO) load. Additionally, the PJM and NYISO proposal also includes an operational base flow (OBF) of 400 MW from NYISO to PJM over the JK Interface and 400 MW from PJM to NYISO over the ABC Interface.

Figure 9-12 Con Edison Protocol



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.

The number of PJM issued TLRs of level 3a or higher decreased from eight in the first three months of 2016 to three in the first three months of 2017.[72] The number of different flowgates for which PJM declared a TLR 3a or higher was one in the first three months of 2016 and one in the first three months of 2017. The total MWh of transactions curtailed decreased by 94.3 percent from 106,848 MWh in the first three months of 2016 to 6,140 MWh in the first three months of 2017.

The number of MISO issued TLRs of level 3a or higher increased from five in the first three months of 2016 to 18 in the first three months of 2017. The number of different flowgates for which MISO declared a TLR 3a or higher increased from three in the first three months of 2016 to six in the first three months of 2017. The total MWh of transaction curtailments increased by 186.4 percent from 6,556 MWh in the first three months of 2016 to 18,775 MWh in the first three months of 2017.

The number of NYISO issued TLRs of level 3a or higher was zero in the first three months of 2016 and zero in the first three months of 2017. The number of different flowgates for which NYISO declared a TLR 3a or higher was zero in the first three months of 2016 and zero in the first three months of 2017. The total MWh of transaction curtailments was 0 MWh in the first three months of 2016 and 0 MWh in the first three months of 2017.

72 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.

Table 9-38 PJM MISO, and NYISO TLR procedures: January 1, 2014 through March 31, 2017

	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-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
Jan-16	6	0	0	1	0	0	83,752	0	0
Feb-16	2	0	0	1	0	0	23,096	0	0
Mar-16	0	5	0	0	3	0	0	6,556	0
Apr-16	0	6	0	0	2	0	0	2,034	0
May-16	0	6	0	0	4	0	0	5,360	0
Jun-16	0	5	1	0	2	1	0	18,121	217
Jul-16	0	18	0	0	8	0	0	38,815	0
Aug-16	0	16	0	0	3	0	0	30,181	0
Sep-16	0	8	0	0	4	0	0	19,394	0
Oct-16	0	3	0	0	2	0	0	1,702	0
Nov-16	0	9	0	0	3	0	0	5,622	0
Dec-16	1	1	0	1	1	0	443	0	0
Jan-17	3	1	0	1	1	0	6,140	255	0
Feb-17	0	8	0	0	2	0	0	10,566	0
Mar-17	0	9	0	0	4	0	0	7,954	0

Table 9-39 Number of TLRs by TLR level by reliability coordinator: January 1 through March 31, 2017[73]

Year	Reliability Coordinator	3a	3b	4	5a	5b	6	Total
2017	MISO	11	4	0	3	2	0	20
	NYIS	0	0	0	0	0	0	0
	ONT	0	0	0	0	0	0	0
	PJM	2	1	0	0	0	0	3
	SOCO	0	2	0	0	0	0	2
	SWPP	12	1	0	16	5	0	34
	TVA	3	4	0	1	0	0	8
	VACS	0	1	0	0	0	0	1
Total		28	13	0	20	7	0	68

Up to Congestion

The original purpose of up to congestion transactions (UTC) 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.[74]

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 dramatically.

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.[75]

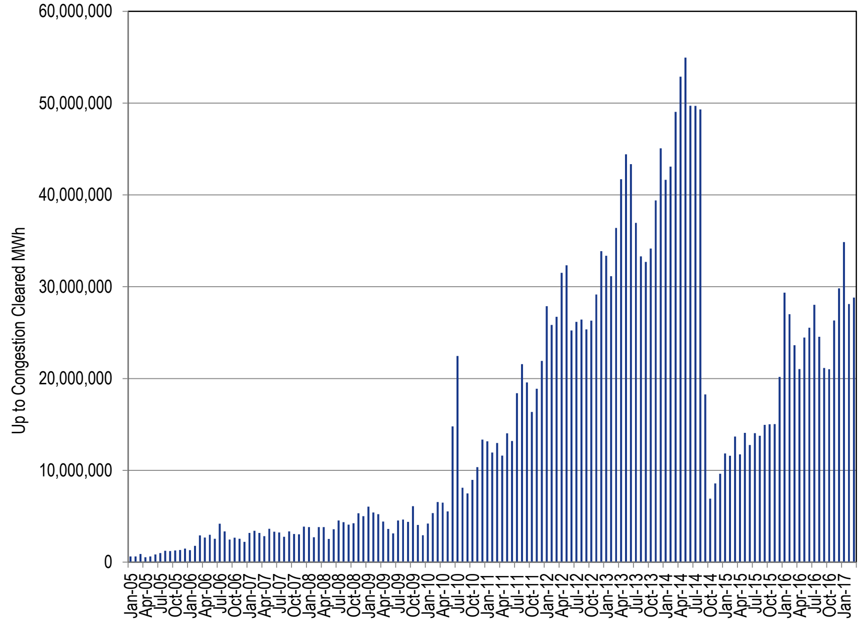
73 Southern Company Services, Inc. (SOCO) is the reliability coordinator covering a portion of Mississippi, Alabama, Florida and Georgia. Southwest Power Pool (SWPP) is the reliability coordinator for SPP. VACAR-South (VACS) is the reliability coordinator covering a portion of North Carolina and South Carolina.
74 See the *2012 State of the Market Report for PJM*, Volume II, Section 8, "Interchange Transactions," for a more detailed discussion.
75 See the *2017 Quarterly State of the Market Report for PJM: January through March*, Section 13: FTRs and ARRs, "FTR Forfeitures" for more information on up to congestion transaction impacts on FTRs.

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.[76]

As a result of the requirement to pay uplift charges and the uncertainty about the level of the required uplift charges, market participants reduced up to congestion trading effective September 8, 2014. There was an increase in up to congestion volume starting in December 2015, coincident with the expiration of the fifteen month limit on the payment of prior uplift charges (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..."[77]

The average number of up to congestion bids submitted in the Day-Ahead Energy Market increased by 47.7 percent, from 134,610 bids per day in the first three months of 2016 to 198,362 bids per day in the first three months of 2017. The average cleared volume of up to congestion bids submitted in the Day-Ahead Energy Market increased by 16.0 percent, from 879,068 MWh per day in the first three months of 2016, to 1,019,907 MWh per day in the first three months of 2017.

Figure 9-13 Monthly up to congestion cleared bids in MWh: January 1, 2005 through March 31, 2017



76 148 FERC ¶ 61,144 (2014) *Order Instituting Section 206 Proceeding and Establishing Procedures.*
77 16 U.S.C. § 824e.

Table 9-40 Monthly volume of cleared and submitted up to congestion bids: January 1, 2016 through March 31, 2017[78]

	Bid MW					Bid Volume				
Month	Import	Export	Wheel	Internal	Total	Import	Export	Wheel	Internal	Total
Jan-16	11,319,511	7,453,438	1,014,763	80,909,489	100,697,200	477,343	219,598	39,513	3,737,937	4,474,391
Feb-16	12,155,175	7,740,113	1,363,163	85,132,591	106,391,042	422,382	228,823	42,609	3,306,154	3,999,968
Mar-16	11,714,639	7,934,801	1,415,976	88,260,658	109,326,075	382,177	225,473	36,332	3,131,152	3,775,134
Apr-16	9,823,079	6,559,076	1,305,759	74,723,429	92,411,342	397,591	189,981	29,138	3,760,097	4,376,807
May-16	9,513,613	6,823,576	1,095,593	71,945,618	89,378,399	404,406	207,483	32,187	3,824,204	4,468,280
Jun-16	10,535,566	7,229,295	934,909	90,318,486	109,018,256	393,040	205,237	34,318	3,980,024	4,612,619
Jul-16	11,954,606	10,034,200	1,573,690	111,637,376	135,199,873	432,142	273,349	36,430	4,583,276	5,325,197
Aug-16	11,435,407	7,826,884	1,203,704	89,117,338	109,583,333	396,134	258,077	33,330	4,352,104	5,039,645
Sep-16	8,865,500	7,188,474	793,894	76,390,509	93,238,378	286,637	236,555	29,616	3,813,679	4,366,487
Oct-16	7,621,317	6,486,553	725,041	75,471,554	90,304,464	292,479	268,611	35,720	4,237,454	4,834,264
Nov-16	9,347,175	7,739,170	1,092,482	83,836,320	102,015,146	361,868	273,254	32,322	4,613,501	5,280,945
Dec-16	9,648,240	7,976,967	856,973	91,141,019	109,623,199	446,573	295,302	29,569	5,778,358	6,549,802
Jan-17	12,071,248	10,779,934	1,022,748	122,301,537	146,175,467	503,193	359,899	34,470	6,725,774	7,623,336
Feb-17	11,420,648	8,942,116	608,065	118,800,901	139,771,730	394,062	268,571	27,086	4,894,155	5,583,874
Mar-17	9,158,336	9,968,026	595,492	102,176,604	121,898,458	284,402	289,574	24,835	4,046,536	4,645,347
TOTAL	1,375,677,548	1,295,966,571	87,491,578	4,449,029,780	7,208,165,476	36,161,249	30,218,015	2,341,487	173,529,731	242,250,482

	Cleared MW					Cleared Volume				
Month	Import	Export	Wheel	Internal	Total	Import	Export	Wheel	Internal	Total
Jan-16	2,944,505	2,026,327	274,430	24,103,637	29,348,899	170,082	69,173	10,390	1,577,269	1,826,914
Feb-16	2,719,184	2,001,418	244,646	22,049,244	27,014,492	126,889	67,289	9,850	1,251,383	1,455,411
Mar-16	2,370,270	2,001,360	198,400	19,061,805	23,631,834	105,098	65,977	8,070	1,085,479	1,264,624
Apr-16	2,348,160	1,264,954	204,465	17,214,976	21,032,555	140,346	48,085	7,067	1,740,662	1,936,160
May-16	2,209,309	1,882,586	235,696	20,137,089	24,464,680	156,256	64,333	6,665	1,987,586	2,214,840
Jun-16	2,178,050	1,871,788	153,654	21,334,532	25,538,023	128,728	62,438	6,906	1,621,997	1,820,069
Jul-16	2,335,606	2,109,811	237,917	23,341,287	28,024,621	120,775	79,269	7,902	1,587,513	1,795,459
Aug-16	1,914,794	2,139,929	183,616	20,303,066	24,541,404	91,351	85,598	7,902	1,522,203	1,707,054
Sep-16	1,706,788	1,572,221	150,834	17,714,998	21,144,842	76,662	74,123	8,808	1,502,828	1,662,421
Oct-16	1,387,294	1,065,855	133,639	18,431,481	21,018,269	84,852	78,316	10,892	1,768,967	1,943,027
Nov-16	2,772,101	1,323,987	292,429	21,932,490	26,321,007	142,207	69,987	8,539	1,889,760	2,110,493
Dec-16	2,904,123	1,857,750	182,373	24,882,966	29,827,212	163,420	96,565	6,814	2,375,795	2,642,594
Jan-17	3,478,967	2,446,235	235,641	28,699,881	34,860,725	153,756	106,883	6,710	2,387,196	2,654,545
Feb-17	2,020,772	1,860,138	88,621	24,147,889	28,117,419	91,586	76,129	5,506	1,648,658	1,821,879
Mar-17	2,106,568	1,736,786	147,294	24,822,836	28,813,485	87,599	86,494	5,157	1,509,134	1,688,384
TOTAL	455,646,130	431,550,243	28,455,700	1,230,778,005	2,146,430,078	13,654,476	11,419,446	792,352	63,797,543	89,663,817

78 See the *2016 State of the Market Report for PJM*, Volume II, Appendix E, "Interchange Transactions," for the monthly volume of cleared and submitted up to congestion bids: 2009 through 2016.

In the first three months of 2017, the cleared MW volume of up to congestion transactions was comprised of 8.3 percent imports, 6.6 percent exports, 0.5 percent wheeling transactions and 84.6 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 up to congestion transactions (UTCs) to pay any uplift determined to be appropriate after Commission review, effective from September 8, 2014.[79] As of March 1, 2017, the Commission has not ruled on whether up to congestion transactions will be charged for uplift accrued during this time. On January 19, 2017, a notice of proposed rulemaking was issued to address UTC uplift for all RTOs/ISOs.[80] The outcome of the investigation in PJM will be held in abeyance pending the outcome of the NOPR proceeding.[81]

During the 15 month refund period of September 8, 2014, through December 7, 2015, 185,303,891 MWh of up to congestion transactions cleared the Day-Ahead Market 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 $18.5 million and $370.6 million. As potential obligations, this exposure creates a credit risk for those UTC traders who engaged in UTC transactions during this period. Table 9-41 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.

79 148 FERC ¶ 61,144 (2014) *Order Instituting Section 206 Proceeding and Establishing Procedures.*
80 *Uplift Cost Allocation and Transparency in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 158 FERC ¶ 61,047.
81 158 FERC ¶ 61,038 at P 3 (January 19, 2017).

Table 9-41 Credit risk associated with varying levels of potential uplift: September 8, 2014 through December 7, 2015

Uplift ($/MWh)	Credit risk if uplift is applied to both sides of UTC
$0.05	$18,530,389
$0.10	$37,060,778
$0.15	$55,591,167
$0.20	$74,121,556
$0.25	$92,651,945
$0.30	$111,182,334
$0.35	$129,712,724
$0.40	$148,243,113
$0.45	$166,773,502
$0.50	$185,303,891
$0.55	$203,834,280
$0.60	$222,364,669
$0.65	$240,895,058
$0.70	$259,425,447
$0.75	$277,955,836
$0.80	$296,486,225
$0.85	$315,016,614
$0.90	$333,547,003
$0.95	$352,077,393
$1.00	$370,607,782

PJM market participants that cleared UTCs during the specified refund period of September 8, 2014 through December 7, 2015, 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 during the refund period of September 8, 2014, through December 7, 2015, showed that the top 10 market participants would be responsible for 53.7 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 limit on the payment of prior uplift charges.[82]

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 as to 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.[83]

The MMU recommends that PJMSettlement Inc. immediately request a credit evaluation from all companies that engaged in up to congestion transactions during the refund period of September 8, 2014, through December 7, 2015. To the full extent of its 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.

82 16 U.S.C. § 824e.
83 See OATT Attachment Q § I.A.4.

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 can also be achieved by submitting a transaction that is in the opposite direction of a portion of a larger transaction schedule. 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 cannot see 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 path. However, if a market participant were to break the transaction into multiple segments, one on the NYIS-ONT path, and a second segment on the ONT-MISO-PJM path, the market participant would conceal the true source (NYISO) from PJM, and PJM would price the transaction as if its source were Ontario (the ONT interface price).

For example, market participants can submit one transaction with multiple segments among balancing authorities and another transaction which offsets all or part of a segment of the first transaction. If a market participant submits two separate transactions, one on the ONT-MISO-PJM path, and a second on the PJM-MISO path, the result of these transactions would be a net scheduled transaction from ONT to MISO, as the MISO-PJM segment of the first transaction is offset by the PJM-MISO transaction. In this example, PJM is not required to raise or lower generation as a result of these transactions, as they would for an import or an export, and there are no associated power flows across PJM. Nonetheless, the market participant is paid the price difference between the PJM/ONT interface pricing point and the PJM/MISO Interface pricing point. The market participant would be paid the PJM/ONT interface pricing point for the first transaction (ONT to PJM import) and the market participant would pay the PJM/MISO interface pricing point for the second transaction (PJM to MISO export). If the PJM/ONT interface price were higher than the PJM/MISO interface price, the market participant would be paid a net profit from the PJM market even though there was no impact on PJM operations.

The MMU recommends that PJM implement rules to prevent sham scheduling. The MMU recommends that PJM apply after the fact market settlement adjustments to identified sham scheduling segments to ensure that market participants cannot benefit from 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 noncontiguous nature of the PJM/IMO interface pricing point creates opportunities for market participants to engage in sham scheduling activities. For example, a market participant can use two separate transactions to create a flow from Ontario to MISO. In this example, the market participant uses the PJM energy market as a temporary generation and load point by first submitting a wheeling transaction from Ontario, through MISO and into PJM, then by submitting a second transaction from PJM to MISO. These two transactions, combined, create an actual flow along the Ontario/MISO Interface. Through sham scheduling, the market participant receives settlements from PJM when no changes in generation occur. This activity is similar to that observed when PJM had a Southwest and Southeast interface pricing point. During that time, market participants would 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.[84]

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

84 See "IMO Interface Definition Methodology Report," presented to the MIC (February 11, 2015) <http://www.pjm.com/~/media/committees-groups/committees/mic/20150211/20150211-item-08b-imo-interface-definition-methodology-report.ashx>.

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 the first three months of 2017, of the 581 GWh of the gross scheduled transactions between PJM and IESO, 579 GWh (99.7 percent) wheeled through MISO (see Table 9-23). The MMU recommends that PJM eliminate the PJM/IMO interface pricing point, and assign the transactions that originate or sink in the IESO balancing authority to the PJM/MISO interface pricing point.[85]

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.[86] 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.

85 On October 1, 2013, a sub-group of PJM's Market Implementation Committee started stakeholder discussions to address this inconsistency in market pricing.

86 PJM and the NYISO implemented CTS on November 4, 2014. 146 FERC ¶ 61,096 (2014).

The ITSCED application runs approximately every five minutes and each run produces forecast LMPs for the intervals approximately 30 minutes, 45 minutes, 90 minutes and 135 minutes ahead. Therefore, for each 15 minute interval, the various ITSCED solutions will produce 12 forecasted PJM/NYIS interface prices. To evaluate the accuracy of ITSCED forecasts, the forecasted PJM/NYIS interface price for each 15 minute interval from ITSCED was compared to the actual real-time interface LMP for the first three months of 2017. Table 9-42 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 40.6 percent of the intervals. In those intervals, the average price difference between the ITSCED forecasted LMP and the actual real-time LMP was $1.39 per MWh. In 4.9 percent of all intervals, the absolute value of the average price difference between the ITSCED forecasted LMP and the actual real-time interface LMP was greater than $20.00. The average price differences were $56.19 when the price difference was greater than $20.00, and $58.35 when the price difference was greater than -$20.00.

Table 9-42 Differences between forecast and actual PJM/NYIS interface prices: January 1 through March 31, 2017

Range of Price Differences	Percent of All Intervals	Average Price Difference
> $20	1.7%	$56.19
$10 to $20	2.6%	$13.67
$5 to $10	5.2%	$7.04
$0 to $5	40.6%	$1.39
$0 to -$5	39.4%	$1.39
-$5 to -$10	4.7%	$7.03
-$10 to -$20	2.6%	$14.02
< -$20	3.2%	$58.35

Table 9-43 shows how the accuracy of the ITSCED forecasted LMPs changes as the cases approach real-time. In the final ITSCED results prior to real time, in 76.4 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 78.5 percent in the 135 minute ahead ITSCED results.

Table 9-43 Differences between forecast and actual PJM/NYIS interface prices: January 1 through March 31, 2017

	~ 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	1.3%	$64.47	0.7%	$87.36	0.9%	$89.57	3.6%	$63.52
$10 to $20	2.4%	$13.64	2.0%	$13.21	2.2%	$13.66	3.5%	$13.81
$5 to $10	5.1%	$7.19	4.7%	$6.92	5.0%	$7.01	6.1%	$7.00
$0 to $5	35.4%	$1.51	40.3%	$1.41	45.0%	$1.30	46.4%	$1.33
$0 to -$5	43.1%	$1.57	40.7%	$1.42	37.1%	$1.26	33.0%	$1.22
-$5 to -$10	6.0%	$7.09	5.4%	$6.99	4.4%	$6.96	2.9%	$6.93
-$10 to -$20	3.1%	$13.88	2.8%	$13.99	2.2%	$13.91	1.9%	$14.21
< -$20	3.5%	$57.23	3.4%	$58.71	3.3%	$58.05	2.6%	$56.19

In 6.2 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 $63.52 when the price difference was greater than $20.00, and $56.19 when the price difference was greater than -$20.00.

Table 9-44 and Table 9-45 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 decline in the accuracy of the ITSCED forecast ability during periods of cold and hot weather.

Table 9-44 Monthly Differences between forecast and actual PJM/NYIS interface prices (percent of intervals): January 1 through March 31, 2017

Interval	Range of Price Differences	Jan	Feb	Mar	YTD Avg
~ 30 Minutes Prior to Real-Time	> $20	4.8%	1.3%	4.6%	3.6%
	$10 to $20	3.6%	1.2%	5.4%	3.5%
	$5 to $10	5.5%	4.1%	8.6%	6.1%
	$0 to $5	47.8%	50.6%	41.1%	46.4%
	$0 to -$5	31.0%	37.2%	31.2%	33.0%
	-$5 to -$10	3.1%	2.9%	2.7%	2.9%
	-$10 to -$20	1.3%	1.5%	2.8%	1.9%
	< -$20	3.1%	1.2%	3.5%	2.6%
Interval	Range of Price Differences	Jan	Feb	Mar	YTD Avg
~ 45 Minutes Prior to Real-Time	> $20	1.4%	0.1%	1.1%	0.9%
	$10 to $20	2.9%	0.7%	2.8%	2.2%
	$5 to $10	4.6%	2.7%	7.5%	5.0%
	$0 to $5	44.7%	48.3%	42.3%	45.0%
	$0 to -$5	36.8%	41.4%	33.4%	37.1%
	-$5 to -$10	4.3%	3.5%	5.3%	4.4%
	-$10 to -$20	1.6%	1.7%	3.2%	2.2%
	< -$20	3.7%	1.6%	4.5%	3.3%
Interval	Range of Price Differences	Jan	Feb	Mar	YTD Avg
~ 90 Minutes Prior to Real-Time	> $20	1.1%	0.0%	0.8%	0.7%
	$10 to $20	2.2%	0.8%	3.0%	2.0%
	$5 to $10	3.2%	3.1%	7.7%	4.7%
	$0 to $5	37.8%	43.7%	39.7%	40.3%
	$0 to -$5	44.1%	43.8%	34.5%	40.7%
	-$5 to -$10	4.9%	4.8%	6.4%	5.4%
	-$10 to -$20	2.8%	2.2%	3.3%	2.8%
	< -$20	3.9%	1.6%	4.7%	3.4%
Interval	Range of Price Differences	Jan	Feb	Mar	YTD Avg
~ 135 Minutes Prior to Real-Time	> $20	1.5%	0.2%	2.0%	1.3%
	$10 to $20	1.6%	1.3%	4.2%	2.4%
	$5 to $10	4.4%	3.9%	6.9%	5.1%
	$0 to $5	33.3%	40.6%	32.8%	35.4%
	$0 to -$5	46.9%	45.3%	37.4%	43.1%
	-$5 to -$10	5.2%	4.6%	8.1%	6.0%
	-$10 to -$20	3.2%	2.3%	3.8%	3.1%
	< -$20	3.9%	1.7%	4.7%	3.5%

Table 9-45 Monthly differences between forecast and actual PJM/NYIS interface prices (average price difference): January 1 through March 31, 2017

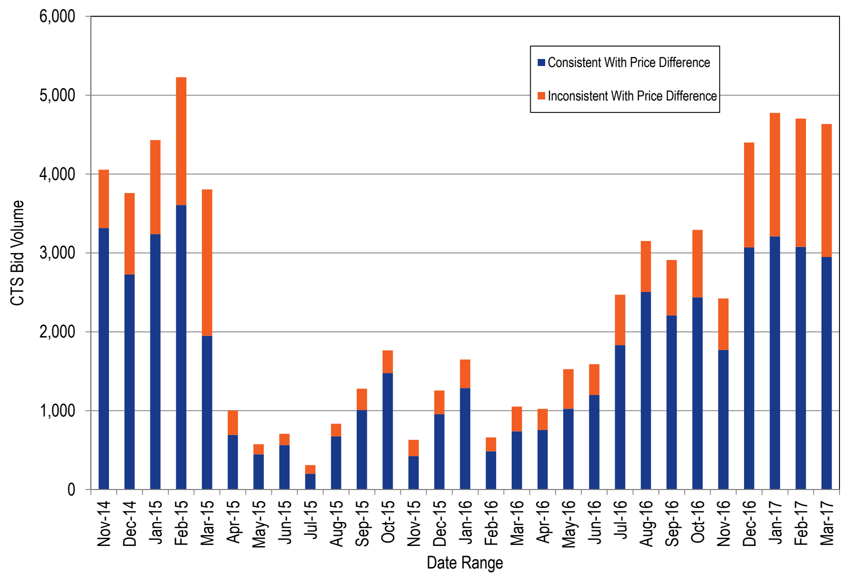
Interval	Range of Price Differences	Jan	Feb	Mar	YTD Avg
~ 30 Minutes Prior to Real-Time	> $20	$63.36	$38.03	$70.05	$63.52
	$10 to $20	$13.96	$12.85	$13.90	$13.81
	$5 to $10	$6.99	$7.03	$7.01	$7.00
	$0 to $5	$1.20	$1.24	$1.58	$1.33
	$0 to -$5	$1.07	$1.12	$1.48	$1.22
	-$5 to -$10	$6.92	$7.14	$6.72	$6.93
	-$10 to -$20	$13.76	$13.84	$14.60	$14.21
	< -$20	$48.79	$61.42	$61.04	$56.19
Interval	Range of Price Differences	Jan	Feb	Mar	YTD Avg
~ 45 Minutes Prior to Real-Time	> $20	$129.62	$27.09	$39.66	$89.57
	$10 to $20	$13.93	$13.48	$13.42	$13.66
	$5 to $10	$6.94	$6.85	$7.11	$7.01
	$0 to $5	$1.16	$1.22	$1.54	$1.30
	$0 to -$5	$1.09	$1.21	$1.49	$1.26
	-$5 to -$10	$7.05	$7.01	$6.87	$6.96
	-$10 to -$20	$13.89	$13.71	$14.01	$13.91
	< -$20	$55.02	$54.95	$61.58	$58.05
Interval	Range of Price Differences	Jan	Feb	Mar	YTD Avg
~ 90 Minutes Prior to Real-Time	> $20	$119.08	$33.83	$42.81	$87.36
	$10 to $20	$12.58	$13.63	$13.59	$13.21
	$5 to $10	$7.00	$6.54	$7.03	$6.92
	$0 to $5	$1.26	$1.35	$1.61	$1.41
	$0 to -$5	$1.30	$1.39	$1.61	$1.42
	-$5 to -$10	$6.98	$7.01	$6.99	$6.99
	-$10 to -$20	$14.12	$13.90	$13.95	$13.99
	< -$20	$56.42	$59.93	$60.23	$58.71
Interval	Range of Price Differences	Jan	Feb	Mar	YTD Avg
~ 135 Minutes Prior to Real-Time	> $20	$106.59	$28.28	$34.69	$64.47
	$10 to $20	$14.50	$12.23	$13.70	$13.64
	$5 to $10	$7.33	$7.14	$7.12	$7.19
	$0 to $5	$1.31	$1.47	$1.75	$1.51
	$0 to -$5	$1.45	$1.56	$1.72	$1.57
	-$5 to -$10	$7.06	$7.18	$7.08	$7.09
	-$10 to -$20	$14.00	$13.85	$13.79	$13.88
	< -$20	$56.09	$54.70	$58.99	$57.23

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 March 31, 2017, 69,896 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 20,078 (28.7 percent) of the intervals was inconsistent with the differences in real-time PJM/NYISO and NYISO/PJM prices. For example, if a market participant submits a CTS transaction from NYISO to PJM with a spread bid of $5.00, and NYISO's forecasted PJM interface price was at least $5.00 lower than PJM's forecasted NYISO interface price, the transaction would be approved. For 28.7 percent of the approved transactions, the actual, real-time price differentials were in the opposite direction of the forecast differential. The actual, real-time price differentials meant that the transactions would have been economic in the opposite direction. For 71.3 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 percent of cleared bids that resulted in flows consistent and inconsistent with price differences.

Figure 9-14 Monthly cleared PJM/NYIS CTS bid volume: November 1, 2014 through March 31, 2017



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.

To evaluate the accuracy of ITSCED forecasts, the forecasted PJM/MISO interface price for each 15 minute interval from ITSCED was compared to the actual real-time interface LMP for the first three months of 2017. Table 9-46 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 40.3 percent of all intervals. In those intervals, the average price difference between the ITSCED forecasted LMP and the actual real-time LMP was $1.31. In 4.8 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 $43.54 when the price difference was greater than $20.00, and $53.55 when the price difference was greater than -$20.00.

Table 9-46 Differences between forecast and actual PJM/MISO interface prices: January 1 through March 31, 2017

Range of Price Differences	Percent of All Intervals	Average Price Difference
> $20	2.0%	$43.54
$10 to $20	3.1%	$13.76
$5 to $10	6.1%	$7.03
$0 to $5	40.3%	$1.31
$0 to -$5	39.5%	$1.28
-$5 to -$10	4.2%	$6.94
-$10 to -$20	2.0%	$13.93
< -$20	2.8%	$53.55

Table 9-47 shows how the accuracy of the ITSCED forecasted LMPs change as the cases approach real-time. In the final ITSCED results prior to real time, in 78.8 percent of all intervals, the average price difference between the ITSCED forecasted LMP and the actual real-time interface LMP fell within +/- $5.00 of the actual PJM/MISO interface real-time LMP, compared to 78.6 percent in the 135 minute ahead ITSCED results.

Table 9-47 Differences between forecast and actual PJM/MISO interface prices: January 1 through March 31, 2017

	~ 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	1.5%	$34.29	1.2%	$37.16	0.9%	$40.35	3.5%	$50.52
$10 to $20	3.6%	$13.77	2.7%	$13.52	2.5%	$13.63	3.6%	$14.10
$5 to $10	5.8%	$7.19	5.7%	$6.92	5.9%	$6.94	6.7%	$7.05
$0 to $5	32.4%	$1.37	41.8%	$1.32	45.6%	$1.26	45.4%	$1.29
$0 to -$5	46.2%	$1.42	39.1%	$1.25	36.9%	$1.17	33.4%	$1.15
-$5 to -$10	5.4%	$6.86	4.4%	$6.87	3.6%	$6.92	3.4%	$7.09
-$10 to -$20	2.2%	$13.71	2.0%	$13.77	1.8%	$13.76	1.8%	$14.07
< -$20	3.0%	$52.60	2.9%	$52.80	2.7%	$54.72	2.3%	$55.78

In 5.8 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 $50.52 when the price difference was greater than $20.00, and $55.78 when the price difference was greater than -$20.00.

Table 9-48 and Table 9-49 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 decline in the accuracy of the ITSCED forecast ability during periods of cold and hot weather.

Table 9-48 Monthly Differences between forecast and actual PJM/MISO interface prices (percent of intervals): January 1 through March 31, 2017

Interval	Range of Price Differences	Jan	Feb	Mar	YTD Avg
~ 30 Minutes Prior to Real-Time	> $20	3.4%	1.6%	5.3%	3.5%
	$10 to $20	3.4%	1.1%	6.2%	3.6%
	$5 to $10	5.7%	3.7%	10.3%	6.7%
	$0 to $5	48.7%	48.7%	39.0%	45.4%
	$0 to -$5	32.9%	39.9%	27.9%	33.4%
	-$5 to -$10	2.2%	2.8%	5.0%	3.4%
	-$10 to -$20	1.5%	0.9%	3.0%	1.8%
	< -$20	2.1%	1.3%	3.3%	2.3%
Interval	Range of Price Differences	Jan	Feb	Mar	YTD Avg
~ 45 Minutes Prior to Real-Time	> $20	0.7%	0.2%	1.7%	0.9%
	$10 to $20	2.7%	0.5%	4.2%	2.5%
	$5 to $10	5.0%	3.1%	9.3%	5.9%
	$0 to $5	47.0%	48.0%	41.9%	45.6%
	$0 to -$5	37.3%	42.6%	31.4%	36.9%
	-$5 to -$10	3.1%	2.7%	5.0%	3.6%
	-$10 to -$20	1.5%	1.2%	2.8%	1.8%
	< -$20	2.7%	1.7%	3.7%	2.7%
Interval	Range of Price Differences	Jan	Feb	Mar	YTD Avg
~ 90 Minutes Prior to Real-Time	> $20	1.1%	0.2%	2.2%	1.2%
	$10 to $20	2.4%	1.0%	4.8%	2.7%
	$5 to $10	3.9%	3.4%	9.6%	5.7%
	$0 to $5	40.5%	45.7%	39.6%	41.8%
	$0 to -$5	42.9%	43.3%	31.6%	39.1%
	-$5 to -$10	4.3%	3.4%	5.5%	4.4%
	-$10 to -$20	2.0%	1.3%	2.7%	2.0%
	< -$20	3.0%	1.7%	3.9%	2.9%
Interval	Range of Price Differences	Jan	Feb	Mar	YTD Avg
~ 135 Minutes Prior to Real-Time	> $20	1.6%	0.3%	2.5%	1.5%
	$10 to $20	3.6%	1.5%	5.5%	3.6%
	$5 to $10	4.9%	3.8%	8.5%	5.8%
	$0 to $5	31.9%	36.0%	29.6%	32.4%
	$0 to -$5	48.2%	51.6%	39.2%	46.2%
	-$5 to -$10	4.6%	4.1%	7.2%	5.4%
	-$10 to -$20	2.3%	1.1%	3.2%	2.2%
	< -$20	2.9%	1.7%	4.2%	3.0%

Table 9-49 Monthly differences between forecast and actual PJM/MISO interface prices (average price difference): January 1 through March 31, 2017

Interval	Range of Price Differences	Jan	Feb	Mar	YTD Avg
~ 30 Minutes Prior to Real-Time	> $20	$43.86	$42.30	$57.15	$50.52
	$10 to $20	$13.89	$13.95	$14.25	$14.10
	$5 to $10	$7.11	$6.92	$7.06	$7.05
	$0 to $5	$1.17	$1.10	$1.67	$1.29
	$0 to -$5	$0.99	$1.03	$1.48	$1.15
	-$5 to -$10	$7.19	$6.96	$7.12	$7.09
	-$10 to -$20	$14.04	$14.32	$14.02	$14.07
	< -$20	$60.49	$50.06	$54.83	$55.78
Interval	Range of Price Differences	Jan	Feb	Mar	YTD Avg
~ 45 Minutes Prior to Real-Time	> $20	$42.79	$34.22	$40.06	$40.35
	$10 to $20	$13.11	$14.62	$13.86	$13.63
	$5 to $10	$6.98	$6.60	$7.02	$6.94
	$0 to $5	$1.05	$1.07	$1.70	$1.26
	$0 to -$5	$1.01	$1.11	$1.44	$1.17
	-$5 to -$10	$7.09	$6.91	$6.83	$6.92
	-$10 to -$20	$13.69	$13.42	$13.91	$13.76
	< -$20	$57.60	$47.03	$55.84	$54.72
Interval	Range of Price Differences	Jan	Feb	Mar	YTD Avg
~ 90 Minutes Prior to Real-Time	> $20	$33.41	$37.26	$39.08	$37.16
	$10 to $20	$13.60	$13.14	$13.55	$13.52
	$5 to $10	$6.95	$6.75	$6.96	$6.92
	$0 to $5	$1.12	$1.10	$1.76	$1.32
	$0 to -$5	$1.11	$1.23	$1.48	$1.25
	-$5 to -$10	$7.00	$6.84	$6.79	$6.87
	-$10 to -$20	$14.11	$13.10	$13.80	$13.77
	< -$20	$55.41	$47.69	$52.80	$52.80
Interval	Range of Price Differences	Jan	Feb	Mar	YTD Avg
~ 135 Minutes Prior to Real-Time	> $20	$32.31	$38.91	$35.10	$34.29
	$10 to $20	$14.39	$12.96	$13.54	$13.77
	$5 to $10	$7.07	$7.28	$7.21	$7.19
	$0 to $5	$1.15	$1.16	$1.84	$1.37
	$0 to -$5	$1.26	$1.39	$1.65	$1.42
	-$5 to -$10	$6.90	$6.82	$6.86	$6.86
	-$10 to -$20	$13.64	$12.97	$14.00	$13.71
	< -$20	$56.50	$46.86	$52.01	$52.60

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 nonfirm 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. 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 9-50 shows that since the inception of the business rule change on April 12, 2013, there was uncollected congestion in only one month, January 2016. The negative congestion means that market participants who used the not willing to pay congestion transmission option for their wheel through transactions had transactions that flowed in the direction opposite to congestion. When market participants use the not willing to pay congestion product, it also means that they are not willing to receive congestion credits, which was the case in January 2016.

Table 9-50 Monthly uncollected congestion charges: January 1, 2010 through March 31, 2017

Month	2010	2011	2012	2013	2014	2015	2016	2017
Jan	$148,764	$3,102	$0	$5	$0	$0	($44)	$0
Feb	$542,575	$1,567	($15)	$249	$0	$0	$0	$0
Mar	$287,417	$0	$0	$0	$0	$0	$0	$0
Apr	$31,255	$4,767	($68)	($3,114)	$0	$0	$0	
May	$41,025	$0	($27)	$0	$0	$0	$0	
Jun	$169,197	$1,354	$78	$0	$0	$0	$0	
Jul	$827,617	$1,115	$0	$0	$0	$0	$0	
Aug	$731,539	$37	$0	$0	$0	$0	$0	
Sep	$119,162	$0	$0	$0	$0	$0	$0	
Oct	$257,448	($31,443)	($6,870)	$0	$0	$0	$0	
Nov	$30,843	($795)	($4,678)	$0	$0	$0	$0	
Dec	$127,176	($659)	($209)	$0	$0	$0	$0	
Total	$3,314,018	($20,955)	($11,789)	($2,860)	$0	$0	($44)	$0

Spot Imports

Prior to April 1, 2007, PJM did not limit nonfirm service imports that were willing to pay congestion, including spot imports, secondary network service imports and bilateral imports using nonfirm point-to-point service. Spot market imports, nonfirm 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.

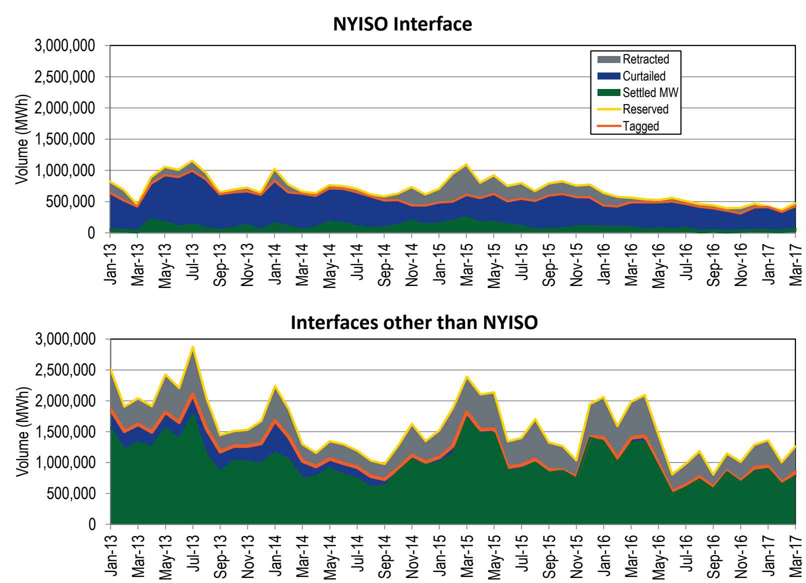
However, PJM has interpreted its JOA with MISO to require restrictions on spot imports and exports although MISO has not implemented a corresponding restriction.[87] The result is that the availability of spot import service is limited by ATC and not all spot transactions are approved. Spot import service (a network service) is provided at no charge to the market participant offering into the PJM spot market.

The 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.[88] 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 two 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 January 1, 2013 through March 31, 2017. 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 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: January 1, 2013 through March 31, 2017



87 See OASIS "Modifications to the Practices of Non-Firm and Spot Market Import Service," (April 20, 2007) <http://www.pjm.com/~/media/etools/oasis/wpc-white-paper.ashx>.
88 See OASIS "Regional Transmission and Energy Scheduling Practices," (March 31, 2016) <http://www.pjm.com/~/media/etools/oasis/regional-practices-clean-pdf.ashx>.

The MMU continues to recommend that PJM permit unlimited spot market imports (as well as all nonfirm 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.[89] 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.

89 The minimum duration for a real-time dispatchable transaction was modified to 15 minutes as per FERC Order 764.

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 nonmarket 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.

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 nonfirm 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 nonfirm 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.[90] [91] On April 17, 2014, FERC issued its order which found that PJM's 45 minute duration rule was inconsistent with Order 764.[92]

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.[93]

MISO Multi-Value Project Usage Rate ("MUR")

A multi-value project (MVP) is a project, as defined by MISO, that enables the reliable and economic delivery of energy in support of public policy needs, provides multiple types of regional economic value or provides a combination of regional reliability and economic value.[94] On July 15, 2010, MISO submitted revisions to the MISO Tariff to implement criteria for identifying and allocating the costs of MVPs.[95] On December 16, 2010, the Commission accepted the proposed MVP charge for export and wheel-through transactions, except for transactions that sink in PJM.[96] The Commission stated that MISO had not shown that their proposal did not constitute a resumption of rate pancaking along the MISO-PJM seam. Following the December 16, 2010, Order, MISO began applying a multi-value usage rate (MUR) to monthly net actual energy withdrawals, export schedules and through schedules with the exception of transactions sinking in PJM. The MUR charge was applied to the relevant transactions in addition to the applicable transmission, ancillary service and network upgrade charges.

90 *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).
91 Order No. 764 at P 51.
92 *See Id.* at P 12.
93 *See* joint statement of PJM and the MMU re Interchange Scheduling issued July 29, 2014, which can be accessed at: <http://www.monitoringanalytics.com/reports/Market_Messages/Messages/PJM_IMM_Statement_on_Interchange_Scheduling_20140729.pdf>.
94 See MISO, "Multi Value Project Portfolio Analysis," <https://www.misoenergy.org/Planning/TransmissionExpansionPlanning/Pages/MVPAnalysis.aspx>.
95 See Midwest Independent Transmission Operator Inc. filing, Docket No. ER10-1791-000 (July 15, 2010).
96 133 FERC ¶ 61,221 (2010); *order on reh'g*, 137 FERC ¶ 61,074 (2011).

On June 7, 2014, the U.S. Court of Appeals for the Seventh Circuit granted a petition for review regarding the Commission's determination in the MVP Order and MVP Rehearing Order.[97] The Court ordered the Commission to consider on remand whether, in light of current conditions, what if any limitations on export pricing to PJM by MISO are justified.[98] The Seventh Circuit highlighted the fact that at the time of the Commission's decision to prohibit rate pancaking on transactions between MISO and PJM, all of MISO's transmission projects were local and provided only local benefits.[99]

On July 13, 2016, FERC issued an Order permitting MISO to collect charges associated with MVPs for all transactions sinking in PJM, effective immediately.[100] The July 13th Order noted that in light of "the development of large scale wind generation capable of serving both MISO's and its neighbors' energy policy requirements in the western areas of MISO; the reported need of PJM entities to access those resources; and the reported need for MISO to build new transmission facilities to deliver the output of those resources within MISO for export... it is appropriate to allow MISO to assess the MVP usage charge for transmission service used to export to PJM just as MISO assesses the MVP usage charge for transmission service used to export energy to other regions."[101] Table 9-51 shows the projected usage rate to be collected for all wheels through and exports from MISO, including those that sink in PJM, for 2017 through 2036.[102] It is not clear whether the MUR charge has affected interchange volumes from MISO into PJM.

Table 9-51 MISO Projected Multi Value Project Usage Rate: 2017 through 2036

Year	Total Indicative MVP Usage Rate ($/MWh)
2017	$1.39
2018	$1.63
2019	$1.84
2020	$1.86
2021	$1.90
2022	$1.89
2023	$1.88
2024	$1.87
2025	$1.84
2026	$1.81
2027	$1.78
2028	$1.75
2029	$1.72
2030	$1.69
2031	$1.66
2032	$1.63
2033	$1.60
2034	$1.57
2035	$1.54
2036	$1.52

97 Illinois Commerce Commission, et al. v. FERC, 721 F.3d 764, 778–780 (7th Cir. 2013).
98 *Id.* at 780.
99 *Id.* at 779.
100 156 FERC ¶ 61,034 (2016).
101 *Id.* at P 55.
102 See MISO, "Schedule 26A Indicative Annual Charges," (August 29, 2016) <https://www.misoenergy.org/_layouts/miso/ecm/redirect.aspx?id=230305>.

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 Synchronized Reserve Market, the PJM DASR Market, and the PJM Regulation Market for the first three months of 2017.

Table 10-1 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.
- 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 nonsynchronized reserve market clears with a nonzero price.

Table 10-2 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 6.9 percent of all cleared hours in the first three months of 2017.
- 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. Offers above $0.00 set the clearing price in 496 hours (22.8 percent).
- Market design was evaluated as mixed because the DASR product does not include performance obligations, and 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 10-3 The Regulation Market results were competitive

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

1 75 FERC ¶ 61,080 (1996).
2 Energy imbalance service refers to the Real-Time Energy Market.

- The regulation market structure was evaluated as not competitive for the first three months of 2017 because the PJM Regulation Market failed the three pivotal supplier (TPS) test in 92.1 percent of the hours in the first three months of 2017.
- Participant behavior in the PJM Regulation Market was evaluated as competitive for the first three months of 2017 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 noncompetitive behavior.
- Market performance was evaluated as competitive, despite significant issues with the market design.
- Market design was evaluated as flawed. 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. The result is significantly flawed market signals to existing and prospective suppliers of regulation.

Overview

Primary Reserve

PJM's primary reserves are made up of resources, both synchronized and nonsynchronized, that can provide energy within 10 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 10 minutes), and nonsynchronized reserve (generation currently off-line but available to start and provide energy within 10 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 hourly average primary reserve requirement in the RTO Zone in the first three months of 2017 was 2,191.2 MW. The primary reserve requirement in the MAD Subzone was 1,700 MW for all hours.

Tier 1 Synchronized Reserve

Synchronized reserve is provided by generators or demand response resources synchronized to the grid and capable of increasing output or decreasing load within 10 minutes. Synchronized reserve consists of tier 1 and tier 2 synchronized reserves.

Tier 1 synchronized reserve is part of primary reserve and is the capability of online resources following economic dispatch to ramp up in 10 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 the first three months of 2017, there was an average hourly supply of 1,252.2 MW of tier 1 for the RTO Synchronized Reserve Zone, and an average hourly supply of 1,059.4 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

3 See PJM. "Manual 10: Pre-Scheduling Operations," Revision. 34 (July 1, 2016), p. 24.

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 nonsynchronized reserve market clearing price.

Of the Degree of Generator Performance (DGP) adjusted tier 1 synchronized reserve MW estimated at market clearing, 59.3 percent actually responded during the one synchronized reserve event with duration of 10 minutes or longer in the first three months of 2017.

- **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 $89,719,045 to tier 1 resources in 2014, $34,397,441 in 2015, $4,948,084 in 2016, and $428,212 in the first three months of 2017.

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 the first three months of 2017, the supply of offered and eligible synchronized reserve was 23,563.7 MW in the RTO Zone of which 6,779.8 MW (including 1,514.4 MW of DSR) was available to the MAD 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. After subtracting the tier 1 synchronized reserve estimate from the default requirement, the hourly average required tier 2 synchronized reserve was 412.8 MW in the MAD Subzone and 616.4 MW in the RTO.
- **Market Concentration.** In the first three months of 2017, the weighted average HHI for tier 2 synchronized reserve in the Mid-Atlantic Dominion Subzone was 5689 which is classified as highly concentrated. The MMU calculates that 92.2 percent of hours would have failed a three pivotal supplier test in the Mid-Atlantic Dominion Subzone.

  In the first three months of 2017, the weighted average HHI for cleared tier 2 synchronized reserve in the RTO Synchronized Reserve Zone was 4672 which is classified as highly concentrated. The MMU calculates that 61.2 percent of hours would have failed a three pivotal supplier test in the RTO Synchronized Reserve Zone.

  The MMU concludes from these results that both the Mid-Atlantic Dominion Subzone Tier 2 Synchronized Reserve Market and the RTO Synchronized Reserve Zone Market were characterized by structural market power in the first three months of 2017.

Market Conduct

- **Offers.** There is a must offer requirement for tier 2 synchronized reserve. All nonemergency 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.

There has been less than complete compliance with the tier 2 synchronized reserve must offer requirement.

Market Performance

- **Price.** The weighted average price for tier 2 synchronized reserve for all cleared hours in the Mid-Atlantic Dominion (MAD) Subzone was $2.22 per MW in the first three months of 2017, a decrease of $2.77, from the first three months of 2016.

  The weighted average price for tier 2 synchronized reserve for all cleared hours in the RTO Synchronized Reserve Zone was $2.32 per MW in the first three months of 2017, a decrease of $2.34, from the first three months of 2016.

NonSynchronized Reserve Market

Nonsynchronized reserve is part of primary reserve and includes the RTO Reserve Zone and the Mid-Atlantic Dominion Reserve Subzone (MAD). Nonsynchronized reserve is comprised of nonemergency energy resources not currently synchronized to the grid that can provide energy within 10 minutes. Nonsynchronized reserve is available to fill the primary reserve requirement above the synchronized reserve requirement. The market for nonsynchronized reserve does not include any direct participation by market participants. PJM defines the demand curve for nonsynchronized reserve and PJM defines the supply curve based on nonemergency generation resources that are available to provide energy and can start in 10 minutes or less, and on the associated resource opportunity costs calculated by PJM. Generation owners do not submit supply offers.

Market Structure

- **Supply.** In the first three months of 2017, the supply of eligible nonsynchronized reserve was 2,244.9 MW in the RTO Zone and 1,847.2 MW in MAD Subzone.
- **Demand.** Demand for nonsynchronized reserve is the remaining primary reserve requirement after tier 1 synchronized reserve is estimated and tier 2 synchronized reserve is scheduled.[4] In the RTO Zone, the market cleared an hourly average of 676.2 MW of nonsynchronized reserve in the first three months of 2017. The MAD Subzone cleared an average of 379.4 MW in the first three months of 2017.
- **Market Concentration.** In the first three months of 2017, the weighted average HHI for cleared nonsynchronized reserve in the MAD Subzone was 4107 which is classified as highly concentrated. In the RTO Zone the weighted average HHI was 4098, which is also highly concentrated. The MMU calculates that 33.8 percent of hours would have failed a three pivotal supplier test in the MAD Subzone and zero percent of hours would have failed a three pivotal supplier test in the RTO Zone.

Market Conduct

- **Offers.** No offers are made for nonsynchronized reserve by resource owners. Nonemergency generation resources that are available to provide energy and can start in 10 minutes or less are considered available for nonsynchronized reserves by the market solution software. PJM calculates the associated offer prices based on PJM calculations of resource specific opportunity costs.

Market Performance

- **Price.** The nonsynchronized reserve price is determined by the opportunity cost of the marginal nonsynchronized reserve unit. The nonsynchronized reserve weighted average price for all cleared hours (284 hours) in the RTO Reserve Zone was $0.10 per MW in the first three months of 2017 and in 98.4 percent of hours the market clearing price was $0.00. The MAD Subzone cleared separately from the RTO Zone in 34 hours in the first three months of 2017, with a weighted average price of $0.10.

Secondary Reserve

There is no NERC standard for secondary reserve. PJM defines secondary reserve as reserves (online or offline available for dispatch) that can be converted to

4 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Revision 82 (July 1, 2016), p. 81. "Because Synchronized Reserve may be utilized to meet the Primary Reserve requirement, there is no explicit requirement for non-synchronized reserves."

energy in 30 minutes. PJM defines a secondary reserve requirement but does not have a goal to maintain this reserve requirement in real time.

PJM maintains a day-ahead, offer based market for 30-minute day-ahead secondary reserve.[5] The Day-Ahead Scheduling Reserves Market (DASR) has no performance obligations except that a unit which clears the DASR market is required to be available for dispatch in real time.[6]

Market Structure

- **Supply.** The DASR Market is a must offer market. Any resources that do not make an offer have their offer set to $0.00 per MW. DASR is calculated by the day-ahead market solution as the lesser of the thirty minute energy ramp rate or the economic maximum MW minus the day-ahead dispatch point for all online units. In the first three months of 2017, the average available hourly DASR was 37,058 MW.
- **Demand.** The DASR requirement for 2017 is 5.52 percent of peak load forecast, down from 5.70 percent in 2016. The average DASR MW purchased was 3,916.3 MW per hour in the first three months of 2017.
- **Concentration.** In the first three months of 2017, the DASR Market failed the three pivotal supplier test in 6.9 percent of hours.

Market Conduct

- **Withholding.** Economic withholding remains an issue in the DASR Market. The direct marginal cost of providing DASR is zero. PJM calculates the opportunity cost for each resource. All offers by resource owners greater than zero constitute economic withholding. In the first three months of 2017, a daily average of 39.3 percent of units offered above $0.00. A daily average of 14.2 percent of units offered above $5.
- **DR.** Demand resources are eligible to participate in the DASR Market. Some demand resources have entered offers for DASR. No demand resources cleared the DASR market in the first three months of 2017.

5 See PJM. "Glossary," <http://www.pjm.com/Glossary.aspx>.
6 See PJM, "Manual 11: Energy & Ancillary Services Market Operations," Revision 85 (November 1, 2016), p. 166 §11.1.

Market Performance

- **Price.** In the first three months of 2017, the weighted average DASR price for all hours when the DASRMCP was above $0.00 was $0.06, a decrease of $1.55 per MW from 2016.

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 one of two regulation signals, RegA or RegD. PJM jointly optimizes regulation with synchronized reserve and energy to provide all three products at least cost. The PJM regulation market design includes three clearing price components: capability; performance; and lost opportunity cost. The RegA signal is designed for energy unlimited resources with physically constrained ramp ability. The RegD signal is designed for energy limited resources with very fast ramp rates. In the Regulation Market RegD MW are converted to marginal effective MW using a marginal rate of substitution (MRTS), called a marginal benefit function (MBF). Correctly implemented, the MBF would define and be used as the marginal rate of technical substitution (MRTS) between RegA and RegD, holding the level of regulation service constant. The current market design is critically flawed as it has not properly implemented the MBF as an MRTS between RegA and RegD resource MW and the MBF has not been consistently applied in the optimization, clearing and settlement of the Regulation Market.

Market Structure

- **Supply.** In the first three months of 2017, the average hourly eligible supply of regulation for nonramp hours was 1,187.5 actual MW (852.4 effective MW). This was an increase of 4.2 actual MW (32.0 effective MW) from the first three months of 2016, when the average hourly eligible supply of regulation was 1,183.3 actual MW (820.4 effective MW). In the first three months of 2017, the average hourly eligible supply of regulation for ramp hours was 1,449.4 actual MW (1,158.4 effective MW). This was an increase of 236.9 actual MW (199.5 effective MW) from the first three months of 2016, when the average hourly eligible supply of regulation was 1,212.4 actual MW (958.9 effective MW).

- **Demand.** Prior to January 9, 2017, the hourly regulation demand was set to 525.0 effective MW for nonramp hours and 700.0 effective MW for ramp hours. Starting January 9, 2017, the hourly regulation demand was set to 525.0 effective MW for nonramp hours and 800.0 effective MW for ramp hours.[7]

- **Supply and Demand.** The nonramp regulation requirement of 525.0 effective MW was provided by a combination of RegA and RegD resources equal to 503.4 hourly average actual MW in the first three months of 2017. This is a decrease of 36.6 actual MW from the first three months of 2016, when the average hourly total regulation cleared MW for nonramp hours were 540.1 actual MW. The ramp regulation requirement of 700.0 effective MW prior to January 9, 2017, and 800.0 effective MW after January 9, 2017, was provided by a combination of RegA and RegD resources equal to 702.1 hourly average actual MW in the first three months of 2017. This is an increase of 48.5 actual MW from the first three months of 2016, where the average hourly regulation cleared MW for ramp hours were 653.6 actual MW.

  The ratio of the average hourly eligible supply of regulation to average hourly regulation demand for ramp hours was 2.06 in the first three months of 2017. This is an increase of 11.3 percent from the first three months of 2016, when the ratio was 1.85. The ratio of the average hourly eligible supply of regulation to average hourly regulation demand required for nonramp hours was 2.36 in the first three months of 2017. This is an increase of 7.7 percent from the first three months of 2016, when the ratio was 2.19.

- **Market Concentration.** In the first three months of 2017, the three pivotal supplier test was failed in 92.1 percent of hours. In the first three months of 2017, the weighted average HHI of RegA resources was 2860, which is highly concentrated and the weighted average HHI of RegD resources was 1642, which is highly concentrated. The weighted average HHI of all resources was 1155 which is moderately concentrated.

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.[8] In the first three months of 2017, there were 147 resources following the RegA signal and 44 resources following the RegD signal.

Market Performance

- **Price and Cost.** The weighted average clearing price for regulation was $13.87 per effective MW of regulation in the first three months of 2017, a decrease of $1.68 per MW, or 10.8 percent, from of the first three months of 2016. The cost of regulation in the first three months of 2017 was $18.40 per effective MW of regulation, an increase of $0.48 per MW, or 2.7 percent, from the first three months of 2016. The decrease in regulation price in the first three months of 2017 resulted primarily from reductions in the LOC component of the regulation clearing prices due to low energy prices in the first three months of 2017 compared to the first three months of 2016.

- **Prices.** 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. 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 MBF

7 On peak and off peak hours are now designated as ramp and nonramp hours. The definitions change by season. See "Regulation requirement definition," <http://www.pjm.com/~/media/markets-ops/ancillary/regulation-requirement-definition.ashx>

8 See the *2016 State of the Market Report for PJM*, Volume II, Appendix F "Ancillary Services Markets."

is less than one, RegD resources are generally overpaid on a per effective MW basis. Currently, the MBF is less than one, resulting in persistent overpayment of RegD resources that creates an artificial incentive for inefficient entry of RegD resources. The MBF averaged less than one in each of the first three months of 2017, resulting in RegD resources being paid an average of 1,016.4 percent more than they should have in the first three months of 2017. In the first three months of 2016, the MRTS averaged was also less than one, resulting in RegD resources being paid an average of 222.4 percent more than they should have been.

- **Marginal Benefit Factor Function.** The marginal benefit factor (MBF) is intended to measure the substitutability of RegD resources for RegA resources. The marginal benefit factor function is currently incorrectly defined and applied in the PJM market clearing and incorrectly describes the operational relationship between RegA and RegD regulation resources. Correctly defined, the MBF function represents the Marginal Rate of Technical Substitution (MRTS) between RegA and RegD. Correctly implemented, the MBF would be consistently applied in the Regulation Market clearing and settlement. The current incorrect and inconsistent implementation of the MBF function has resulted in the PJM Regulation Market over procuring RegD relative to RegA in most hours and in 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.
- **Interim changes to the MBF function.** On December 14, 2015, PJM changed the MBF curve in an attempt to reduce the over procurement of RegD. The modification to the marginal benefit curve did not correct the identified issues.
- **Changes to the Regulation Market.** Changes were approved by the Regulation Market Issues Senior Task Force (RMISTF), which went into effect on January 9, 2017. These include changing the definition of off-peak and on-peak hours (now called nonramp and ramp hours) based on the season, increasing the effective MW requirement during ramp hours from 700 MW to 800 MW, adjusting the currently independent RegA and RegD signals to be interdependent, and changing the 15-minute neutrality requirement of the RegD signal to a 30-minute conditional neutrality requirement.

Black Start Service

Black start service is required for the reliable restoration of the grid following a blackout. Black start service is the ability of a generating unit to start without an outside electrical supply, or is the demonstrated ability of a generating unit to automatically remain operating at reduced levels when disconnected from the grid (automatic load rejection or ALR).[9]

In the first three months of 2017, total black start charges were $17.1 million with $17.0 million in revenue requirement charges and $.057 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 for first three months of 2017 ranged from $0.05 per MW-day in the DLCO Zone (total charges were $12,507) to $4.30 per MW-day in the PENELEC Zone (total charges were $1,127,246).

Reactive

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

Reactive capability revenue requirements are based on FERC approved filings. Reactive service charges are paid to units that operate in real time outside of their normal range at the direction of PJM for the purpose of providing reactive service. Reactive service charges are paid for scheduling in the Day-Ahead Energy Market and committing units in real time that provide

9 OATT Schedule 1 § 1.3BB.

reactive service. In the first three months of 2017, total reactive charges were $86.4 million, a 17.6 percent increase from $73.4 million in 2016. Reactive capability revenue requirement charges increased from $73.2 million in 2016 to $80.5 million and reactive service charges increased from $0.3 million to $5.9 million in 2017. Total charges in 2017 ranged from $636 in the RECO Zone to $9.7 million in the AEP Zone.

Ancillary Services Costs per MWh of Load: January through March, 1999 through 2017

Table 10-4 shows PJM ancillary services costs for January through March, 1999 through 2017, 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: January through March, 1999 through 2017[10]

Year (Jan-Mar)	Regulation	Scheduling, Dispatch and System Control	Reactive	Synchronized Reserve	Total
1999	$0.04	$0.23	$0.25	$0.00	$0.52
2000	$0.21	$0.38	$0.37	$0.00	$0.96
2001	$0.49	$0.64	$0.22	$0.00	$1.35
2002	$0.24	$0.67	$0.16	$0.00	$1.07
2003	$0.65	$1.01	$0.22	$0.11	$1.99
2004	$0.54	$1.06	$0.26	$0.17	$2.03
2005	$0.47	$0.80	$0.25	$0.07	$1.59
2006	$0.48	$0.70	$0.28	$0.09	$1.55
2007	$0.58	$0.72	$0.25	$0.11	$1.66
2008	$0.59	$0.73	$0.30	$0.07	$1.69
2009	$0.38	$0.35	$0.34	$0.03	$1.10
2010	$0.34	$0.36	$0.35	$0.05	$1.10
2011	$0.27	$0.30	$0.38	$0.12	$1.07
2012	$0.18	$0.41	$0.48	$0.03	$1.10
2013	$0.28	$0.41	$0.63	$0.04	$1.36
2014	$0.63	$0.38	$0.37	$0.29	$1.67
2015	$0.32	$0.41	$0.36	$0.18	$1.26
2016	$0.11	$0.42	$0.38	$0.04	$0.95
2017	$0.11	$0.46	$0.46	$0.06	$1.09

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 that all data necessary to perform the Regulation Market three pivotal supplier test be saved so that the test can be replicated. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that there be a penalty enforced in the Regulation Market as a reduction in performance score and/or a forfeiture of revenues when resource owners elect to deassign assigned regulation resources within the hour, to prevent gaming. (Priority: Medium. First reported 2016. Status: Not adopted.)

10 Note: The totals in this table account for after the fact billing adjustments made by PJM and may not match totals presented in past reports.

- 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: Not adopted.)
- The MMU recommends that the rule requiring the payment of the tier 2 synchronized reserve price to tier 1 synchronized reserve resources when the nonsynchronized reserve price is above zero be eliminated immediately and that tier 1 synchronized reserve resources not be paid the tier 2 price when they do not respond. (Priority: High. First reported 2013. Status: Not adopted.)
- 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 unit owners to select a reason in Markets Gateway whenever making a unit unavailable either daily or hourly or setting the offer MW to 0 MW. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM be more explicit and transparent about why tier 1 biasing is used in defining demand in the Tier 2 Synchronized Reserve Market. The MMU recommends that PJM define rules for estimating tier 1 MW, define rules for the use and amount of tier 1 biasing and identify the rule based reasons for each instance of biasing. (Priority: Medium. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM modify the DASR Market to ensure that all resources cleared incur a real-time performance obligation. (Priority: Low. First reported 2013. Modified 2017. Status: Not adopted.)
- 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 2015. Status: Not adopted.)
- The MMU recommends that separate payments for reactive capability be eliminated and the cost of reactive capability be recovered in the capacity market. (Priority: Medium. First reported 2016. 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 five minute clearing price based on actual LMP and actual LOC, modifications to the LOC calculation, a software change to save some data elements necessary for verifying market outcomes, and further documentation of the implementation of the market design. (Priority: Medium. First reported 2010. Status: Partially adopted in 2012.)
- 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 single clearing price for synchronized reserves be determined based on the actual five minute LMP and actual LOC and not the forecast LMP. (Priority: Low. First reported 2010. Status: Adopted.)
- 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 2014. Status: Adopted 2014.)

Conclusion

The design of the PJM Regulation Market is significantly flawed. The market design has failed to correctly incorporate the marginal benefit factor, or marginal rate of technical substitution, in optimization, pricing and settlement. The market design uses the marginal benefit factor in the optimization (incorrectly) and pricing (correctly), but a mileage ratio instead of the marginal benefit factor in settlement. This failure to correctly and consistently 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 all hours. The market results continue to include the incorrect definition of opportunity cost. These issues have led to the MMU's conclusion that the regulation market design is flawed. PJM and the MMU have developed a joint proposal to correct these issues.

The structure of the 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 product 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 remains less than 100 percent. For the six spinning events 10 minutes or longer in 2016, the average tier 2 synchronized reserve response was 85.5 percent of all scheduled MW. For the one spinning event of 10 minutes or longer in 2017, the response was 75.3 percent of scheduled tier 2 MW.

The rule that requires payment of the tier 2 synchronized reserve price to tier 1 synchronized reserve resources when the nonsynchronized 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, and tier 1 resources do not incur any costs when they are part of the tier 1 estimate in the market solution. Tier 1 resources are paid for their response if they do respond. Tier 1 resources require no additional payment. If tier 1 resources wish to be paid as tier 2 resources, the rules provide the opportunity to make competitive offers in the tier 2 market and take on the associated obligations. Overpayment of tier 1 resources based on this rule added $89.7 million to the cost of primary reserve in 2014, $34.1 million in 2015, $4.9 million in 2016, and $0.4 million in the first three months of 2017.

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, although the market design is flawed. The MMU concludes that the synchronized reserve market results were competitive. The MMU concludes that the DASR market results were competitive, although offers above the competitive level continue to affect prices.

Primary Reserve

NERC Performance Standard BAL-002-1, Disturbance Control Performance, requires PJM to carry sufficient contingency reserve to recover from a sudden loss of load (disturbance) within 15 minutes. The NERC requirement is 100 percent compliance and must be reported quarterly. PJM implements this contingency reserve requirement using primary reserves.[11] PJM maintains 10 minute reserves (primary reserve) to ensure reliability in the event of disturbances. PJM's primary reserves are made up of resources, both synchronized and nonsynchronized, that can provide energy within 10 minutes.

Market Structure

Supply

In the first three months of 2017, PJM's primary reserve requirement was 2,175 MW for the RTO Zone, and 1,700 MW for the MAD Subzone.[12] 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

11 See PJM, "Manual 10: Pre-Scheduling Operations," revision 35, January 1, 2017, p. 24, 25

12 In this State of the Market Report, scheduled MW and average clearing prices are calculated differently for the RTO Zone than in prior reports. Formerly data were reported for three geographic structures for primary reserve and its component synchronized and non-synchronized reserve. Those three structures were, Full RTO Zone, Mid-Atlantic Dominion Subzone, and the RTO Zone excluding the Mid-Atlantic Subzone. In this report the term RTO Zone is the Full RTO Zone.

remainder of primary reserves can come from the least expensive combination of synchronized and nonsynchronized reserves.

Estimated tier 1 is credited against PJM's primary reserve requirement. In the MAD Subzone an average of 953.5 MW of tier 1 was identified by the ASO market solution as available hour ahead (Table 10-6).[13] Of this, an average of 947.4 MW of tier 1 was actually used by the market solution in satisfying the synchronized reserve requirement. This tier 1 reduced the amount of tier 2 and nonsynchronized reserve needed to fill the synchronized reserve and primary reserve requirements. Tier 1 synchronized reserve fully satisfied the MAD Subzone synchronized reserve requirement in 2.1 percent of hours in the first three months of 2017. In the RTO Zone, an average of 948.4 MW of tier 1 was available (Table 10-6). Tier 1 synchronized reserve fully satisfied the RTO Zone synchronized reserve requirement in 26.3 percent of all hours.

Regardless of online/offline state, all nonemergency generation capacity resources must submit a daily offer for tier 2 synchronized reserve in Markets Gateway prior to the offer submission deadline (14:15 the day prior to the operating day). Offer MW and other non-cost offer parameters 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, landfill gas and batteries, are expected to have zero MW tier 2 synchronized reserve offer quantities.[14]

After tier 1 is estimated, the remainder of the synchronized reserve requirement is met by tier 2. In the RTO Zone there were 23,563.7 MW of tier 2 synchronized reserve offered daily. Of this, 6,779.8 MW were located in the MAD Subzone (Figure 10-12) and available to meet the average tier 2 hourly demand of 524.2 MW (Table 10-5).

In the MAD Subzone, there was an average of 2,052.3 MW of eligible nonsynchronized reserve supply available to meet the average hourly demand of 379.3 MW (Table 10-6). In the RTO Zone, an hourly average of 2,255.3 MW supply was available to meet the average hourly demand of 396.1 MW (Table 10-5).

Demand

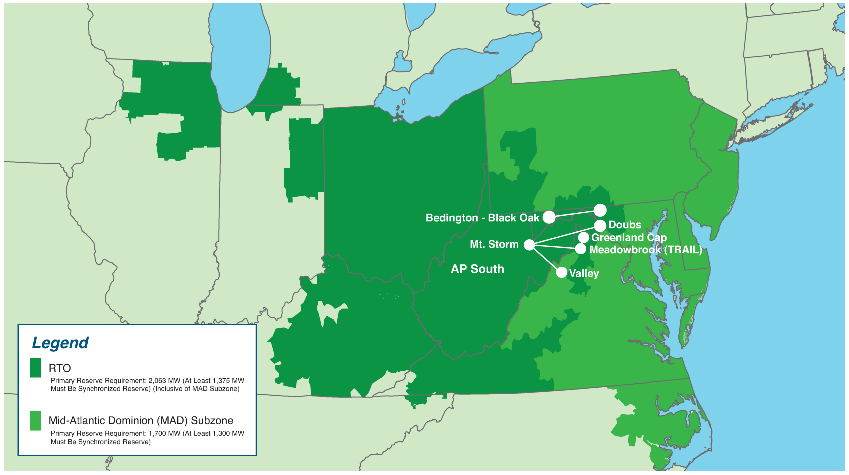
PJM requires that 150 percent of the largest contingency on the system be maintained as primary reserve. Adjustments to this value can occur when grid maintenance or outages change the largest contingency or in cases of hot weather alerts or cold weather alerts.

On January 10, 2017, the default primary reserve requirement in the RTO Reserve Zone was raised from 2,175 MW to 3,300 MW for 32 hours. The hourly average RTO primary reserve requirement in the first three months of 2017 was 2,191.2 MW. In the MAD Subzone, the primary reserve requirement remained at 1,700 MW for all hours for the first three months of 2017.

Transmission constraints limit the deliverability of reserves within the RTO, requiring the definition of the Mid-Atlantic Dominion (MAD) Subzone.[15] 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).

13 ASO, Ancillary Services Optimizer. This is the hour-ahead market software that optimizes ancillary services with energy. ASO schedules hourly the Tier 2 Synchronized Reserve, Regulation, and Nonsynchronized Reserves.
14 See PJM, "Manual 11: Energy & Ancillary Services Market Operations," Revision 85 (November 1, 2016), p. 84.
15 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 84 (August 251, 2016), p. 87.

Figure 10-1 PJM RTO Zone and MAD Subzone geography: 2017



The Mid-Atlantic Dominion Reserve (MAD) Subzone is generally defined dynamically by the most limiting constraint separating MAD from the PJM RTO Reserve Zone. However, PJM can override the dynamic determination of the most limiting constraint that defines the MAD Subzone market. From October 10, 2016 through January 16, 2017, the most limiting constraint had been fixed by PJM as the AP South transfer interface.

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 reserves used to satisfy the primary reserve requirement, MAD Subzone: January 1, 2016 through March 31, 2017

Year	Month	Tier 1 Total MW	Tier 2 Synchronized Reserve MW	Non-Synchronized Reserve MW	Total Primary Reserve MW
2016	Jan	1,263.5	228.5	295.9	1,787.9
2016	Feb	1,230.1	241.5	302.2	1,773.8
2016	Mar	993.3	485.7	265.7	1,744.7
2016	Apr	912.4	565.0	289.2	1,766.5
2016	May	956.5	511.3	292.2	1,760.0
2016	Jun	1,116.9	348.4	368.7	1,834.0
2016	Jul	1,254.7	208.8	621.3	2,084.7
2016	Aug	1,228.4	239.7	669.1	2,137.2
2016	Sep	1,170.6	293.0	603.7	2,067.2
2016	Oct	1,086.1	481.3	508.7	2,076.2
2016	Nov	774.8	687.8	360.4	1,822.9
2016	Dec	995.0	479.6	520.7	1,995.3
2016		1,081.8	397.5	424.8	1,904.2
2017	Jan	981.6	508.5	361.1	1,851.2
2017	Feb	1,111.6	355.5	377.7	1,844.9
2017	Mar	767.4	693.3	399.3	1,860.0
2017		953.5	519.1	379.4	1,852.0

Table 10-6 Average monthly reserves used to satisfy the primary reserve requirement, RTO Zone: January 1, 2016 through March 31, 2017

Year	Month	Tier 1 Total MW	Tier 2 Synchronized Reserve MW	Non-Synchronized Reserve MW	Total Primary Reserve MW
2016	Jan	1,659.4	374.5	319.1	2,353.0
2016	Feb	1,564.1	411.4	329.4	2,304.9
2016	Mar	1,089.1	818.1	300.0	2,207.2
2016	Apr	1,011.7	878.3	318.0	2,207.9
2016	May	1,160.9	722.6	349.5	2,233.0
2016	Jun	1,546.0	497.1	384.2	2,427.3
2016	Jul	1,663.8	360.1	634.0	2,657.9
2016	Aug	1,605.6	419.0	682.4	2,707.0
2016	Sep	1,290.4	578.6	617.5	2,486.5
2016	Oct	802.7	982.4	524.0	2,309.1
2016	Nov	810.8	1,014.1	375.4	2,200.4
2016	Dec	953.1	807.3	533.0	2,293.4
2016		1,263.1	655.3	447.2	2,365.6
2017	Jan	1,020.4	915.5	372.3	2,308.2
2017	Feb	1,172.0	686.0	395.1	2,253.2
2017	Mar	654.2	1,128.9	420.9	2,204.0
2017		948.9	910.1	396.1	2,255.1

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); and the real-time (short term) security constrained economic dispatch market solution (RT-SCED).

The ASO jointly optimizes energy, synchronized reserves, and nonsynchronized 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 needed. 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 needed.

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 are 1,450 MW of tier 1 available, then ASO jointly optimizes synchronized reserve and nonsynchronized reserve to assign the remaining primary reserve up to 1,700 MW. If there are 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 nonsynchronized reserve (light blue area). Since nonsynchronized 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 nonsynchronized reserve.

Figure 10-2 Mid-Atlantic Dominion Subzone primary reserve MW by source (Daily Averages): January through March, 2017

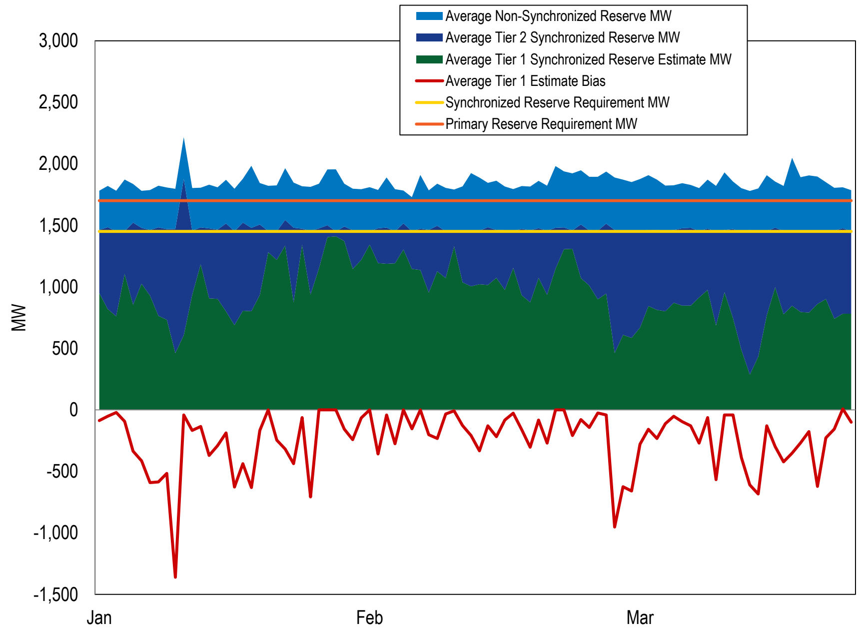
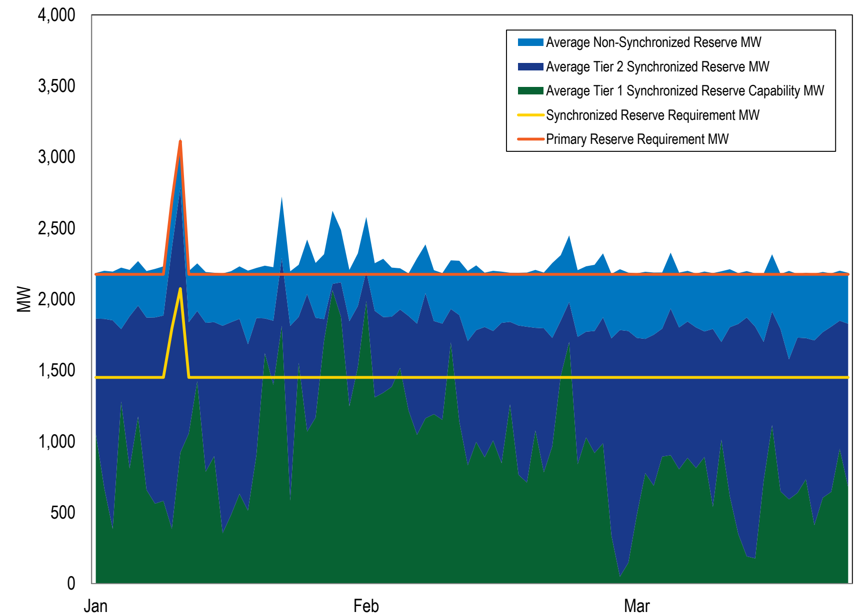


Figure 10-3 RTO Reserve Zone primary reserve MW by source (Daily Averages): January through March, 2017



The solution method is similar for the RTO Reserve Zone (Figure 10-3) except that the required primary reserve MW is 2,175 MW.[16] Figure 10-3 shows how the hour ahead ASO satisfies the primary reserve requirement for the RTO Zone.

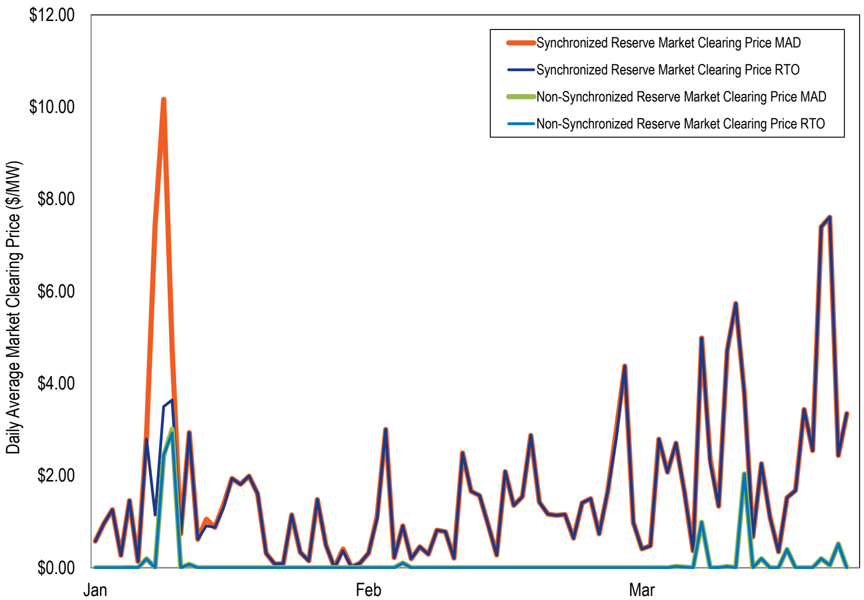
Figure 10-2 and Figure 10-3 show that tier 1 synchronized reserve remains the major contributor to satisfying the synchronized reserve requirements both in the RTO Zone and the Mid-Atlantic Dominion (MAD) Subzone.

16 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 method used by the ASO, IT-SCED, and RT-SCED market solutions which assume zero cost.

Price and Cost

Figure 10-4 shows daily average synchronized and nonsynchronized market clearing prices in the first three months of 2017.

Figure 10-4 Daily weighted average market clearing prices ($/MW) for synchronized reserve and nonsynchronized reserve: January through March, 2017



PJM's primary reserves are made up of three components, Tier 1 Synchronized Reserve, Tier 2 Synchronized Reserve, and Nonsynchronized Reserve, each with its own price and cost determinants and interdependent scheduling algorithms. The overall price and cost for meeting the BAL-002-1 primary reserve requirement is calculated by combining the three components (Table 10-7). Under most market conditions, most primary reserve identified by the hour ahead market solution is provided at no incremental cost from nonsynchronized 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.

On a combined basis, the price cost ratio for primary reserve is low at 44 percent due to the current inappropriately incurred cost of Estimated Tier 1 Synchronized Reserve. While Tier 1 has no actual incremental cost and has no clearing price, estimated Tier 1 is paid the Tier 2 clearing price in any hour where non-synchronized reserves clears at a non zero price. Table 10-7 shows that the cost per MW of Tier 1 reserves is $5.13 dollars and 59.1 percent greater than the cost of tier 2 reserves entirely as a result of paying tier 1 reserves when the price of nonsynchronized reserves is greater than zero.

Table 10-7 MW credited, price, cost, and all-in price for primary reserve and its component products, RTO Reserve Zone: January through March, 2017

Product	MW Share of Primary Reserve Requirement	MW	Credits Paid	Price Per MW Reserve	Cost Per MW Reserve	All-In Cost
Tier 1 Synchronized Reserve Response	NA	2,632	$171,452	NA	$65.14	$0.00
Tier 1 Synchronized Reserve Estimated	1.1%	34,124	$428,212	$0.00	$12.55	$0.00
Tier 2 Synchronized Reserve Scheduled	43.0%	1,339,352	$9,762,807	$2.33	$7.29	$0.05
Non Synchronized Reserve Scheduled	55.8%	1,738,897	$958,311	$0.10	$0.55	$0.01
Primary Reserve (total of above)	100.0%	3,115,005	$11,320,782	$1.06	$3.63	$0.06

Tier 1 Synchronized Reserve

Tier 1 synchronized reserve is a component of primary reserve comprised of all online 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 10 minute ramp and the difference between the economic dispatch point and the economic maximum output. Tier 1 resources are identified by the market solution. The sum of their 10 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 nonsynchronized 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 obligated to respond during an event. Tier 1 resources are credited if they do respond but are not penalized if they do not.

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 and any response to a spinning event will be credited at the Synchronized Energy Premium Price as defined below.

There have been issues with the tier 1 estimate, and the process for estimating tier 1 synchronized reserve has been refined. 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 online resources for each market solution. DGP measures how closely the unit has been following economic dispatch for the past 30 minutes.[17] The available tier 1 MW estimated by the market solution for each resource is based upon its economic dispatch, and energy schedule ramp rate or overriding submitted synchronized reserve ramp rate, adjusted by its DGP percent. PJM communicates to generation operators whose tier 1 MW is part of the market solution the latest estimate of units' tier 1 MW and units' current DGP.[18] Total estimated tier 1 MW also reflect any tier 1 bias added by PJM operators.

In the first three months of 2017, PJM estimated tier 1 MW for an average of 135 units as part of the market solution each hour. The average tier 1 synchronized reserve DGP was 88.5 percent for those 135 units.

The supply of tier 1 synchronized reserve available to the market solution is further adjusted by eliminating tier 1 MW from units that cannot reliably provide synchronized reserve. These units are identified as nuclear, wind, solar, energy storage, and hydro units.[19] These units will be credited the synchronized energy premium price, like any other responding unit, if they respond to a spinning event. These units will not, however, be paid as Tier 1 resources when the Nonsynchronized Reserve Market Clearing Price goes above $0.

In the first three months of 2017, in the RTO Reserve Zone, the average hourly estimated tier 1 synchronized reserve was 948.9 MW (Table 10-8). In 26.3 percent of hours, the estimated tier 1 synchronized reserve was greater than the synchronized reserve requirement, meaning that the synchronized reserve requirement was met entirely by tier 1 synchronized reserve.

In the first three months of 2017, in the MAD Reserve Subzone, the average hour ahead estimated tier 1 synchronized reserve was 544.4 MW in MAD and 516.0 MW in the RTO (Table 10-8). In 2.1 percent of hours, the estimated tier 1 synchronized reserve available in MAD was greater than the subzone requirement for synchronized reserve and no Tier 2 Synchronized Reserve Market was needed.

17 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Revision 85 (November 1, 2016), p. 85.
18 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).
19 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Revision 85 (November 1, 2016), p. 83.

Table 10-8 Monthly average market solution Tier 1 Synchronized Reserve (MW) identified hourly: January 1, 2016 through March 31, 2017

Year	Month	Average Hourly Tier 1 Local To MAD	Tier 1 Synchronized Reserve From RTO Zone	Average Hourly Tier 1 Used in MAD	Average Hourly Tier 1 Used in RTO Zone
2016	Jan	586.1	659.3	1,245.4	1,659.4
2016	Feb	609.3	635.9	1,245.2	1,564.1
2016	Mar	402.4	660.7	1,063.0	1,089.1
2016	Apr	341.7	620.2	961.9	1,011.7
2016	May	408.2	613.9	1,022.1	1,160.9
2016	Jun	638.4	504.0	1,142.5	1,546.0
2016	Jul	756.7	513.5	1,270.2	1,663.8
2016	Aug	750.5	495.2	1,245.7	1,605.6
2016	Sep	658.9	566.8	1,225.7	1,290.4
2016	Oct	393.6	723.9	1,117.5	802.7
2016	Nov	385.2	478.6	863.8	810.8
2016	Dec	660.4	419.8	1,080.2	953.1
2016		549.3	574.3	1,123.6	1,263.1
2017	Jan	592.0	498.8	1,090.8	1,316.9
2017	Feb	577.0	602.1	1,179.1	1,395.3
2017	Mar	464.1	455.8	919.9	1,057.8
2017		544.4	518.9	1,063.3	1,256.7

Demand

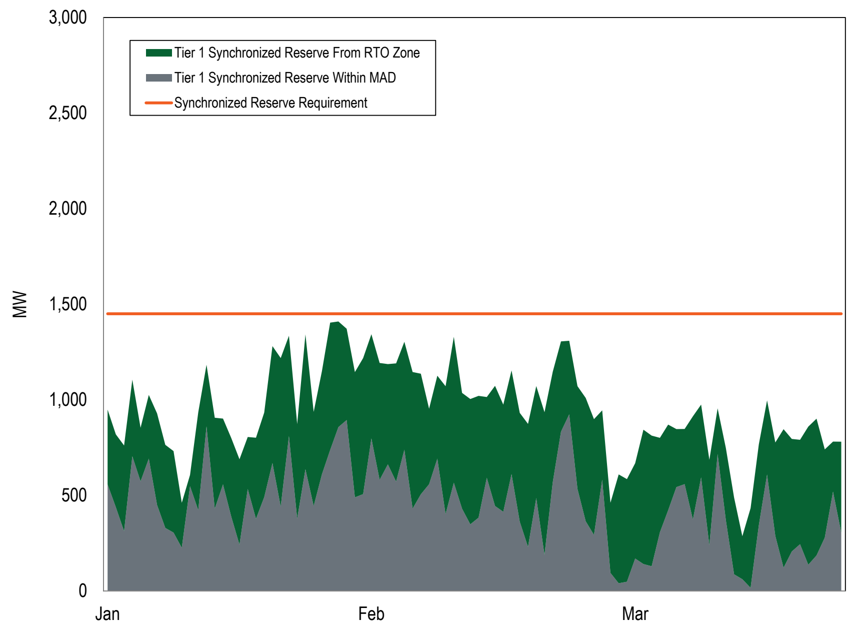
There is no required amount of tier 1 synchronized reserve. The tier 1 synchronized reserve for each online resource is estimated from its synchronized reserve ramp rate as part of each market solution. Given estimated tier 1, the market software (ASO) determines the demand for tier 2 and nonsynchronized reserve 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 nonsynchronized reserve market clearing price is above $0. As a result, the optimization cannot minimize the total cost of primary reserves.

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.

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: January through March, 2017



Average demand for synchronized reserve in the RTO Zone in the first three months of 2017 was 1,460.8 MW. There was a temporary increase in the hourly synchronized reserve requirement to 2,200 MW on January 10 and 11, 2017.

Tier 1 Synchronized Reserve Event Response

Tier 1 synchronized reserve is awarded credits when a synchronized reserve event occurs and it responds. These synchronized reserve event response credits for tier 1 response are independent of the tier 1 estimated, independent of the synchronized reserve market clearing price, and independent of the nonsynchronized 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. During a synchronized reserve event, tier 1 credits are awarded to all units that increase their output during the event regardless of their estimated tier 1 MW, or tier 1 deselection status at market clearing time, unless the units have cleared the tier 2 market.

In the first three months of 2017, tier 1 synchronized reserve synchronized reserve event response credits of $171,452 were paid for 2,632.2 MWh of tier 1 response at an average cost per MWh of $65.14, for 11 spinning event hours (Table 10-9).

Table 10-9 Tier 1 synchronized reserve event response costs: January 1, 2016 through March 31, 2017

Year	Month	Total Synchronized Reserve Event Response Hour Count	Total Credited Tier 1 Synchronized Reserve Event Response MWh	Total Tier 1 Synchronized Reserve Event Response Credits	Tier 1 Synchronized Reserve Event Response Cost Per MWh	Average Tier 1 MWh Response
2016	Jan	2	731.1	$70,330	$96.24	365.4
2016	Feb	2	675.0	$40,622	$60.18	337.5
2016	Mar	0	0.0	$0	$0.00	0.0
2016	Apr	1	339.0	$66,199	$195.27	339.0
2016	May	2	113.4	$9,790	$86.35	56.7
2016	Jun	1	206.9	$11,129	$53.78	206.9
2016	Jul	3	714.3	$58,114	$81.36	357.1
2016	Aug	1	334.5	$13,026	$38.95	334.5
2016	Sep	2	452.4	$34,824	$76.97	226.2
2016	Oct	2	281.1	$24,130	$85.85	140.5
2016	Nov	1	204.3	$10,910	$53.41	204.3
2016	Dec	1	256.8	$14,766	$57.50	256.8
2016		18	4,308.8	$353,840	$76.57	235.4
2017	Jan	6	1,250.2	$60,447	$48.35	208.4
2017	Feb	3	624.1	$55,705	$89.26	208.0
2017	Mar	2	757.9	$55,300	$72.96	379.0
2017		11	2,632.2	$171,452	$65.14	265.1

Paying Tier 1 the Tier 2 Price

The market solutions treat tier 1 synchronized reserve as having zero marginal cost. The price for tier 1 synchronized reserves is zero as there is no marginal cost associated with having the ability to ramp up from the current economic dispatch point. However, the PJM rules artificially create a marginal cost of tier 1 when the price of nonsynchronized reserve is greater than zero and tier 1 is paid the tier 2 price. But the PJM market solutions do not include that marginal cost and therefore do not solve for the efficient level of tier 1, tier 2 and nonsynchronized reserve in those cases. When called to respond to a spinning event tier 1 is compensated at the Synchronized Energy Premium Price (Table 10-12). 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 nonsynchronized 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 nonsynchronized reserve market clearing price was above $0.00 in 32 hours from the first three months of 2017. For those 32 hours, tier 1 synchronized reserve resources were paid a weighted average synchronized reserve market clearing price of $12.62 per MW and earned $428,213 in credits. In 2016, PJM paid $4,948,084 in credits for tier 1 estimated during the 297 hours when the nonsynchronized reserve market clearing price was above $0.

Table 10-10 Weighted price of tier 1 synchronized reserve attributable to a nonsynchronized reserve price above zero: January 1, 2016 through March 31, 2017

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
2016	Jan	41	$14.18	56,841	$806,038	1,624.0
2016	Feb	16	$9.42	24,752	$233,208	1,768.0
2016	Mar	73	$6.57	105,142	$690,294	1,440.3
2016	Apr	40	$28.83	38,662	$1,114,670	1,137.1
2016	May	22	$9.01	27,027	$243,515	1,228.5
2016	Jun	9	$15.24	11,630	$177,275	1,453.8
2016	Jul	10	$21.38	13,975	$298,736	1,397.5
2016	Aug	14	$32.45	19,649	$637,554	1,403.6
2016	Sep	9	$26.22	11,247	$294,857	1,249.7
2016	Oct	50	$12.12	33,761	$409,208	675.2
2016	Nov	12	$3.04	13,867	$42,216	1,155.6
2016	Dec	1	$0.58	888	$515	888.2
2016		297	$13.84	357,442	$4,948,084	1,285.1
2017	Jan	17	$11.38	19,441	$221,157	1,143.6
2017	Feb	1	$12.35	1,293	$15,971	1,293.2
2017	Mar	14	$14.27	13,389	$191,084	956.4
2017		32	$12.67	34,124	$428,212	1,131.1

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 the first three months of 2017, 59.3 percent of the DGP adjusted market solution's estimated tier 1 resources MW actually responded during synchronized reserve events of greater than 10 minutes. Thus, 40.7 percent of DGP adjusted tier 1 estimated MW did not respond during spinning events. However, all resources that were included in the Tier 1 estimates were paid the Tier 2 price for their full estimated MW when the nonsynchronized reserve (NSR) price was 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 nonsynchronized reserve 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 the first three months of 2017, tier 1 synchronized reserve was paid $171,452 for responding to synchronized reserve events. During the same time period tier 1 synchronized reserve was paid a windfall of $428,212 simply because the NSRMCP was greater than $0.00 in 32 hours (Table 10-11).

Table 10-11 Excess payments for tier 1 synchronized reserve: January 1, 2016 through March 31, 2017

		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
2016	Jan	754	$70,330	366	56,841	$806,038	1,624.0
2016	Feb	675	$40,622	338	24,752	$233,208	1,768.0
2016	Mar	0	$0	0	105,142	$690,294	1,440.3
2016	Apr	339	$66,199	339	38,662	$1,114,670	1,137.1
2016	May	113	$9,790	57	27,028	$243,515	1,228.5
2016	Jun	207	$11,129	207	11,630	$177,275	1,453.8
2016	Jul	714	$58,114	238	13,975	$298,736	1,397.5
2016	Aug	334	$13,026	334	19,650	$637,554	1,403.6
2016	Sep	452	$34,824	226	11,247	$294,857	1,249.7
2016	Oct	141	$24,130	141	33,761	$409,208	675.2
2016	Nov	204	$10,910	204	13,867	$42,216	1,155.6
2016	Dec	695	$43,512	347	888	$515	888.2
2016		4,629	$382,585	233	357,442	$4,948,084	1,285.1
2017	Jan	1,250	$60,447	250	19,441	$221,157	1,143.6
2017	Feb	624	$55,705	208	1,293	$15,971	1,293.2
2017	Mar	758	$55,300	379	13,389	$191,084	956.4
2017		2,632	$171,452	279	34,124	$428,212	1,131.1

The MMU recommends that the rule requiring the payment of tier 1 synchronized reserve resources when the nonsynchronized reserve price is above zero be eliminated immediately.[20] 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.

20 This recommendation was presented as a proposal, "Tier 1 Compensation," to the Markets and Reliability Committee Meeting, October 22, 2015. The MMU proposal and a PJM counterproposal were both rejected.

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's market solution software allows the dispatcher to bias the synchronized reserve solution by forcing the software to assume a different tier 1 MW value than it estimates. PJM no longer allows dispatchers to use tier 1 biasing in the intermediate and real-time SCED solutions, but tier 1 biasing is used in the hour ahead reserve market solution, ASO. Biasing means manually modifying (decreasing or increasing) 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 nonsynchronized reserve to satisfy the synchronized reserve and primary reserve requirements than would have cleared under the market solution. Negative biasing is the primary form of biasing actually used.

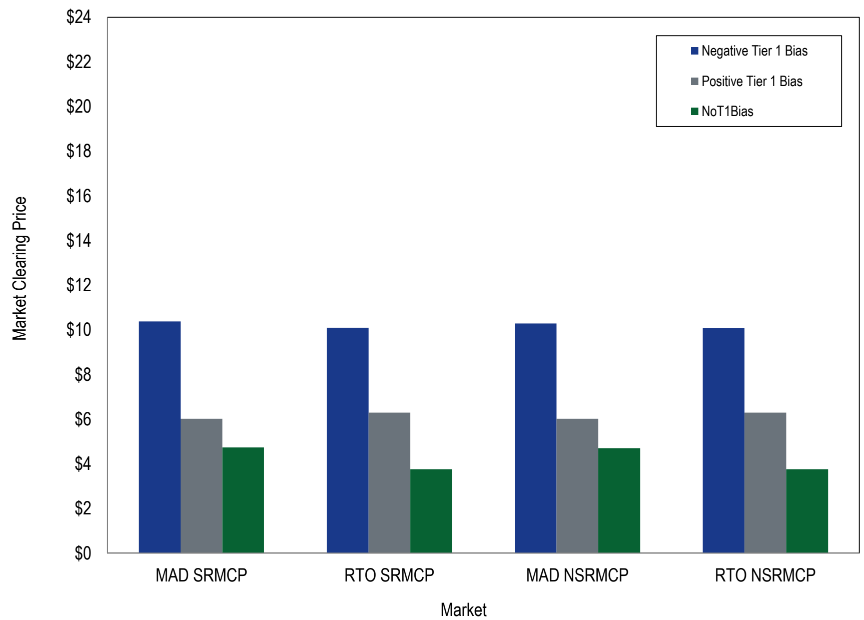
PJM uses tier 1 estimate biasing in the MAD Subzone and in the full RTO Zone of the ASO market solution (Table 10-14).

Table 10-14 RTO Zone ASO tier 1 estimate biasing: January 1, 2016 through March 31, 2017

Year	Month	Number of Hours Biased Negatively	Average Negative Bias (MW)	Number of Hours Biased Positively	Average Positive Bias (MW)
2016	Jan	21	(682.7)	64	1,104.7
2016	Feb	27	(484.3)	12	762.5
2016	Mar	1	(400.0)	28	732.1
2016	Apr	31	(303.2)	22	502.1
2016	May	19	(452.4)	21	335.7
2016	Jun	46	(502.1)	3	500.0
2016	Jul	53	(532.1)	1	250.0
2016	Aug	134	(687.1)	1	1,000.0
2016	Sep	105	(864.7)	0	NA
2016	Oct	77	(729.9)	0	NA
2016	Nov	139	(877.0)	1	100.0
2016	Dec	262	(1,420.4)	0	NA
2016		915	(661.3)	153	648.4
2017	Jan	332	(987.7)	4	362.5
2017	Feb	194	(719.7)	0	NA
2017	Mar	354	(760.5)	3	200.0
2017		880	(822.6)	7	281.3

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 and uncertainty about expected generator performance, which result in uncertainty about the accuracy of the market solution's tier 1 estimate. The purpose of Tier 1 estimate biasing is to modify the demand for tier 2 and therefore the market results both for tier 2 synchronized reserve and for nonsynchronized reserve. Biasing the tier 1 estimate forces the market solution to clear more or less tier 2 and thus affects the price for tier 2 reserves. Figure 6 compares the average tier 2 and nonsynchronized reserve clearing price for the RTO Zone and MAD Subzone markets, whenever the price is above $0 for all hours when tier 1 is biased negatively and all hours when tier 1 is biased positively.

Figure 10-6 Impact of tier 1 bias on clearing prices for synchronized and nonsynchronized reserve in both the RTO Zone and MAD Subzone: January through March, 2017



The MMU recommends that PJM be more explicit and transparent about why tier 1 biasing is used in defining demand in the Tier 2 Synchronized Reserve Market. The MMU recommends that PJM define rules for estimating tier 1 MW, define rules for the use and amount of tier 1 biasing and identify the rule based reasons for each instance of biasing.

Tier 2 Synchronized Reserve Market

Synchronized reserve is provided by generators or demand response resources synchronized to the grid and capable of increasing output or decreasing load within 10 minutes. Synchronized reserve consists of tier 1 and tier 2 synchronized reserves. When the synchronized reserve requirement cannot be met by tier 1 synchronized reserve, PJM clears a market to satisfy the requirement with tier 2 synchronized reserve. Tier 2 synchronized reserve is provided by online 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 resources have a must offer requirement. 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.

Tier 2 synchronized reserve resources committed for a full hour by the hour ahead market solution are defined to be inflexible resources. Inflexible resources cannot be released for energy during the operating hour. Tier 2 synchronized reserve resources may also be inflexible because of asserted physical limitations. Such resources include synchronous condensers operating solely for the purpose of providing synchronized reserves and demand resources.

During the operating hour, the IT-SCED and the RT-SCED market solutions software can dispatch additional resources flexibly. A flexible commitment is one in which the IT-SCED or RT-SCED redispatches tier 1 generating resources as tier 2 synchronized reserve to meet the synchronized and primary reserve requirements within the operational hour. Resources that are redispatched as tier 2 within the hour are required to maintain their available ramp and are paid the SRMCP plus any lost opportunity costs or energy use costs that exceed the SRMCP.

Market Structure

Supply

PJM has a must offer tier 2 synchronized reserve requirement. All nonemergency generating resources are required to submit tier 2 synchronized reserve offers. All online, nonemergency 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 offline emergency generation capacity resources available to provide energy must submit an offer for tier 2 synchronized reserve.[21]

In the first three months of 2017, the Mid Atlantic Dominion (MAD) Reserve Subzone averaged 6,779.8 MW of tier 2 synchronized reserve offers, and the RTO Reserve Zone averaged 23,563.7 MW of synchronized reserve offers (Figure 10-12).

The supply of tier 2 synchronized reserve in the first three months of 2017 was sufficient to cover the requirement net of tier 1 in both the RTO Reserve Zone and the MAD Reserve Subzone.

The largest portion of cleared tier 2 synchronized reserve in 2017 was from CTs, 68.1 percent (Figure 10-7). 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. This means that in many hours demand resources make up considerably more than 33 percent of the cleared Tier 2 MW. The DR MW share of the total cleared Tier 2 Synchronized Reserve Market was 8.8 percent in 2016.[22] The DR MW share of the total cleared Tier 2 Synchronized Reserve Market in the first three months of 2017 was 20.5 percent.

21 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Revision 84 (August 25, 2016), p. 85.
22 The cap on demand response participation is defined in MW terms. There is no cap on the proportion of cleared demand response consistent with the MW cap.

Figure 10-7 Cleared tier 2 synchronized reserve average hourly MW per hour by unit type, RTO Zone: January 1, 2016 through March 31, 2017

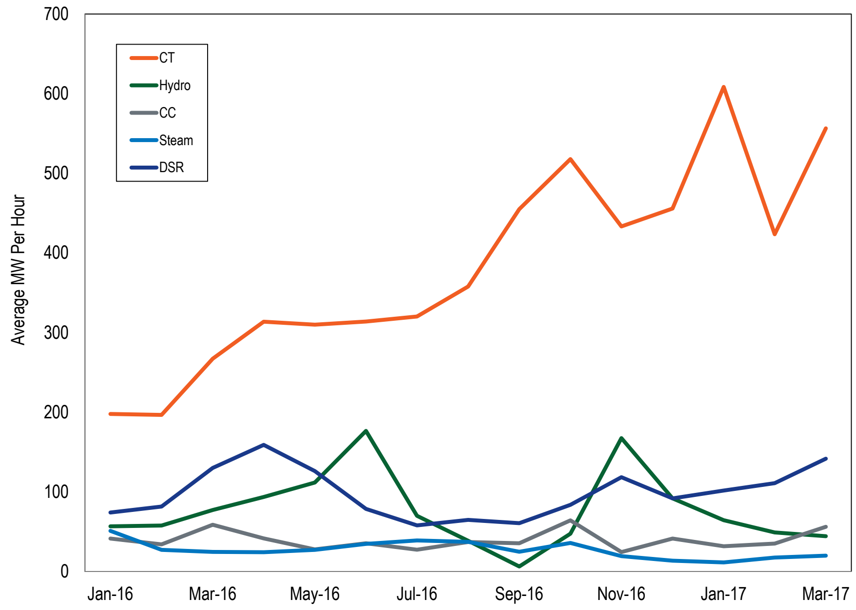
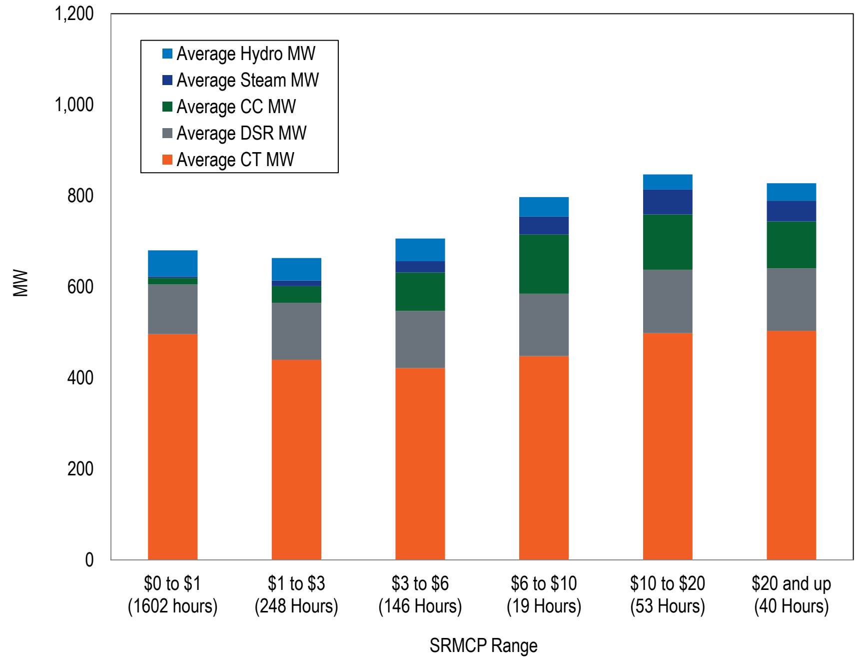


Figure 10-8 provides the average hourly cleared tier 2 MW by unit type by tier 2 clearing price range (SRMCP).

Figure 10-8 Average hourly tier 2 MW by unit type by SRMCP range: January through March, 2017



Demand

The default synchronized reserve requirement is set at 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.[23]

23 PJM. "Manual 11: Energy & Ancillary Services Market Operations," Revision 85 (November 1, 2016) pp. 88.

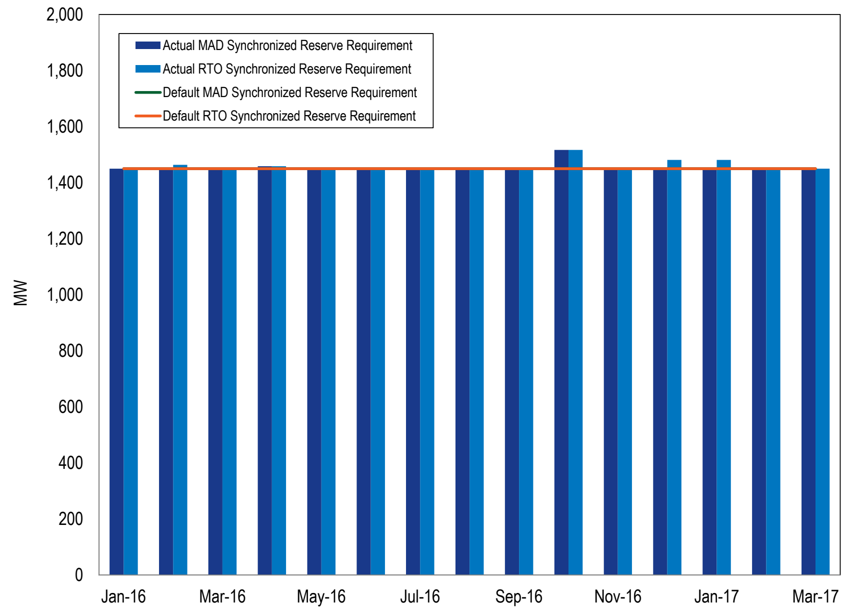
The synchronized reserve requirement was temporarily increased for the RTO Zone on January 10 and January 11, 2017, for a 31 hour period to 2,200 MW.

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 when grid maintenance or outages change the largest contingency. Figure 10-9 shows monthly average actual synchronized reserve requirements and the default synchronized reserve requirements..

Figure 10-9 Monthly average actual vs default synchronized reserve requirements, RTO Zone and MAD Subzone: January 2016 through March 2017



The RTO Reserve Zone cleared an hourly average of 616.4 MW of tier 2 synchronized reserves the first three months of 2017. Of this, an average of 113.6 MW cleared within the RTO exclusive of MAD and 502.8 MW cleared in the MAD Subzone.

Figure 10-10 and Figure 10-11 show the average monthly synchronized reserve required and the average monthly tier 2 synchronized reserve MW scheduled (PJM scheduled plus self-scheduled) from January 2016 through March 2017, for the RTO Reserve Zone and MAD Reserve Subzone.

Figure 10-10 MAD monthly average tier 2 synchronized reserve scheduled MW: January 1, 2016 through March 31, 2017

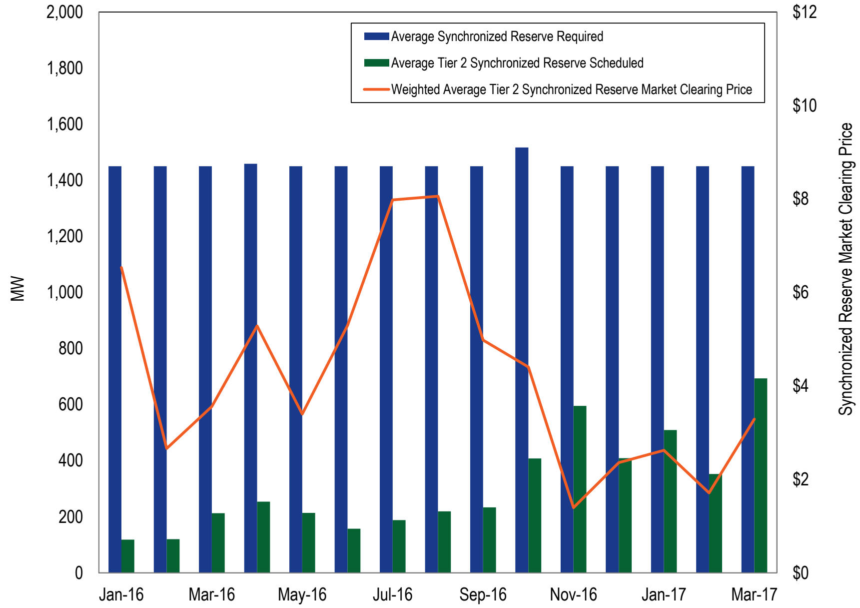
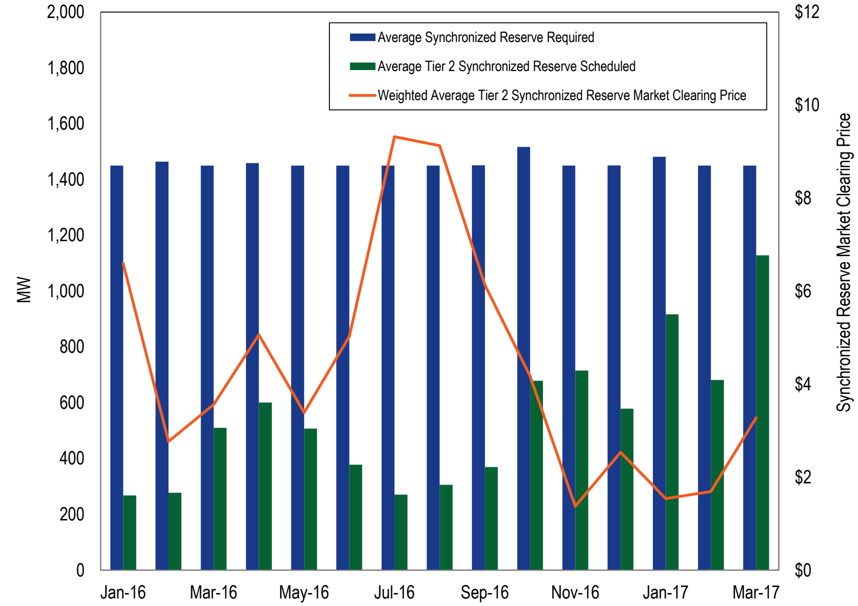


Figure 10-11 RTO monthly average tier 2 synchronized reserve scheduled MW: January 1, 2016 through March 31, 2017



Market Concentration

The HHI for tier 2 synchronized reserve for cleared hours in the Mid-Atlantic Dominion Subzone Tier 2 Synchronized Reserve Market in the first three months of 2017 was 5689, which is defined as highly concentrated. The largest hourly market share was 100 percent and 95.0 percent of all cleared hours had a maximum market share greater than or equal to 40 percent.

The HHI for tier 2 synchronized reserve for cleared hours of the RTO Zone Tier 2 Synchronized Reserve Market in the first three months of 2017 was 7321, which is defined as highly concentrated. The largest hourly market share was 100 percent and 81.3 percent of cleared hours had a maximum market share greater than or equal to 40 percent.

In the MAD Subzone, flexible synchronized reserve was 8.5 percent of all tier 2 synchronized reserve in the first three months of 2017. In the RTO Zone, flexible synchronized reserve assigned was 11.2 percent of all tier 2 synchronized reserve during the same period.

The MMU calculates that 92.2 percent of hours would have failed the three pivotal supplier test in the MAD Subzone in the first three months of 2017 for the inflexible Synchronized Reserve Market (excluding self-scheduled synchronized reserve) in the hour ahead market (Table 10-16) and 61.2 percent of hours would have failed a three pivotal supplier test in the RTO Zone during the same time period.

Table 10-16 Three pivotal supplier test results for the RTO Zone and MAD Subzone: January 1, 2016 through March 31, 2017

Year	Month	Mid Atlantic Dominion Reserve Subzone Pivotal Supplier Hours	RTO Reserve Zone Pivotal Supplier Hours
2016	Jan	82.7%	43.1%
2016	Feb	72.0%	39.6%
2016	Mar	93.4%	59.1%
2016	Apr	97.9%	55.6%
2016	May	94.2%	31.3%
2016	Jun	90.4%	27.4%
2016	Jul	79.4%	14.2%
2016	Aug	75.9%	14.4%
2016	Sep	84.3%	41.9%
2016	Oct	87.9%	80.9%
2016	Nov	96.0%	65.9%
2016	Dec	92.3%	69.8%
2016		87.2%	45.3%
2017	Jan	93.5%	73.5%
2017	Feb	88.4%	62.3%
2017	Mar	94.6%	48.0%
2017		92.2%	61.2%

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 offers are submitted for each unit by the unit owner. For generators the offer 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, spin as a condenser status, and condense available status. 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. 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 10 minutes. A resource that is unable to participate in the synchronized reserve market during a given hour may set its hourly offer to 0.00 MW. Defined resources are not required to offer tier 2 because they cannot reliably provide synchronized reserve: nuclear, wind, solar, batteries and landfill gas.[24]

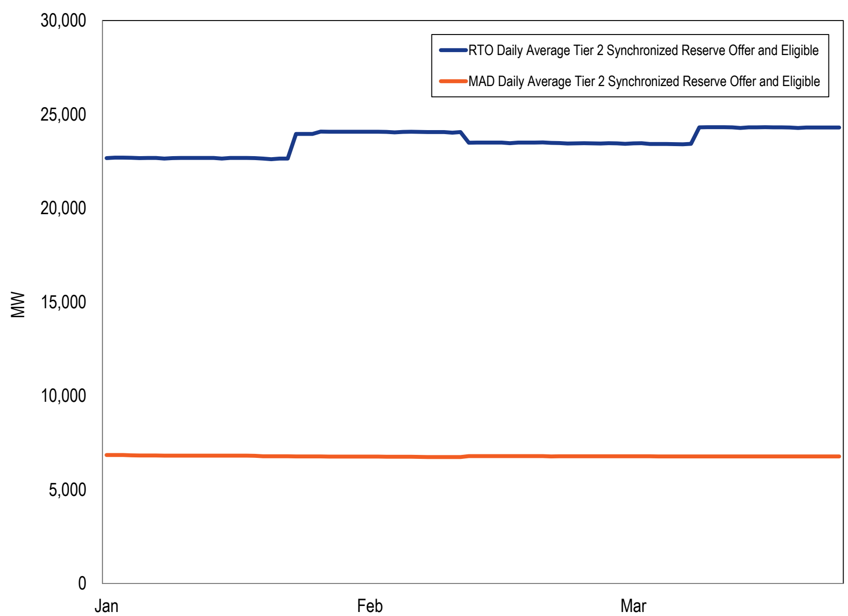
Figure 10-12 shows the daily average of hourly offered tier 2 synchronized reserve MW for both the RTO Synchronized Reserve Zone and the Mid-Atlantic Dominion Synchronized Reserve Subzone. In the first three months of 2017, the ratio of online and eligible tier 2 synchronized reserve to synchronized reserve required in the Mid-Atlantic Dominion Subzone was 4.96 averaged over all hours. For the RTO Synchronized Reserve Zone the ratio was 5.74.

PJM has a tier 2 synchronized reserve must offer requirement for all generation that is online, nonemergency, 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

24 See PJM "Manual 11: Energy & Ancillary Services Market Operations," Revision 85 (November 1, 2016) p. 86.

required regardless of online/offline state.[25] The Tier 2 Synchronized Reserve Market is not actually cleared based on 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 10-12). Changes to the hourly offer status are only permitted when resources are physically unable to provide tier 2. Changes to hourly eligibility levels are the result of online status, minimum/maximum runtimes, minimum notification times, maintenance status and grid conditions including constraints. However, resource operators can make their units unavailable for an hour or block of hours 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 10-12 Tier 2 synchronized reserve hourly offer and eligible volume (MW), averaged daily: January through March, 2017



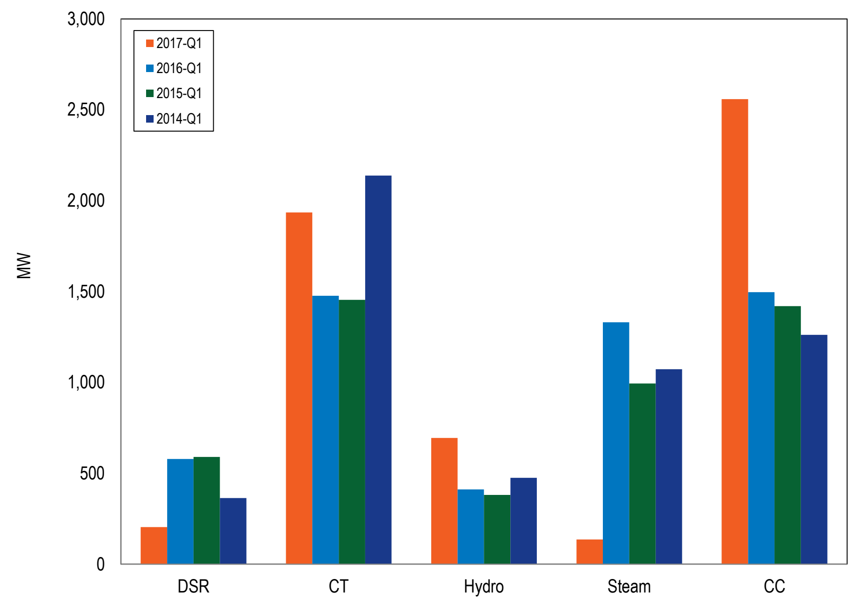
25 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Revision 85 (November 1, 2016) p. 85, "Regardless of online/offline state, all non-emergency generation capacity resources must submit a daily offer for Tier 2 Synchronized Reserve in eMKT..."

Of all nonemergency resources capable of reliably producing synchronized reserve and therefore obligated to offer, an average of 4.2 percent of units capable of providing tier 2 synchronized reserve did not enter a daily tier 2 synchronized reserve offer for the first three months of 2017.

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 unit owners to select a reason in Markets Gateway whenever making a unit unavailable either daily or hourly or setting the offer MW to 0 MW.[26]

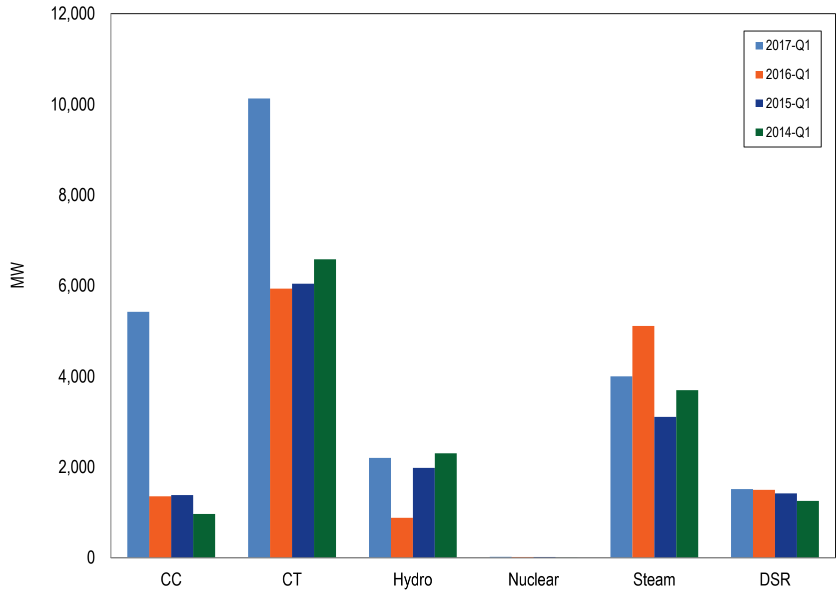
Figure 10-13 shows average offer MW volume by market and unit type for the MAD Subzone and Figure 10-14 shows average offer MW volume by market and unit type for the RTO Zone.

Figure 10-13 MAD average daily tier 2 synchronized reserve offer by unit type (MW): January through March, 2014 through 2017



26 PJM has indicated that it will initiate a new procedure in the second quarter of 2017 to enforce compliance with the tier 2 must-offer requirement.

Figure 10-14 RTO Zone average daily tier 2 synchronized reserve offer by unit type (MW): January through March, 2014 through 2017



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. In hours where total tier 1 MW synchronized reserve MW is less than the synchronized reserve requirement, PJM must clear a tier 2 market for synchronized reserves.

In the first three months of 2017, a tier 2 synchronized reserve market was cleared for the MAD Subzone in 97.9 percent of all hours. In 2.1 percent of hours there was enough tier 1 synchronized reserve to cover the full requirement. The MAD tier 2 market cleared an average of 379.3 MW at a weighted average clearing price of $2.22 compared to $4.99 in the first three months of 2016.

In the first three months of 2017, the Tier 2 Synchronized Reserve Market for the RTO Zone cleared an average of 396.1 MW at a weighted average price of $2.32 compared to $4.96 in the first three months of 2016.

In 97.9 percent of cleared hours, the synchronized reserve market clearing price was the same for both the MAD Subzone and the RTO Zone. In the 2.1 percent of hours when the price diverged, the average clearing price was $10.53 in the MAD Subzone, and $8.03 in the RTO Zone.

Supply, performance, and demand are reflected in the price of synchronized reserve. (Figure 10-10 and Figure 10-11).

Table 10-17 Mid-Atlantic Dominion subzone, weighted average SRMCP and average scheduled, tier 1 estimated and demand response MW: January 1, 2016 through March 31, 2017

Year	Month	Weighted Average Synchronized Reserve Market Clearing Price	Average Tier 2 Generation Synchronized Reserve Purchased (MW)	Average Hourly Tier 1 Synchronized Reserve Estimated Hour Ahead (MW)	Average Hourly Demand Response Cleared (MW)
2016	Jan	$4.70	206.1	586.1	62.2
2016	Feb	$1.99	205.3	609.3	63.1
2016	Mar	$3.07	386.8	402.4	97.8
2016	Apr	$4.62	500.9	341.7	125.7
2016	May	$2.88	432.0	408.2	96.6
2016	Jun	$4.34	311.7	638.4	67.1
2016	Jul	$7.98	188.0	756.7	46.8
2016	Aug	$8.06	219.2	750.5	50.5
2016	Sep	$4.66	230.6	658.9	43.6
2016	Oct	$4.00	407.9	393.6	58.8
2016	Nov	$1.28	595.1	385.2	92.8
2016	Dec	$2.21	408.7	500.5	69.5
2016		$4.15	341.0	539.2	72.9
2017	Jan	$2.18	400.7	592.0	75.3
2017	Feb	$1.60	288.8	577.0	84.8
2017	Mar	$2.88	549.3	464.1	108.4
2017		$2.22	412.9	544.4	89.5

Table 10-18 RTO zone weighted average SRMCP and average scheduled, tier 1 estimated and demand response MW: January 1, 2016 through March 31, 2017

Year	Month	Weighted Average Synchronized Reserve Market Clearing Price	Average Tier 2 Generation Synchronized Reserve Purchased (MW)	Average Hourly Tier 1 Synchronized Reserve Estimated Hour Ahead (MW)	Average Hourly Demand Response Cleared (MW)
2016	Jan	$6.64	269.5	1,659.4	74.3
2016	Feb	$2.76	277.9	1,564.1	81.5
2016	Mar	$3.56	510.2	1,089.1	130.0
2016	Apr	$5.06	602.2	1,011.7	159.3
2016	May	$3.39	508.3	1,160.9	125.8
2016	Jun	$5.03	378.3	1,546.0	78.4
2016	Jul	$9.32	270.5	1,663.8	59.6
2016	Aug	$9.13	306.0	1,605.6	64.5
2016	Sep	$5.62	364.6	1,290.4	60.7
2016	Oct	$4.17	678.9	802.7	83.5
2016	Nov	$1.37	715.6	810.8	117.7
2016	Dec	$2.54	578.6	953.1	92.5
2016		$4.88	455.1	1,399.0	94.0
2017	Jan	$2.00	639.2	592.0	100.9
2017	Feb	$1.70	483.5	577.0	110.6
2017	Mar	$3.28	728.2	464.1	140.7
2017		$2.33	617.0	544.4	117.4

Cost

As a result of changing grid conditions, load forecasts, and unexpected generator performance, prices do not always cover the full cost including the final LOC for each resource. Because price formation occurs within the hour (on a five minute basis integrated over the hour) but the synchronized reserve commitment occurs prior to the hour, the realized within hour price can be zero even when some tier 2 synchronized reserve is cleared. All resources cleared in the market are guaranteed to be made whole and are paid if the SRMCP does not compensate them for their offer plus LOC.

The full cost of tier 2 synchronized reserve including payments for the clearing price and out of market costs is calculated and compared to the price. The closer the price to cost ratio is to one hundred percent, the more the market price reflects the full cost of tier 2 synchronized reserve. A price to cost ratio close to one hundred percent is an indicator of an efficient synchronized reserve market design.

In the first three months of 2017, the price to cost (including self-scheduled) ratio of the RTO Zone Tier 2 Synchronized Reserve Market averaged 32.5 percent (Table 10-19); the price to cost ratio of the MAD Subzone averaged 32.0 percent.

Table 10-19 RTO Zone, Mid-Atlantic Subzone tier 2 synchronized reserve MW, credits, weighted price, and cost (including self-scheduled): January 1 through March 31, 2017

Zone	Year	Month	Tier 2 Credited MW	Tier 2 Credits	Weighted Average Synchronized Reserve Market Clearing Price	Tier 2 Synchronized Reserve Cost	Price/ Cost Ratio
MAD Subzone	2017	Jan	297,672	$1,926,899	$2.18	$6.47	33.7%
MAD Subzone	2017	Feb	194,076	$1,423,859	$1.60	$7.34	21.8%
MAD Subzone	2017	Mar	406,593	$2,846,983	$2.88	$7.00	41.2%
MAD Subzone	2017		898,341	$6,197,742	$2.22	$6.94	32.0%
RTO Zone	2017	Jan	475,031	$3,201,712	$2.00	$6.74	29.7%
RTO Zone	2017	Feb	324,910	$2,082,841	$1.70	$6.41	26.5%
RTO Zone	2017	Mar	539,411	$4,478,254	$3.28	$8.30	39.5%
RTO Zone	2017		1,339,352	$9,762,807	$2.33	$7.15	32.5%

Compliance

The MMU has identified and quantified the actual performance of scheduled tier 2 synchronized reserve resources when called on to deliver during synchronized reserve events since 2011.[27] 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.[28] Tier 2 resources are obligated to sustain their final output for the

27 See the *2011 State of the Market Report for PJM*, Volume II, Section 9, "Ancillary Services" at pg. 250.
28 See PJM "Manual 11: Energy & Ancillary Services Market Operations," Revision 84 (August 25, 2016) § 4.2.11 Verification, p. 97.

shorter of the length of the event or 30 minutes. Penalties can be assessed for failure of a scheduled tier 2 resource to perform during any synchronized reserve event lasting 10 minutes or longer.

The MMU has reported the wide range of synchronized reserve event response levels and recommended that PJM take action to increase compliance rates. In 2015, there were 21 spinning events of which seven were 10 minutes or longer. In 2016, there were 16 spinning events of which six were 10 minutes or longer. In the first three months of 2017 there have been nine spinning events only one of which was longer than 10 minutes.

Tier 1 resource owners are paid for the actual amount of synchronized reserve they provide in response to a synchronized reserve event.[29] Tier 2 resource owners are paid for being available and responding but are not paid based on the actual response to a synchronized reserve event. Tier 1 resource owners do not have an obligation to respond and are not penalized for a failure to respond. Tier 2 resource owners are penalized for a failure to respond.

A tier 2 resource is 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.[30] The penalty period extends for the average number of days between spinning events. For the first three months of 2017, PJM used the average number of days between spinning events from November 2015 through October 2016 which is 13 days.[31] 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 to reduce an under response penalty.

There was only one synchronized reserve event of 10 minutes or longer that occurred in the first three months of 2017. In that event from March 23, 2017, 24.7 percent of all scheduled tier 2 synchronized reserve MW were not delivered and were penalized (Table 10-20).

29 See PJM "Manual 11: Energy & Ancillary Services Market Operations," Revision 85 (November 1, 2016) § 4.2.12 Non Performance, p. 98.
30 See PJM. "Manual 28: Operating Agreement Accounting," Revision 75 (November 18, 2016) p. 47. *See also* "See PJM "Manual 11: Energy & Ancillary Services Market Operations," Revision 85 (November 1, 2016) § 4.2.12 Non-Performance, p. 99.
31 "2016 Third Quarter Synchronized Reserve Performance & 2017 Synchronized Reserve Penalty Days," presentation to the Operating Committee, December 13, 2016. <http://www.pjm.com/~/media/committees-groups/committees/oc/20161213/20161213-item-16-2016-third-quarter-synchronized-reserve-performance-with-2017-penalty-days.ashx>

Table 10-20 Synchronized reserve events 10 minutes or longer, tier 2 response compliance, RTO Reserve Zone: January 1 through March 31, 2017

Spin Event (Day, Time)	Duration (Minutes)	Tier 1 Estimate (MW Adj by DGP)	Tier 1 Resp (MW)	Tier 2 Scheduled (MW)	Tier 2 Response (MW)	Tier 2 Penalty (MW)	Tier 1 Response Pct	Tier 2 Response Pct
Mar 23, 2017 06:48	24	926.8	549.6	742.8	559.1	183.7	59.3%	75.3%

History of Synchronized Reserve Events

Synchronized reserve is designed to provide relief for disturbances.[32 33] A disturbance is defined as loss of generation and/or transmission resources. In the absence of a disturbance, PJM dispatchers have used synchronized reserve as a source of energy to provide relief from low ACE. There were three low ACE events in the first three months of 2017, on January 12, 2017 for 8 minutes, February 13, 2017 for 7 minutes, and on March 23, 2017 for 24 minutes.

The risk of using synchronized reserves for energy or any other non-disturbance reason is that it reduces the amount of synchronized reserve available for a disturbance. Disturbances are unpredictable. Synchronized reserve has a requirement to sustain its output for only 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 1, 2010 through March 31, 2017, PJM experienced 193 synchronized reserve events (Table 10-21), approximately 2.2 events per month. During this period, synchronized reserve events had an average duration of 12.2 minutes.

32 2013 State of the Market Report for PJM, Appendix F – PJM's DCS Performance, pp 451-452.
33 See PJM. "Manual 12: Balancing Operations," Revision 34 (April 28, 2016) § 4.1.2 Loading Reserves pp. 36.

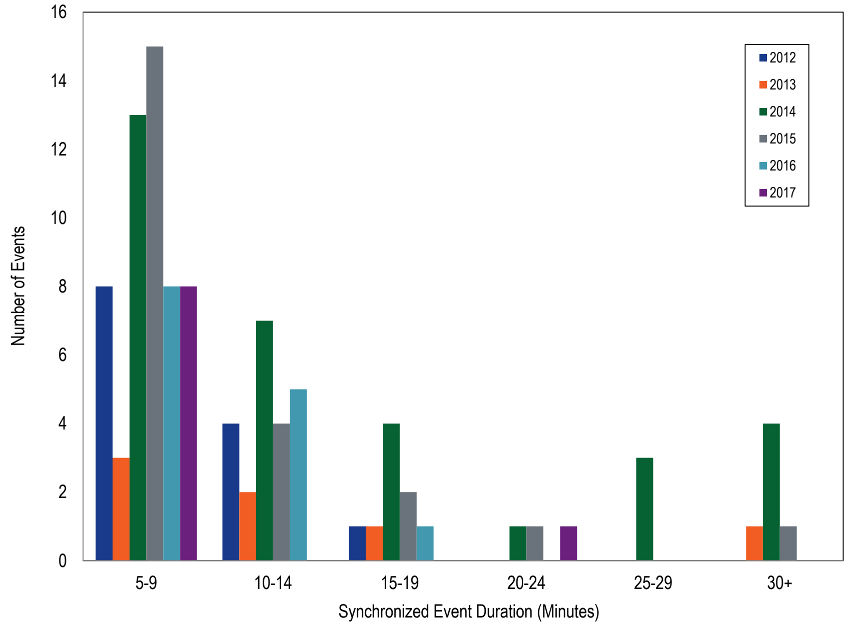
Table 10-21 Synchronized reserve events: January 1, 2010 through March 31, 2017

Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)
FEB-18-2010 13:27	Mid-Atlantic	19	JAN-11-2011 15:10	Mid-Atlantic	6	JAN-03-2012 16:51	RFC	9	JAN-22-2013 08:34	RTO	8
MAR-18-2010 11:02	RFC	27	FEB-02-2011 01:21	RFC	5	JAN-06-2012 23:25	RFC	8	JAN-25-2013 15:01	RTO	19
MAR-23-2010 20:14	RFC	13	FEB-08-2011 22:41	Mid-Atlantic	11	JAN-23-2012 15:02	Mid-Atlantic	8	FEB-09-2013 22:55	RTO	10
APR-11-2010 13:12	RFC	9	FEB-09-2011 11:40	Mid-Atlantic	16	MAR-02-2012 19:54	RFC	9	FEB-17-2013 23:10	RTO	13
APR-28-2010 15:09	Mid-Atlantic	8	FEB-13-2011 15:35	Mid-Atlantic	14	MAR-08-2012 17:04	RFC	6	APR-17-2013 01:11	RTO	11
MAY-11-2010 19:57	Mid-Atlantic	9	FEB-24-2011 11:35	Mid-Atlantic	14	MAR-19-2012 10:14	RFC	10	APR-17-2013 20:01	RTO	9
MAY-15-2010 03:03	RFC	6	FEB-25-2011 14:12	RFC	10	APR-16-2012 00:20	Mid-Atlantic	9	MAY-07-2013 17:33	RTO	8
MAY-28-2010 04:06	Mid-Atlantic	5	MAR-30-2011 19:13	RFC	12	APR-16-2012 11:18	RFC	8	JUN-05-2013 18:54	RTO	20
JUN-15-2010 00:46	RFC	34	APR-02-2011 13:13	Mid-Atlantic	11	APR-19-2012 11:54	RFC	16	JUN-08-2013 15:19	RTO	9
JUN-19-2010 23:49	Mid-Atlantic	9	APR-11-2011 00:28	RFC	6	APR-20-2012 11:08	Mid-Atlantic	7	JUN-12-2013 17:35	RTO	10
JUN-24-2010 00:56	RFC	15	APR-16-2011 22:51	RFC	9	JUN-20-2012 13:35	RFC	7	JUN-30-2013 01:22	RTO	10
JUN-27-2010 19:33	Mid-Atlantic	15	APR-21-2011 20:02	Mid-Atlantic	6	JUN-26-2012 17:51	RFC	7	JUL-03-2013 20:40	RTO	13
JUL-07-2010 15:20	RFC	8	APR-27-2011 01:22	RFC	8	JUL-23-2012 21:45	RFC	18	JUL-15-2013 18:43	RTO	29
JUL-16-2010 20:45	Mid-Atlantic	19	MAY-02-2011 00:05	Mid-Atlantic	21	AUG-03-2012 12:44	RFC	10	JUL-28-2013 14:20	RTO	10
AUG-11-2010 19:09	RFC	17	MAY-12-2011 19:39	RFC	9	SEP-08-2012 04:34	RFC	12	SEP-10-2013 19:48	RTO	68
AUG-13-2010 23:19	RFC	6	MAY-26-2011 17:17	Mid-Atlantic	20	SEP-27-2012 17:19	Mid-Atlantic	7	OCT-28-2013 10:44	RTO	33
AUG-16-2010 07:08	RFC	17	MAY-27-2011 12:51	RFC	6	OCT-17-2012 10:48	RTO	10	DEC-01-2013 11:17	RTO	9
AUG-16-2010 19:39	Mid-Atlantic	11	MAY-29-2011 09:04	RFC	7	OCT-23-2012 22:29	RTO	19	DEC-07-2013 19:44	RTO	7
SEP-15-2010 11:20	RFC	13	MAY-31-2011 16:36	RFC	27	OCT-30-2012 05:12	RTO	14			
SEP-22-2010 15:28	Mid-Atlantic	24	JUN-03-2011 14:23	RFC	7	NOV-25-2012 16:32	RTO	12			
OCT-05-2010 17:20	RFC	10	JUN-06-2011 22:02	Mid-Atlantic	9	DEC-16-2012 07:01	RTO	9			
OCT-16-2010 03:22	Mid-Atlantic	10	JUN-23-2011 23:26	RFC	8	DEC-21-2012 05:51	RTO	7			
OCT-16-2010 03:25	RFCNonMA	7	JUN-26-2011 22:03	Mid-Atlantic	10	DEC-21-2012 10:29	RTO	5			
OCT-27-2010 10:35	RFC	7	JUL-10-2011 11:20	RFC	10						
OCT-27-2010 12:50	Mid-Atlantic	10	JUL-28-2011 18:49	RFC	12						
NOV-26-2010 14:24	RFC	13	AUG-02-2011 01:08	RFC	6						
NOV-27-2010 11:34	RFC	8	AUG-18-2011 06:45	Mid-Atlantic	6						
DEC-08-2010 01:19	RFC	11	AUG-19-2011 14:49	RFC	5						
DEC-09-2010 20:07	RFC	5	AUG-23-2011 17:52	RFC	7						
DEC-14-2010 12:02	Mid-Atlantic	24	SEP-24-2011 15:48	RFC	8						
DEC-16-2010 18:40	Mid-Atlantic	20	SEP-27-2011 14:20	RFC	7						
DEC-17-2010 22:09	Mid-Atlantic	6	SEP-27-2011 16:47	RFC	9						
DEC-29-2010 19:01	Mid-Atlantic	15	OCT-30-2011 22:39	Mid-Atlantic	10						
			DEC-15-2011 14:35	Mid-Atlantic	8						
			DEC-21-2011 14:26	RFC	18						

Table 10-21 Synchronized reserve events: January 1, 2010 through March 31 2017 (continued)

Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)
JAN-06-2014 22:01	RTO	68	JAN-07-2015 22:36	RTO	8	JAN-18-2016 17:58	RTO	12	Jan-08-2017 03:21	RTO	7
JAN-07-2014 02:20	RTO	25	FEB-24-2015 02:51	RTO	5	FEB-08-2016 15:05	RTO	10	Jan-09-2017 19:24	RTO	9
JAN-07-2014 04:18	RTO	34	FEB-26-2015 15:20	RTO	6	FEB-28-2016 18:29	RTO	8	Jan-10-2017 13:05	MAD	9
JAN-07-2014 11:27	RTO	11	MAR-03-2015 17:02	RTO	11	APR-14-2016 20:09	RTO	10	Jan-15-2017 20:13	RTO	8
JAN-07-2014 13:20	RTO	41	MAR-16-2015 10:25	RTO	24	MAY-11-2016 15:55	RTO	6	Jan-23-2017 09:08	RTO	7
JAN-10-2014 16:46	RTO	12	MAR-17-2015 23:34	RTO	17	JUN-01-2016 09:01	RTO	5	Feb-13-2017 18:30	RTO	7
JAN-21-2014 18:52	RTO	6	MAR-23-2015 23:44	RTO	15	JUL-06-2016 00:40	RTO	5	Feb-14-2017 00:11	RTO	6
JAN-22-2014 02:26	RTO	7	APR-06-2015 14:23	RTO	8	JUL-28-2016 13:28	RTO	15	Feb-15-2017 06:37	RTO	6
JAN-22-2014 22:54	RTO	8	APR-07-2015 17:11	RTO	31	AUG-31-2016 19:29	RTO	8	Mar-23-2017 06:48	RTO	24
JAN-25-2014 05:22	RTO	10	APR-15-2015 08:14	RTO	8	SEP-09-2016 19:11	RTO	6			
JAN-26-2014 17:11	RTO	6	APR-25-2015 03:21	RTO	9	SEP-11-2016 19:30	RTO	9			
JAN-31-2014 15:05	RTO	13	JUL-30-2015 14:04	RTO	10	OCT-12-2016 08:21	RTO	5			
FEB-02-2014 14:03	Dominion	8	AUG-05-2015 19:47	RTO	7	OCT-12-2016 14:40	RTO	7			
FEB-08-2014 06:05	Dominion	18	AUG-19-2015 16:47	RTO	9	NOV-04-2016 17:13	RTO	11			
FEB-22-2014 23:05	RTO	7	SEP-05-2015 01:16	RTO	7	DEC-03-2016 00:11	RTO	7			
MAR-01-2014 05:18	RTO	26	SEP-10-2015 10:12	RTO	8	DEC-31-2016 05:10	RTO	12			
MAR-05-2014 21:25	RTO	8	SEP-29-2015 00:58	Mid-Atlantic	11						
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									

Figure 10-15 Synchronized reserve events duration distribution curve: January through March, 2012 through 2017



NonSynchronized Reserve Market

Nonsynchronized reserve consists of MW available within 10 minutes but not synchronized to the grid. Startup time for nonsynchronized reserve resources is not subject to testing. There is no defined requirement for nonsynchronized 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 nonsynchronized reserves. Generation resources that are not available to provide energy are not eligible to provide nonsynchronized reserves.

The market mechanism for nonsynchronized reserve does not include any direct participation by market participants. PJM defines the demand curve for nonsynchronized reserve and PJM defines the supply curve based on nonemergency generation resources that are available to provide energy and can start in 10 minutes or less and on the associated resource opportunity costs calculated by PJM. Generation owners do not submit supply offers. Since nonsynchronized 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 nonsynchronized reserve clearing price is zero.

Market Structure

Demand

PJM specifies that 1,700 MW of 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 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 nonsynchronized reserve. PJM market operations increased the required amount of primary reserve from 2,175 MW to 3,300 MW on January 10 and January 11, 2017, for a 32 hour period.

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 nonsynchronized reserve (light blue area).

There are no offers for non-synchronized reserve. The hour ahead market solution considers the MW supply of nonsynchronized reserve to be all generation resources currently not synchronized to the grid but available and capable of providing energy within 10 minutes. Generators that have set themselves as unavailable or have set their output to be emergency-only will not be considered. The market solution considers the offered MW to be the lesser of the economic maximum or the ramp rate times10 minutes minus the startup and notification time. The offer price of nonsynchronized is the unit's opportunity cost of providing reserves.

The market solution optimizes synchronized reserve, nonsynchronized reserve, and energy to satisfy the primary reserve requirement at the lowest cost. Nonsynchronized reserve resources are scheduled economically based on LOC until the Primary Reserve requirement is filled. The nonsynchronized reserve market clearing price is determined at the end of the hour based on the LOC of the marginal unit. When a unit clears the nonsynchronized reserve market and is scheduled, it is committed to remain offline for the hour and available to provide 10 minute reserves.

Resources that generally qualify as nonsynchronized reserve include run of river hydro, pumped hydro, combustion turbines, combined cycles and diesels.[34] In the first three months of 2017, an average of 379.4 MW of nonsynchronized reserve was scheduled hourly out of 1,847.2 eligible MW as part of the primary reserve requirement in the Mid-Atlantic Dominion Subzone. In the first three months of 2017, an average of 676.2 MW of nonsynchronized reserve was scheduled hourly out of 2,244.9 MW eligible MW in the RTO Zone.

In the first three months of 2017, CTs provided 35.6 percent of scheduled nonsynchronized reserve and hydro provided 63.9 percent. The remaining 0.5 percent of cleared nonsynchronized reserve was provided by diesel resources.

Market Concentration

The supply of nonsynchronized reserves in the Mid-Atlantic Dominion Subzone and the RTO Zone was highly concentrated in the first three months of 2017.

Table 10-22 Nonsynchronized reserve market HHIs: January 1 through March 31, 2017

Year	Month	MAD HHI	RTO HHI
2017	Jan	3968	3966
2017	Feb	3995	3986
2017	Mar	4359	4343
2017	Average	4107	4098

Table 10-23 Nonsynchronized reserve market pivotal supply test: January 1 through March 31, 2017

Year	Month	MAD Three Pivotal Supplier Hours	RTO Three Pivotal Supplier Hours
2017	Jan	32.2%	0.0%
2017	Feb	31.1%	0.0%
2017	Mar	38.1%	0.0%
2017	Average	33.8%	0.0%

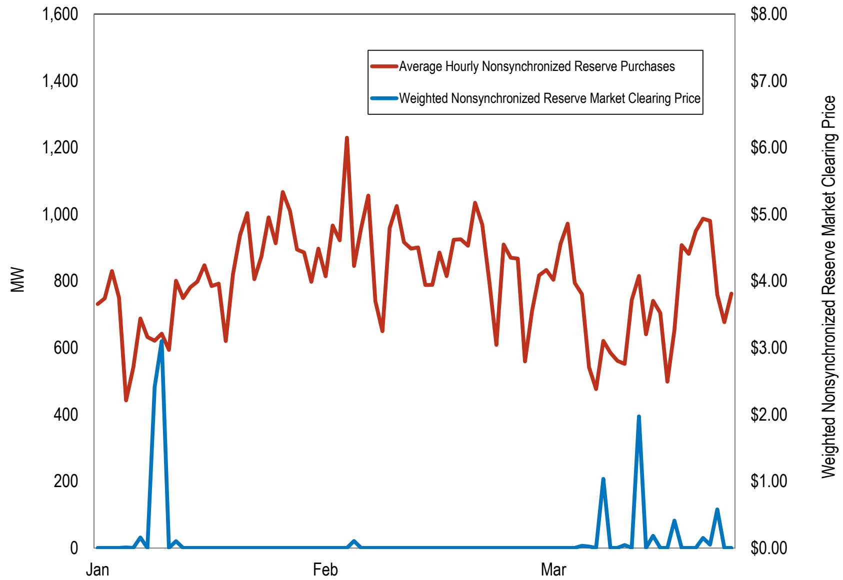
Price

The price of nonsynchronized reserve is calculated in real time every five minutes and averaged hourly for the RTO Reserve Zone and the Mid-Atlantic Dominion Reserve Subzone.

Figure 10-16 shows the daily average nonsynchronized reserve market clearing price and average scheduled MW for the RTO Zone. In the MAD Subzone and the RTO Zone in the first three months of 2017, the average nonsynchronized market clearing price was $0.11 per MW. The hourly average nonsynchronized reserve assigned was 805.0 MW. The market cleared at a price greater than $0 in 34 hours. The maximum hourly clearing price was $27.53 per MW on March 18, 2017.

34 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Revision 84 (August 25, 2016), p. 101.

Figure 10-16 Daily average RTO Zone nonsynchronized reserve market clearing price and MW purchased: January 1 through March 31, 2017



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. When real time LMP rises above the generator's cost at economic minimum, then an LOC is paid.[35]

The full cost of nonsynchronized reserve including payments for the clearing price and uplift costs is calculated and compared to the price (Table 10-24). The closer the price to cost ratio comes to one, the more the market price reflects the full cost of non-synchronized reserve.

In the first three months of 2017, the price to cost ratio in both the RTO Zone Nonsynchronized Reserve Market averaged 18.1 percent; and the price to cost ratio of the MAD Subzone averaged 20.5 percent.

Resources that are not synchronized to the grid are generally off because it is not economic for them to produce energy. A resource scheduled for nonsynchronized reserve is obligated to remain unsynchronized even if its LMP changes and it becomes economic to start. In that case, the unit has a positive LOC.

Both nonsynchronized reserve markets cleared at a price above $0 in only 1.6 percent of hours.

The costs of nonsynchronized reserves could be minimized if PJM could flexibly substitute lower LOC units for higher LOC units in real time as system conditions changed. Under current rules, PJM is required to keep committed a unit for which the LOC increases within the hour even if lower LOC units are available as substitutes.

Table 10-24 RTO zone, MAD subzone nonsynchronized reserve MW, charges, price, and cost: January 1 through March 31, 2017

Market	Year	Month	Total Non-synchronized Reserve MW	Total Non-synchronized Reserve Charges	Weighted Non-synchronized Reserve Market Price	Non-synchronized Reserve Cost	Price/ Cost Ratio
RTO Zone Full	2017	Jan	585,413	$386,166	$0.15	$0.66	22.9%
RTO Zone Full	2017	Feb	599,911	$180,670	$0.00	$0.30	1.2%
RTO Zone Full	2017	Mar	553,573	$391,475	$0.15	$0.71	20.5%
RTO Zone Full	2017	Total	1,738,897	$958,311	$0.10	$0.55	18.1%
MAD	2017	Jan	584,751	$329,190	$0.15	$0.56	26.3%
MAD	2017	Feb	599,851	$178,880	$0.00	$0.30	1.2%
MAD	2017	Mar	552,418	$331,164	$0.15	$0.60	24.3%
MAD	2017	Total	1,737,020	$839,234	$0.10	$0.48	20.5%

35 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Revision 85 (November 1, 2016), p. 103.

Secondary Reserve

There is no NERC standard for secondary reserve. PJM defines secondary reserve as reserves (online or offline available for dispatch) that can be converted to energy in 30 minutes. PJM defines a secondary reserve requirement but does not have a goal to maintain this reserve requirement in real time.

PJM maintains a day-ahead, offer based market for 30-minute day-ahead secondary reserve.[36] The Day-Ahead Scheduling Reserves Market (DASR) has no performance obligations except that a unit which clears the DASR market is required to be available for dispatch in real time.[37]

Market Structure

Supply

DASR is offered by both generation and demand resources. DASR offers consist of price only. DASR MW are calculated by the market clearing engine. DASR MW are the lesser of the energy ramp rate per minute for online units times thirty minutes, or the economic maximum MW minus the day-ahead dispatch point. For offline resources capable of being online in thirty minutes, the DASR quantity is the economic maximum. In the first three months of 2017, the average available hourly DASR was 37,058 MW, a 6.6 percent increase from 2016. The DASR hourly MW purchased averaged 5,323.3 MW, a small decrease from 5,645.4 MW the first three months of 2016.

PJM excludes resources that cannot reliably provide reserves in real time from participating in the DASR Market. Such resources include nuclear, run-of-river hydro, self-scheduled pumped hydro, wind, solar, and energy storage resources.[38] The intent of this proposal is to limit cleared DASR resources to those resources actually capable of providing reserves in the real-time market. Owners of excluded resources may request an exemption from their default non-eligibility.

36 See PJM. "Glossary."<http://www.pjm.com/Glossary.aspx>.
37 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Revision 85 (November 1, 2016), p. 166 §11.1.
38 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Revision 85 (November 1, 2016), p. 169 §11.2.3 Day-Ahead Scheduling Reserve Market Rules.

On December 14, 2015, PJM announced a plan to recover DASR credits awarded to owners for units that clear the day-ahead scheduled reserve market but become unavailable through forced outage in real time.[39] The recovery was for hours cleared from April 2015 through March 2016. This recovery is completed for a total of $404K.

All generation resources are required to offer a price for DASR.[40] Of the 5,323.3 MW average hourly DASR cleared in the first three months of 2017, 67.1 percent was from CTs, 6.3 percent was from steam, 19.6 percent was from hydro, and 6.2 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 the first three months of 2017, seven demand resources offered into the DASR Market.

Demand

Secondary reserve (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.[41] The RFC and Dominion secondary reserve requirements are added together to form a single RTO DASR requirement defined as the sum of a percent of the load forecast error and forced outage rate times the daily peak load forecast. For 2017, the DASR requirement is set to 5.52 percent of daily peak load forecast. This is down from 5.70 for 2016. The DASR requirement is applicable for all hours of the operating day.

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."[42] The amount of additional DASR MW that may be required is the Adjusted Fixed Demand (AFD) determined by a Seasonal Conditional Demand (SCD) factor.[43] The SCD

39 See PJM Market Settlements Subcommittee Meeting, December 14, 2015, "Item 01 – CT LOC Reconciliation," <http://www.pjm.com/~/media/committees-groups/subcommittees/mss/20151214/20151214-item-01-ct-loc-reconciliation.ashx>
40 See PJM Manual 11: Energy & Ancillary Services Market Operations," Revision 82 (July 1, 2016), p. 144 §11.2.3 Day-Ahead Scheduling Reserve Market Rules.
41 See PJM. "Manual 13: Emergency Operations," Revision 61 (January 1, 2017), p. 12.
42 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>.
43 See PJM. "See PJM "Manual 11: Energy & Ancillary Services Market Operations," Revision 85 (November 11, 2016) p. 166 at 11.2.1 Day-Ahead Scheduling Reserve Market Requirement.

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 10 peak load days from the prior year. 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.[44] PJM has defined the reasons for conservative operations to include, potential fuel delivery issues, forest/brush fires, extreme weather events, environmental alerts, solar disturbances, unknown grid operating state, physical or cyber attacks.[45] The result is substantial discretion for PJM to increase the demand for DASR under a variety of circumstances. PJM did not invoked adjusted fixed demand in the first three months of 2017.

The MMU recommends that PJM modify the DASR Market to ensure that all resources cleared incur a real-time performance obligation.

The MMU recommends that PJM make a change to the DASR market so that any resource that clears the DASR market incurs a real-time obligation to be available for secondary reserve.

Market Concentration

DASR market three pivotal test results are provided in Table 10-25.

44 See PJM "See PJM "Manual 11: Energy & Ancillary Services Market Operations," Revision 85 (November 1, 2016) p. 167 at 11.2.1 Day-Ahead Scheduling Reserve Market Requirement.
45 See PJM, "Manual 13: Emergency Operations" Revision 61, (January 1e 2017), p. 53 at 3.2 Conservative Operations

Table 10-25 DASR market three pivotal supplier test results and number of hours with DASRMCP above $0: January 1, 2016 through March 31, 2017

Year	Month	Number of Hours When DASRMCP > $0	Percent of Hours Pivotal
2016	Jan	326	0.3%
2016	Feb	235	0.4%
2016	Mar	369	1.9%
2016	Apr	392	0.0%
2016	May	259	4.2%
2016	Jun	193	6.2%
2016	Jul	474	38.0%
2016	Aug	402	42.8%
2016	Sep	383	45.7%
2016	Oct	373	35.1%
2016	Nov	351	20.8%
2016	Dec	209	23.9%
2016	Average	331	18.3%
2017	Jan	93	16.1%
2017	Feb	49	2.0%
2017	Mar	359	2.5%
2017	Average	167	6.9%

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.[46] 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 zero. All offers greater than zero constitute economic withholding. In the first three months of 2017, 39.3 percent of generation units offered DASR at a daily price above $0.00. This compares to 36.2 percent in 2016. In the first three months of 2017, 14.2 percent of daily offers were above $5.00 per MW.

Market Performance

In the first three months of 2017 the DASR market cleared at a price above $0 in 501 hours. In the first three months of 2017, the weighted average DASR

46 See PJM "Manual 11: Energy & Ancillary Services Market Operations," Revision 85 (November 1, 2016), p. 168.

price for all hours when the DASRMCP was above $0.00 was $0.06. In 2016, the weighted average DASR price for all hours when the DASRMCP was above $0.00 was $1.61. The average cleared MW in all hours was 3,916.3 MW. The average cleared MW in all hours when the DASRMCP was above $0.00 was 4,180.8 MW. The highest DASR price was $3.00 on Mar 23, 2017.

The introduction of Adjusted Fixed Demand (AFD) on March 1, 2015, created a bifurcated market (Table 10-26). In 2015, PJM added AFD to the normal 5.93 percent of forecast load in 367 hours. In 2016, PJM added AFD to the normal 5.7 percent of forecast load in 522 hours. The difference in market clearing price, MW cleared, obligation incurred, and charges to PJM load are substantial. During the 522 hours when AFD was in effect, the weighted average DASR price was $9.30 compared to $2.69 for hours when DASRMCP was greater than $0.00 and PJM dispatch did not augment the requirement. PJM did not invoke adjusted fixed demand in 2017, and this has resulted in lower demand and lower prices.

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.

Table 10-26 DASR Market, regular hours vs. adjusted fixed demand hours: January 1, 2016 through March 31, 2017

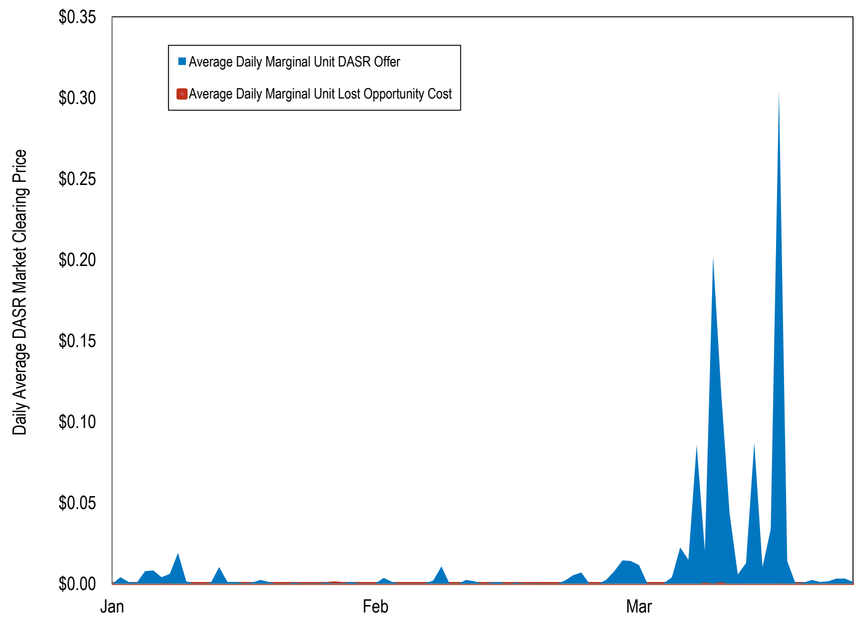
		Number of Hours DASRMCP>$0		Weighted DASRMCP		Average PJM Load MW		Hourly Average Cleared DASR MW		Average Hourly DASR Credits	
Year	Month	Normal Hour	AFD Hour	Normal Hour	AFD Hour	Normal Hour	AFD Hour	Normal Hour	AFD Hour	Normal Hour	AFD Hour
2016	Jan	326		$0.15		103,263		4,723		$720	
2016	Feb	212	24	$0.05	$3.10	102,040	107,852	4,640	6,830	$249	$21,167
2016	Mar	369		$0.04		83,994		4,175		$175	
2016	Apr	393		$0.26		80,925		4,083		$1,060	
2016	May	259		$0.43		89,181		4,228		$1,839	
2016	Jun	191		$0.53		111,102		5,377		$2,892	
2016	Jul	188	288	$0.71	$8.23	117,686	112,587	5,794	10,226	$4,117	$84,195
2016	Aug	247	143	$0.76	$10.82	122,187	113,823	6,076	11,150	$4,639	$120,663
2016	Sep	316	67	$1.11	$11.53	100,198	110,940	5,231	12,163	$5,792	$138,972
2016	Oct	373	0	$0.58	$0.00	82,824	0	4,265		$2,494	
2016	Nov	350	0	$0.10	$0.00	84,561	0	4,095		$420	
2016	Dec	210	0	$0.04	$0.00	102,293	0	4,444		$169	
2016		286	75	$0.40	$4.81	98,355	63,600	4,761	10,092	$2,047	$91,249
2017	Jan	93		$0.02		106,095		4,386		$91	
2017	Feb	49		$0.02		96,628		4,444		$92	
2017	Mar	359		$0.08		91,182		4,092		$330	
2017		167		$0.04		97,968		4,307		$171	

The implementation of AFD in 367 hours of 2015 and 528 hours of 2016 significantly increased the cost of DASR as a result of increases in DASR MW cleared and corresponding increases in the DASR clearing prices (Table 10-27).

Table 10-27 DASR Market all hours of DASR market clearing price greater than $0: January 1, 2016 through March 31, 2017

Year	Month	Number of Hours DASRMCP > $0	Weighted DASR Market Clearing Price	Average Hourly RT Load MW	Total PJM Cleared DASR MW	Total PJM Cleared Additional DASR MW	Total Charges
2016	Jan	326	$0.15	103,263	1,539,783	0	$234,679
2016	Feb	212	$0.49	102,631	1,147,608	72,197	$560,692
2016	Mar	369	$0.04	83,994	1,540,415	0	$64,728
2016	Apr	393	$0.26	80,925	1,604,693	0	$416,418
2016	May	259	$0.43	89,181	1,094,991	0	$476,305
2016	Jun	191	$0.54	111,102	1,027,053	0	$552,455
2016	Jul	476	$6.20	114,601	4,034,436	1,161,661	$25,022,218
2016	Aug	390	$5.94	119,563	3,095,240	742,332	$18,400,638
2016	Sep	383	$4.51	102,077	2,467,814	409,330	$11,141,362
2016	Oct	373	$0.58	82,824	1,591,016	0	$930,355
2016	Nov	350	$0.10	84,561	1,433,267	0	$147,023
2016	Dec	210	$0.04	102,292	933,225	0	$33,582
2016	Average	328	$1.61	98,085	1,792,462	198,793	$4,831,704
2016	Total	3932			21,509,542	2,385,520	$57,980,453
2017	Jan	93	$0.02	106,095	407,922	0	$8,426
2017	Feb	49	$0.02	96,628	217,737	0	$4,487
2017	Mar	359	$0.08	91,182	1,468,921	0	$118,345
2017	Average	167	$0.04	97,968	698,193	0	$43,752
2017	Total	501			2,094,580	0	$131,257

Figure 10-17 Daily average components of DASR clearing price ($/MW), marginal unit offer and LOC: January 1 through March 31, 2017



When the DASR requirement is increased by PJM dispatch, the reserve requirement frequently cannot be met without redispatching online resources which significantly affects the price by creating an LOC, (Figure 10-17). DASR prices increase at peak loads as a result of high LOCs. For the first three months of 2017, DASR prices were low to moderate and included LOC in only 43 hours of the 501 hours when DASRMCP was above $0. The first three months of 2017 showed the same pattern as the first three months of 2016 with low prices and therefore little LOC.

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 PJM Regulation Market in 2012.[47]

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. The RegA signal is designed for energy unlimited resources (for example, thermal and/or hydro resources) with physically constrained ramp ability. The RegD signal is designed for energy limited resources with very fast ramp rates. Some resource types (such as some Combustion Turbines) can qualify as both RegA and RegD.

Regulation was historically provided by resources following the RegA signal. Since regulation service could be provided solely with RegA following resources, performance adjusted RegA MW are used as the common unit of measure, called effective MW, of regulation service provided in the PJM Regulation Market. The regulation requirement (the amount of regulation MW needed to control for ACE) is defined in terms of the total effective MW required to provide an expected amount of area control error (ACE) control.

In concept, the Regulation Market solution starts with an assumption of the effective regulation requirement being met entirely with performance adjusted RegA MW. When solving for the least cost combination of RegA and RegD MW to meet the effective regulation requirement, the Regulation Market will substitute RegD MW for RegA MW so long as it is economic (reduces total cost while maintaining a fixed level of control) to do so. The Regulation Market functions by converting performance adjusted RegD MW into their marginal effective MW equivalent using a marginal rate of substitution called a marginal benefit function (MBF). The MBF is used to convert incremental additions of RegD MW into incremental effective MW. Correctly implemented, the total effective MW for a given amount of RegD MW are determined by the area under the MBF curve (the sum of the incremental effective MW contributions). This conversion into a common unit of measure allows a direct comparison of RegA and RegD offers. The MBF reflects the fact that each additional MW of RegD has a progressively smaller value defined as incremental effective MW. Total regulation provided by a given combination of RegA and RegD is defined in terms of total effective MW. In a correctly implemented market structure, all resources, either RegA or RegD, would be paid the same price per marginal effective MW provided.

To meet the objective of minimizing cost, 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. Correctly implemented, the MBF would define and be used as the marginal rate of technical substitution (MRTS) between RegA and RegD, holding regulation service constant. Consistently applying the MBF from optimization to settlement 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 as the MRTS between RegA and RegD and it is not consistently applied throughout the market design, from optimization to settlement.

The result has been that the PJM Regulation Market has over procured RegD relative to RegA in most 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 level defined by an accurate MBF function, there is an artificial incentive for inefficient entry of RegD resources.

The MBF related issues with the Regulation Market have been raised in the PJM stakeholder process. In 2015, PJM stakeholders approved an interim, partial

47 See the *2012 State of the Market Report for PJM*, Volume II, Section 9, "Ancillary Services," p. 271.

solution to the RegD over procurement problem which was implemented on December 14, 2015. The interim solution was designed to reduce the relative value of RegD MW in the optimization in all hours and to cap purchases of RegD MW during critical performance hours. But the interim solution did not address the fundamental issues in the optimization or the lack of consistency in the application of the MBF. Additional changes were approved by the Regulation Market Issues Senior Task Force (RMISTF) in 2016, with an implementation date of January 9, 2017, that introduced new signal designs and regulation requirements intended to improve system performance. These modifications include changing the definition of off-peak and on-peak hours, adjusting the currently independent RegA and RegD signals to be interdependent, and changing the 15-minute neutrality requirement of the RegD signal to a 30-minute neutrality requirement. Previously, off-peak hours were from 00:00 to 04:59, and on-peak hours were between 05:00 and 23:59 every day. With the changes that went into effect on January 9, 2017, off-peak and on-peak hours are now called nonramp and ramp, and have new timeframes that are based on the season. In addition to different timeframes, the regulation requirement for ramp hours has been increased from 700 MW to 800 MW (See Table 10-28). Like the interim solution implemented in December 4, 2015, the latest market changes still do 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 comprehensive solution through the Regulation Market Issues Senior Task Force ("RMISTF").

Table 10-28 Seasonal Regulation Requirement Definitions[48]

Season	Dates	Nonramp Hours	Ramp Hours
Winter	Dec 1 - Feb 28(29)	00:00 - 03:59 09:00 - 15:59	04:00 - 08:59 16:00 - 23:59
Spring	Mar 1 - May 31	00:00 - 04:59 08:00 - 16:59	05:00 - 07:59 17:00 - 23:59
Summer	Jun 1 - Aug 31	00:00 - 04:59 14:00 - 17:59	05:00 - 13:59 18:00 - 23:59
Fall	Sep 1 - Nov 30	00:00 - 04:59 08:00 - 16:59	05:00 - 07:59 17:00 - 23:59

Market solution software relevant to regulation 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 security constrained economic dispatch market solution (RT-SCED) solving every five minutes. The market clearing price is determined by pricing software (LPC) that looks at the units cleared in the RT-SCED 15 minutes ahead of the pricing interval. The marginal price as identified by the LPC for each of these intervals is then averaged over the hour for an hourly regulation market clearing price.

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 RegD resource's capability (actual) MW into marginal effective MW and offers into $/effective MW.

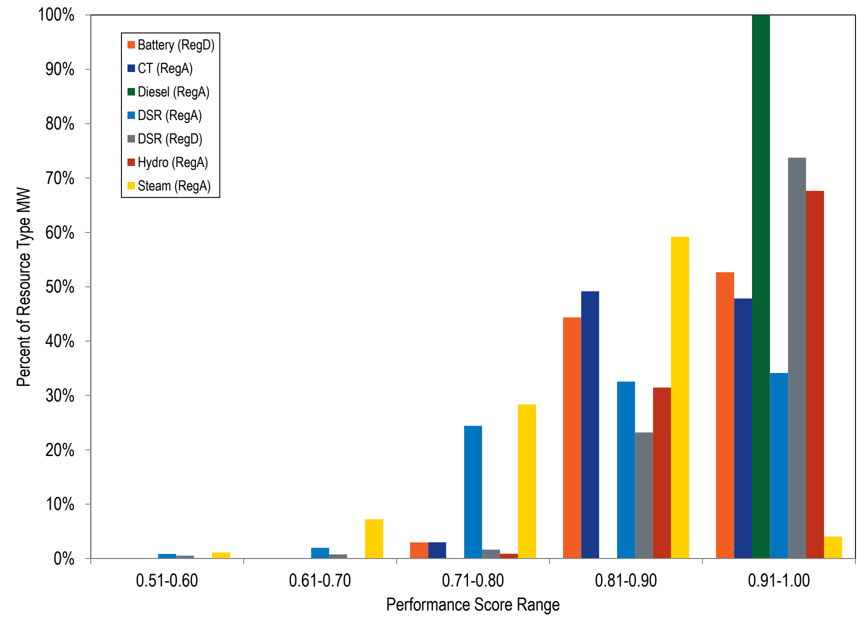
The absence of a penalty, imposed as a reduction in performance score and/or as a forfeiture of revenues, for deselection initiated by the resource owner within the hour, creates a possible gaming opportunity for resources which may overstate their capability to follow the regulation signal. The MMU recommends that there be a penalty enforced as a reduction in performance score and/or a forfeiture of revenues when resource owners elect to deassign assigned regulation resources within the hour, to prevent gaming.

48 See PJM. "Regulation Requirement Definition," <http://www.pjm.com/~/media/markets-ops/ancillary/regulation-requirement-definition.ashx>.

Regulation performance scores (0.0 to 1.0) measure the response of a regulating resource to its assigned regulation signal (RegA or RegD) every 10 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.[49]

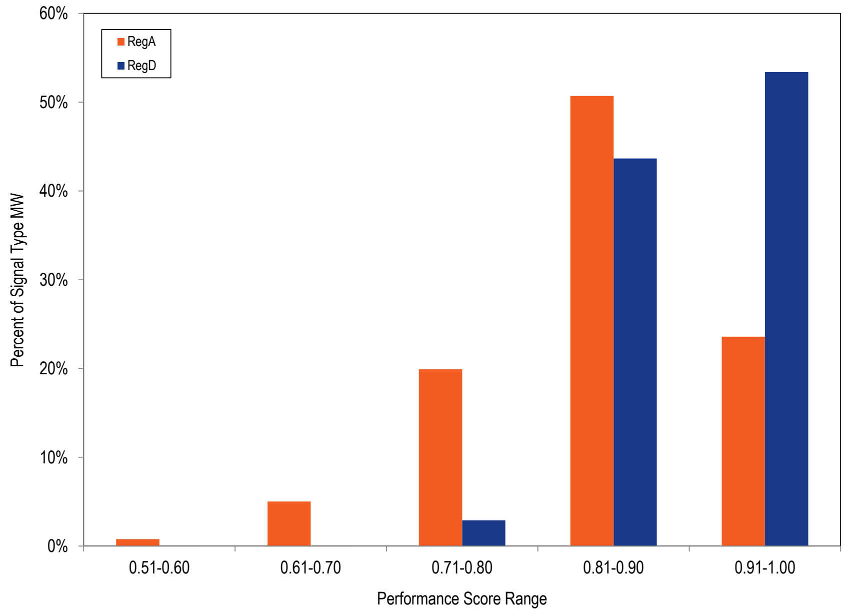
Figure 10-18 and Figure 10-19 show the average performance score by resource type and the signal followed for the first three months of 2017. In these figures, the MW used are actual MW and the performance score is the hourly performance score of the regulation resource.[50] Each category (color bar) is based on the percentage of the full performance score distribution for each resource (or signal) type. As Figure 10-19 shows, 53.4 percent of RegD resources had average performance scores within the 0.91-1.00 range, and 23.6 percent of RegA resources had average performance scores within that range.

Figure 10-18 Hourly average performance score by unit type: January 1 through March 31, 2017



49 PJM "Manual 12: Balancing Operations," Rev. 36 (February 1, 2017) at 4.5.6, p 54.
50 Except where explicitly referred to as effective MW or effective regulation MW, MW means actual MW unadjusted for either marginal benefit factor or performance factor.

Figure 10-19 Hourly average performance score by regulation signal type: January 1 through March 31, 2017



PJM creates an individual resource's regulation signal by comparing the individual resource's TREG signal to the 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 common unit of measure (effective MW). The marginal benefit factor (MBF) is the marginal measure of substitutability of RegD resources for RegA resources in satisfying the regulation requirement at any combination of RegA and RegD MW that can be used to meet the regulation requirement.

The MBF, as the marginal rate of technical 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, defined as the amount of regulation that would be provided by a specified amount of RegA MW alone (which is the total effective MW requirement defined in terms of MW of RegA). The use of the MBF in the optimization should result in the selection of the least cost combination/ratio of RegA and RegD MW that achieves this level of specified regulation service when the prices of RegA and RegD are known. PJM's optimization engine has not properly implemented the MBF so that the market clearing combination of RegA and RegD MW is consistent with the combinations defined by the MBF curve.

At any valid combination of RegA and RegD, regulation offers are converted to dollars per effective MW by dividing the RegD offer by the corresponding MRTS associated with that combination of RegA and RegD. The marginal contribution of a RegD MW to total effective MW at a valid RegA/RegD combination is equal to the MRTS associated with that RegA/RegD combination.

For example, a 1.0 MW RegD resource with a total offer price of $2/MW with a marginal benefit factor of 0.5 and a performance score of 100 percent, would be calculated as offering 0.5 effective MW (0.5 marginal 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).

PJM's market design does not correctly calculate total effective RegD MW. Under PJM's method, cleared RegD MW are converted to total effective MW by multiplying each resource's offered MW by the product of the resource specific marginal benefit factor and performance score. This resource specific block assignment approach undercounts total effective MW because the method fails to count part of the area under the MBF curve. Total effective RegD MW are correctly calculated as the area under the MBF curve.

Market Design Issues

Marginal Benefit Factor Not Reflected Consistently or Correctly in Market

The marginal benefit factor function is incorrectly defined and improperly implemented in the current PJM Regulation Market. The market results do not represent the least cost solution that is consistent with a specific level of regulation service.

Properly defined, the marginal benefit factor is the marginal rate of technical substitution between RegA and RegD MW at specific combinations of RegA and RegD that can be used to provide a defined level of regulation service. The specific combinations of RegA and RegD that can be used to provide a defined level of regulation service are feasible combinations of RegA and RegD. The objective of the market design is to find, given the relative costs of RegA and RegD MW, the least cost feasible combination of RegA and RegD MW. If the marginal benefit factor function is incorrectly defined, or improperly implemented in the market clearing and settlement, the resulting combinations of RegA and RegD will 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.[51]

The result of the FERC directive is that the marginal benefit factor is used in the optimization (currently using the incorrect PJM MBF) 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. PJM posts clearing prices for the Regulation Market (RMCCP, RMPCP and RMCP) in dollars per effective MW. The regulation market clearing price (RMCP in \$/effective MW) 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 (RMPCP in \$/effective MW) is based on the marginal performance offer (RMPCP) for the hour. The capability clearing price (RMCCP in \$/effective MW) is equal to the difference between the RMCP for the hour and the RMPCP for the hour.

If the marginal benefit factor were consistently applied in the optimization, clearing, pricing and settlement, every resource would receive the same clearing price per marginal effective MW provided to the system. Because the marginal benefit factor is not consistently applied in the optimization, clearing, pricing and settlement, resources do not receive the same clearing price per marginal effective MW provided to the system.

While prices are set on the basis of dollars per effective MW, only RegA resources receive payments (credits) that are consistent with this price per effective MW (RMCP).[52] RegA resources are paid the RMCCP per effective MW plus the RMPCP per effective MW. RegD resources do not receive payments consistent with this price per effective MW. RegD resources are paid the RMCCP per performance adjusted MW (not per effective MW) plus the RMPCP times the mileage ratio per performance adjusted MW (not per effective MW).[53] As a result the current market design does not send the correct price signal to the RegD resources.

51 145 FERC ¶ 61,011 (2013).

52 This is due to the fact that RegA resources performance adjusted MW are their effective MW as the MRTS of RegA resources is always equal to one, as effective MW are defined in terms of RegA performance adjusted MW.

53 Performance adjusted RegD MW are converted to effective MW by multiplying the performance adjusted MW by the market clearing MRTS.

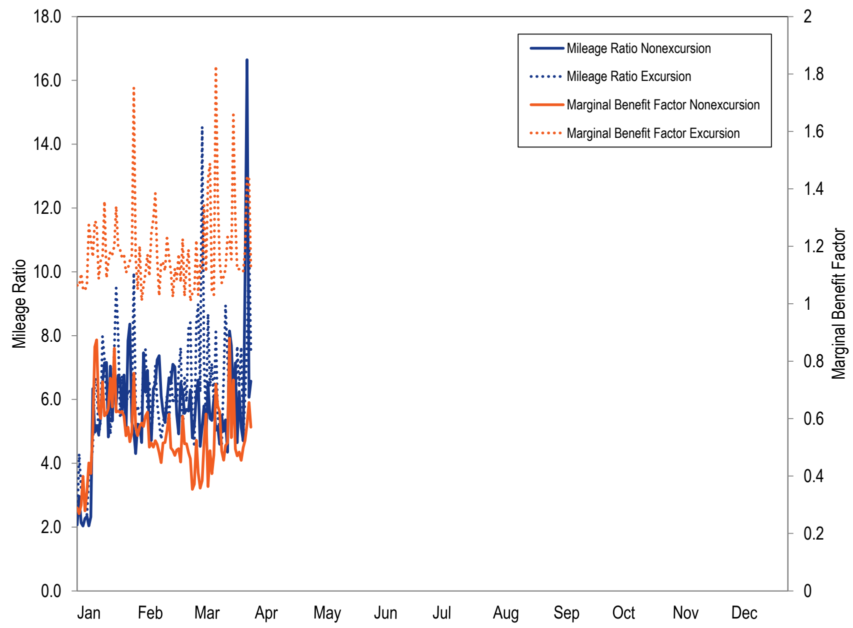
Figure 10-20 compares the daily average marginal benefit factor and the mileage ratio for excursion and nonexcursion hours. Excursion hours (hours ending 7:00, 8:00, 18:00-21:00) are hours in which PJM has decided that more RegA is needed and has therefore limited the minimum marginal benefit factor that can be assigned to RegD MW to 1.0.[54] Once this limit is reached, the remaining regulation requirement satisfied with RegA MW. The shift in values seen in Figure 10-20 is due to the implementation of the new ramp/nonramp timeframes and the new regulation requirement of 800 MW for ramp hours, on January 9, 2017.

The high mileage ratios on March 6, 2017, and March 29, 2017, were a result of the mechanics of the mileage ratio calculation. The extreme mileage ratios result when the RegA signal is fixed to control ACE and the RegD signal is not. The result of a fixed RegA signal is that RegA mileage is very small and therefore the mileage ratio of RegD/RegA is very large.

This result demonstrates why it is not appropriate to use the mileage ratio, rather than the marginal benefit factor, to measure the relative value of RegA and RegD resources. In these events RegA resources are providing ACE control (regulation service) despite not changing MW output (no mileage), while the change in MW output from RegD resources (positive mileage) is alternating between helping and hurting ACE control.

54 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Rev. 86 (February 1, 2017) at 3.2.7, p 70.

Figure 10-20 Daily average marginal benefit factor and mileage ratio during excursion and nonexcursion hours: January 1 through March 31, 2017



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. Currently, the marginal benefit factor is generally less than one, resulting in persistent overpayment of RegD resources.

The effect of using the mileage ratio instead of the marginal benefit factor to convert RegD MW into effective MW for purposes of settlement is illustrated in Table 10-29. Table 10-29 provides the monthly average payment by RegD per effective MW realized under the current, incorrect mileage ratio based settlement process and compares it to the dollar per effective MW that is being paid to RegA MW and should be paid to RegD MW based on the MRTS based settlement process for each of the first three months in 2016 and 2017. As a result of the relative amount of RegD being procured, as well as the changes to the MRTS slope that went into effect on December 14, 2015, the MRTS averaged less than one in each month of 2016, resulting in RegD resources being paid $4.29 million (222.4 percent) more than they should have in the first three months of 2016. In 2017, the MRTS also averaged less than one, resulting in RegD resources being paid $4.10 million (1,016.4 percent) more than they should have been.

Table 10-29 Average monthly price paid per effective MW of RegD and RegA under mileage and MRTS based settlement: January 1 through March 31, 2016 through 2017

		RegD Settlement Payments				
	Month	Mileage Based ($/Effective RegD MW)	Marginal Rate of Technical Substitution Based ($/Effective RegD MW)	RegA ($/ Effective MW)	RegD Under/ Over Payment ($)	Percent RegD Under/Over Payment
2016	Jan	$30.61	$15.60	$15.60	$1,319,364	96.2%
	Feb	$43.33	$17.56	$17.56	$1,591,651	146.8%
	Mar	$70.02	$13.21	$13.21	$1,375,711	430.1%
Average		$49.68	$15.41	$15.41	$4,286,727	222.4%
2017	Jan	$80.44	$13.62	$13.62	$956,485	490.7%
	Feb	$293.97	$10.64	$10.64	$1,161,959	2,662.3%
	Mar	$80.90	$15.06	$15.06	$1,977,295	437.2%
Average		$147.18	$13.18	$13.18	$4,095,739	1,016.4%

Figure 10-21 shows, for the first three months of 2017, the maximum, minimum and average marginal benefit factor, based on PJM's incorrect marginal benefit factor curve, by month, for excursion and nonexcursion hours. The average MBF during excursion hours in the first three months of 2017 was 1.18, and the average MBF during nonexcursion hours in the first three months of 2017 was 0.48. The average MBF during excursion hours in the first three months of 2016 was 1.15, and the average MBF during nonexcursion hours in the first three months of 2016 was 0.38. The marginal benefit factor (MBF) levels were a result of changes in the marginal benefit factor curve made effective on December 14, 2015, which reduced the relative value of RegD MW in the optimization in all hours. The slope of the benefit factor curve was changed to alter where it intercepts the x-axis, defined in terms of RegD MW as a percent of the regulation requirement, to 40 percent instead of 62 percent. PJM also capped the procurement of RegD MW during excursion hours at the point where the MBF on the curve is equal to 1.0.

Figure 10-21 Maximum, minimum, and average PJM calculated marginal benefit factor by month for excursion and nonexcursion hours: January 1 through March 31, 2017

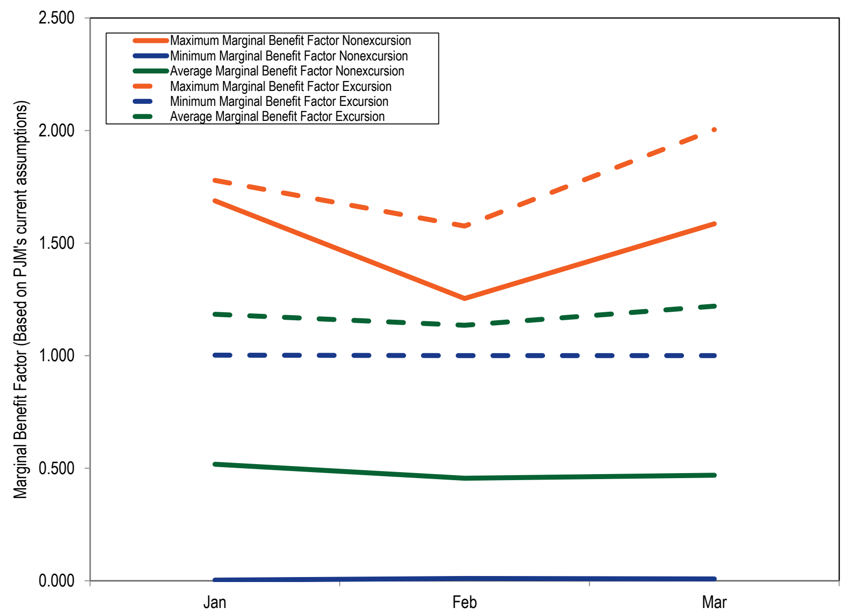
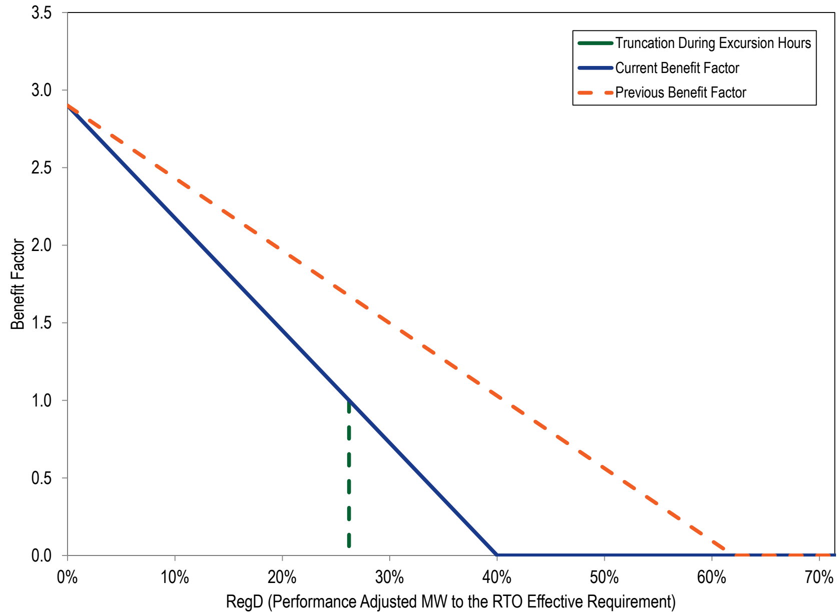


Figure 10-22 shows the marginal benefit factor curve (as incorrectly defined by PJM) before and after the December 14, 2015, modification. The modification to the marginal benefit factor curve reduced the amount of RegD procured, but did not correct for identified issues with the optimization engine.

Correcting the issues with the optimization engine would require correctly defining and using the marginal benefit factor curve, rather than continuing to incorrectly define the MBF as RegD MW cleared as a percentage of the effective MW target.

Figure 10-22 Marginal 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 and correct application of the marginal benefit factor throughout the optimization, assignment and settlement process.[55]

55 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>.

Incorrect MBF and Inconsistent Application of MBF in Optimization Causing Incorrect Proportion of RegD MW to Be Purchased

The current PJM MBF incorrectly defines the contribution of RegD MW as a percent of the regulation requirement rather than using the correct MBF, defined as the marginal rate of technical substitution between RegA and RegD.

As a result, the market clearing engine is not correctly maintaining the shares of RegA and RegD that are the basis of the MBF function. The MBF, as the marginal rate of technical substitution between RegA and RegD resource MW for a given regulation requirement, defines specific combinations/ratios of RegA and RegD MW that are needed to meet specified regulation performance goals. Properly implemented, the use of the MBF should result in the selection of the least cost combination of RegA and RegD MW.

Instead, the current market clearing engine uses the incorrect MBF function to adjust RegD offers (both MW and price) for purposes of rank ordering RegA and RegD resources in the supply stack and then clears RegA and RegD resources in price order until the calculated effective MW target is reached. In other words, PJM's market clearing engine rank orders resources by prices and then clears them as a single supply stack at the point of intersection of cumulative effective supply and the regulation requirement. Self scheduling or pricing at zero causes RegD resources to appear at the bottom of the supply stack, forcing the clearing engine to take the RegD MW so long as the MBF is greater than zero. This market clearing is done without confirming that the resulting combinations of RegA and RegD are feasible and can meet the defined demand for regulation. This guarantees that an increasing proportion of RegD MW in the market incorrectly appears as a cheap feasible source of incremental effective regulation MW regardless of whether there is sufficient RegA MW clearing the market to support this market solution

The market design, combined with an increasing proportion of RegD offering at an effective price of zero, is that the market clears too much RegD relative to RegA MW.

This is illustrated in Table 10-30, for both the MBF curve used prior to December 14, 2015, and the current MBF curve. In Table 10-30, the contribution to the total regulation requirement of 700 MW for an on peak hour is given on both a performance adjusted actual RegD MW and effective RegD MW basis. For example, if the market cleared 280 MW of performance adjusted RegD (40 percent of the 700 performance adjusted MW needed) at a price of zero, the market clearing engine would determine it would need 149.9 MW of RegA to meet the 700 MW requirement using the previous MBF curve, and would need 294.0 MW using the current MBF curve. The resulting proportion of RegD to total regulation cleared would be 65 percent and 49 percent for the previous and current MBF curves, rather than the 40 percent that was assumed by the MBF function. Although there is a smaller difference between the proportion of RegD cleared under the current MBF curve and the correct amount, as compared to that of the previous MBF curve, the error still persists and is not eliminated by simply adjusting the curve. A full correction requires that the proportions assumed in the curve are maintained through the market clearing process.

Table 10-30 MBF assumed RegD proportions versus market solution realized RegD proportions[56]

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 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 based on the area under the marginal benefit factor 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). PJM calculates the total effective MW of a unit as the simple product of the MW and the MBF, rather than the area under the MBF. The result is that 100 MW of RegD (performance adjusted) provided by a single resource (one 100 MW unit) will appear to provide fewer total effective MW than 100 MW (performance adjusted) provided by two separate 50 MW units although they provide exactly the same total effective MW.

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 total 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 total effective MW as the simple product of the MW and the MBF, rather than the area under the MBF curve. This resulted in understating total effective MW from RegD resources cleared at an effective price of zero or self-scheduled.

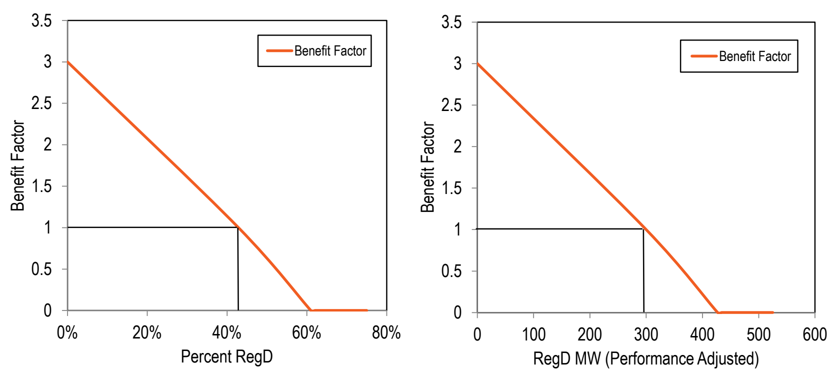
The identified total effective MW measurement issue was not fully addressed by the modification that was put into effect on December 14,

56 This example assumes that the calculation of effective MW from RegD was calculated correctly as the area under the MBF curve.

2015. The modification rank orders self-scheduled units 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 unit block effective MW calculation for all units 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.

An example illustrates the issue. Figure 10-23 shows the same marginal benefit factor 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 10-23 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.

Figure 10-23 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 10-24, 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 unit block method is flawed. By assigning a single benefit value to every MW, the unit block method undervalues the amount of effective MW provided by RegD MW. This means that the amount of RegD and RegA cleared is not consistent with the combinations of RegD and RegA that will provide the target level of regulation service. This is because the marginal 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 10-24. 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 10-24 Illustration of correct method for calculating effective MW

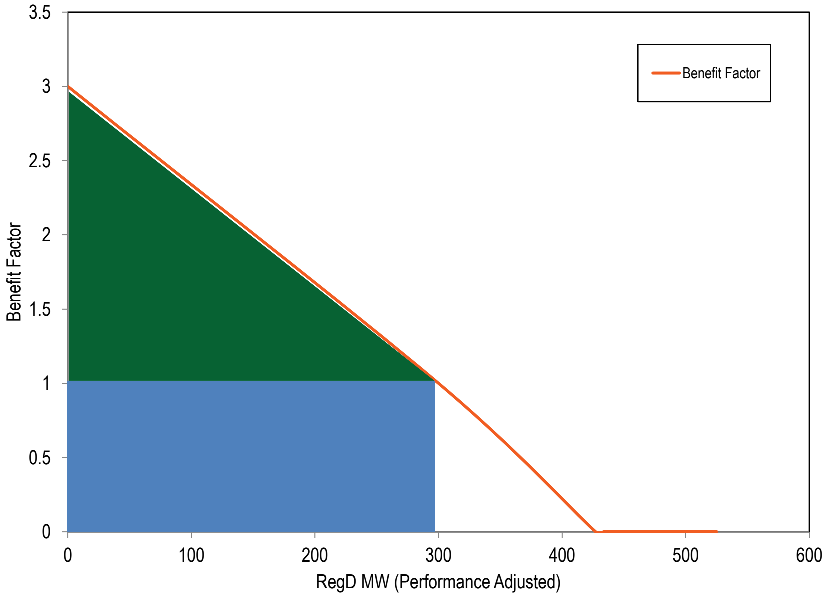


Figure 10-25 illustrates PJM's December 14, 2015, correction of the price block issue for RegD resources that clear with an effective price of zero. In this example, the PJM market clears two self-scheduled resources, one with 100 MW and one with 83 MW, for a total of 183 MW and a market MBF of 1.0. Prior to the correction, all 183 MW of RegD would have been 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 based on the MBF associated with the last MW of each unit that cleared. Using this 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 marginal benefit factor of 1.0 (see figure).

This correction did not address the unit block issue. 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). Using the area under the curve approach would correctly result in a total effective MW total of 356.9 MW being attributed to the 183 MW cleared in the market, not the 266 total effective MW of the corrected method.

Figure 10-25 Example of pre and post December 14, 2015, total effective MW calculations for RegD MW offered at $0.00 or as self supply

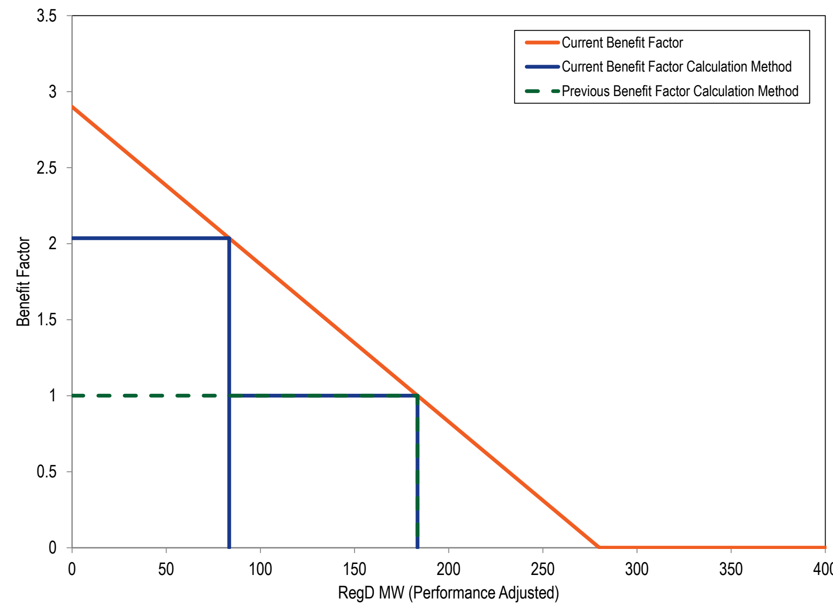
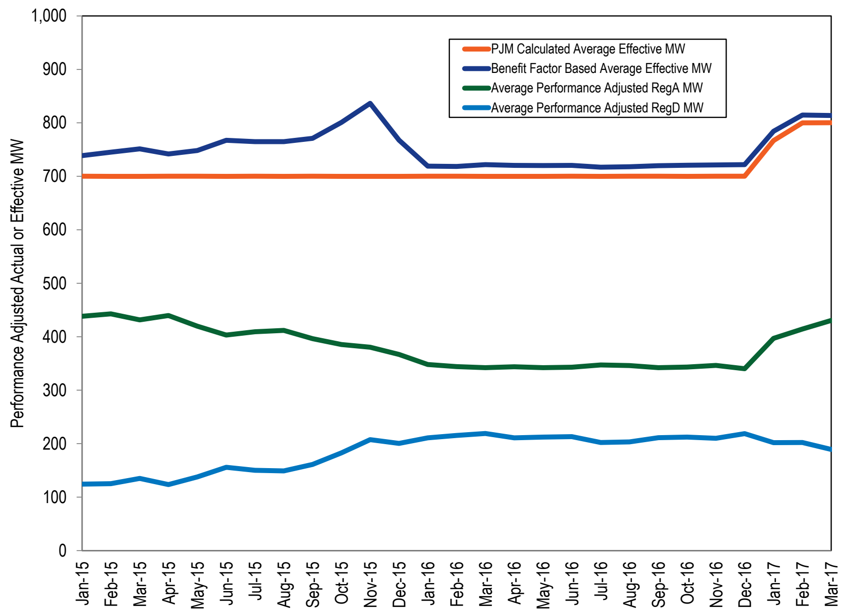


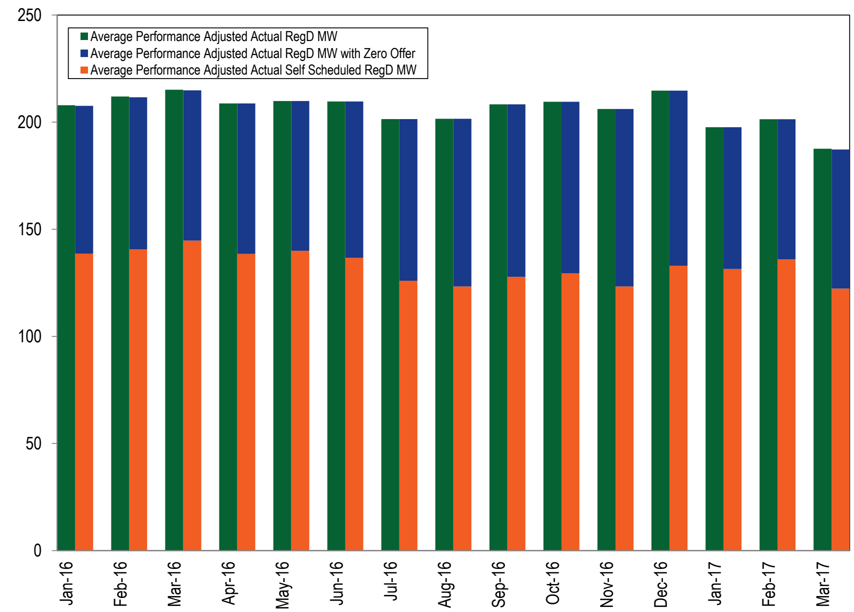
Figure 10-26 shows the average monthly peak total effective MW as calculated by PJM's incorrect effective MW accounting method(s) and as calculated by a correctly applied marginal benefit factor for the January 1, 2015, through March 31, 2016, period. The figure also shows the monthly average performance adjusted RegA MW and RegD MW cleared in the Regulation Market for the period. Figure 10-26 shows that PJM had been clearing an increasing surplus of total effective MW prior to December of 2015. The implementation of the 800 effective MW regulation requirement for ramp hours has increased the average amount of RegA, because the majority of the additional MW being procured are from RegA.

Figure 10-26 Average monthly ramp total effective MW: PJM market calculated versus benefit factor based: January 1, 2015 through March 31, 2017



The excess procurement of RegD combined with the overpayment of RegD has resulted in an increase in the level of $0.00 offers from RegD resources. RegD MW providers are ensured that $0.00 offers will be cleared and will be paid a price determined by the offers of RegA resources. Figure 10-27 shows, by month, the proportion of cleared RegD MW with an effective price of $0.00. The figure shows that all RegD MW clearing the market in the period between January 1, 2016, and December 31, 2016, had an effective offer of $0.00. The level of RegD clearing the market leveled off beginning in January 2016 because the market cleared the maximum allowed RegD actual MW.

Figure 10-27 Average cleared RegD MW and average cleared RegD with an effective price of $0.00 by month: January 1, 2016 through March 31, 2017



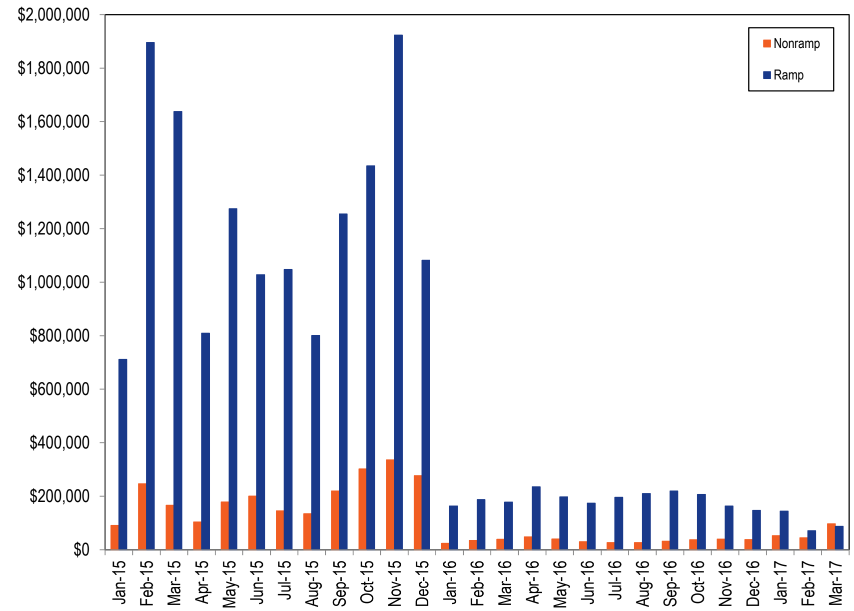
The Cost of Purchasing Too Many Regulation MW Due to Incorrect Effective MW Calculation Approach

Figure 10-28 shows the estimated cost of the excess effective MW cleared by month, peak and off peak, from January 1, 2015, through March 31, 2017, 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 calculated using the full area under the incorrect PJM marginal benefit factor curve, and the difference between that value and the one used by PJM is multiplied by the price in each hour. The calculation of excess cost shown in

Figure 10-28 that is caused by purchasing too much RegD is conservatively underestimated because it does not incorporate how the market clearing price and settlement would have been affected by replacing the current optimization and settlement process with a correct and consistent utilization of the MBF. Specifically, the calculation only reflects differences in RegA and RegD proportions due to incorrect versus correct application of the MBF in the clearing engine, holding the actual market price and the mileage ratio based settlement constant.

In the first three months of 2017, the estimated total cost of excess effective RegD MW during on peak and off peak hours was $0.30 million and $0.19 million. In the first three months of 2016, the estimated total cost of excess RegD MW during on peak and off peak hours was $0.53 million and $0.10 million. The implementation of the partial solution to the effective MW calculation and the changes in the marginal benefit factor curve in December of 2015 reduced, but did not eliminate, the excess effective MW clearing in the Regulation Market.

Figure 10-28 Cost of excess effective MW cleared by month, peak and off peak: January 1, 2015 through March 31, 2017



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 the first three months of 2017. Total Effective MW are adjusted by the historic 100-hour moving average performance score and resource-specific benefit factor.[57] 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

57 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.

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. In the first three months of 2017, the average hourly eligible supply of regulation for nonramp hours was 1,187.5 actual MW (852.4 effective MW). This was an increase of 4.2 actual MW (32.0 effective MW) from the first three months of 2016, when the average hourly eligible supply of regulation was 1,183.3 actual MW (820.4 effective MW). In the first three months of 2017, the average hourly eligible supply of regulation for ramp hours was 1,449.4 actual MW (1,158.4 effective MW). This was an increase of 236.9 actual MW (199.5 effective MW) from the first three months of 2016, when the average hourly eligible supply of regulation was 1,212.4 actual MW (958.9 effective MW).

Table 10-31 PJM regulation capability, daily offer and hourly eligible: January through March, 2017[58] [59]

			By Resource Type		By Signal Type	
		All Regulation	Generating Resources	Demand Resources	RegA Following Resources	RegD Following Resources
Capability MW	Daily	10,042.5	10,017.8	24.7	9,705.3	656.3
Offered MW	Daily	7,024.6	7,009.7	14.9	6,648.6	375.9
Actual Eligible MW	Ramp	1,449.4	1,431.5	17.9	1,077.1	372.2
	Nonramp	1,187.5	1,170.9	16.6	815.8	371.7
Effective Eligible MW	Ramp	1,158.4	1,138.4	20.0	780.0	378.5
	Nonramp	852.4	836.1	16.3	571.8	280.6
Actual Cleared MW	Ramp	702.1	692.2	10.0	484.0	218.2
	Nonramp	503.4	494.6	8.8	289.9	213.5
Effective Cleared MW	Ramp	786.6	768.2	18.4	411.6	374.9
	Nonramp	525.0	509.8	15.2	246.2	278.8

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 performance adjusted capability MW increased from 1,268,830.1 MW in the first three months of 2016 to 1,457,098.0 MW in the first three months of 2017. The average proportion of regulation provided by battery units had the largest increase, providing 43.7 percent of regulation in the first three months of 2016 and 48.0 percent of regulation in the first three months of 2017. Hydro units had the largest decrease in average proportion of regulation provided, decreasing from 20.7 percent in the first three months of 2016, to 15.6 percent in the first three months of 2017. The total regulation credits in the first three months of 2017 were $20,752,915 down 3.0 percent from $21,386,126 in the first three months of 2016.

Table 10-32 PJM regulation by source: January through March, 2016 and 2017[60]

	2016 (Jan-Mar)				2017 (Jan-Mar)			
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	21	554,571.3	43.7%	$8,400,232	21	700,004.1	48.0%	$7,964,751
Coal	49	97,990.0	7.7%	$2,123,964	39	77,435.9	5.3%	$1,673,859
Hydro	39	263,246.6	20.7%	$5,033,328	24	227,201.8	15.6%	$4,140,938
Natural Gas	152	342,839.8	27.0%	$5,668,338	88	421,126.7	28.9%	$6,610,197
DR	35	10,182.4	0.8%	$160,263	20	31,329.6	2.2%	$363,170
Total	296	1,268,830.1	100.0%	$21,386,126	192	1,457,098.0	100.0%	$20,752,915

Significant flaws in the regulation market design have led to a significant over procurement of RegD MW primarily in the form of storage capacity. The incorrect market signals have led to more storage projects entering PJM's interconnection queue, despite clear evidence that the market design is flawed and despite operational evidence that the RegD market is saturated (Table 10-33).

58 Average Daily Offer MW excludes units that have offers but are unavailable for the day.

59 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.

60 Biomass data have been added to the natural gas category for confidentiality purposes.

Table 10-33 Active battery storage projects in the PJM queue system by submitted year: 2012 to 2017

Year	Number of Storage Projects	Total Capacity (MW)
2012	2	8.5
2013	0	0.0
2014	8	132.0
2015	38	280.1
2016	15	191.3
2017	1	9.0
Total	64	620.9

The supply of regulation can be affected by regulating units retiring from service. If all units that are requesting retirement through the end of 2017 retire, the supply of regulation in PJM will be reduced by less than one percent.

Although the marginal benefit factor for RegA resources is 1.0, the effective MW of RegA resources were lower than the offered MW in the first three months of 2017, because the average performance score was less than 1.00. For the first three months of 2017, the MW weighted average RegA performance score was 0.85 and there were 147 resources following the RegA signal.

For RegD resources, the total effective MW vary from actual MW because the marginal benefit factor for RegD resources can range from 2.9 to 0.0. In the first three months of 2017, the marginal benefit factor, based on PJM's current assumed marginal benefit factor curve, for cleared RegD resources ranged from 0.003 to 1.688 with an average over all nonexcursion hours of 0.481 and from 1.000 to 2.004 with an average over all excursion hours of 1.181. In the first three months of 2017, the MW weighted average RegD resource performance score was 0.91 and there were 44 resources following the RegD signal.

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 until January 9, 2017. A change to the regulation requirement was approved by the RMISTF in 2016, with an implementation date of January 9, 2017. The regulation requirement was increased from 700 effective MW to 800 effective MW during ramp (formerly known as on-peak) hours (See Table 10-28).

Table 10-34 shows the average hourly required regulation by month and the ratio of supply to demand for both actual and effective MW, for ramp and nonramp hours. The average hourly required regulation by month is an average of the ramp and nonramp hours in the month. For January, the average ramp regulation requirement is a combination of the old peak hours and 700 effective MW requirement before January 9, and the new ramp hours and 800 effective MW requirement for the rest of the month.

Table 10-34 PJM Regulation Market required MW and ratio of eligible supply to requirement for ramp and nonramp hours: January through March, 2016 through 2017[61]

		Average Required Regulation (MW)		Average Required Regulation (Effective MW)		Ratio of Supply MW to MW Requirement		Ratio of Supply Effective MW to Effective MW Requirement	
Hours	Month	2016	2017	2016	2017	2016	2017	2016	2017
Ramp	Jan	657.5	690.8	700.1	766.8	1.83	2.10	1.34	1.48
	Feb	663.6	705.8	700.1	800.1	1.84	2.11	1.38	1.52
	Mar	640.6	714.7	700.0	800.1	1.90	1.96	1.39	1.41
Nonramp	Jan	553.8	503.6	525.0	525.1	2.15	2.45	1.56	1.65
	Feb	550.0	508.3	525.6	525.0	2.17	2.47	1.56	1.75
	Mar	517.0	499.9	525.0	525.0	2.25	2.22	1.57	1.52

Market Concentration

In the first three months of 2017, the effective MW weighted average HHI of RegA resources was 2860 which is highly concentrated and the weighted average HHI of RegD resources was 1642 which is also highly concentrated.[62] The weighted average HHI of all resources was 1155, which is moderately concentrated. The HHI of RegA resources and the HHI of RegD resources are higher than the HHI for all resources because different owners have large market shares in the RegA and RegD markets.

Table 10-35 includes a monthly summary of three pivotal supplier (TPS) results. In the first three months of 2017, 92.1 percent of hours had three or fewer pivotal suppliers. The MMU concludes that the PJM Regulation Market in the first three months of 2017 was characterized by structural market power. The TPS values are provided by PJM. The TPS results cannot be verified by the MMU or PJM because PJM does not save the necessary data. The MMU recommends that PJM save this data and make it available so that the TPS test calculations can be replicated by both PJM and the MMU. PJM has agreed that the lack of information is an issue but does not have a specific plan or timeline to resolve the issue.

61 The regulation requirement for January 2017 includes eight days of 700 effective MW and 23 days of 800 effective MW.

62 HHI results are based on market shares of effective MW, defined as regulation capability MW adjusted by performance score and resource specific benefit factor, consistent with the way the regulation market is cleared.

Table 10-35 Regulation market monthly three pivotal supplier results: January 1, 2015 through March 31, 2017

	Percent of Hours Pivotal		
Month	2015	2016	2017
Jan	97.8%	93.9%	90.6%
Feb	96.3%	90.9%	93.1%
Mar	97.3%	87.8%	92.7%
Apr	98.1%	93.5%	
May	99.3%	94.0%	
Jun	98.6%	89.3%	
Jul	98.8%	92.2%	
Aug	97.7%	93.7%	
Sep	97.1%	94.0%	
Oct	96.1%	90.6%	
Nov	99.2%	96.2%	
Dec	97.2%	90.4%	
Average	97.8%	92.2%	92.1%

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 not allow the sum of its regulating ramp rate and energy ramp rate to exceed its overall ramp rate.[63] When offering into the regulation market, regulating resources must submit a cost offer and may submit a price offer (capped at $100/MW) by 2:15 pm the day before the operating day.[64]

Offers in the PJM 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 fuel costs 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 (increased VOM and increased fuel costs) resulting from moving the unit up and down to provide regulation.

63 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Rev. 86 (February 1, 2017) at 3.2.1, p 65.

64 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Rev. 86 (February 1, 2017) at 3.2.6, p 70.

Batteries and flywheels have zero cost for lower efficiency from providing regulation instead of energy, as they are not net energy producers. On April 1, 2015, PJM added an Energy Storage Loss component for batteries and flywheels as a cost component of regulation performance offers, to reflect the net energy consumed to provide regulation service.[65]

Up until one hour before the operating hour, the regulating resource must provide: 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 are willing to provide.[66]

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 10-37).[67] Figure 10-29 compares average hourly regulation and self scheduled regulation during ramp and nonramp 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.[68] Self scheduled regulation comprised an average of 44.6 percent during ramp hours and 47.9 percent during nonramp hours in the first three months of 2017.

65 See PJM. "Manual 15: Cost Development Guidelines," Rev. 28 (October 18, 2016) at 11.8, p 65.
66 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Rev. 86 (February 1, 2017) at 3.2.2, p 68.
67 See PJM. "Manual 28: Operating Agreement Accounting," Rev. 75 (November 18 1, 2016) at 4.1, p 22.
68 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Rev. 86 (February 1, 2017) at 3.2.9, p 79.

Figure 10-29 Off peak, on peak, nonramp, and ramp regulation levels: January 1, 2016 through March 31, 2017

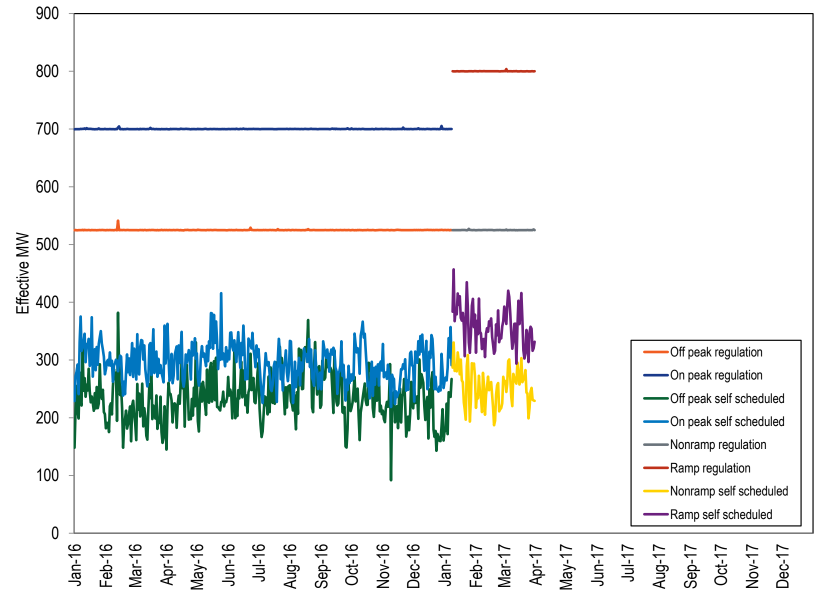


Table 10-36 shows the role of RegD resources in the regulation market. RegD resources are both a growing proportion of the market (10.9 percent of the total effective MW at the start of the performance based regulation market design in October 2012 and 49.4 percent of the total effective MW in March 2017) and a growing proportion of resources that self schedule (10.1 percent of all self scheduled MW in October 2012 and 27.0 percent of all self scheduled MW in March 2017). The increase in the share of RegD making up the total effective MW for 2016 (starting with the changes made to the MBF curve in December 2015), were due to the use of the unit block method of calculating the MBF over the previous price block method (See Figure 10-25). The decrease in the RegD share of total effective MW for the first three months of 2017 was due to the increased regulation requirement (from 700 effective MW to 800 effective MW during ramp hours), which resulted in more RegA clearing MW.

Table 10-36 RegD self-scheduled regulation by month: October 31, 2012 through March 31, 2017

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%
2013 Average		91.7	129.2	300.5	688.0	44.1%	13.6%	19.0%
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%
2014 Average		123.5	227.1	325.6	663.7	49.1%	18.6%	34.2%
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%
2015 Average		138.8	275.8	283.4	663.7	42.7%	20.9%	41.6%
2016	Jan	187.7	335.9	295.3	663.8	44.5%	28.3%	50.6%
2016	Feb	179.9	339.0	274.6	663.6	41.4%	27.1%	51.1%
2016	Mar	182.6	340.8	280.1	663.7	42.2%	27.5%	51.3%
2016	Apr	182.2	339.5	287.0	663.5	43.3%	27.5%	51.2%
2016	May	183.9	341.1	301.5	663.5	45.4%	27.7%	51.4%
2016	Jun	178.8	340.5	302.4	663.6	45.6%	26.9%	51.3%
2016	Jul	165.2	337.5	273.3	663.5	41.2%	24.9%	50.9%
2016	Aug	165.8	338.5	283.2	663.5	42.7%	25.0%	51.0%
2016	Sep	160.9	341.4	279.9	663.6	42.2%	24.2%	51.4%
2016	Oct	168.6	340.0	283.0	663.5	42.6%	25.4%	51.2%

Table 10-36 RegD self-scheduled regulation by month: October 31, 2012 through March 31, 2017 (continued)

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
2016	Nov	156.2	338.0	259.8	664.3	39.1%	23.5%	50.9%
2016	Dec	162.2	342.7	274.7	663.6	41.4%	24.4%	51.6%
2016 Average		172.8	339.6	282.9	663.7	42.6%	26.0%	51.2%
2017	Jan	187.1	334.9	318.0	673.9	47.2%	27.8%	49.7%
2017	Feb	192.7	337.8	296.6	674.2	44.0%	28.6%	50.1%
2017	Mar	172.2	315.3	297.5	638.5	46.6%	27.0%	49.4%
YTD		184.0	329.3	304.0	662.2	45.9%	27.8%	49.7%

Increased self-scheduled regulation lowers the requirement for cleared regulation, resulting in fewer MW cleared in the market and lower clearing prices. Of the LSEs' obligation to provide regulation in the first three months of 2017, 47.4 percent was purchased in the PJM market, 46.2 percent was self-scheduled, and 6.4 percent was purchased bilaterally (Table 10-37). Table 10-38 shows the total regulation by source including spot market regulation, self scheduled regulation, and bilateral regulation for the first three months of each year from 2012 to 2017. Table 10-37 and Table 10-38 are based on settled (purchased) actual MW.

Table 10-37 Regulation sources: spot market, self-scheduled, bilateral purchases: January 1, 2016 through March 31, 2017

Year	Month	Spot Market Regulation (Unadjusted MW)	Spot Market Percent of Total	Self Scheduled Regulation (Unadjusted MW)	Self Scheduled Percent of Total	Bilateral Regulation (Unadjusted MW)	Bilateral Percent of Total	Total Regulation (Unadjusted MW)
2016	Jan	197,085.6	47.8%	193,843.1	47.0%	21,671.0	5.3%	412,599.7
2016	Feb	190,668.7	49.7%	173,704.0	45.2%	19,546.0	5.1%	383,918.8
2016	Mar	196,173.9	49.4%	178,691.7	45.0%	22,017.0	5.5%	396,882.6
2016	Apr	192,872.3	50.1%	173,923.2	45.2%	18,058.0	4.7%	384,853.5
2016	May	185,673.4	47.4%	185,434.2	47.4%	20,221.0	5.2%	391,328.7
2016	Jun	177,041.1	46.7%	180,936.5	47.7%	21,295.5	5.6%	379,273.1
2016	Jul	176,073.5	45.6%	168,116.9	43.5%	42,233.0	10.9%	386,423.4
2016	Aug	187,641.6	48.6%	172,116.0	44.6%	26,299.5	6.8%	386,057.1
2016	Sep	169,565.3	45.0%	171,466.0	45.5%	35,462.5	9.4%	376,493.8
2016	Oct	190,611.4	49.0%	174,555.6	44.8%	24,074.0	6.2%	389,241.0
2016	Nov	206,016.3	55.0%	155,359.8	41.5%	13,289.5	3.5%	374,665.6
2016	Dec	190,565.5	48.8%	176,628.1	45.2%	23,642.5	6.0%	390,836.1
Total		2,259,988.6	48.6%	2,104,775.1	45.2%	287,809.5	6.2%	4,652,573.2
2017	Jan	181,234.1	45.8%	188,924.6	47.8%	25,490.5	6.4%	395,649.2
2017	Feb	179,287.3	50.4%	154,308.8	43.3%	22,371.0	6.3%	355,967.1
2017	Mar	173,565.1	46.3%	177,638.3	47.3%	23,963.0	6.4%	375,166.4
YTD		534,086.5	47.4%	520,871.7	46.2%	71,824.5	6.4%	1,126,782.7

Table 10-38 Regulation sources by year: 2012 through 2017, January through March

Year (Jan-Mar)	Spot Market Regulation (Unadjusted MW)	Spot Market Percent of Total	Self Scheduled Regulation (Unadjusted MW)	Self Scheduled Percent of Total	Bilateral Regulation (Unadjusted MW)	Bilateral Percent of Total	Total Regulation (Unadjusted MW)
2012	1,510,190.1	73.4%	485,672.8	23.6%	61,563.0	3.0%	2,057,425.9
2013	1,026,962.9	73.0%	342,003.1	24.3%	38,538.5	2.7%	1,407,504.5
2014	724,996.3	61.1%	404,832.1	34.1%	56,853.5	4.8%	1,186,681.9
2015	670,281.4	58.5%	411,928.8	36.0%	63,367.6	5.5%	1,145,577.7
2016	583,928.2	48.9%	546,238.8	45.8%	63,234.0	5.3%	1,193,401.0
2017	534,086.5	47.4%	520,871.7	46.2%	71,824.5	6.4%	1,126,782.7

In the first three months of 2017, DR provided an average of 10.0 MW of regulation per hour during ramp hours (4.3 MW of regulation per hour during ramp hours in the first three months of 2016), and an average of 8.8 MW of regulation per hour during nonramp hours (2.9 MW of regulation per hour during off peak hours in the first three months of 2016). Generating units supplied an average of 692.2 MW of regulation per hour during ramp hours (649.4 MW of regulation per hour during ramp hours in the first three months of 2016), and an average of 494.6 MW per hour during nonramp hours (537.2 MW of regulation per hour during nonramp hours in the first three months of 2016).

Market Performance

Price

After regulation performance was implemented on October 1, 2012, both regulation price and regulation cost per MW were higher than they were prior to October 1, 2012, for each year until 2016 (Table 10-42). In the first three months of 2017, the price and cost of regulation continued to be lower than the price and cost of regulation for the first three months in the years prior to 2016. The weighted average RMCP for the first three months of 2017 was $13.87 per effective MW. This is a 10.8 percent decrease from the weighted average RMCP of $15.55 per MW in the first three months of 2016. The decrease in the regulation clearing price was the result of a reduction in energy prices and the related reduction in the LOC component of RMCP. The increase in self supply and $0.00 offers from RegD resources since 2016 also contributed to lower prices.

In September 2016, an issue was identified concerning the real time clearing price for five minute intervals in the regulation market. Regulation units available to set price in a given five minute interval are based on the latest five minute RT-SCED 15 minute look ahead scheduling and assignment of regulation resources. This means that at the end of an hour, pricing in five minute intervals starting at 00:45, 00:50, and 00:55 is based on RT-SCED scheduling information (regulation assignments) from 01:00, 01:05, and 01:10 of the following hour. In cases where units provided regulation in an hour, but are not assigned to provide regulation in the following hour, these deassigned units appeared as unavailable for purposes of determining price in the last three, five minute intervals of their assigned regulation hour (00:45, 00:50, and 00:55). The pricing algorithm instead used the list of resources assigned to regulation for the next hour to set the price in intervals 00:45, 00:50, and 00:55 of the current hour. The result was that the prices did not accurately reflect the units actually running in intervals 00:45, 00:50, and 00:55. In November 2016, PJM corrected this problem by forcing the pricing algorithm to use the regulation availability status of the current hour to determine which units are eligible to set the regulation price for the current hour.

Figure 10-30 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 actual regulation capability MW basis. This data is based on actual five minute interval operational data. As Figure 10-30 illustrates, the LOC component (blue line) is the dominant component of the clearing price.

Figure 10-30 PJM regulation market daily weighted average market-clearing price, marginal unit opportunity cost and offer price (Dollars per MW): January through March, 2017

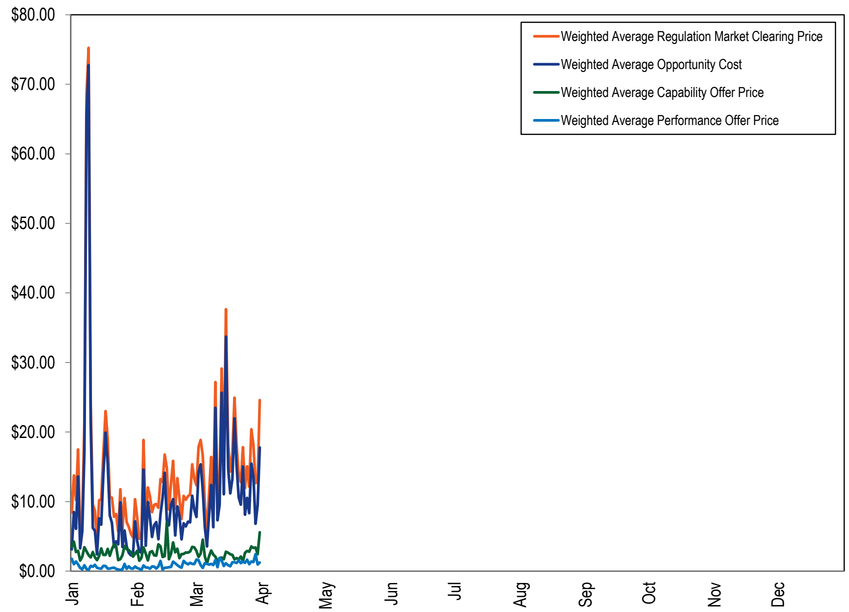


Table 10-39 shows the components of the monthly average regulation prices. NA is the unexplained portion of the total weighted average market price.

Table 10-39 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): January through March, 2017

Month	Weighted Average Regulation Marginal Unit LOC ($/Actual MW)	Weighted Average Regulation Marginal Unit Capability Offer ($/Actual MW)	Weighted Average Regulation Marginal Unit Performance Offer ($/Actual MW)	Weighted Average Regulation Market Clearing Price ($/ Actual MW)	NA	Weighted Average Regulation Market Price from Settlements ($/Actual MW)
Jan	$11.77	$2.68	$0.59	$15.04	$0.98	$14.06
Feb	$7.49	$2.84	$0.75	$11.08	($0.05)	$11.12
Mar	$12.81	$2.50	$1.21	$16.52	$0.23	$16.29
Average	$10.69	$2.67	$0.85	$14.21	$0.39	$13.82

Monthly, total annual, and total year to date scheduled regulation MW and regulation charges, as well as monthly and monthly average regulation price and regulation cost are shown in Table 10-40. Total scheduled regulation is based on settled (actual) MW. The total of all regulation charges for the first three months of 2017 was $20.7 million, compared to $21.4 million for the first three months of 2016.

Table 10-40 Total regulation charges: January 1, 2016 through March 31, 2017[69]

Year	Month	Scheduled Regulation (MW)	Total Regulation Charges ($)	Weighted Average Regulation Market Price ($/MW)	Cost of Regulation ($/MW)	Price as Percent of Cost
2016	Jan	412,310.8	$7,589,231	$15.65	$18.41	85.0%
2016	Feb	383,646.6	$7,677,113	$17.63	$20.01	88.1%
2016	Mar	396,604.0	$6,107,773	$13.43	$15.40	87.2%
2016	Apr	384,591.8	$8,367,326	$19.07	$21.76	87.7%
2016	May	391,135.2	$7,217,226	$15.67	$18.45	84.9%
2016	Jun	379,014.9	$5,993,073	$14.03	$15.81	88.7%
2016	Jul	386,146.2	$7,954,280	$17.86	$20.60	86.7%
2016	Aug	385,843.5	$7,703,653	$17.59	$19.97	88.1%
2016	Sep	376,321.1	$7,780,425	$17.91	$20.67	86.6%
2016	Oct	389,139.0	$7,018,089	$15.68	$18.03	87.0%
2016	Nov	374,665.6	$5,777,367	$13.12	$15.42	85.1%
2016	Dec	390,836.1	$5,113,222	$11.15	$13.08	85.2%
2016 Annual		4,650,254.7	$84,298,779	$15.73	$18.13	86.7%
2017	Jan	395,649.2	$6,824,379	$14.06	$17.25	81.5%
2017	Feb	355,967.1	$5,327,528	$11.12	$14.97	74.3%
2017	Mar	375,166.4	$8,581,366	$16.29	$22.87	71.2%
YTD		1,126,782.7	$20,733,273	$13.82	$18.36	75.7%

69 Weighted average market clearing prices presented here are taken from PJM settlements data, and differ from the values reported in Table 10-11, which are from five minute interval operational data. The MMU is investigating the cause of the discrepancies with PJM.

The capability, performance, and opportunity cost components of the cost of regulation are shown in Table 10-41. Total scheduled regulation is based on settled actual MW. In the first three months of 2017, the monthly average total cost of regulation was $18.36, 2.4 percent higher than $17.94 in the first three months of 2016. In the first three months of 2017, the monthly average capability component cost of regulation was $12.33, 13.0 percent lower than $14.17 in the first three months of 2016. In the first three months of 2017, the monthly average performance component cost of regulation was $4.37, 92.0 percent higher than $2.28 in the first three months of 2016.

Table 10-41 Components of regulation cost, January through March, 2016 through 2017

Year	Month	Scheduled Regulation (MW)	Cost of Regulation Capability ($/MW)	Cost of Regulation Performance ($/MW)	Opportunity Cost ($/MW)	Total Cost ($/MW)
2016	Jan	412,310.8	$14.49	$1.97	$1.95	$18.41
	Feb	383,646.6	$16.00	$2.61	$1.40	$20.01
	Mar	396,604.0	$12.01	$2.25	$1.14	$15.40
	YTD	1,192,561.4	$14.17	$2.28	$1.50	$17.94
2017	Jan	395,649.2	$13.17	$2.43	$1.65	$17.25
	Feb	355,967.1	$9.91	$3.69	$1.37	$14.97
	Mar	375,166.4	$13.91	$7.00	$1.97	$22.87
	YTD	1,126,782.7	$12.33	$4.37	$1.66	$18.36

Table 10-42 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 the first three months of 2017 was 75.4 percent, a 13.1 percent decrease from 86.8 percent in the first three months of 2016.

Table 10-42 Comparison of average price and cost for PJM regulation: January through March, 2009 through 2017

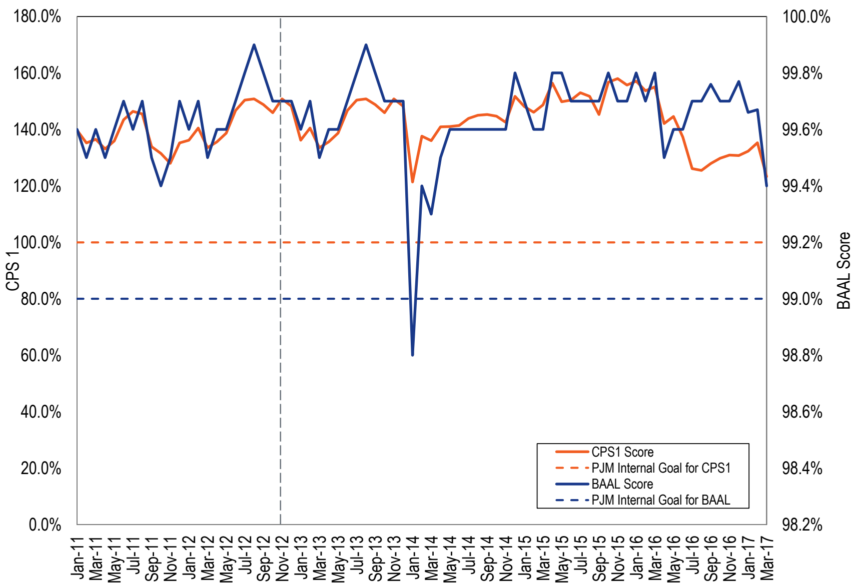
Year (Jan-Mar)	Weighted Regulation Market Price	Weighted Regulation Market Cost	Regulation Price as Percent Cost
2009	$22.25	$34.06	65.3%
2010	$17.97	$31.24	57.5%
2011	$11.52	$25.03	46.0%
2012	$12.62	$16.75	75.3%
2013	$33.91	$39.36	86.2%
2014	$92.97	$112.30	82.8%
2015	$47.91	$58.23	82.3%
2016	$15.55	$17.92	86.8%
2017	$13.87	$18.40	75.4%

Performance Standards

PJM's performance as measured by CPS1 and BAAL standards is shown in Figure 10-31 for every month from January 2011 through December 2016 with the dashed vertical line marking the date (October 1, 2012) of the implementation of the Performance Based Regulation Market design.[70] 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.

70 See the *2016 State of the Market Report for PJM*, Appendix F: Ancillary Services.

Figure 10-31 PJM monthly CPS1 and BAAL performance: January 1, 2011 through March 31, 2017



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, while recognizing that the most effective way to provide black start service may be across zones, 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 gave PJM substantial flexibility in procuring black start resources and made 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.[71] [72] 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.

PJM issued two incremental RFPs in 2014. On April 11, 2014, PJM sought additional black start in the AEP Zone and one proposal was selected. On November 24, 2014, PJM sought additional black start in northeastern Ohio and western Pennsylvania, but no proposals were selected because they did not meet the bid requirements. On July 28, 2015, PJM issued an Incremental Request for Proposals, for northeastern Ohio and western Pennsylvania together. On August 8, 2016, PJM made one award which will cover both areas.

Black start payments are nontransparent 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. In 2014, zonal reporting of black start payments was implemented, partially fulfilling the recommendation.

71 See PJM. "RTO-Wide Five-Year Selection Process Request for Proposal for Black Start Service," (July 1, 2013).
72 RFPs issued can be found on the PJM website. See PJM. <http://www.pjm.com/markets-and-operations/ancillary-services.aspx>.

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 nonzone peak transmission use and point to point transmission reservations.[73]

In the first three months of 2017, total black start charges were $17.0 million, an increase of $0.3 million (1.8 percent) from the same period of 2016. Operating reserve charges for black start service increased from $0.057 million in 2016 to $0.058 million in 2017. Table 10-43 shows total revenue requirement charges from 2010 through 2017. (Prior to December 2012, PJM did not define a black start operating reserve category. As a result of the changes in the black start operating reserve category, 2013 was the first full year in which operating reserves charges were allocated to black start, resulting in the increase in operating reserves charges. Starting in 2014, the ALR black start units began to be replaced with new black start units, resulting in a decline in operating reserve charges. Prior to December 2012, operating reserve charges resulting from units providing black start service were allocated as operating reserve charges for reliability in the western region.)

Table 10-43 Black start revenue requirement charges: 2010 through 2017

Year Jan-Mar	Revenue Requirement Charges	Operating Reserves Charges	Total
2010	$2,673,689	$0	$2,673,689
2011	$2,793,709	$0	$2,793,709
2012	$3,864,301	$0	$3,864,301
2013	$5,412,855	$22,210,646	$27,623,501
2014	$5,104,104	$7,561,533	$12,665,637
2015	$10,276,712	$4,699,965	$14,976,676
2016	$16,677,315	$57,082	$16,734,396
2017	$16,977,182	$57,772	$17,034,954

Black start zonal charges in the first three months of 2017 ranged from $0.05 per MW-day in the DLCO Zone (total charges were $12,507) to $4.30 per MW-day in the PENELEC Zone (total charges were $1,127,246). For each zone, Table 10-44 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 $0.0414 per MW of reserve capacity during the first three months of 2017.

73 OATT Schedule 6A (paras. 25, 26 and 27 outline how charges are to be applied).

Table 10-44 Black start zonal charges for network transmission use: January through March, 2016 and 2017

	Jan-Mar 2016					Jan-Mar 2017				
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	$498,192	$6,210	$504,402	232,305	$2.17	$625,055	$0	$625,055	240,606	$2.60
AEP	$3,700,273	$20,455	$3,720,728	2,249,984	$1.65	$3,648,502	$1,006	$3,649,508	2,022,813	$1.80
AP	$1,046,187	$0	$1,046,187	873,018	$1.20	$966,701	$0	$966,701	784,548	$1.23
ATSI	$753,343	$0	$753,343	1,124,432	$0.67	$756,392	$0	$756,392	1,147,698	$0.66
BGE	$2,024,438	$0	$2,024,438	610,783	$3.31	$1,612,788	$0	$1,612,788	594,081	$2.71
ComEd	$1,216,614	$12,558	$1,229,172	1,834,769	$0.67	$1,211,762	$9,119	$1,220,881	1,905,714	$0.64
DAY	$59,439	$8,784	$68,223	298,553	$0.23	$56,824	$9,966	$66,789	300,591	$0.22
DEOK	$292,248	$0	$292,248	466,193	$0.63	$260,610	$0	$260,610	477,729	$0.55
Dominion	$738,170	$4,361	$742,531	1,970,232	$0.38	$1,077,751	$28,576	$1,106,327	1,758,429	$0.63
DPL	$260,192	$1,206	$261,398	374,374	$0.70	$572,710	$0	$572,710	371,412	$1.54
DLCO	$12,883	$0	$12,883	255,164	$0.05	$12,507	$0	$12,507	251,685	$0.05
EKPC	$71,452	$0	$71,452	317,617	$0.22	$102,456	$0	$102,456	259,002	$0.40
JCPL	$1,724,360	$0	$1,724,360	529,447	$3.26	$1,703,417	$0	$1,703,417	535,932	$3.18
Met-Ed	$145,886	$0	$145,886	254,654	$0.57	$149,649	$5,504	$155,153	265,266	$0.58
PECO	$407,647	$620	$408,267	736,590	$0.55	$388,222	$1,047	$389,269	752,751	$0.52
PENELEC	$1,196,171	$0	$1,196,171	275,211	$4.35	$1,127,246	$0	$1,127,246	261,846	$4.30
Pepco	$641,618	$0	$641,618	570,361	$1.12	$628,995	$0	$628,995	592,524	$1.06
PPL	$249,314	$0	$249,314	732,996	$0.34	$299,455	$0	$299,455	632,223	$0.47
PSEG	$1,065,246	$1,067	$1,066,314	873,136	$1.22	$1,044,699	$0	$1,044,699	882,027	$1.18
RECO	$0	$0	$0	NA	NA	$0	$0	$0	NA	NA
(Imp/Exp/Wheels)	$573,640	$1,821	$575,461	519,320	$1.11	$731,442	$2,554	$733,996	633,529	$1.16
Total	$16,677,315	$57,082	$16,734,396	15,099,139	$1.11	$16,977,182	$57,772	$17,034,954	14,670,406	$1.16

Table 10-45 provides a revenue requirement estimate by zone for the 2016/2017, 2017/2018 and 2018/2019 delivery years.[74] 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.

74 The Market Monitoring Unit was requested to provide estimated black start revenue requirements in the System Restoration Strategy Task Force group.

NERC – CIP

Currently, no black start units have requested new or additional black start NERC – CIP Capital Costs.[75]

Table 10-45 Black start zonal revenue requirement estimate: 2016/2017 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
AP	$4,150,000	$4,150,000	$4,150,000
ATSI	$3,100,000	$3,100,000	$3,100,000
BGE	$8,400,000	$3,650,000	$3,550,000
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	$2,750,000
Dominion	$5,400,000	$5,400,000	$5,400,000
DPL	$2,600,000	$2,600,000	$2,500,000
EKPC	$450,000	$450,000	$300,000
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	$75,100,000	$70,850,000	$71,350,000

Reactive Service

Suppliers of reactive power are compensated separately for reactive capability, day-ahead operating reserves, and for real-time lost opportunity costs. Compensation for reactive capability must be approved by FERC per Schedule 2 of the OATT. Generators may obtain FERC approval to recover a share of units' fixed costs by calculating a reactive revenue requirement, the reactive capability rate, and to collect such rates from PJM transmission customers.[76]

Any reactive service provided operationally that involves a MW reduction outside of its normal operating range or a startup for reactive power will be logged by PJM operators and awarded uplift or LOC credits.

Reactive Service, Reactive Supply and Voltage Control are provided by generation and other sources of reactive power (such as static VAR compensators and capacitor banks).[77] While a fixed requirement for reactive power is not established, reactive power helps maintain appropriate voltages on the transmission system.

Total reactive capability charges are the sum of FERC approved reactive supply revenue requirements which are posted monthly on the PJM website.[78] Zonal reactive supply revenue requirement charges are allocated monthly to PJM customers proportionally to their zone and nonzone peak transmission use and point to point transmission reservations.[79]

In 2016, the FERC began to reexamine its policies on reactive compensation.[80] Changes in the default capabilities of generators, disparities between nameplate values and tested values and questions about the way the allocation factors have been calculated have called continued reliance on the *AEP* method into question.[81] The continued use of fleet rates rather than unit specific rates is also an issue.

Recommended Market Approach to Reactive Costs

The best approach for recovering reactive capability costs is through markets where markets are available as they are in PJM and some other RTOs/ISOs. The best approach for recovering reactive capability costs in PJM is through the capacity market. The capacity market already incorporates reactive costs

75 OATT Schedule 6A para. 21. The Market Monitoring Unit shall include a Black Start Service summary in its annual State of the Market report which will set forth a descriptive summary of the new or additional Black Start NERC-CIP Capital costs requested by Black Start Units, and include a list of the types of capital costs requested and the overall cost of such capital improvements on an aggregate basis such that no data is attributable to an individual Black Start Unit.

76 See also PJM, Manual 27 (Open Access Transmission Tariff Accounting), Rev. 86, (January 26, 2017) at 3.

77 OATT Schedule 2.

78 See PJM. Markets & Operations: Billing, Settlements & Credit <http://www.pjm.com/~/media/markets-ops/settlements/reactive-revenue-requirements-table-may-2016.ashx> (June 8, 2016).

79 OATT Schedule 2.

80 *See, e.g., Reactive Supply Compensation in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Docket No. AD16-17-000 (March 17, 2016) (Notice of Workshop).

81 See 88 FERC ¶ 61,141 (July 30, 1999).

and reactive revenues. The treatment of reactive costs in the PJM market needs to be modified so that the capacity market incorporates reactive costs and revenues in a more efficient manner.

Reactive capability is an integral part of all generating units; no generating unit is built without reactive capability.[82] There is no support for the assertion that the fixed costs of reactive capability either can be or should be separated from the total fixed costs of a generating unit. There is no support for the assertion that reactive capability should be compensated outside the markets when the units participate in organized markets. Reactive capability is a precondition for participating in organized markets. Resources must invest in the equipment needed to have minimum reactive capability as a condition of receiving interconnection service from PJM and other markets.[83]

PJM requires a power factor of at least 0.95 leading to 0.90 lagging for synchronous units and at least 0.95 leading to 0.95 lagging for nonsynchronous units.[84] The regulations specify a minimum power factor range of 0.95 leading and 0.95 lagging power factor unless the market operators' rules specify otherwise.[85] The Commission has recently extended the interconnection service requirement to have reactive capability to wind and solar units, which previously had been exempt.[86] Reactive capability is a requirement for participating in organized markets and is therefore appropriately treated as part of the gross Cost of New Entry in organized markets.

There are two ways to address the cost of reactive in the PJM market design.

82 *See Reactive Power Requirements for Non-Synchronous Generation*, Order No. 827, 155 FERC ¶ 61,277 at 9 (2016) ("[T]he equipment needed for a wind generator to provide reactive power has become more commercially available and less costly, such that the cost of installing equipment that is capable of providing reactive power is comparable to the costs of a traditional generator.").

83 *See* 18 CFR § 35.28(f)(1); *Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, FERC Stats. & Regs. ¶ 31,146, Appendix G (Large Generator Interconnection Agreement (LGIA)), *order on reh'g*, Order No. 2003-A, FERC Stats. & Regs. ¶ 31,160, *order on reh'g*, Order No. 2003-B, FERC Stats. & Regs. ¶ 31,171 (2004), *order on reh'g*, Order No. 2003-C, FERC Stats. & Regs. ¶ 31,190 (2005), *aff'd sub nom.* Nat'l Ass'n of Regulatory Util. Comm'rs v. FERC, 475 F.3d 1277 (D.C. Cir. 2007), *cert. denied*, 552 U.S. 1230 (2008); *Standardization of Small Generator Interconnection Agreements and Procedures*, Order No. 2006, FERC Stats. & Regs. ¶ 31,180, Attachment F (Small Generator Interconnection Agreement), *order on reh'g*, Order No. 2006-A, FERC Stats. & Regs. ¶ 31,196 (2005), *order granting clarification*, Order No. 2006-B, FERC Stats. & Regs. ¶ 31,221 (2006).

84 *See* OATT Attachment O Appendix 2 § 4.7.

85 *See, e.g., id.* LGIA Article 9.6.1 ("Interconnection Customer shall design the Large Generating Facility to maintain a composite power delivery at continuous rated power output at the Point of Interconnection at a power factor within the range of 0.95 leading to 0.95 lagging, unless Transmission Provider has established different requirements that apply to all generators in the Control Area on a comparable basis.").

86 *Reactive Power Requirements for Non-Synchronous Generation*, Order No. 827, 155 FERC ¶ 61,277 (2016); see also PJM Interconnection, L.L.C., 151 FERC ¶ 61,097 at P 28 (2015).

Under the current capacity market rules, the gross costs of the entire plant, including any reactive costs, are included in the gross Cost of New Entry (CONE) and the revenues from reactive service capability rates are an offset to the gross CONE. The result is that, conceptually, the cost of reactive is not part of net CONE.[87] This is logically consistent with the separate collection of reactive costs through a cost of service rate in that there is no double counting if the revenue offset is done accurately. Under this approach there is a separate collection of reactive capability costs.

An alternative approach to the current treatment of reactive costs in the capacity market would be to include the gross costs of the entire plant including any reactive costs in the gross Cost of New Entry (CONE) but to calculate net CONE without a reactive revenue offset for reactive service capability rates. The result of this approach would be that the cost of reactive is part of net CONE. This is logically consistent with the elimination of the separate collection of reactive costs through a cost of service rate in that there is no double counting if done accurately. Under this approach there would be no separate collection of reactive capability costs.

PJM currently uses the first approach. There is no reason that PJM could not easily implement the second approach.

The second approach is preferable. The second approach relies on competitive markets to provide incentives to provide energy, both real and reactive, at the lowest possible cost. The second approach provides a consistent and nondiscriminatory approach to compensation, avoiding reliance on a large number of costly and sporadic ratemaking proceedings. The second approach does not require the use of arbitrary, approximate and generally inaccurate allocators to determine the cost of providing reactive. The second approach does not require the use of estimated, average and inaccurate net reactive revenue offsets to calculate Net CONE. It is critical in the PJM Capacity Market that Net CONE be as accurate as possible. Only the second approach assures this.

87 *See* OATT Attachment DD § 5.10(a)(iv).

Units are compensated for reactive capability costs under the second approach. But the compensation is based on the outcome of a competitive capacity market rather than based on current or historical cost of service filings for units or fleets of units.

The first approach, although internally logically consistent, relies on unnecessary and inaccurate approximations. The reactive allocator is such an approximation. The reactive revenue offset is an inaccurate estimate based on historical data from reactive revenue requirement filings. The reactive revenues used in the net CONE calculation are based on an average of reactive filings over the three years from 2005 through 2007 and therefore do not reflect even the allocated reactive costs and revenues for a new unit, as would be required to be consistent with the CONE logic.[88] To the extent that the reactive portion of the Net Energy and Ancillary Services Offset is inaccurate, the net CONE is inaccurate.

The reactive revenue offset is set equal to $ 2,199/MW-year in the OATT.[89] This figure is the average annual reactive revenue for combustion turbines from 2005 through 2007, based on the actual costs reported to the Commission in reactive service filings of CTs, as developed by the MMU.

The Net Cost of New Entry is a key parameter in the PJM Capacity Market as it affects the location of the VRR or demand curve and thus has a direct impact on capacity market prices.[90]

If revenues for reactive capacity were removed from the Net Energy and Ancillary Services Revenue Offset, then the fixed costs for investment in reactive capability would be recoverable through the capacity market. By employing a simple and direct approach using CONE with no offset, the rules for cost of service compensation included in Schedule 2 could be eliminated and the requirement for cost of service filings would be eliminated.

As a result of the nature of reactive filings, it is not possible to identify the reactive capability revenues for all individual units that receive reactive capability revenues. As a result, the offer caps in the capacity market are not as accurate as they should be.

Relying on capacity markets instead of cost of service allocations would enhance competition and efficient pricing.

Actual experience with the cost of service approach suggests that customers would be better off under a competition based approach. The Commission's recent investigations into particular rates raises questions about the accuracy and basis of rates currently charged for reactive capability.

Cost of service ratemaking creates unnecessary monitoring difficulties. Because service providers do not have to file rates periodically, suppliers have no incentive to adjust reactive capability rates except when they increase. Suppliers have direct access to information about the costs for their own units; the Commission and other parties do not have such access. When rates are established on a fleet basis or result from a black box settlement, the ability of parties to review and challenge rates is further reduced.

The current FERC review provides an excellent opportunity to discard an anachronistic cost of service approach that has not been working well and that is inconsistent with markets and is unnecessary in organized markets.[91] Increased reliance on markets for the recovery of reactive capability costs would promote efficiency and consistency. Customers, market administrators and regulators will be better served by a simpler and more effective competition based approach.

The MMU recommends that separate payments for reactive capability be eliminated and the cost of reactive capability be recovered in the capacity market.

88 OATT Attachment DD § 5.10(a)(v)(A) ("The Office of the Interconnection shall determine the Net Energy and Ancillary Services Revenue Offset each year for the PJM Region as (A) the annual average of the revenues that would have been received by the Reference Resource from the PJM energy markets during a period of three consecutive calendar years preceding the time of the determination, based on (1) the heat rate and other characteristics of such Reference Resource; (2) fuel prices reported during such period at an appropriate pricing point for the PJM Region with a fuel transmission adder appropriate for such region, as set forth in the PJM Manuals, assumed variable operation and maintenance expenses for such resource of $6.47 per MWh, and actual PJM hourly average Locational Marginal Prices recorded in the PJM Region during such period; and (3) an assumption that the Reference Resource would be dispatched for both the Day-Ahead and Real-Time Energy Markets on a Peak-Hour Dispatch basis; plus (B) ancillary service revenues of $2,199 per MW-year.").

89 *Id.*

90 *Id.*

91 See FERC Docket No. AD16-17.

Improvements to Current Approach

If OATT Schedule 2 reactive capability payments are not eliminated, then the MMU recommends, at a minimum, that steps be taken to ensure that payments are based on capability that is measured in tests performed by PJM or demonstrated in market data showing actual reactive output and based on capability levels that are useful to PJM system operators to maintain system stability. The FERC recently has initiated a number of investigations into the basis for reactive rates, and the MMU has intervened in and is participating in those proceedings.[92]

Under the *AEP* method, units must establish their MVAR rating based on "the capability of the generators to produce VArs."[93] Typically this has meant reliance on manufacturers' specified nameplate power factor.[94] More recently, the Commission has, in the *Wabash* Orders, required that "reactive power revenue requirement filings must include reactive power test reports."[95] Noting a difference between tested reactive MVAR ratings and nameplate MVAR ratings, the Commission has, in a number of cases, set the issue of MVAR rating degradation for hearing.[96]

The Commission has identified a significant issue. Tests are essential to "evaluate and analyze" proposed reactive revenue requirements.[97] The MVAR rating has a significant influence on the level of the requirements and should accurately reflect the MVAR capability actually available to maintain reliability.

There is no reason to use the nameplate MVAR rating to develop a reactive allocation and there is no basis in the *AEP* method for reliance on the nameplate MVAR rating. Nameplate reactive power ratings are generally higher than the actual ratings as defined by the PJM mandated tests of capability because nameplate power ratings are generally calculated using leading and lagging power factors that are lower than are achievable when installed in a specific plant interconnected to a specific transmission network. Although this issue is characterized as degradation, the difference between pre installation nameplate ratings and post installation tested capability exists even when units are new. Testing will reveal whether the tested capability degrades further. Reliance on tested results would address both the issue of degradation and the issue of theoretical versus actual MVAR ratings.

The logic of the *Wabash* orders should be extended to exclude manufacturers' nameplate MVAR ratings and the corresponding theoretical power factors. Nameplate MVAR ratings should not be relied upon to define the allocator used to calculate the costs of reactive capability. Current performance and testing show significant disparities between nameplate MVAR output and actual output. This is significant regardless of whether the cause is degradation of power factors or simply the difference between theoretical and tested power factors.[98] PJM determined in 1999 that nameplate MVAR and power factor ratings do not reflect the value to the system operator of a units' reactive output after it is interconnected at a specific location.[99] Only operator evaluation of reactive capability can provide a meaningful measure of reactive capability.

The information for MVAR ratings should come from data on the MVAR output provided. System operators can evaluate the usefulness and value of reactive capacity based on the actual availability and use of such capability.

Data from periodic testing for reactive capability is another approach to measuring MVAR output. Testing at relatively long intervals is not likely to be as accurate as actual market operations data, but it is more reliable than an untested and dated manufacturers' nameplate rating.

92 *See, e.g.*, FERC Dockets Nos. EL16-32, EL16-44, EL16-51, EL16-54, EL16-65, EL16-66, EL16-79, EL16-89, EL16-90, EL16-98, EL16-72, EL16-100, EL16-103, EL16-118, EL16-1004, ER16-1456, ER16-2217, EL17-19, EL17-38, EL17-39, EL17-49, ER17-259 and ER17-801.
93 *AEP mimeo* at 31.
94 *See, e.g.*, *id.*
95 154 FERC ¶ 61,246 at P 28 (2016); see also 154 FERC ¶ 61,246 at P 29 (*Wabash* Orders).
96 *See, e.g.*, *Talen Energy Marketing, LLC*, 154 FERC ¶ 61,087 at P 10 (2016) ("The Informational Filing contains information that raises concerns about the justness and reasonableness of Ironwood's reactive power rate, including, but not limited to, the degradation of the Facility's current MVAR capability as compared with the MVAR capability that was originally used to calculate the revenue requirement for Reactive Service included in Ironwood's reactive power rate.").
97 154 FERC ¶ 61,246 at P 28 (2016); see also 154 FERC ¶ 61,246 at P 29.
98 In response to a 1999 low voltage event, PJM performed a root cause analysis. The analysis concluded that "PJM narrowly avoided a voltage collapse" and that "if PJM had realized that the MVAR reserves that the EMS indicated were available were not realistic, other action could have been take [sic] to stabilize the system." PJM State & Member Training Dept., Slides, Reactive Reserves and Generator D-Curves at 13 (included as an Attachment), which can be accessed at: <*http://www.pjm.com/~/media/training/nerc-certifications/gen-exam-materials/gof/20160104-reactive-reserves-and-d-curve.ashx*>.
99 *Id.*, including Attachment.

The estimated capability costs also include estimated heating losses relative to MVAR output.[100] Heating losses are variable costs and not fixed costs and should not be included in the definition of reactive capability costs.[101] Heating losses can be accurately calculated for each hour of operation if each unit had an accurate, recent D-curve test.

Heating losses are variable costs and should not be included in the cost of reactive capability. The production of reactive power slightly reduces the MWh output of the generator as the generator follows its D-curve. The value of this heating loss component is generally estimated based on estimated operation and associated estimated losses and estimated market prices, treated as a fixed cost, and included in the cost of reactive capability. Losses are minimal and occur during normal operations and should not be treated as a fixed cost. Losses can be better and more accurately accounted for as a variable cost based on actual unit operations and market conditions.

Reactive service is supplied during normal operation as needed and directed by PJM dispatchers. Most reactive service is provided with no impact to operational dispatch. When a need for reactive service requires that a unit's MW output be reduced outside of its normal operational range, or when a unit is started to provide reactive power, it is logged by PJM dispatchers and will be paid reactive service credits in the zone or zones where the reactive service was provided proportionally to their zone and nonzone peak transmission use and point to point transmission reservations.

Cost of service rates are established under Schedule 2 of the OATT and may cover rates for single units or a fleet of units.[102] Until the Commission took corrective action, fleet rates remained in place in PJM even when the actual units in the fleet changed as a result of unit retirements or sales of units.[103] New rules require unit owners to give notice of fleet changes in an informational filing or to file a new rate based on the remaining units, but do not yet require unit specific reactive rates.[104] Fleet rates should be eliminated. Compensation should be based on unit specific costs. Fleet rates make it almost impossible to monitor whether compensation for reactive capability is based on actual unit specific performance and costs.

To the extent that the Commission decides that PJM and other markets should continue to rely on a cost of service method to compensate reactive capability, the rules should be modified to improve the accuracy of the calculations of reactive capability cost. Rates that do not accurately reflect the cost of the service provided are not just and reasonable.

Reactive capability rates schedules must be accurate, and they must also coordinate properly with the PJM market rules. Revenues received for reactive capability are revenues for ancillary services that should be netted against avoidable costs whenever avoidable cost rate offers are submitted in RPM capacity market auctions.[105] Participants have not been properly including reactive revenues in capacity market offers, and the MMU has notified participants of its compliance concerns. The identification of revenues for reactive capability on a unit specific basis is necessary for the calculation of accurate avoidable cost rate offers and is needed to avoid disputes that could interfere with the orderly administration of RPM auctions. The MMU has sought to address this issue through participation in proceedings at the FERC concerning reactive capability rates for PJM units.

Reactive Costs

In the first three months of 2017, total reactive charges were $86.4 million, a 17.6 percent increase from the 2016 level of $73.4 million.[106] Reactive service charges increased in the first three months of 2017 to $5.9 million from $251 thousand in the first three months of 2016. All $5.9 million in 2017 were paid for reactive service provided by 18 units in 97 hours. The reason for the increase in reactive service charges from the first three months in 2016 to 2017 is primarily due to the need to control regional voltages resulting from outages and locational seasonal light loads.

100 *See, e.g., id.* at P 10 n12 citing *PPL Energy Plus, LLC*, Letter Order, Docket No. ER08-1462-000 (Sept. 24, 2008); *Dynegy Midwest Generation, Inc.*, 125 FERC ¶ 61,280, at P 35 (2008).
101 *See* Transcript, *Reactive Supply Compensation in Markets Operated by Regional Transmission System Operators Workshop*, AD16-17-000 (June 30, 2016) at 26:21–27:23.
102 *See, e.g.*, OATT Schedule 2; *Virginia Electric and Power Company*; 114 FERC ¶ 61,318 (2006).
103 *See PJM Interconnection, L.L.C.*, 149 FERC ¶ 61,132 (2014); 151 FERC ¶ 61,224 (2015); OATT Schedule 2.
104 *Id.*
105 See OATT Attachment DD §§ 6.4, 6.8(d).
106 See the *2015 State of the Market Report for PJM*, Volume II, Section 4, "Energy Uplift."

Table 10-46 shows reactive service charges in 2016 and 2017, reactive capability revenue requirement charges and total charges.

Table 10-46 Reactive zonal charges for network transmission use: January through March, 2016 and 2017

	Jan-Mar 2016			Jan-Mar 2017		
Zone	Reactive Service Charges	Reactive Capability Revenue Requirement Charges	Total Charges	Reactive Service Charges	Reactive Capability Revenue Requirement Charges	Total Charges
AECO	$0	$1,360,729	$1,360,729	$4,392	$1,542,545	$1,546,936
AEP	$14,106	$9,191,375	$9,205,481	$102,082	$9,551,200	$9,653,281
AP	$0	$4,205,441	$4,205,441	$24,854	$4,194,868	$4,219,722
ATSI	$0	$5,547,337	$5,547,337	$32,667	$5,565,868	$5,598,535
BGE	$0	$1,927,384	$1,927,384	$1,681,755	$1,936,287	$3,618,042
ComEd	$1,091	$6,420,094	$6,421,185	$1,184,616	$7,885,880	$9,070,496
DAY	$0	$2,141,598	$2,141,598	$8,407	$1,901,104	$1,909,511
DEOK	$0	$1,431,077	$1,431,077	$12,641	$1,631,892	$1,644,534
Dominion	$0	$7,528,684	$7,528,684	$48,153	$7,457,061	$7,505,214
DPL	$224,934	$3,243,447	$3,468,381	$72,136	$3,123,980	$3,196,116
DLCO	$0	$0	$0	$6,479	$0	$6,479
EKPC	$0	$543,758	$543,758	$6,384	$538,585	$544,969
JCPL	$0	$2,260,113	$2,260,113	$10,251	$2,088,950	$2,099,201
Met-Ed	$0	$1,950,686	$1,950,686	$15,597	$1,791,128	$1,806,725
PECO	$0	$4,477,340	$4,477,340	$19,130	$4,406,222	$4,425,352
PENELEC	$10,366	$1,853,304	$1,863,670	$1,018,417	$2,610,963	$3,629,380
Pepco	$0	$1,338,510	$1,338,510	$1,582,888	$2,053,524	$3,636,412
PPL	$0	$4,786,381	$4,786,381	$21,901	$8,121,164	$8,143,065
PSEG	$0	$9,056,964	$9,056,964	$19,574	$9,081,874	$9,101,447
RECO	$0	$0	$0	$636	$0	$636
(Imp/Exp/Wheels)	$0	$3,919,825	$3,919,825	$0	$5,038,621	$5,038,621
Total	$250,496	$73,184,046	$73,434,542	$5,872,960	$80,521,715	$86,394,674

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.[4]

Overview

Congestion Cost

- **Total Congestion.** Total congestion costs decreased by $134.2 million or 45.9 percent, from $292.2 million in the first three months of 2016 to $157.9 million in the first three months of 2017.
- **Day-Ahead Congestion.** Day-ahead congestion costs decreased by $158.0 million or 48.9 percent, from $322.9 million in the first three months of 2016 to $164.9 million in the first three months of 2017.

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 the 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 April 20, 2017, and are subject to change, based on continued PJM billing updates.

- **Balancing Congestion.** Balancing congestion costs increased by $23.8 million or 77.4 percent, from -$30.8 million in the first three months of 2016 to -$6.9 million in the first three months of 2017.
- **Real-Time Congestion.** Real-time congestion costs decreased by $135.1 million or 45.9 percent, from $294.3 million in the first three months of 2016 to $159.2 million in the first three months of 2017.
- **Monthly Congestion.** Monthly total congestion costs in the first three months of 2017 ranged from $46.5 million in February to $59.9 million in January.
- **Geographic Differences in CLMP.** Differences in CLMP among eastern, southern and western control zones in PJM were primarily a result of congestion on the Cherry Valley Transformer, the Alpine – Belvidere Flowgate, the AP South Interface, the Emilie – Falls Line, and the Westwood Flowgate.
- **Congestion Frequency.** Congestion frequency continued to be significantly higher in the Day-Ahead Energy Market than in the Real-Time Energy Market in the first three months of 2017. The number of congestion event hours in the Day-Ahead Energy Market was about 14 times the number of congestion event hours in the Real-Time Energy Market.

  Day-ahead congestion event hours decreased significantly after September 8, 2014. The decrease 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. However, day-ahead congestion frequency increased by 22.5 percent from 66,431 congestion event hours in the first three months of 2016 to 81,409 congestion event hours in the first three months of 2017. The increase was a result of the increase in UTC transactions that followed the expiration of the fifteen month resettlement period for the proceeding related to uplift charges for UTC transactions.[5]

  Real-time congestion frequency decreased by 13.9 percent from 6,763 congestion event hours in the first three months of 2016 to 5,823 congestion event hours in the first three months of 2017.
- **Congested Facilities.** Day-ahead, congestion-event hours increased on all types of facilities. Real-time, congestion-event hours increased on interfaces and transformers and decreased on lines and flowgates.

  The Cherry Valley Transformer was the largest contributor to congestion costs in the first three months of 2017. With $10.9 million in total congestion costs, it accounted for 6.9 percent of the total PJM congestion costs in the first three months of 2017.
- **Zonal Congestion.** ComEd had the largest total congestion costs among all control zones in the first three months of 2017. ComEd had $52.1 million in total congestion costs, comprised of -$56.2 million in total load congestion payments, -$108.0 million in total generation congestion credits and $0.3 million in explicit congestion costs. The Alpine – Belvidere Flowgate, the Cherry Valley Transformer, the Nelson Flowgate, the Byron - Cherry Valley Flowgate and the Lakeview – Greenfield Line contributed $27.0 million, or 51.8 percent of the total ComEd control zone congestion costs.
- **Ownership.** In the first three months of 2017, both financial entities and physical entities were net payers of congestion charges. In the first three months of 2017, financial entities paid $1.1 million in congestion charges compared to $16.7 million received in congestion credits in the first three months of 2016. In the first three months of 2017, physical entities paid $156.9 million in congestion charges, a decrease of $152.0 million or 49.2 percent compared to the first three months of 2016.

Marginal Loss Cost

- **Total Marginal Loss Costs.** Total marginal loss costs increased by $1.5 million or 0.9 percent, from $170.1 million in the first three months of 2016 to $171.5 million in the first three months of 2017. The loss MWh in PJM decreased by 10.3 GWh or 0.3 percent, from 3,879.2 GWh in the first three months of 2016 to 3,889.5 GWh in the first three months of 2017. The loss component of real-time LMP increased from $0.0141 in the first three months of 2016 to $0.0151 or 6.7 percent in the first three months of 2017.

5 *See* FERC Docket No. EL14-37.

- **Monthly Total Marginal Loss Costs.** Monthly total marginal loss costs in the first three months of 2017 ranged from $46.4 million in February to $62.8 million in March.
- **Day-Ahead Marginal Loss Costs.** Day-ahead marginal loss costs increased by $16.6 million or 9.0 percent, from $183.3 million in the first three months of 2016 to $199.9 million in the first three months of 2017.
- **Balancing Marginal Loss Costs.** Balancing marginal loss costs decreased by $15.1 million or 114.6 percent, from -$13.2 million in the first three months of 2016 to -$28.3 million in the first three months of 2017.
- **Total Marginal Loss Surplus.** The total marginal loss surplus decreased in the first three months of 2017 by $6.3 million or 11.3 percent, from $55.7 million in the first three months of 2016, to $49.4 million in the first three months of 2017.

Energy Cost

- **Total Energy Costs.** Total energy costs decreased by $8.3 million or 7.3 percent, from -$113.6 million in the first three months of 2016 to -$121.9 million in the first three months of 2017.
- **Day-Ahead Energy Costs.** Day-ahead energy costs decreased by $33.4 million or 22.2 percent, from -$150.4 million in the first three months of 2016 to -$183.8 million in the first three months of 2017.
- **Balancing Energy Costs.** Balancing energy costs increased by $27.4 million or 76.5 percent, from $35.8 million in the first three months of 2016 to $63.2 million in the first three months of 2017.
- **Monthly Total Energy Costs.** Monthly total energy costs in the first three months of 2017 ranged from -$48.2 million in January to -$31.8 million in February.

Conclusion

Congestion is defined to be 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 63.8 and 86.5 percent of total congestion costs including congestion in the Day-Ahead Energy Market and the balancing energy market for the 14/15 and 15/16 planning periods. For the first 10 months of the 16/17 planning period ARRs and self scheduled FTRs offset 92.4 percent of total 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.[6] The first derivative of total losses with respect to the power flow equals marginal losses. Congestion cost reflects the incremental cost of relieving transmission constraints while maintaining system power balance. Congestion occurs when available, least-cost energy cannot be delivered to all loads because transmission facilities are not adequate to deliver that energy. When the least-cost available energy cannot be delivered to load in a transmission constrained area, higher cost units in the constrained area must be dispatched to meet that load.[7] 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 for January 1 through March 31, 2009 through 2017.[8]

The load-weighted average real-time LMP increased $3.48 or 13.0 percent from $26.80 in the first three months of 2016 to $30.28 in the first three months of 2017. The load-weighted average congestion component decreased by $0.01 from $0.03 in the first three months of 2016 to $0.02 in the first three months of 2017. The load-weighted average loss component increased from $0.01 in the first three months of 2016 to $0.02 in the first three months of 2017. The load-weighted average energy component increased by $3.49 or 13.1 percent from $26.75 in the first three months of 2016 to $30.25 in the first three months of 2017.

Table 11-1 PJM real-time, load-weighted average LMP components (Dollars per MWh): January 1 through March 31, 2009 through 2017[9]

(Jan - Mar)	Real-Time LMP	Energy Component	Congestion Component	Loss Component
2009	$49.60	$49.51	$0.05	$0.04
2010	$45.92	$45.81	$0.06	$0.05
2011	$46.35	$46.30	$0.03	$0.03
2012	$31.21	$31.18	$0.02	$0.00
2013	$37.41	$37.37	$0.02	$0.02
2014	$92.98	$93.08	($0.13)	$0.03
2015	$50.91	$50.89	($0.00)	$0.03
2016	$26.80	$26.75	$0.03	$0.01
2017	$30.28	$30.25	$0.02	$0.02

Table 11-2 shows the PJM day-ahead, load-weighted average LMP components for January 1 through March 31 of 2009 through 2017.[10]

The load-weighted average day-ahead LMP increased $2.46, or 8.8 percent, from $27.94 in the first three months of 2016 to $30.40 in the first three months of 2017. The load-weighted average congestion component decreased $0.11, or 77.0 percent, from $0.15 in the first three months of 2016 to $0.03 in the first three months of 2017. The load-weighted average loss component decreased from -$0.002 in the first three months of 2016 to -$0.020 in the first three months of 2017. The load-weighted average energy component increased $2.59, or 9.3 percent, from $27.80 in the first three months of 2016 to $30.39 in the first three months of 2017.

6 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>.

7 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.

8 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.

9 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.

10 In the Real-Time Energy Market, the energy component (SMP) equals the system load-weighted price, with the caveat about state-estimated versus metered load. However, in the Day-Ahead Energy Market the day-ahead energy component of LMP (SMP) and the PJM day-ahead load-weighted LMP are not equal. The difference between the day-ahead energy component of LMP and the PJM day-ahead load-weighted LMP is a result of the difference in the types of load used to weight the load-weighted reference bus and the load-weighted LMP. In the Day-Ahead Energy Market, the distributed load reference bus is weighted by fixed-demand bids only and the day-ahead SMP is, therefore, a system fixed demand weighted price. The day-ahead load-weighted LMP calculation uses all types of demand, including fixed, price-sensitive and decrement bids.

Table 11-2 PJM day-ahead, load-weighted average LMP components (Dollars per MWh): January 1 through March 31, 2009 through 2017

(Jan - Mar)	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
2009	$49.44	$49.75	($0.18)	($0.13)
2010	$47.77	$47.74	$0.01	$0.02
2011	$47.14	$47.36	($0.11)	($0.11)
2012	$31.51	$31.45	$0.08	($0.03)
2013	$37.26	$37.19	$0.07	$0.01
2014	$94.96	$94.52	$0.43	$0.00
2015	$52.02	$51.55	$0.48	($0.02)
2016	$27.94	$27.80	$0.15	($0.00)
2017	$30.40	$30.39	$0.03	($0.02)

Zonal Components

The real-time components of LMP for each control zone are presented in Table 11-3 for the first three months of 2016 and the first three months of 2017. In the first three months of 2017, BGE had the highest real-time congestion component of all control zones and ComEd had the lowest real-time congestion component.

Table 11-3 Zonal and PJM real-time, load-weighted average LMP components (Dollars per MWh): January 1 through March 31, 2016 and 2017

	2016 (Jan - Mar)				2017 (Jan - Mar)			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AECO	$25.73	$26.67	($1.34)	$0.39	$29.59	$30.25	($1.32)	$0.66
AEP	$26.49	$26.73	$0.09	($0.32)	$29.39	$30.20	($0.23)	($0.58)
AP	$27.63	$26.85	$0.60	$0.17	$30.63	$30.31	$0.14	$0.18
ATSI	$26.03	$26.46	($0.87)	$0.44	$30.45	$30.01	($0.06)	$0.50
BGE	$36.11	$27.05	$7.89	$1.16	$34.79	$30.55	$2.85	$1.40
ComEd	$23.45	$26.33	($1.64)	($1.24)	$26.95	$29.90	($1.35)	($1.59)
DAY	$26.08	$26.69	($0.99)	$0.38	$29.88	$30.15	($0.37)	$0.10
DEOK	$25.42	$26.68	($0.61)	($0.65)	$28.57	$30.16	($0.43)	($1.17)
DLCO	$25.68	$26.52	($0.69)	($0.15)	$29.67	$30.06	($0.23)	($0.16)
Dominion	$31.29	$27.20	$3.96	$0.14	$32.58	$30.67	$1.49	$0.42
DPL	$30.56	$27.17	$2.35	$1.04	$33.13	$30.60	$1.36	$1.17
EKPC	$25.78	$27.28	($0.77)	($0.73)	$28.75	$30.63	($0.73)	($1.15)
JCPL	$23.79	$26.69	($3.33)	$0.43	$30.63	$30.26	($0.36)	$0.72
Met-Ed	$23.63	$26.76	($3.40)	$0.27	$30.41	$30.21	($0.43)	$0.63
PECO	$23.29	$26.73	($3.70)	$0.26	$29.58	$30.25	($1.03)	$0.36
PENELEC	$25.29	$26.56	($1.76)	$0.49	$29.79	$30.07	($0.77)	$0.49
Pepco	$32.38	$27.06	$4.62	$0.70	$33.26	$30.54	$1.81	$0.92
PPL	$23.88	$26.82	($3.15)	$0.21	$30.35	$30.27	($0.42)	$0.50
PSEG	$23.95	$26.50	($2.99)	$0.44	$30.51	$30.05	($0.26)	$0.72
RECO	$23.79	$26.55	($3.23)	$0.47	$30.77	$30.13	($0.15)	$0.80
PJM	$26.80	$26.75	$0.03	$0.01	$30.28	$30.25	$0.02	$0.02

The day-ahead components of LMP for each control zone are presented in Table 11-4 for the first three months of 2016 and the first three months of 2017. In the first three months of 2017, 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): January 1 through March 31, 2016 and 2017

	2016 (Jan - Mar)				2017 (Jan - Mar)			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AECO	$25.38	$27.56	($2.37)	$0.18	$29.62	$30.36	($1.04)	$0.30
AEP	$27.30	$27.81	($0.27)	($0.24)	$29.69	$30.37	($0.21)	($0.47)
AP	$28.84	$27.84	$0.95	$0.06	$30.80	$30.45	$0.27	$0.08
ATSI	$27.04	$27.56	($0.89)	$0.37	$30.69	$30.24	$0.00	$0.45
BGE	$38.70	$28.14	$9.59	$0.97	$34.70	$30.65	$2.86	$1.20
ComEd	$24.21	$27.42	($2.14)	($1.07)	$27.70	$30.11	($1.37)	($1.04)
DAY	$27.02	$27.67	($1.02)	$0.37	$30.05	$30.30	($0.40)	$0.15
DEOK	$26.55	$27.77	($0.66)	($0.56)	$29.05	$30.36	($0.35)	($0.96)
DLCO	$26.71	$27.63	($0.66)	($0.26)	$29.89	$30.23	($0.09)	($0.25)
Dominion	$33.27	$28.25	$4.77	$0.25	$32.59	$30.77	$1.41	$0.42
DPL	$32.49	$28.11	$3.58	$0.81	$32.80	$30.69	$1.52	$0.59
EKPC	$26.41	$28.26	($1.18)	($0.67)	$29.21	$30.89	($0.61)	($1.07)
JCPL	$24.08	$27.75	($3.97)	$0.30	$30.42	$30.41	($0.40)	$0.41
Met-Ed	$23.96	$27.64	($3.73)	$0.05	$30.26	$30.33	($0.35)	$0.28
PECO	$23.56	$27.72	($4.24)	$0.08	$29.29	$30.36	($1.13)	$0.06
PENELEC	$26.45	$27.85	($1.73)	$0.33	$29.77	$30.27	($0.65)	$0.15
Pepco	$34.70	$28.06	$6.03	$0.62	$33.32	$30.53	$2.00	$0.78
PPL	$24.20	$27.71	($3.54)	$0.03	$30.01	$30.33	($0.46)	$0.13
PSEG	$25.19	$27.61	($2.82)	$0.40	$30.68	$30.30	($0.07)	$0.45
RECO	$24.56	$27.56	($3.38)	$0.38	$30.74	$30.17	$0.09	$0.48
PJM	$27.94	$27.80	$0.15	($0.00)	$30.40	$30.39	$0.03	($0.02)

Hub Components

The real-time components of LMP for each hub are presented in Table 11-5 for the first three months of 2016 and the first three months of 2017.

Table 11-5 Hub real-time, load-weighted average LMP components (Dollars per MWh): January 1 through March 31, 2016 and 2017

	2016 (Jan - Mar)				2017 (Jan - Mar)			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AEP Gen Hub	$25.34	$27.86	($1.25)	($1.27)	$28.07	$30.15	($0.60)	($1.47)
AEP-DAY Hub	$25.65	$27.27	($1.16)	($0.46)	$29.05	$30.17	($0.33)	($0.79)
ATSI Gen Hub	$25.96	$27.39	($1.30)	($0.14)	$29.88	$30.30	($0.33)	($0.09)
Chicago Gen Hub	$21.94	$26.36	($2.81)	($1.60)	$26.05	$29.98	($1.94)	($1.99)
Chicago Hub	$23.79	$26.62	($1.61)	($1.22)	$27.17	$30.00	($1.30)	($1.53)
Dominion Hub	$30.72	$27.10	$3.75	($0.13)	$32.59	$31.01	$1.42	$0.16
Eastern Hub	$28.94	$26.37	$1.64	$0.93	$32.60	$29.95	$1.57	$1.08
N Illinois Hub	$23.49	$26.48	($1.62)	($1.37)	$26.96	$30.12	($1.45)	($1.72)
New Jersey Hub	$24.09	$26.53	($2.85)	$0.41	$30.33	$30.10	($0.45)	$0.68
Ohio Hub	$25.21	$26.69	($1.08)	($0.40)	$29.16	$30.18	($0.27)	($0.75)
West Interface Hub	$26.97	$26.69	$0.56	($0.28)	$30.89	$30.69	$0.47	($0.27)
Western Hub	$29.48	$28.17	$1.13	$0.18	$31.55	$30.96	$0.34	$0.26

The day-ahead components of LMP for each hub are presented in Table 11-6 for January 1 through March 31, 2016 and 2017.

Table 11-6 Hub day-ahead, load-weighted average LMP components (Dollars per MWh): January 1 through March 31, 2016 and 2017

	2016 (Jan - Mar)				2017 (Jan - Mar)			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AEP Gen Hub	$25.76	$27.68	($0.86)	($1.06)	$28.82	$30.60	($0.50)	($1.29)
AEP-DAY Hub	$26.31	$27.62	($0.94)	($0.37)	$29.33	$30.25	($0.28)	($0.64)
ATSI Gen Hub	$24.79	$25.18	($0.48)	$0.09	$27.68	($0.86)	($1.06)	$0.03
Chicago Gen Hub	$22.68	$27.66	($3.48)	($1.50)	$26.31	$29.75	($2.07)	($1.37)
Chicago Hub	$24.07	$27.35	($2.28)	($1.00)	$27.58	$29.84	($1.31)	($0.95)
Dominion Hub	$32.89	$28.28	$4.57	$0.04	$32.25	$30.80	$1.24	$0.20
Eastern Hub	$31.62	$27.86	$2.94	$0.82	$32.84	$30.48	$1.75	$0.61
N Illinois Hub	$24.09	$27.39	($2.09)	($1.20)	$27.17	$29.74	($1.42)	($1.15)
New Jersey Hub	$24.77	$27.56	($3.10)	$0.31	$30.44	$30.33	($0.28)	$0.39
Ohio Hub	$26.10	$27.56	($1.10)	($0.35)	$29.23	$30.18	($0.33)	($0.62)
West Interface Hub	$28.36	$27.91	$0.69	($0.24)	$29.71	$29.31	$0.60	($0.20)
Western Hub	$29.67	$28.00	$1.65	$0.03	$30.52	$30.18	$0.43	($0.08)

Component Costs

Table 11-7 shows the total energy, loss and congestion component costs and the total PJM billing for January 1 through March 31, 2009 through 2017. These totals are actually net energy, loss and congestion costs. Total congestion cost decreased and marginal loss cost increased in the first three months of 2017 compared to the first three months of 2016.

Table 11-7 Total PJM costs by component (Dollars (Millions)): January 1 through March 31, 2009 through 2017[11 12]

	Component Costs (Millions)					
(Jan - Mar)	Energy Costs	Loss Costs	Congestion Costs	Total Costs	Total PJM Billing	Total Costs Percent of PJM Billing
2009	($218)	$454	$307	$543	$7,515	7.2%
2010	($208)	$417	$345	$554	$8,415	6.6%
2011	($210)	$410	$360	$560	$9,584	5.8%
2012	($136)	$234	$122	$220	$6,938	3.2%
2013	($178)	$278	$186	$286	$7,762	3.7%
2014	($515)	$776	$1,236	$1,497	$21,070	7.1%
2015	($272)	$425	$632	$785	$14,040	5.6%
2016	($114)	$170	$292	$349	$9,500	3.7%
2017	($122)	$172	$158	$208	$9,710	2.1%

11 The energy costs, loss costs and congestion costs include net inadvertent charges.
12 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.[13] 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.

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. Explicit congestion costs are calculated for internal purchase, import and export transaction, and up to congestion transactions (UTCs.)
- **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. Total congestion costs, when positive, measure the total congestion payment by a PJM member and when negative, measure the total congestion credit paid

13 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.

14 OA. Schedule 1 (PJM Interchange Energy Market) §3.7.

to a PJM member. Load congestion payments, when positive, measure the total congestion payment by a PJM member and when negative, measure the total congestion credit paid to a PJM member. Generation congestion credits, when negative, measure the total congestion payment by a PJM member and when positive, measure the total congestion credit paid to a PJM member. Explicit congestion costs, when positive, measure the congestion payment by a PJM member and when negative, measure the congestion credit paid to a PJM member. Explicit congestion costs are calculated for up to congestion transactions (UTCs).

The CLMP is calculated with respect to the system reference bus LMP, also called the system marginal price (SMP). When a transmission constraint occurs, the resulting CLMP is positive on one side of the constraint and negative on the other side of the constraint and the corresponding congestion costs are positive or negative. For each transmission constraint, the CLMP reflects the cost of a constraint at a pricing node and is equal to the product of the constraint shadow price and the distribution factor at the respective pricing node. The total CLMP at a pricing node is the sum of all constraint contributions to LMP and is equal to the difference between the actual LMP that results from transmission constraints, excluding losses, and the SMP. If an area experiences lower prices because of a constraint, the CLMP in that area is negative.[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.

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>.

Total congestion costs in PJM in the first three months of 2017 were $157.9 million, which was comprised of load congestion payments of $23.9 million, generation credits of -$130.1 million and explicit congestion of $3.9 million.

Total Congestion

Table 11-8 shows total congestion in the first three months of 2008 through 2017. 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)): January 1 through March 31, 2008 through 2017

	Congestion Costs (Millions)			
(Jan - Mar)	Congestion Cost	Percent Change	Total PJM Billing	Percent of PJM Billing
2008	$486	NA	$7,718	6.3%
2009	$307	(36.8%)	$7,515	4.1%
2010	$345	12.4%	$8,415	4.1%
2011	$360	4.3%	$9,584	3.8%
2012	$122	(66.0%)	$6,938	1.8%
2013	$186	51.9%	$7,762	2.4%
2014	$1,236	564.8%	$21,070	5.9%
2015	$632	(48.9%)	$14,040	4.5%
2016	$292	(53.7%)	$9,500	3.1%
2017	$158	(45.9%)	$9,710	1.6%

Table 11-9 shows the congestion costs by accounting category by market in the first three months of 2008 through 2017. Table 11-9 shows that the total balancing explicit congestion cost was positive in the first three months of 2017 and was negative in the first three months of 2008 through 2016. The change was caused by the increase of total balancing explicit net congestion charges incurred by UTCs, that caused UTCs to go from $19.1 million in net balancing credits the first three months of 2016 to $0.9 million in net balancing charges in the first three months of 2017 (Table 11-10 and Table 11-11).

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, Effective Date: May 30, 2016. <http://www.pjm.com/documents/agreements.aspx>.
17 See "NYISO Tariffs New York Independent System Operator, Inc.," (May 26, 2016) Section 35.12.1, Effective Date: October 22, 2014. <http://www.pjm.com/documents/agreements.aspx>.

Table 11-9 Total PJM congestion costs by accounting category by market (Dollars (Millions)): January 1 through March 31, 2008 through 2017

	Congestion Costs (Millions)									
	Day Ahead				Balancing					
(Jan - Mar)	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
2008	$332.4	($220.0)	$39.9	$592.3	($46.0)	$29.5	($31.2)	($106.7)	$0.0	$485.6
2009	$120.2	($221.3)	$47.9	$389.5	($14.2)	($6.0)	($74.4)	($82.6)	($0.0)	$306.9
2010	$85.9	($293.1)	$12.9	$391.9	($5.7)	$12.1	($29.1)	($47.0)	($0.0)	$344.9
2011	$176.5	($226.7)	$4.1	$407.3	$21.6	$27.8	($41.2)	($47.4)	$0.0	$359.9
2012	$21.9	($131.4)	$27.5	$180.9	($5.1)	$11.3	($42.0)	($58.4)	$0.0	$122.4
2013	$85.0	($199.1)	$47.8	$331.9	($6.6)	$73.3	($66.0)	($145.9)	$0.0	$185.9
2014	$333.7	($1,193.9)	($94.3)	$1,433.3	$73.0	$208.9	($61.3)	($197.2)	$0.0	$1,236.1
2015	$327.0	($457.9)	($11.0)	$773.9	$5.4	$69.6	($78.0)	($142.2)	($0.0)	$631.7
2016	$120.2	($193.5)	$9.2	$322.9	($1.1)	$11.9	($17.7)	($30.8)	$0.0	$292.2
2017	$24.2	($137.7)	$3.0	$164.9	($0.3)	$7.6	$0.9	($6.9)	($0.0)	$157.9

Table 11-10 and Table 11-11 show the total congestion costs for each transaction type in the first three months of 2017 and 2016. Table 11-10 shows that in the first three months of 2017 DECs were paid $0.8 million in congestion credits in the day-ahead market, were paid $4.2 million in congestion credits in the balancing energy market, and were paid $5.0 million in total congestion credits. In the first three months of 2017, INCs were paid $2.3 million in congestion credits in the day-ahead market, were paid $0.3 million in congestion credits in the balancing energy market and received $2.6 million in total congestion credits. In the first three months of 2017, up to congestion (UTCs) paid $2.3 million in congestion charges in the day-ahead market, paid $0.9 million in congestion charges in balancing market and paid $3.1 million in total congestion charges.

Table 11-10 Total PJM congestion costs by transaction type by market (Dollars (Millions)): January 1 through March 31, 2017

	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	($0.8)	$0.0	$0.0	($0.8)	($4.2)	$0.0	$0.0	($4.2)	$0.0	($5.0)
Demand	$7.6	$0.0	$0.0	$7.6	$4.7	$0.0	$0.0	$4.7	$0.0	$12.3
Demand Response	($0.0)	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)
Explicit Congestion Only	$0.0	$0.0	$0.8	$0.8	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.8
Export	($10.8)	$0.0	($0.1)	($10.8)	($1.6)	$0.0	$0.8	($0.8)	$0.0	($11.6)
Generation	$0.0	($168.4)	$0.0	$168.4	$0.0	$8.0	$0.0	($8.0)	$0.0	$160.3
Grandfathered Overuse	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.4)	($0.4)	$0.0	($0.4)
Import	$0.0	$0.1	$0.0	($0.1)	$0.0	($1.5)	($0.3)	$1.2	$0.0	$1.1
INC	$0.0	$2.3	$0.0	($2.3)	$0.0	$0.3	$0.0	($0.3)	$0.0	($2.6)
Internal Bilateral	$28.2	$28.2	$0.0	($0.0)	$0.7	$0.7	$0.0	($0.0)	$0.0	($0.0)
Up to Congestion	$0.0	$0.0	$2.3	$2.3	$0.0	$0.0	$0.9	$0.9	$0.0	$3.1
Wheel In	$0.0	$0.1	$0.0	($0.0)	$0.0	($0.0)	($0.0)	($0.0)	$0.0	($0.0)
Wheel Out	$0.1	$0.0	$0.0	$0.1	($0.0)	$0.0	$0.0	($0.0)	$0.0	$0.0
Total	$24.2	($137.7)	$3.0	$164.9	($0.3)	$7.6	$0.9	($6.9)	$0.0	$157.9

Table 11-11 Total PJM congestion costs by transaction type by market (Dollars (Millions)): January 1 through March 31, 2016

	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	$17.9	$0.0	$0.0	$17.9	($18.1)	$0.0	$0.0	($18.1)	$0.0	($0.2)
Demand	$12.0	$0.0	$0.0	$12.0	$13.5	$0.0	$0.0	$13.5	$0.0	$25.5
Demand Response	($0.0)	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.0	($0.0)	$0.0	($0.0)
Export	$0.0	$0.0	$1.1	$1.1	$0.0	$0.0	($0.0)	($0.0)	$0.0	$1.1
Explicit Congestion Only	($19.2)	$0.0	($0.6)	($19.7)	($2.2)	$0.0	$0.7	($1.5)	$0.0	($21.3)
Generation	$0.0	($303.0)	$0.0	$303.0	$0.0	$20.8	$0.0	($20.8)	$0.0	$282.2
Grandfathered Overuse	$0.0	$0.0	$0.1	$0.1	$0.0	$0.0	$0.0	$0.0	$0.0	$0.1
Import	$0.0	($7.5)	$0.1	$7.6	$0.0	($12.7)	$0.6	$13.4	$0.0	$21.0
INC	$0.0	$7.1	$0.0	($7.1)	$0.0	($1.8)	$0.0	$1.8	$0.0	($5.4)
Internal Bilateral	$113.4	$113.7	$0.3	($0.0)	$5.7	$5.7	$0.0	($0.0)	$0.0	($0.0)
Up to Congestion	$0.0	$0.0	$6.1	$6.1	$0.0	$0.0	($19.1)	($19.1)	$0.0	($13.0)
Wheel In	$0.0	($3.9)	$2.1	$6.0	$0.0	($0.0)	$0.0	$0.0	$0.0	$6.0
Wheel Out	($3.9)	$0.0	$0.0	($3.9)	($0.0)	$0.0	$0.0	($0.0)	$0.0	($3.9)
Total	$120.2	($193.5)	$9.2	$322.9	($1.1)	$11.9	($17.7)	($30.7)	$0.0	$292.2

Table 11-12 shows the change in total congestion cost incurred by transaction type from the first three months of 2016 to the first three months of 2017. Total congestion cost incurred by generation decreased by $121.9 million, total congestion cost incurred by demand decreased by $13.2 million, and the total congestion cost incurred by up to congestion transactions (UTCs) increased by $16.1 million.

Total day-ahead congestion costs paid by UTCs decreased by $3.8 million from $6.1 million in the first three months of 2016 to $2.3 million in the first three months of 2017. Over the same period balancing congestion payments to UTCs decreased by $19.9 million, from $19.1 million in the first three months of 2016 to -$0.9 million in the first three months of 2017. UTCs were paid $13.0 million in total congestion in the first three months of 2016 but paid $3.1 million in total congestion the first three months of 2017.

Table 11-12 Change in total PJM congestion costs by transaction type by market: January 1 through March 31, 2016 and 2017 (Dollars (Millions))

	Change in 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	($18.7)	$0.0	$0.0	($18.7)	$13.9	$0.0	$0.0	$13.9	$0.0	($4.8)
Demand	($4.4)	$0.0	$0.0	($4.4)	($8.8)	$0.0	$0.0	($8.8)	$0.0	($13.2)
Demand Response	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Explicit Congestion Only	$0.0	$0.0	($0.4)	($0.4)	$0.0	$0.0	$0.0	$0.0	$0.0	($0.3)
Export	$8.4	$0.0	$0.5	$8.9	$0.6	$0.0	$0.1	$0.7	$0.0	$9.6
Generation	$0.0	$134.6	$0.0	($134.6)	$0.0	($12.7)	$0.0	$12.7	$0.0	($121.9)
Grandfathered Overuse	$0.0	$0.0	($0.1)	($0.1)	$0.0	$0.0	($0.4)	($0.4)	$0.0	($0.5)
Import	$0.0	$7.6	($0.1)	($7.7)	$0.0	$11.3	($0.9)	($12.2)	$0.0	($19.9)
INC	$0.0	($4.8)	$0.0	$4.8	$0.0	$2.1	$0.0	($2.1)	$0.0	$2.7
Internal Bilateral	($85.2)	($85.5)	($0.3)	($0.0)	($4.9)	($4.9)	$0.0	$0.0	$0.0	$0.0
Up to Congestion	$0.0	$0.0	($3.8)	($3.8)	$0.0	$0.0	$19.9	$19.9	$0.0	$16.1
Wheel In	$0.0	$3.9	($2.1)	($6.0)	$0.0	$0.0	($0.0)	($0.0)	$0.0	($6.0)
Wheel Out	$3.9	$0.0	$0.0	$3.9	$0.0	$0.0	$0.0	$0.0	$0.0	$3.9
Total	($96.0)	$55.8	($6.2)	($158.0)	$0.8	($4.3)	$18.7	$23.8	$0.0	($134.2)

Monthly Congestion

Table 11-13 shows that monthly total congestion costs ranged from $46.5 million in February to $59.9 million in January in the first three months of 2017.

Table 11-13 Monthly PJM congestion costs by market (Dollars (Millions)): January 1, 2016 through March 31, 2017

	Congestion Costs (Millions)							
	2016				2017			
	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total
Jan	$123.5	($16.0)	$0.0	$107.6	$66.4	($6.5)	($0.0)	$59.9
Feb	$123.8	($12.5)	$0.0	$111.3	$44.4	$2.1	$0.0	$46.5
Mar	$75.6	($2.2)	($0.0)	$73.3	$54.1	($2.6)	$0.0	$51.6
Apr	$81.2	($3.0)	$0.0	$78.2				
May	$41.6	$7.5	($0.0)	$49.1				
Jun	$68.2	($8.6)	($0.0)	$59.6				
Jul	$124.4	($13.6)	($0.0)	$110.8				
Aug	$116.0	($5.0)	($0.0)	$111.0				
Sep	$123.4	($2.1)	($0.0)	$121.4				
Oct	$115.7	($12.6)	($0.0)	$103.1				
Nov	$48.9	($0.9)	($0.0)	$48.0				
Dec	$58.0	($7.8)	($0.0)	$50.3				
Total	$1,100.4	($76.8)	($0.0)	$1,023.7	$164.9	($6.9)	($0.0)	$157.9

Figure 11-1 shows PJM monthly total congestion cost for January 1, 2009 through March 31, 2017.

Figure 11-1 PJM monthly total congestion cost (Dollars (Millions)): January 1, 2009 through March 31, 2017

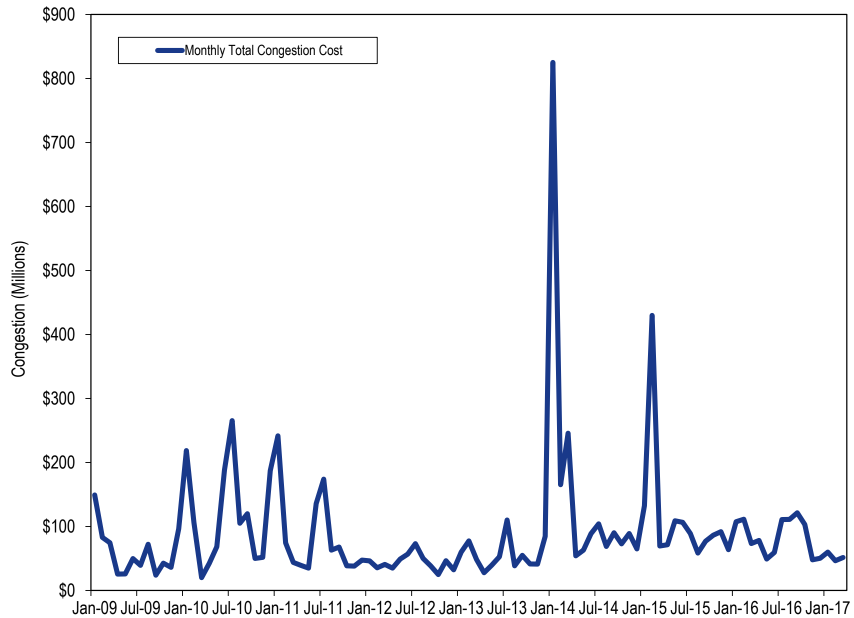


Table 11-14 shows the monthly total congestion costs for each virtual transaction type in the first three months of 2017 and Table 11-15 shows the monthly total congestion costs for each virtual transaction type in 2016. Virtual transaction congestion costs, when positive, measure the total congestion cost to the virtual transaction and when negative, measure the total congestion credit to the virtual transaction. Table 11-14 and Table 11-15 show that virtuals were paid in the first three months of 2017 and in the first three months of 2016.

Table 11-14 Monthly PJM congestion costs by virtual transaction type and by market (Dollars (Millions)): January 1 through March 31, 2017

	Congestion Costs (Millions)								
	Day-Ahead				Balancing				
	DEC	INC	Up to Congestion	Virtual Total	DEC	INC	Up to Congestion	Virtual Total	Virtual Grand Total
Jan	$1.1	$0.3	$2.9	$4.3	($3.0)	($1.1)	($2.0)	($6.1)	($1.9)
Feb	($0.7)	($4.9)	$0.7	($4.8)	($1.6)	$3.4	$1.7	$3.5	($1.4)
Mar	($1.2)	$2.3	($1.4)	($0.3)	$0.4	($2.6)	$1.2	($1.0)	($1.3)
Total	($0.8)	($2.3)	$2.3	($0.9)	($4.2)	($0.3)	$0.9	($3.6)	($4.5)

Table 11-15 Monthly PJM congestion costs by virtual transaction type and by market (Dollars (Millions)): 2016

	Congestion Costs (Millions)								
	Day-Ahead				Balancing				
	DEC	INC	Up to Congestion	Virtual Total	DEC	INC	Up to Congestion	Virtual Total	Virtual Grand Total
Jan	$6.8	($0.8)	$4.2	$10.1	($6.1)	($1.5)	($11.6)	($19.2)	($9.0)
Feb	$6.0	($1.0)	$1.2	$6.1	($8.1)	($0.5)	($6.3)	($14.9)	($8.8)
Mar	$5.1	($5.3)	$0.8	$0.5	($3.9)	$3.8	($1.2)	($1.3)	($0.8)
Apr	$5.0	($3.9)	($0.9)	$0.2	($5.1)	$4.3	($0.7)	($1.5)	($1.3)
May	$3.4	($8.9)	$0.8	($4.8)	($2.4)	$7.4	$1.8	$6.9	$2.1
Jun	$3.9	$0.0	$7.6	$11.6	($2.6)	($1.5)	($7.2)	($11.4)	$0.2
Jul	$3.5	$0.2	$5.5	$9.2	($6.0)	($1.7)	($7.5)	($15.2)	($5.9)
Aug	$7.4	($3.0)	$4.9	$9.3	($7.4)	$1.2	($5.5)	($11.8)	($2.5)
Sep	$6.8	($3.9)	$4.5	$7.4	($7.9)	$1.6	($1.2)	($7.6)	($0.2)
Oct	$4.9	($3.7)	$0.1	$1.3	($5.0)	$3.1	($4.0)	($5.8)	($4.5)
Nov	$1.7	($1.6)	$1.5	$1.6	($1.8)	$0.9	($1.0)	($1.9)	($0.3)
Dec	$1.7	($1.1)	$2.7	$3.4	($3.3)	$0.1	($2.7)	($5.9)	($2.5)
Total	$56.3	($33.1)	$32.7	$55.9	($59.6)	$17.2	($47.0)	($89.5)	($33.5)

Congested Facilities

A congestion event exists when a unit or units must be dispatched out of merit order to control for the potential impact of a contingency on a monitored facility or to control an actual overload. A congestion-event hour exists when a specific facility is constrained for one or more five-minute intervals within an hour. A congestion-event hour differs from a constrained hour, which is any hour during which one or more facilities are congested. Thus, if two facilities are constrained during an hour, the result is two congestion-event hours and one constrained hour. Constraints are often simultaneous, so the number of congestion-event hours usually exceeds the number of constrained hours and the number of congestion-event hours usually exceeds the number of hours in a year.

In order to have a consistent metric for real-time and day-ahead congestion frequency, real-time congestion frequency is measured using the convention that an hour is constrained if any of its component five-minute intervals is constrained. This is consistent with the way in which PJM reports real-time congestion. In the first three months of 2017, there were 81,409 day-ahead, congestion-event hours compared to 66,431 day-ahead congestion-event hours in the first three months of 2016. Of the first three months of 2017 day-ahead congestion-event hours, only 2,942 (3.6 percent) were also constrained in the Real-Time Energy Market. In the first three months of 2017, there were 5,823 real-time, congestion-event hours compared to 6,763 real-time, congestion-event hours in the first three months of 2016. Of the first three months of 2017 real-time congestion-event hours, 2,905 (49.9 percent) were also constrained in the Day-Ahead Energy Market.

The Cherry Valley Transformer was the largest contributor to total congestion costs in the first three months of 2017. With $10.9 million in total congestion costs, it accounted for 6.9 percent of the total PJM congestion costs in the first three months of 2017. The top five constraints in terms of congestion costs contributed $45.8 million, or 29.0 percent, of the total PJM congestion costs in the first three months of 2017. The top five constraints were the Cherry Valley Transformer, the Alpine – Belvidere Flowgate, the AP South Interface, the Emilie – Falls Line, and the Westwood Flowgate.

Congestion by Facility Type and Voltage

In the first three months of 2017, day-ahead, congestion-event hours increased on all types of facilities.

The increase in day-ahead, congestion-event hours on flowgates was largely a result of the increase of day-ahead, congestion-event hours on MISO flowgates.

The day-ahead, congestion-event hours on flowgates in MISO increased from 5,233 event hours in the first three months of 2016 to 7,528 event hours in the first three months of 2017. The increase in day-ahead, congestion-event hours on interfaces was a result of the increase of day-ahead, congestion-event hours on Pepco and West. The increase in day-ahead, congestion-event hours on lines was primarily a result of an increase in day-ahead, congestion-event hours incurred by lines in AEP, PENELEC and PSEG zones. The increase in day-ahead, congestion-event hours on transformers was primarily a result of the increase in day-ahead, congestion-event hours on transformers in the AEP, ComEd and PSEG zones.

Real-time, congestion-event hours decreased on flowgates and lines. The decrease in real-time, congestion-event hours on flowgates was primarily a result of the decrease in real-time, congestion-event hours on flowgates in NYSO. The decrease in real-time, congestion-event hours on lines was primarily a result of a decrease in real-time, congestion-event hours incurred by lines in BGE and DPL zones.

Day-ahead congestion costs decreased on all types of facilities in the first three months of 2017 compared to the first three months of 2016, primarily as a result of the decrease in day-ahead load-weighted CLMP. The load-weighted average congestion component decreased $0.11, or 77.0 percent, from $0.15 in the first three months of 2016 to $0.03 in the first three months of 2017.

Balancing congestion costs increased on all types of facilities except interfaces in the first three months of 2017 compared to the first three months of 2016. Table 11-16 provides congestion-event hour subtotals and congestion cost subtotals comparing the first three months of 2017 results by facility type: line, transformer, interface, flowgate and unclassified facilities.[18] [19] Table 11-17 presents this information for the first three months of 2016.

18 Unclassified are congestion costs related to nontransmission facility constraints in the Day-Ahead Market and any unaccounted for difference between PJM billed congestion charges and calculated congestion costs including rounding errors. Nontransmission facility constraints include day-ahead market only constraints such as constraints on virtual transactions and constraints associated with phase-angle regulators.

19 The term flowgate refers to MISO reciprocal coordinated flowgates and NYISO M2M flowgates.

Table 11-16 Congestion summary (By facility type): January 1 through March 31, 2017

	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	($19.6)	($65.5)	($6.0)	$39.9	$1.1	$1.4	($0.1)	($0.4)	$39.5	8,043	1,743
Interface	$10.4	($9.4)	($1.3)	$18.5	($0.2)	$1.6	$0.3	($1.6)	$16.9	1,850	250
Line	$24.9	($51.7)	$6.7	$83.4	($1.1)	$6.1	$1.7	($5.5)	$77.9	42,817	2,566
Other	$3.3	$0.5	$0.1	$2.9	$0.4	$0.3	$0.2	$0.4	$3.3	4,059	240
Transformer	$5.2	($11.5)	$3.5	$20.1	($0.3)	($1.8)	($0.4)	$1.1	$21.3	24,640	1,024
Unclassified	$0.0	($0.0)	$0.0	$0.0	($0.2)	$0.0	($0.8)	($1.0)	($1.0)	NA	NA
Total	$24.2	($137.7)	$3.0	$164.9	($0.3)	$7.6	$0.9	($6.9)	$157.9	81,409	5,823

Table 11-17 Congestion summary (By facility type): January 1 through March 31, 2016

	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	$17.6	($39.1)	($2.9)	$53.8	($0.9)	$3.9	($5.3)	($10.1)	$43.7	5,240	1,832
Interface	$15.1	($11.4)	($1.4)	$25.1	($0.1)	$0.3	$0.3	($0.0)	$25.0	1,746	86
Line	$62.8	($85.8)	$10.7	$159.2	$0.5	$5.4	($11.1)	($16.1)	$143.1	39,241	3,890
Other	($0.2)	($0.6)	$0.0	$0.4	$0.1	$0.0	$0.1	$0.1	$0.5	1,393	39
Transformer	$24.9	($56.6)	$2.7	$84.2	($1.8)	$2.0	($2.1)	($6.0)	$78.3	18,811	916
Unclassified	$0.0	($0.1)	$0.1	$0.2	$1.2	$0.3	$0.5	$1.4	$1.5	NA	NA
Total	$120.2	($193.5)	$9.2	$322.9	($1.1)	$11.9	($17.7)	($30.8)	$292.2	66,431	6,763

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 the first three months of 2017, there were 81,409 congestion-event hours in the Day-Ahead Energy Market. Of those day-ahead congestion-event hours, only 2,942 (3.6 percent) were also constrained in the Real-Time Energy Market. In the first three months of 2016, of the 66,431 day-ahead congestion-event hours, only 3,988 (6.0 percent) were binding in the Real-Time Energy Market.[20]

Among the hours for which a facility was constrained in the Real-Time Energy Market, the number of hours during which the facility was also constrained in the Day-Ahead Energy Market are presented in Table 11-19. In the first three months of 2017, of the 5,823 congestion-event hours in the Real-Time Energy Market, 2,905 (49.9 percent) were also constrained in the Day-Ahead Energy Market. In the first three months of 2016, of the 6,763 real-time congestion-event hours, 3,980 (58.8 percent) were also in the Day-Ahead Energy Market.

20 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 11-18 Congestion event hours (day-ahead against real-time): January 1 through March 31, 2016 and 2017

	Congestion Event Hours					
	2016 (Jan - Mar)			2017 (Jan - Mar)		
Type	Day Ahead Constrained	Corresponding Real Time Constrained	Percent	Day Ahead Constrained	Corresponding Real Time Constrained	Percent
Flowgate	5,240	776	14.8%	8,043	910	11.3%
Interface	1,746	42	2.4%	1,850	179	9.7%
Line	39,241	2,603	6.6%	42,817	1,450	3.4%
Other	1,393	6	0.4%	4,059	0	0.0%
Transformer	18,811	561	3.0%	24,640	403	1.6%
Total	66,431	3,988	6.0%	81,409	2,942	3.6%

Table 11-19 Congestion event hours (real-time against day-ahead): January 1 through March 31, 2016 and 2017

	Congestion Event Hours					
	2016 (Jan - Mar)			2017 (Jan - Mar)		
Type	Real Time Constrained	Corresponding Day Ahead Constrained	Percent	Real Time Constrained	Corresponding Day Ahead Constrained	Percent
Flowgate	1,832	778	42.5%	1,743	904	51.9%
Interface	86	44	51.2%	250	208	83.2%
Line	3,890	2,583	66.4%	2,566	1,394	54.3%
Other	39	6	15.4%	240	0	0.0%
Transformer	916	569	62.1%	1,024	399	39.0%
Total	6,763	3,980	58.8%	5,823	2,905	49.9%

Table 11-20 shows congestion costs by facility voltage class for the first three months of 2017. Congestion costs in the first three months of 2017 decreased for all facilities except facilities rated at 138 kV, 115 kV, and 34 kV compared to the first three months of 2016 (Table 11-21).

Table 11-20 Congestion summary (By facility voltage): January 1 through March 31, 2017

	Congestion Costs (Millions)										
	Day Ahead				Balancing					Event Hours	
Voltage (kV)	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
765	$0.5	($0.7)	$0.3	$1.6	($0.2)	$0.0	$0.0	($0.2)	$1.4	476	31
500	$11.6	($10.5)	($1.0)	$21.1	($0.1)	$1.6	$1.1	($0.5)	$20.6	2,077	194
345	($5.5)	($25.5)	$0.6	$20.6	$2.5	$1.6	($1.8)	($0.8)	$19.7	16,697	1,368
230	$24.8	($11.8)	($0.1)	$36.6	$0.8	$2.9	$0.7	($1.4)	$35.2	13,820	1,436
161	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	6	0
138	($5.6)	($80.4)	$2.9	$77.6	($1.2)	$4.4	$0.1	($5.5)	$72.1	35,601	2,015
115	($2.1)	($8.6)	$0.6	$7.1	$0.2	$1.2	$1.1	$0.1	$7.3	8,250	395
69	$0.3	($0.1)	($0.4)	$0.0	($2.2)	($4.0)	$0.5	$2.4	$2.4	3,170	384
34	$0.1	$0.0	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	1,284	0
18	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	1	0
13	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	27	0
Unclassified	$0.0	($0.0)	$0.0	$0.0	($0.2)	$0.0	($0.8)	($1.0)	($1.0)	NA	NA
Total	$24.2	($137.7)	$3.0	$164.9	($0.3)	$7.6	$0.9	($6.9)	$157.9	81,409	5,823

Table 11-21 Congestion summary (By facility voltage): January 1 through March 31, 2016

	Congestion Costs (Millions)										
	Day Ahead				Balancing					Event Hours	
Voltage (kV)	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
765	$0.1	($0.8)	$0.5	$1.4	$0.0	$0.0	$0.0	$0.0	$1.4	636	0
500	$21.4	($23.6)	($1.8)	$43.2	$1.9	$1.9	$1.1	$1.2	$44.4	2,364	372
345	$0.0	($53.6)	$5.7	$59.3	$0.1	$6.6	($4.5)	($10.9)	$48.4	13,191	884
230	$81.4	($42.2)	($3.1)	$120.5	$4.5	$2.7	$1.8	$3.6	$124.1	13,359	2,115
161	($7.4)	($24.9)	($2.9)	$14.6	($2.1)	$2.6	($1.1)	($5.8)	$8.8	2,040	580
138	$16.7	($46.9)	$9.0	$72.6	($3.7)	$3.3	($13.9)	($20.9)	$51.7	24,017	1,652
115	$2.2	($2.2)	$0.5	$4.9	($1.3)	$0.6	($1.0)	($2.9)	$2.0	4,762	404
69	$5.7	$0.7	$1.1	$6.1	($1.7)	($6.0)	($0.7)	$3.6	$9.7	5,339	756
34	$0.0	$0.0	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	719	0
12	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	4	0
Unclassified	$0.0	($0.1)	$0.1	$0.2	$1.2	$0.3	$0.5	$1.4	$1.5	NA	NA
Total	$120.2	($193.5)	$9.2	$322.9	($1.1)	$11.9	($17.7)	($30.8)	$292.2	66,431	6,763

Constraint Duration

Table 11-22 lists the constraints in the first three months of 2016 and 2017 that were most frequently binding and Table 11-23 shows the constraints which experienced the largest change in congestion-event hours from the first three months of 2016 to the first three months of 2017.

Table 11-22 Top 25 constraints with frequent occurrence: January 1 through March 31, 2016 and 2017

			Event Hours						Percent of Annual Hours					
			Day Ahead (Jan - Mar)			Real Time (Jan - Mar)			Day Ahead (Jan - Mar)			Real Time (Jan - Mar)		
No.	Constraint	Type	2016	2017	Change	2016	2017	Change	2016	2017	Change	2016	2017	Change
1	Emilie - Falls	Line	461	2,049	1,588	26	355	329	5%	23%	18%	0%	4%	4%
2	Olive	Other	327	1,898	1,571	0	0	0	4%	22%	18%	0%	0%	0%
3	Waukegan	Transformer	241	1,742	1,501	0	0	0	3%	20%	17%	0%	0%	0%
4	Westwood	Flowgate	0	1,477	1,477	0	198	198	0%	17%	17%	0%	2%	2%
5	Cherry Valley	Transformer	1,026	1,544	518	141	85	(56)	12%	18%	6%	2%	1%	(1%)
6	Zion	Line	688	1,436	748	0	0	0	8%	16%	8%	0%	0%	0%
7	Quad Cities	Transformer	201	1,370	1,169	0	0	0	2%	16%	13%	0%	0%	0%
8	Loretto - Vienna	Line	502	1,272	770	0	7	7	6%	14%	9%	0%	0%	0%
9	Saddlebrook	Transformer	128	1,255	1,127	0	0	0	1%	14%	13%	0%	0%	0%
10	Hudson	Transformer	662	1,110	448	0	0	0	8%	13%	5%	0%	0%	0%
11	West Chicago	Transformer	270	1,081	811	0	0	0	3%	12%	9%	0%	0%	0%
12	Maywood	Transformer	499	1,069	570	0	0	0	6%	12%	6%	0%	0%	0%
13	Lakeview - Greenfield	Line	82	972	890	0	94	94	1%	11%	10%	0%	1%	1%
14	Graceton - Safe Harbor	Line	49	775	726	19	277	258	1%	9%	8%	0%	3%	3%
15	Powerton - Goodings Grove	Line	163	862	699	92	142	50	2%	10%	8%	1%	2%	1%
16	Elwood - Elwood	Other	787	981	194	0	0	0	9%	11%	2%	0%	0%	0%
17	Howard - Shelby	Line	524	940	416	0	0	0	6%	11%	5%	0%	0%	0%
18	West Moulton-City Of St. Marys	Line	468	921	453	0	0	0	5%	10%	5%	0%	0%	0%
19	Kendall Co. Energy Ctr.	Transformer	238	898	660	0	0	0	3%	10%	8%	0%	0%	0%
20	East Bend	Transformer	1,086	879	(207)	0	0	0	12%	10%	(2%)	0%	0%	0%
21	Tanners Creek	Transformer	903	878	(25)	0	0	0	10%	10%	(0%)	0%	0%	0%
22	Gould Street - Westport	Line	569	869	300	0	0	0	6%	10%	3%	0%	0%	0%
23	Bellefonte - Grangston	Line	345	855	510	0	0	0	4%	10%	6%	0%	0%	0%
24	Central East	Flowgate	0	515	515	516	332	(184)	0%	6%	6%	6%	4%	(2%)
25	Braidwood	Transformer	1,346	830	(516)	0	0	0	15%	9%	(6%)	0%	0%	0%

Table 11-23 Top 25 constraints with largest year-to-year change in occurrence: January 1 through March 31, 2016 and 2017

			Event Hours						Percent of Annual Hours					
			Day Ahead (Jan - Mar)			Real Time (Jan - Mar)			Day Ahead (Jan - Mar)			Real Time (Jan - Mar)		
No.	Constraint	Type	2016	2017	Change	2016	2017	Change	2016	2017	Change	2016	2017	Change
1	Mercer IP - Galesburg	Flowgate	1,713	0	(1,713)	549	0	(549)	20%	0%	(20%)	6%	0%	(6%)
2	Monroe - Vineland	Line	1,917	101	(1,816)	252	3	(249)	22%	1%	(21%)	3%	0%	(3%)
3	Emilie - Falls	Line	461	2,049	1,588	26	355	329	5%	23%	18%	0%	4%	4%
4	Milford - Steele	Line	1,481	0	(1,481)	265	0	(265)	17%	0%	(17%)	3%	0%	(3%)
5	Westwood	Flowgate	0	1,477	1,477	0	198	198	0%	17%	17%	0%	2%	2%
6	Olive	Other	327	1,898	1,571	0	0	0	4%	22%	18%	0%	0%	0%
7	Graceton	Transformer	1,114	0	(1,114)	427	0	(427)	13%	0%	(13%)	5%	0%	(5%)
8	Waukegan	Transformer	241	1,742	1,501	0	0	0	3%	20%	17%	0%	0%	0%
9	Miami Fort	Transformer	1,671	239	(1,432)	2	0	(2)	19%	3%	(16%)	0%	0%	(0%)
10	Bagley - Graceton	Line	1,051	230	(821)	433	30	(403)	12%	3%	(9%)	5%	0%	(5%)
11	Quad Cities	Transformer	201	1,370	1,169	0	0	0	2%	16%	13%	0%	0%	0%
12	Saddlebrook	Transformer	128	1,255	1,127	0	0	0	1%	14%	13%	0%	0%	0%
13	Kewanee - Hennepin Tap	Line	1,004	0	(1,004)	107	0	(107)	11%	0%	(11%)	1%	0%	(1%)
14	Lakeview - Greenfield	Line	82	972	890	0	94	94	1%	11%	10%	0%	1%	1%
15	Graceton - Safe Harbor	Line	49	775	726	19	277	258	1%	9%	8%	0%	3%	3%
16	Mardela - Vienna	Line	773	172	(601)	380	5	(375)	9%	2%	(7%)	4%	0%	(4%)
17	East Danville - Banister	Line	1,001	31	(970)	0	0	0	11%	0%	(11%)	0%	0%	0%
18	Cedar Grove Sub - Roseland	Line	870	0	(870)	10	0	(10)	10%	0%	(10%)	0%	0%	(0%)
19	Bremo	Transformer	870	1	(869)	0	0	0	10%	0%	(10%)	0%	0%	0%
20	Tidd	Transformer	1,111	276	(835)	0	0	0	13%	3%	(10%)	0%	0%	0%
21	Hinchman	Transformer	0	830	830	0	0	0	0%	9%	9%	0%	0%	0%
22	Roxana - Praxair	Flowgate	662	164	(498)	335	13	(322)	8%	2%	(6%)	4%	0%	(4%)
23	West Chicago	Transformer	270	1,081	811	0	0	0	3%	12%	9%	0%	0%	0%
24	Loretto - Vienna	Line	502	1,272	770	0	7	7	6%	14%	9%	0%	0%	0%
25	Powerton - Goodings Grove	Line	163	862	699	92	142	50	2%	10%	8%	1%	2%	1%

Constraint Costs

Table 11-24 and Table 11-25 show the top constraints affecting congestion costs by facility for the first three months of 2017 and 2016. The Cherry Valley Transformer was the largest contributor to congestion costs in the first three months of 2017. With $10.9 million in total congestion costs, it accounted for 6.9 percent of the total PJM congestion costs in the first three months of 2017.

Table 11-24 Top 25 constraints affecting PJM congestion costs (By facility): January 1 through March 31, 2017

				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	2017 (Jan - Mar)
1	Cherry Valley	Transformer	ComEd	$3.7	($6.7)	$1.1	$11.6	($0.2)	$0.8	$0.4	($0.6)	$10.9	6.9%
2	Alpine - Belvidere	Flowgate	MISO	($2.3)	($14.0)	($0.9)	$10.8	$0.0	$0.0	$0.0	$0.0	$10.8	6.8%
3	AP South	Interface	500	$6.3	($3.7)	($0.8)	$9.2	($0.0)	$1.3	$0.8	($0.5)	$8.7	5.5%
4	Emilie - Falls	Line	PECO	$3.5	($4.7)	$0.5	$8.7	$0.0	$0.5	($0.0)	($0.5)	$8.2	5.2%
5	Westwood	Flowgate	MISO	($9.5)	($17.3)	($0.4)	$7.4	$1.2	$0.8	($0.5)	($0.1)	$7.3	4.6%
6	Conastone - Northwest	Line	BGE	$6.3	($0.5)	($0.3)	$6.4	($0.2)	($0.1)	$0.7	$0.6	$7.0	4.4%
7	Lakeview - Greenfield	Line	ATSI	($0.6)	($7.3)	$0.1	$6.9	($0.2)	$0.6	$0.4	($0.4)	$6.5	4.1%
8	Greentown	Flowgate	MISO	($1.4)	($7.6)	($0.7)	$5.6	($0.8)	($0.2)	$1.1	$0.5	$6.1	3.8%
9	Graceton - Safe Harbor	Line	BGE	$6.5	$1.2	$0.0	$5.3	$0.3	$0.5	$0.5	$0.4	$5.7	3.6%
10	Bedington - Black Oak	Interface	500	$2.4	($1.9)	($0.2)	$4.1	($0.0)	$0.2	$0.4	$0.2	$4.3	2.7%
11	Middletown Jct - Brunner Island	Line	PPL	$1.7	($2.3)	($0.2)	$3.8	$0.0	$0.0	$0.0	$0.0	$3.8	2.4%
12	Capital Hill - Chemical	Line	AEP	$1.6	($0.7)	$0.4	$2.7	$0.0	$0.0	$0.0	$0.0	$2.7	1.7%
13	Nottingham	Other	PECO	$3.2	$0.5	($0.0)	$2.6	$0.0	$0.0	$0.0	$0.0	$2.6	1.7%
14	Nelson	Flowgate	MISO	($1.7)	($4.2)	($0.1)	$2.4	$0.0	$0.0	$0.0	$0.0	$2.4	1.5%
15	Piney Grove	Transformer	DPL	($0.7)	($0.6)	($0.4)	($0.5)	($2.1)	($4.4)	$0.6	$2.9	$2.4	1.5%
16	Jenkins - Susquehanna	Line	PPL	$1.4	($1.1)	($0.1)	$2.4	$0.0	$0.0	$0.0	$0.0	$2.4	1.5%
17	Loretto - Vienna	Line	DPL	$2.3	$0.5	$0.5	$2.3	$0.0	($0.0)	($0.0)	($0.0)	$2.3	1.4%
18	Byron - Cherry Valley	Flowgate	MISO	($0.5)	($2.8)	($0.0)	$2.3	$0.0	$0.0	$0.0	$0.0	$2.3	1.4%
19	Conastone - Peach Bottom	Line	500	$2.0	$0.1	$0.1	$2.0	$0.1	($0.0)	$0.1	$0.1	$2.2	1.4%
20	AEP - DOM	Interface	500	$1.1	($1.2)	$0.2	$2.5	($0.0)	$0.1	($0.3)	($0.4)	$2.1	1.3%
21	Nelson - Garden Plain	Line	ComEd	$0.2	($0.1)	$0.1	$0.4	($1.8)	$0.3	($0.4)	($2.5)	($2.1)	(1.3%)
22	Bagley - Raphaerd	Line	BGE	$1.9	$0.2	($0.1)	$1.6	($0.0)	($0.1)	$0.1	$0.1	$1.7	1.1%
23	Bagley - Graceton	Line	BGE	$1.4	($0.3)	$0.0	$1.7	($0.0)	$0.0	$0.1	$0.0	$1.7	1.1%
24	Nelson	Transformer	ComEd	$0.0	$0.0	$0.0	$0.0	($0.2)	$0.9	($0.6)	($1.7)	($1.7)	(1.1%)
25	Crozet - Dooms	Line	Dominion	$1.5	($0.1)	$0.1	$1.7	$0.2	$0.4	$0.1	($0.1)	$1.6	1.0%

Table 11-25 Top 25 constraints affecting PJM congestion costs (By facility): January 1 through March 31, 2016

				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	2016 (Jan - Mar)
1	Graceton	Transformer	BGE	$17.7	($11.5)	($1.8)	$27.4	($0.5)	($0.9)	$2.0	$2.4	$29.8	10.2%
2	Bagley - Graceton	Line	BGE	$21.5	($1.8)	($1.4)	$21.8	$0.6	($1.2)	$1.2	$3.0	$24.8	8.5%
3	Conastone - Northwest	Line	BGE	$20.1	($4.4)	($2.0)	$22.5	$0.5	$0.4	$2.2	$2.3	$24.8	8.5%
4	Milford - Steele	Line	DPL	($8.3)	($25.7)	$0.1	$17.5	$2.2	$1.4	($1.7)	($0.9)	$16.6	5.7%
5	Person - Halifax	Flowgate	MISO	$29.9	$16.1	($0.2)	$13.5	$0.0	$0.0	($0.2)	($0.2)	$13.3	4.5%
6	Kanawha River - Matt Funk	Line	AEP	$2.7	($17.1)	($1.1)	$18.8	($0.7)	$2.5	($3.3)	($6.6)	$12.2	4.2%
7	Loudoun	Transformer	500	$1.1	($9.8)	($0.3)	$10.6	$0.8	$0.7	$0.5	$0.6	$11.1	3.8%
8	AP South	Interface	500	$8.8	($3.2)	($1.2)	$10.7	$0.0	$0.0	$0.0	$0.0	$10.7	3.7%
9	Mercer IP - Galesburg	Flowgate	MISO	($7.3)	($23.2)	($2.8)	$13.1	($0.0)	$2.2	($0.8)	($3.0)	$10.1	3.4%
10	Conastone - Peach Bottom	Line	500	$5.8	($2.6)	($0.2)	$8.2	$0.7	$1.0	$0.4	$0.1	$8.3	2.8%
11	Cherry Valley	Transformer	ComEd	$7.3	($8.2)	$1.1	$16.5	($2.6)	$1.5	($4.2)	($8.3)	$8.2	2.8%
12	Bedington - Black Oak	Interface	500	$4.5	($4.2)	($0.7)	$8.0	$0.1	$0.1	$0.2	$0.2	$8.2	2.8%
13	Cherry Valley	Flowgate	MISO	($0.4)	($7.6)	$0.4	$7.7	$0.0	$0.0	$0.0	$0.0	$7.7	2.6%
14	Cherry Valley - Silver Lake	Flowgate	MISO	($1.3)	($7.2)	$0.7	$6.6	$0.0	$0.0	$0.0	$0.0	$6.6	2.3%
15	Kanawha	Transformer	AEP	$0.1	($5.7)	$0.3	$6.1	$0.0	$0.0	$0.0	$0.0	$6.1	2.1%
16	Mardela - Vienna	Line	DPL	($1.4)	($3.5)	($0.1)	$2.0	($0.6)	($4.1)	$0.5	$4.0	$6.0	2.1%
17	AEP - DOM	Interface	500	$1.4	($2.6)	$0.7	$4.7	$0.2	($0.0)	$0.1	$0.4	$5.1	1.7%
18	Meadow Brook - Strasburg	Line	AP	$8.0	$4.1	($0.2)	$3.6	($0.9)	($0.7)	$0.9	$0.6	$4.2	1.5%
19	Bremo	Transformer	Dominion	($1.4)	($5.1)	$0.3	$4.0	$0.0	$0.0	$0.0	$0.0	$4.0	1.4%
20	Braidwood - East Frankfurt	Flowgate	MISO	($0.0)	($3.2)	$0.4	$3.6	$0.0	$0.0	$0.0	$0.0	$3.6	1.2%
21	Kammer	Transformer	AEP	($1.3)	($5.5)	($0.2)	$4.0	$0.3	$0.6	($0.5)	($0.8)	$3.2	1.1%
22	Batesville - Hubble	Flowgate	MISO	($1.2)	($4.5)	($0.3)	$3.0	$0.2	($0.2)	($0.5)	($0.2)	$2.8	1.0%
23	Monroe - Vineland	Line	AECO	$6.4	$4.7	$1.7	$3.4	($1.0)	($1.6)	($1.3)	($0.6)	$2.7	0.9%
24	Richmond - Waneeta	Line	PECO	$0.5	($2.0)	$0.0	$2.5	$0.1	$0.6	$0.7	$0.2	$2.7	0.9%
25	Braidwood - East Frankfort	Line	ComEd	($0.1)	($2.6)	$0.1	$2.6	$0.0	$0.0	$0.0	$0.0	$2.6	0.9%

Figure 11-2 shows the locations of the top 10 constraints by total congestion costs on a contour map of the real-time, load-weighted, average CLMP in the first three months of 2017. Figure 11-3 shows the locations of the top 10 constraints by balancing congestion costs on a contour map of the real-time, load-weighted, average CLMP in the first three months of 2017. Figure 11-4 shows the locations of the top 10 constraints by day-ahead congestion costs on a contour map of the day-ahead, load-weighted, average CLMP in the first three months of 2017.

Figure 11-2 Location of the top 10 constraints by PJM total congestion costs: January 1 through March 31, 2017

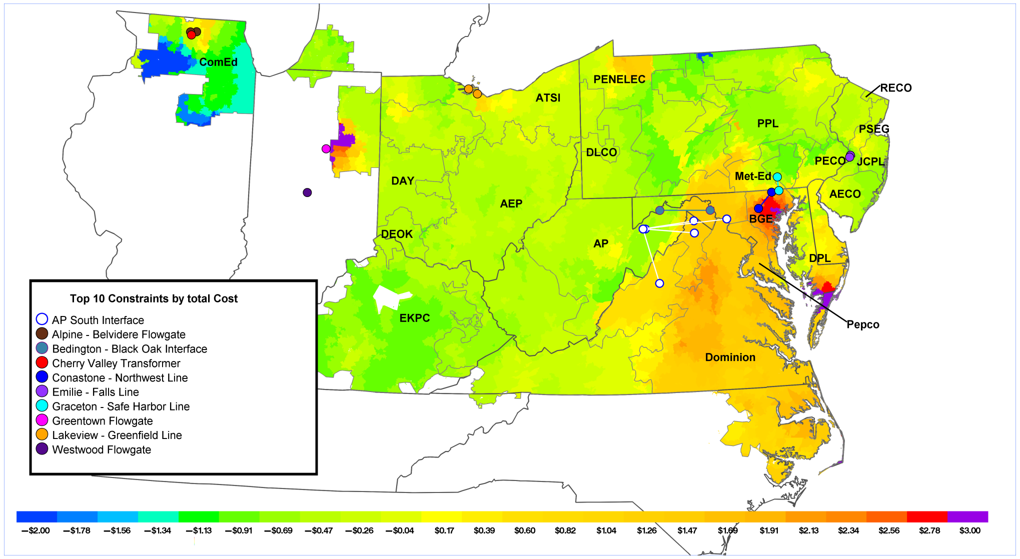


Figure 11-3 Location of the top 10 constraints by PJM balancing congestion costs: January 1 through March 31, 2017

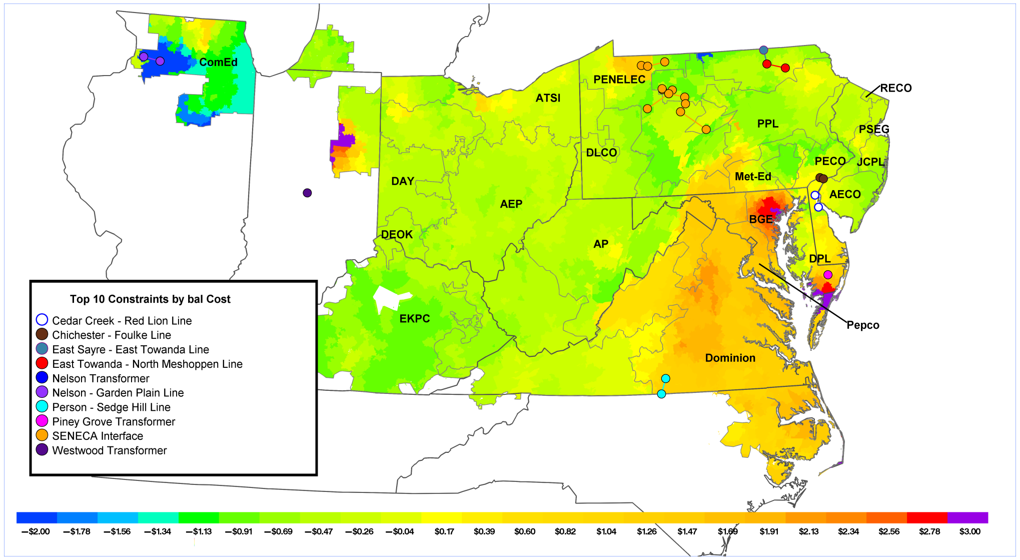
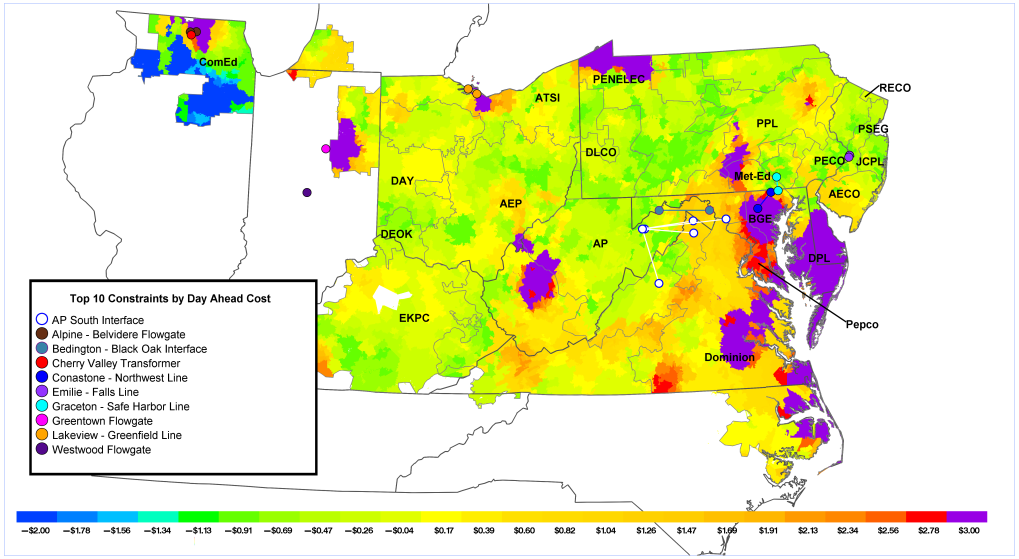


Figure 11-4 Location of the top 10 constraints by PJM day-ahead congestion costs: January 1 through March 31, 2017



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.[21] A flowgate is a facility or group of facilities that may act as constraint points on the regional system.[22] PJM models these coordinated flowgates and controls for them in its security-constrained, economic dispatch.

As of March 31, 2017, PJM had 151 flowgates eligible for M2M (Market to Market) coordination and MISO had 270 flowgates eligible for M2M coordination.

Table 11-26 and Table 11-27 show the MISO flowgates which PJM and/or MISO took dispatch action to control during the first three months of 2017 and 2016, and which had the greatest congestion cost impact on PJM. Total congestion costs associated with a given constraint may be positive or negative in value. The top congestion cost impacts for MISO flowgates affecting PJM and MISO dispatch are presented by constraint, in descending order of the absolute value of total congestion costs. Among MISO flowgates in the first three months of 2017, the Alpine – Belvidere Flowgate made the most significant contribution to positive congestion while the Rising Flowgate made the most significant contribution to negative congestion.

21 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.," (December 11, 2008), Section 6.1, Effective Date: May 30, 2016. <http://www.pjm.com/documents/agreements.aspx>.

22 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, Effective Date: February 14, 2017. <http://www.pjm.com/documents/agreements.aspx>.

Table 11-26 Top 20 congestion cost impacts from MISO flowgates affecting PJM dispatch (By facility): January 1 through March 31, 2017

		Congestion Costs (Millions)										
		Day Ahead				Balancing					Event Hours	
No.	Constraint	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
1	Alpine - Belvidere	($2.3)	($14.0)	($0.9)	$10.8	$0.0	$0.0	$0.0	$0.0	$10.8	339	0
2	Westwood	($9.5)	($17.3)	($0.4)	$7.4	$1.2	$0.8	($0.5)	($0.1)	$7.3	1,477	198
3	Greentown	($1.4)	($7.6)	($0.7)	$5.6	($0.8)	($0.2)	$1.1	$0.5	$6.1	425	248
4	Nelson	($1.7)	($4.2)	($0.1)	$2.4	$0.0	$0.0	$0.0	$0.0	$2.4	343	0
5	Byron - Cherry Valley	($0.5)	($2.8)	($0.0)	$2.3	$0.0	$0.0	$0.0	$0.0	$2.3	94	0
6	Reynolds - Magnetation	($0.2)	($1.3)	$0.3	$1.4	$0.0	($0.0)	($0.1)	($0.0)	$1.4	256	19
7	Westwood	$0.0	$0.0	$0.0	$0.0	$2.4	$0.7	($0.4)	$1.3	$1.3	0	348
8	Eugene - Cayuga	($0.4)	($1.8)	($0.1)	$1.2	$0.2	$0.0	($0.1)	($0.0)	$1.2	262	66
9	Monroe - Lallendorf	($0.3)	($1.7)	($0.4)	$1.0	$0.0	$0.0	$0.0	$0.0	$1.0	37	0
10	Pleasant Prairie - Zion	($0.3)	($1.4)	($0.1)	$1.0	$0.0	$0.0	($0.0)	($0.1)	$1.0	492	100
11	Brokaw - Leroy	$0.1	($0.8)	($0.4)	$0.6	($0.0)	$0.1	$0.3	$0.2	$0.8	330	149
12	Babcock - Stillwell	($0.6)	($1.5)	($0.5)	$0.4	($0.2)	($0.2)	$0.3	$0.3	$0.7	206	102
13	Burnham - Munster	$0.1	($0.5)	$0.0	$0.6	$0.0	$0.0	$0.0	$0.0	$0.6	276	0
14	Shadelnd - Lafaysouth	($0.2)	($0.4)	($0.0)	$0.2	$0.5	$0.0	($0.0)	$0.4	$0.6	60	92
15	Michigan City - Bosserman	$0.0	($0.7)	($0.4)	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	210	0
16	Rising	$0.0	($0.4)	($0.4)	$0.1	$0.1	$0.1	($0.4)	($0.5)	($0.4)	72	42
17	Nelson - Garden Plain	$0.7	$0.1	($0.2)	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	347	0
18	Todd Hunter	($0.1)	($0.4)	$0.0	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	731	0
19	Dumont	$0.0	($0.3)	$0.0	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	96	0
20	Labadie - Graysum	($0.1)	($0.5)	($0.1)	$0.3	($0.0)	$0.0	($0.0)	($0.0)	$0.2	55	75

Table 11-27 Top 20 congestion cost impacts from MISO flowgates affecting PJM dispatch (By facility): January 1 through March 31, 2016

		Congestion Costs (Millions)										
		Day Ahead				Balancing					Event Hours	
No.	Constraint	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
1	Person - Halifax	$29.9	$16.1	($0.2)	$13.5	$0.0	$0.0	($0.2)	($0.2)	$13.3	719	5
2	Mercer IP - Galesburg	($7.3)	($23.2)	($2.8)	$13.1	($0.0)	$2.2	($0.8)	($3.0)	$10.1	1,713	549
3	Cherry Valley	($0.4)	($7.6)	$0.4	$7.7	$0.0	$0.0	$0.0	$0.0	$7.7	293	0
4	Cherry Valley - Silver Lake	($1.3)	($7.2)	$0.7	$6.6	$0.0	$0.0	$0.0	$0.0	$6.6	365	0
5	Braidwood - East Frankfurt	($0.0)	($3.2)	$0.4	$3.6	$0.0	$0.0	$0.0	$0.0	$3.6	169	0
6	Batesville - Hubble	($1.2)	($4.5)	($0.3)	$3.0	$0.2	($0.2)	($0.5)	($0.2)	$2.8	284	58
7	Summer ShadeTVA - Summer Shade Tap	($0.2)	($1.4)	($0.1)	$1.1	($2.1)	$0.4	($0.3)	($2.8)	($1.7)	209	26
8	Roxana - Praxair	($0.9)	($2.3)	($1.0)	$0.4	$0.5	($0.3)	($2.4)	($1.6)	($1.2)	662	335
9	Reynolds - Magnetation	($0.5)	($3.2)	$0.3	$3.1	$0.0	$0.7	($1.3)	($2.0)	$1.1	334	205
10	Monroe - Bayshore	($0.2)	($0.8)	($0.1)	$0.5	($0.0)	($0.0)	($0.0)	($0.0)	$0.4	23	18
11	Rantoul - Rantoul Jct	($0.1)	($0.4)	($0.1)	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	61	0
12	Pleasant Valley - Belvidere	($0.0)	($0.3)	($0.0)	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	12	0
13	Dixon - McGirr Rd	($0.0)	($0.2)	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	48	0
14	Burnham - Munster	($0.0)	($0.1)	$0.1	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	44	0
15	West Dekalb - Glidden	($0.0)	($0.1)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	59	0
16	Gary Ave	($0.1)	($0.3)	($0.1)	$0.2	$0.0	($0.0)	($0.1)	($0.1)	$0.1	56	12
17	North Champaign - Vermilion	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.1)	($0.1)	($0.1)	0	3
18	Vermilion - Tilton	($0.0)	($0.1)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	56	0
19	Butler - Karns City	$0.1	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	9	4
20	Bunsonville	($0.0)	($0.1)	($0.0)	$0.0	($0.0)	$0.0	$0.0	($0.0)	$0.0	34	0

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.[23] 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.[24]

Table 11-28 and Table 11-29 show the NYISO flowgates which PJM and/or NYISO took dispatch action to control during the first three months of 2017 and 2016, and which had the greatest congestion cost impact on PJM.

23 See "New York Independent System Operator, Inc. NYISO Tariffs" (May 26, 2016) Section 35.3.1, Effective Date: January 15, 2013. <http://www.pjm.com/documents/agreements.aspx>.
24 See "New York Independent System Operator, Inc. NYISO Tariffs" (May 26, 2016) Section 35.23, Effective Date: June 11, 2014. <http://www.pjm.com/documents/agreements.aspx>.

Table 11-28 Top congestion cost impacts from NYISO flowgates affecting PJM dispatch (By facility): January 1 through March 31, 2017

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
1	Central East	Flowgate	NYISO	($2.7)	($5.7)	($1.7)	$1.3	$0.2	$0.4	($0.1)	($0.3)	$1.0	515	332

Table 11-29 Top two congestion cost impacts from NYISO flowgates affecting PJM dispatch (By facility): January 1 through March 31, 2016

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
1	Central East	Flowgate	NYISO	$0.0	$0.0	$0.0	$0.0	$0.4	$1.0	$0.2	($0.3)	($0.3)	0	516
2	Dysinger East	Flowgate	NYISO	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	0	2

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 the first three months of 2017 and 2016. 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): January 1 through March 31, 2017

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	$6.3	($3.7)	($0.8)	$9.2	($0.0)	$1.3	$0.8	($0.5)	$8.7	376	63
2	Bedington - Black Oak	Interface	500	$2.4	($1.9)	($0.2)	$4.1	($0.0)	$0.2	$0.4	$0.2	$4.3	467	38
3	Conastone - Peach Bottom	Line	500	$2.0	$0.1	$0.1	$2.0	$0.1	($0.0)	$0.1	$0.1	$2.2	450	56
4	AEP - DOM	Interface	500	$1.1	($1.2)	$0.2	$2.5	($0.0)	$0.1	($0.3)	($0.4)	$2.1	298	17
5	West	Interface	500	($0.3)	($1.7)	($0.1)	$1.3	$0.0	$0.0	$0.0	$0.0	$1.3	150	0
6	Three Mile Island	Transformer	500	$0.6	($0.3)	$0.1	$1.0	($0.0)	($0.1)	$0.1	$0.1	$1.1	157	17
7	5004/5005 Interface	Interface	500	($0.3)	($1.3)	($0.2)	$0.7	$0.0	$0.0	$0.0	$0.0	$0.7	47	1
8	East	Interface	500	($0.2)	($0.4)	($0.0)	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	82	0
9	502 Junction	Transformer	500	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	9	0
10	Elmont	Transformer	500	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	8	0
11	Redlion	Transformer	500	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	1	0
12	Black Oak	Transformer	500	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	1	0

Table 11-31 Regional constraints summary (By facility): January 1 through March 31, 2016

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
1	Loudoun	Transformer	500	$1.1	($9.8)	($0.3)	$10.6	$0.8	$0.7	$0.5	$0.6	$11.1	212	45
2	AP South	Interface	500	$8.8	($3.2)	($1.2)	$10.7	$0.0	$0.0	$0.0	$0.0	$10.7	416	0
3	Conastone - Peach Bottom	Line	500	$5.8	($2.6)	($0.2)	$8.2	$0.7	$1.0	$0.4	$0.1	$8.3	502	254
4	Bedington - Black Oak	Interface	500	$4.5	($4.2)	($0.7)	$8.0	$0.1	$0.1	$0.2	$0.2	$8.2	542	52
5	AEP - DOM	Interface	500	$1.4	($2.6)	$0.7	$4.7	$0.2	($0.0)	$0.1	$0.4	$5.1	592	4
6	West	Interface	500	($0.0)	($0.6)	($0.1)	$0.5	$0.0	$0.0	($0.0)	($0.0)	$0.5	38	2
7	5004/5005 Interface	Interface	500	($0.1)	($0.6)	($0.0)	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	29	0
8	Wylie Ridge	Transformer	500	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.1)	($0.1)	0	6
9	East	Interface	500	($0.0)	($0.1)	($0.0)	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	27	0
10	Three Mile Island	Transformer	500	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	6	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.

Financial entities incurred a net increase in congestion charges between the first three months of 2016 and the first three months of 2017. The result was that financial entities were a net recipient of congestion credits in the first three months of 2016 but a net payer of congestion charges in the first three months of 2017. In the first three months of 2016 financial entities received $18.9 million in net congestion credits. In the first three months of 2017, financial entities paid $1.1 million in net congestion charges. Physical entities incurred a net decrease in total congestion charges between the first three months of 2016 and the first three months of 2017. In the first three months of 2016, physical entities paid $308.9 million in congestion charges. In the first three months of 2017, physical entities paid $156.9 million in congestion charges.

Table 11-32 Congestion cost by type of participant: January 1 through March 31, 2017

	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	$1.8	$0.9	($0.1)	$0.8	($2.9)	$0.1	$3.2	$0.2	$0.0	$1.1
Physical	$22.4	($138.5)	$3.1	$164.1	$2.6	$7.5	($2.3)	($7.2)	$0.0	$156.9
Total	$24.2	($137.7)	$3.0	$164.9	($0.3)	$7.6	$0.9	($6.9)	$0.0	$157.9

Table 11-33 Congestion cost by type of participant: January 1 through March 31, 2016

	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	$2.2	($0.5)	($0.5)	$2.2	($10.4)	($2.5)	($11.0)	($18.9)	$0.0	($16.7)
Physical	$118.0	($193.0)	$9.7	$320.7	$9.3	$14.4	($6.8)	($11.9)	$0.0	$308.9
Total	$120.2	($193.5)	$9.2	$322.9	($1.1)	$11.9	($17.7)	($30.8)	$0.0	$292.2

The increase for financial entities was primarily a result of the positive balancing explicit congestion cost. Explicit congestion costs are the primary source of congestion credits to financial entities, primarily UTCs. Total explicit congestion cost is equal to day-ahead explicit congestion cost plus balancing explicit congestion cost. In the first three months of 2017, the total explicit congestion cost was $3.9 million, of which $3.1 million (78.8 percent) was contributed by UTCs. In the first three months of 2016, the total explicit cost was -$8.5 million, of which -$13.0 million (153.0 percent) was credited to UTCs.

Congestion-Event Summary: Impact of Changes in UTC Volumes

FERC issued a notice, effective September 8, 2014, that UTCs could be liable on a retroactive basis for paying uplift charges.[25] That potential refund period ended, after 15 months, on December 7, 2015.[26]

Day-ahead congestion event hours decreased significantly after September 8, 2014, when UTC activity declined. In the first three months of 2015, the average hourly UTC submitted MW decreased by 73.6 percent and UTC cleared MW decreased 72.3 percent compared to the first three months of 2014. Day-ahead congestion event hours decreased by 55.7 percent from 113,666 congestion event hours in the first three months of 2014 to 50,385 congestion event hours in the first three months of 2016.

Day-ahead congestion event hours increased significantly after December 7, 2015, when UTC activity increased. In the first three months of 2016, the average hourly UTC submitted MW increased 146.1 percent and UTC cleared MW increased 113.6 percent, compared to the first three months of 2015. Day-ahead congestion event hours increased by 31.7 percent from 50,384 congestion event hours in the first three months of 2015 to 66,373 congestion event hours In the first three months of 2016.

In the first three months of 2017, the average hourly UTC submitted MW increased 30.1 percent and UTC cleared MW increased 15.9 percent, compared

25 See 18 CFR § 385.213 (2014).
26 *See* FERC Docket No. EL14-37.

to the first three months of 2016. Day-ahead congestion event hours increased by 22.5 percent from 66,431 congestion event hours in the first three months of 2016 to 81,490 congestion event hours in the first three months of 2017.

Figure 11-5 shows the daily day-ahead and real-time congestion event hours for 2014 through March 2017.

Figure 11-5 Daily congestion event hours: January 1, 2014 through March 31, 2017

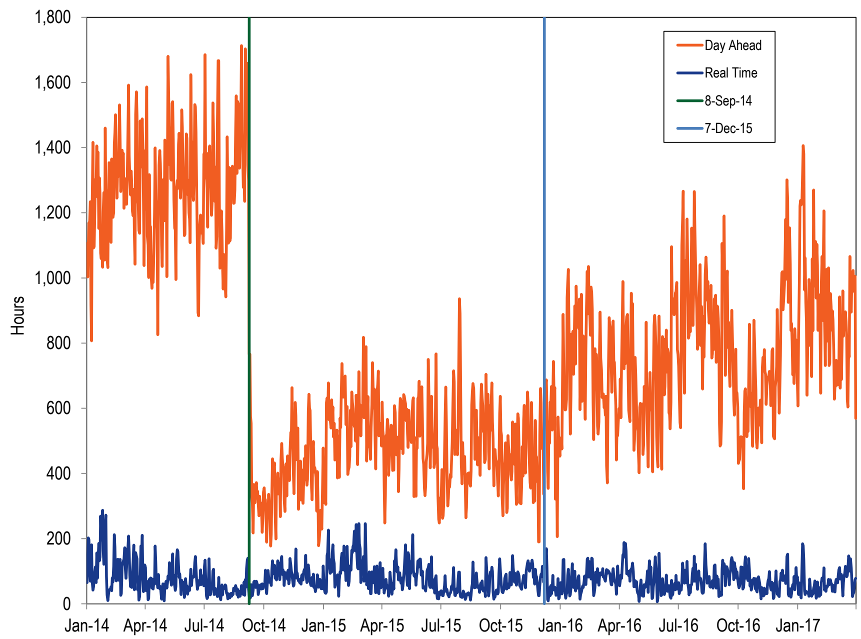
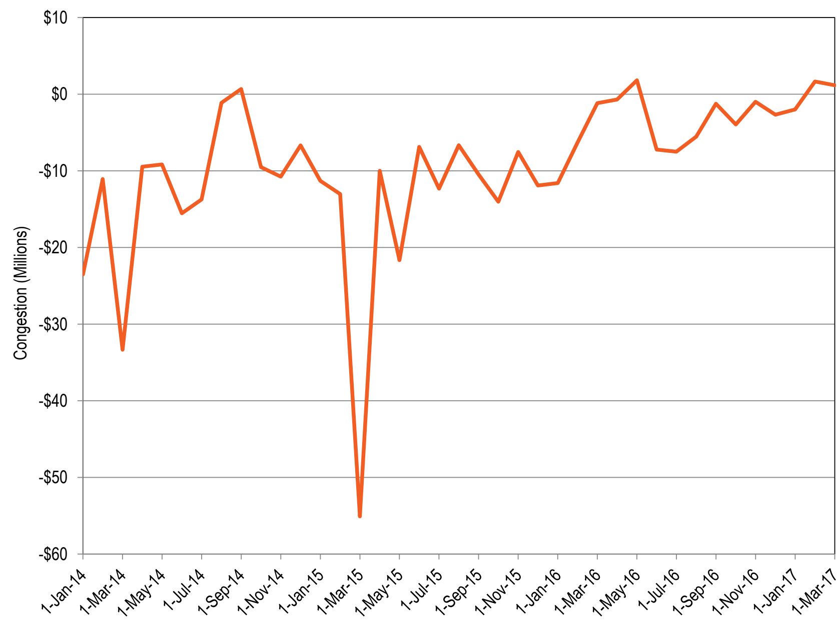


Figure 11-6 shows the change in up to congestion balancing explicit congestion costs from January 1, 2014 through March 31, 2017. Within this period, Figure 11-6 shows the highest monthly payment ($55.1 million) in balancing congestion credits to up to congestion transactions occurred in March of 2015 and the highest monthly charge ($1.8 million) in balancing congestion charges occurred in May of 2016.

Figure 11-6 Monthly balancing congestion cost incurred by up to congestion: January 1, 2014 through March 31, 2017



Marginal Losses

Marginal Loss Accounting

Marginal losses occur in the Day-Ahead and Real-Time Energy Markets. 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 be 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. Total loss costs, when positive, measure the total loss payment by a PJM member and when negative, measure the total loss credit paid to a PJM member. Load loss payments, when positive, measure the total loss payment by a PJM member and when negative, measure the total loss credit paid to a PJM member. Generation loss credits, when negative, measure the total loss payment by a PJM member and when positive, measure the total loss credit paid to a PJM member.

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.

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]

- **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 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.

27 OA. Schedule 1 (PJM Interchange Energy Market) §3.7
28 *Id.*
29 See PJM. "Manual 28: Operating Agreement Accounting," Revision 75 (November 18, 2016), p.70.

- **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, including UTCs. 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]

Total Marginal Loss Cost

The total marginal loss cost in PJM for the first three months of 2017 was $171.5 million, which was comprised of load loss payments of -$13.0 million, generation loss credits of -$196.2 million, explicit loss costs of -$11.6 million and inadvertent loss charges of $0.0 million. Monthly marginal loss costs in the first three months of 2017 ranged from $46.4 million in February to $62.8 million in March. Total marginal loss surplus decreased in the first three months of 2017 by $6.3 million or 11.3 percent from $55.7 million in the first three months of 2016 to $49.4 million in the first three months of 2017.

Table 11-34 shows the total marginal loss costs as a component of total energy related costs for January 1 through March 31, 2009 through 2017.

Table 11-34 Total component costs (Dollars (Millions)): January 1 through March 31, 2009 through 2017[31]

(Jan - Mar)	Loss Costs	Percent Change	Total PJM Billing	Percent of PJM Billing
2009	$454	NA	$7,515	6.0%
2010	$417	(8.2%)	$8,415	5.0%
2011	$410	(1.7%)	$9,584	4.3%
2012	$234	(42.8%)	$6,938	3.4%
2013	$278	18.5%	$7,762	3.6%
2014	$776	179.5%	$21,070	3.7%
2015	$425	(45.2%)	$14,040	3.0%
2016	$170	(60.0%)	$9,500	1.8%
2017	$172	0.9%	$9,710	1.8%

Table 11-35 shows PJM total marginal loss costs by accounting category for January 1 through March 31, 2009 through 2017. Table 11-36 shows PJM total marginal loss costs by accounting category by market for January 1 through March 31, 2009 through 2017.

Table 11-35 Total PJM marginal loss costs by accounting category (Dollars (Millions)): January 1 through March 31, 2009 through 2017

	Marginal Loss Costs (Millions)				
(Jan - Mar)	Load Payments	Generation Credits	Explicit Costs	Inadvertent Charges	Total
2009	($21.3)	($460.6)	$14.7	$0.0	$454.0
2010	($3.8)	($414.1)	$6.3	($0.0)	$416.6
2011	($26.5)	($421.2)	$14.9	$0.0	$409.6
2012	($11.2)	($252.1)	($6.6)	$0.0	$234.3
2013	$8.0	($277.8)	($8.2)	($0.0)	$277.6
2014	($15.1)	($813.7)	($22.8)	$0.0	$775.9
2015	($4.0)	($434.0)	($4.9)	$0.0	$425.1
2016	($8.0)	($184.4)	($6.3)	$0.0	$170.1
2017	($13.0)	($196.2)	($11.6)	($0.0)	$171.5

30 OA. Schedule 1 (PJM Interchange Energy Market) §3.7.

31 The loss costs include net inadvertent charges.

Table 11-36 Total PJM marginal loss costs by accounting category by market (Dollars (Millions)): January 1 through March 31, 2009 through 2017

	Marginal Loss Costs (Millions)									
	Day-Ahead				Balancing					
(Jan - Mar)	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
2009	($23.3)	($457.6)	$30.9	$465.2	$2.1	($3.0)	($16.3)	($11.2)	$0.0	$454.0
2010	($8.5)	($413.5)	$12.8	$417.8	$4.7	($0.6)	($6.5)	($1.2)	($0.0)	$416.6
2011	($37.1)	($430.1)	$26.0	$419.1	$10.6	$8.9	($11.1)	($9.5)	$0.0	$409.6
2012	($16.7)	($256.8)	$8.0	$248.1	$5.6	$4.7	($14.6)	($13.8)	$0.0	$234.3
2013	($0.1)	($288.2)	$8.1	$296.2	$8.1	$10.4	($16.3)	($18.6)	($0.0)	$277.6
2014	($48.6)	($847.4)	$32.3	$831.1	$33.5	$33.7	($55.1)	($55.3)	$0.0	$775.9
2015	($17.4)	($441.6)	$7.8	$432.0	$13.5	$7.6	($12.8)	($6.9)	$0.0	$425.1
2016	($10.7)	($186.3)	$7.6	$183.3	$2.7	$1.9	($14.0)	($13.2)	$0.0	$170.1
2017	($15.1)	($197.5)	$17.5	$199.9	$2.1	$1.3	($29.1)	($28.3)	($0.0)	$171.5

Table 11-37 and Table 11-38 show the total loss costs for each transaction type in the first three months of 2017 and 2016. In the first three months of 2017, generation paid loss costs of $183.3 million, 106.9 percent of total loss costs. In the first three months of 2016, generation paid loss costs of $167.4 million, 98.4 percent of total loss costs.

Virtual transaction loss costs, when positive, measure the total loss costs to virtual transactions and when negative, measure the total loss credits to virtual transaction. In the first three months of 2017, DECs were paid $2.3 million in loss credits in the day-ahead market, paid $1.1 million in congestion costs in the balancing energy market and received $1.2 million in net payment for losses. In the first three months of 2017, INCs paid $5.4 million in loss costs in the day-ahead market, were paid $4.4 million in congestion credits in the balancing energy market and paid $1.0 million in net payment for losses. In the first three months of 2017, up to congestion paid $17.3 million in the day-ahead market, were paid $29.2 million in loss credits in the balancing energy market and received $11.9 million in net payment for losses.

Table 11-37 Total PJM loss costs by transaction type by market (Dollars (Millions)): January 1 through March 31, 2017

	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	($2.3)	$0.0	$0.0	($2.3)	$1.1	$0.0	$0.0	$1.1	$0.0	($1.2)
Demand	($1.8)	$0.0	$0.0	($1.8)	$2.1	$0.0	$0.0	$2.1	$0.0	$0.4
Demand Response	($0.0)	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Export	($5.0)	$0.0	$0.0	($5.0)	($2.1)	$0.0	$0.3	($1.9)	$0.0	($6.8)
Generation	$0.0	($185.0)	$0.0	$185.0	$0.0	$1.7	$0.0	($1.7)	$0.0	$183.3
Grandfathered Overuse	$0.0	$0.0	($0.1)	($0.1)	$0.0	$0.0	($0.1)	($0.1)	$0.0	($0.2)
Import	$0.0	($1.0)	$0.0	$1.0	$0.0	($5.8)	($0.1)	$5.7	$0.0	$6.7
INC	$0.0	($5.4)	$0.0	$5.4	$0.0	$4.4	$0.0	($4.4)	$0.0	$1.0
Internal Bilateral	($6.0)	($6.0)	$0.0	($0.0)	$1.0	$1.0	$0.0	($0.0)	$0.0	($0.0)
Up to Congestion	$0.0	$0.0	$17.3	$17.3	$0.0	$0.0	($29.2)	($29.2)	$0.0	($11.9)
Wheel In	$0.0	$0.0	$0.3	$0.3	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.3
Total	($15.1)	($197.5)	$17.5	$199.9	$2.1	$1.3	($29.1)	($28.3)	$0.0	$171.5

Table 11-38 Total PJM loss costs by transaction type by market (Dollars (Millions)): January 1 through March 31, 2016

	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	$0.4	$0.0	$0.0	$0.4	($0.7)	$0.0	$0.0	($0.7)	$0.0	($0.3)
Demand	($1.0)	$0.0	$0.0	($1.0)	$2.6	$0.0	$0.0	$2.6	$0.0	$1.6
Demand Response	($0.0)	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Export	($3.6)	$0.0	$0.1	($3.6)	($0.1)	$0.0	$0.3	$0.2	$0.0	($3.4)
Generation	$0.0	($173.8)	$0.0	$173.8	$0.0	$6.5	$0.0	($6.5)	$0.0	$167.4
Grandfathered Overuse	$0.0	$0.0	($0.2)	($0.2)	$0.0	$0.0	($0.0)	($0.0)	$0.0	($0.2)
Import	$0.0	($3.0)	$0.5	$3.6	$0.0	($8.3)	$0.3	$8.6	$0.0	$12.2
INC	$0.0	($3.1)	$0.0	$3.1	$0.0	$2.9	$0.0	($2.9)	$0.0	$0.2
Internal Bilateral	($6.4)	($6.3)	$0.0	($0.0)	$0.8	$0.8	$0.0	($0.0)	$0.0	($0.0)
Up to Congestion	$0.0	$0.0	$6.9	$6.9	$0.0	$0.0	($14.5)	($14.5)	$0.0	($7.7)
Wheel In	$0.0	$0.0	$0.3	$0.3	$0.0	$0.0	$0.0	$0.0	$0.0	$0.4
Total	($10.7)	($186.3)	$7.6	$183.3	$2.7	$1.9	($14.0)	($13.2)	$0.0	$170.1

Monthly Marginal Loss Costs

Table 11-39 shows a monthly summary of marginal loss costs by market type for January 1, 2016 through March 31, 2017.

Table 11-39 Monthly marginal loss costs by market (Millions): January 1, 2016 through March 31, 2017

	Marginal Loss Costs (Millions)							
	2016				2017			
	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total
Jan	$78.2	($6.2)	$0.0	$72.0	$75.5	($13.2)	($0.0)	$62.3
Feb	$61.3	($3.8)	$0.0	$57.5	$54.2	($7.8)	$0.0	$46.4
Mar	$43.8	($3.2)	($0.0)	$40.6	$70.2	($7.4)	$0.0	$62.8
Apr	$52.1	($6.0)	$0.0	$46.1				
May	$40.4	($3.9)	($0.0)	$36.6				
Jun	$59.6	($6.5)	($0.0)	$53.1				
Jul	$93.8	($7.5)	($0.0)	$86.4				
Aug	$95.6	($9.8)	($0.0)	$85.8				
Sep	$70.6	($6.6)	($0.0)	$64.0				
Oct	$51.6	($6.6)	($0.0)	$45.0				
Nov	$49.0	($6.9)	($0.0)	$42.1				
Dec	$77.2	($9.7)	($0.0)	$67.5				
Total	$773.2	($76.7)	($0.0)	$696.5	$199.9	($28.3)	($0.0)	$171.5

Figure 11-7 shows PJM monthly marginal loss costs for January 1, 2009 through March 31, 2017.

Figure 11-7 PJM monthly marginal loss costs (Dollars (Millions)): January 1, 2009 through March 31, 2017

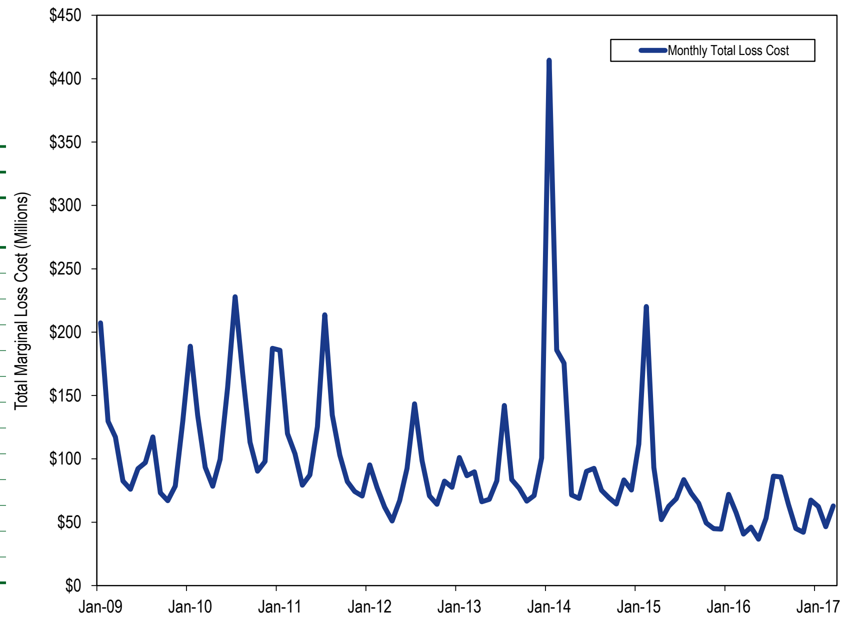


Table 11-40 and Table 11-41 show the monthly total loss costs for each virtual transaction type in the first three months of 2017 and 2016.

Table 11-40 Monthly PJM loss costs by virtual transaction type and by market (Dollars (Millions)): January 1 through March 31, 2017

	Loss Costs (Millions)								
	Day-Ahead				Balancing				
	DEC	INC	Up to Congestion	Virtual Total	DEC	INC	Up to Congestion	Virtual Total	Virtual Grand Total
Jan	($0.6)	$1.5	$6.7	$7.6	($0.0)	($1.3)	($13.4)	($14.7)	($7.1)
Feb	($0.6)	$1.3	$5.3	$6.0	$0.4	($1.1)	($7.7)	($8.4)	($2.4)
Mar	($1.1)	$2.6	$5.3	$6.7	$0.7	($2.0)	($8.1)	($9.3)	($2.6)
Total	($2.3)	$5.4	$17.3	$20.4	$1.1	($4.4)	($29.2)	($32.5)	($12.2)

Table 11-41 Monthly PJM loss costs by virtual transaction type and by market (Dollars (Millions)): 2016

	Loss Costs (Millions)								
	Day-Ahead				Balancing				
	DEC	INC	Up to Congestion	Virtual Total	DEC	INC	Up to Congestion	Virtual Total	Virtual Grand Total
Jan	$0.3	$1.2	$3.7	$5.1	($0.6)	($1.1)	($6.8)	($8.5)	($3.3)
Feb	$0.1	$0.8	$1.9	$2.8	($0.0)	($0.8)	($4.3)	($5.2)	($2.4)
Mar	($0.0)	$1.1	$1.3	$2.4	($0.1)	($1.0)	($3.4)	($4.5)	($2.0)
Apr	($0.1)	$1.0	$3.9	$4.8	($0.1)	($0.8)	($6.3)	($7.3)	($2.5)
May	($0.3)	$0.7	$2.1	$2.4	$0.0	($0.5)	($4.7)	($5.2)	($2.8)
Jun	($0.7)	$1.0	$4.8	$5.1	$0.7	($1.0)	($7.6)	($7.9)	($2.8)
Jul	($1.0)	$1.4	$5.8	$6.2	$0.7	($1.2)	($8.5)	($9.0)	($2.7)
Aug	($0.5)	$1.0	$7.7	$8.2	$0.4	($1.3)	($11.6)	($12.5)	($4.3)
Sep	($0.7)	$0.8	$5.0	$5.1	$0.5	($1.1)	($7.0)	($7.6)	($2.5)
Oct	($0.8)	$0.9	$4.6	$4.7	$0.5	($0.7)	($6.3)	($6.5)	($1.8)
Nov	($0.3)	$0.8	$4.6	$5.1	($0.3)	($0.7)	($6.9)	($7.9)	($2.8)
Dec	($1.1)	$1.1	$6.3	$6.3	$0.5	($0.9)	($11.3)	($11.7)	($5.3)
Total	($5.2)	$11.9	$51.6	$58.3	$2.2	($11.1)	($84.8)	($93.7)	($35.4)

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 the PJM market participants according to the ratio of their real-time load plus their real-time exports to total PJM real-time load plus real-time exports as marginal loss credits. The net residual market adjustment is calculated as known day-ahead error value minus day-ahead loss MW congestion value and minus balancing loss MW congestion value.

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 January 1 through March 31, 2009 through 2017. The total marginal loss surplus decreased $6.3 million in the first three months of 2017 from the first three months of 2016.

Table 11-42 Marginal loss credits (Dollars (Millions)): January 1 through March 31, 2009 through 2017[32]

	Loss Credit Accounting (Millions)					
			Net Residual Market Adjustment			
(Jan - Mar)	Total Energy Charges	Total Marginal Loss Charges	Known Day-ahead Error	Day-ahead Loss MW Congestion	Balancing Loss MW Congestion	Total Loss Surplus
2009	($218.3)	$454.0	$0.0	($0.9)	($0.0)	$236.6
2010	($207.6)	$416.6	$0.0	$0.0	($0.0)	$208.9
2011	($209.9)	$409.6	($0.0)	($0.5)	$0.0	$200.1
2012	($136.4)	$234.3	$0.1	$0.3	$0.0	$97.7
2013	($177.9)	$277.6	$0.1	$0.3	($0.0)	$99.4
2014	($515.3)	$775.9	$0.0	$3.1	$0.2	$257.2
2015	($271.7)	$425.1	($0.5)	$2.9	($0.0)	$150.0
2016	($113.6)	$170.1	$0.0	$0.8	($0.0)	$55.7
2017	($121.9)	$171.5	$0.0	$0.2	($0.0)	$49.4

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 the first three months of 2017 was -$121.9 million, which was comprised of load energy payments of $8,789.4 million, generation energy credits of $8,910.0 million, explicit energy costs of $0.0 million and inadvertent energy charges of -$1.3 million. The monthly energy costs for the first three months of 2017 ranged from -$48.2 million in January to -$31.8 million in February.

Table 11-43 shows total energy component costs and total PJM billing, for January 1 through March 31, 2009 through 2017. The total energy component costs are net energy costs.

Table 11-43 Total PJM costs by energy component (Dollars (Millions)): January 1 through March 31, 2009 through 2017[33]

(Jan - Mar)	Energy Costs	Percent Change	Total PJM Billing	Percent of PJM Billing
2009	($218)	NA	$7,515	(2.9%)
2010	($208)	(4.9%)	$8,415	(2.5%)
2011	($210)	1.1%	$9,584	(2.2%)
2012	($136)	(35.0%)	$6,938	(2.0%)
2013	($178)	30.4%	$7,762	(2.3%)
2014	($515)	189.7%	$21,070	(2.4%)
2015	($272)	(47.3%)	$14,040	(1.9%)
2016	($114)	(58.2%)	$9,500	(1.2%)
2017	($122)	7.3%	$9,710	(1.3%)

Energy costs for January 1 through March 31, 2009 through 2017 are shown in Table 11-44 and Table 11-45. Table 11-44 shows PJM energy costs by accounting category for January 1 through March 31, 2009 through 2017 and Table 11-45 shows PJM energy costs by market category for January 1 through March 31, 2009 through 2017.

Table 11-44 Total PJM energy costs by accounting category (Dollars (Millions)): January 1 through March 31, 2009 through 2017

	Energy Costs (Millions)				
(Jan - Mar)	Load Payments	Generation Credits	Explicit Costs	Inadvertent Charges	Total
2009	$14,058.4	$14,277.4	$0.0	$0.7	($218.3)
2010	$13,424.4	$13,629.0	$0.0	($3.0)	($207.6)
2011	$11,943.9	$12,160.7	$0.0	$6.9	($209.9)
2012	$8,485.4	$8,628.7	$0.0	$6.8	($136.4)
2013	$10,357.2	$10,535.1	$0.0	($0.0)	($177.9)
2014	$28,506.2	$29,014.7	$0.0	($6.9)	($515.3)
2015	$15,702.1	$15,976.4	$0.0	$2.6	($271.7)
2016	$7,764.7	$7,879.3	$0.0	$1.0	($113.6)
2017	$8,789.4	$8,910.0	$0.0	($1.3)	($121.9)

33 The energy costs include net inadvertent charges.

Table 11-45 Total PJM energy costs by market category (Dollars (Millions)): January 1 through March 31, 2009 through 2017

Energy Costs (Millions)											
	Day-Ahead				Balancing						
(Jan - Mar)	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
2009	$14,129.6	$14,375.6	$0.0	($246.0)	($71.2)	($98.2)	$0.0	$27.0	$0.7	($218.3)
2010	$13,408.9	$13,619.2	$0.0	($210.2)	$15.5	$9.8	$0.0	$5.6	($3.0)	($207.6)
2011	$12,055.5	$12,259.3	$0.0	($203.9)	($111.6)	($98.6)	$0.0	($12.9)	$6.9	($209.9)
2012	$8,534.4	$8,649.0	$0.0	($114.6)	($49.0)	($20.4)	$0.0	($28.6)	$6.8	($136.4)
2013	$10,387.2	$10,580.9	$0.0	($193.7)	($29.9)	($45.8)	$0.0	$15.9	($0.0)	($177.9)
2014	$28,412.1	$29,082.9	$0.0	($670.9)	$94.2	($68.3)	$0.0	$162.4	($6.9)	($515.3)
2015	$15,764.8	$16,077.5	$0.0	($312.6)	($62.7)	($101.1)	$0.0	$38.4	$2.6	($271.7)
2016	$7,847.5	$7,997.9	$0.0	($150.4)	($82.8)	($118.6)	$0.0	$35.8	$1.0	($113.6)
2017	$8,927.5	$9,111.3	$0.0	($183.8)	($138.1)	($201.3)	$0.0	$63.2	($1.3)	($121.9)

Table 11-46 and Table 11-47 show the total energy costs for each transaction type in the first three months of 2017 and 2016. In the first three months of 2017, generation was paid $5,982.8 million and demand paid $5,766.1 million in net energy payment. In the first three months of 2016, generation was paid $5,383.3 million and demand paid $5,441.3 million in net energy payment.

Table 11-46 Total PJM energy costs by transaction type by market (Dollars (Millions)): January 1 through March 31, 2017

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	$322.0	$0.0	$0.0	$322.0	($320.7)	$0.0	$0.0	($320.7)	$1.2
Demand	$5,782.3	$0.0	$0.0	$5,782.3	($16.1)	$0.0	$0.0	($16.1)	$5,766.1
Demand Response	($0.1)	$0.0	$0.0	($0.1)	$0.1	$0.0	$0.0	$0.1	($0.0)
Export	$189.8	$0.0	$0.0	$189.8	$79.8	$0.0	$0.0	$79.8	$269.6
Generation	$0.0	$6,052.3	$0.0	($6,052.3)	$0.0	($69.5)	$0.0	$69.5	($5,982.8)
Import	$0.0	$33.8	$0.0	($33.8)	$0.0	$137.3	$0.0	($137.3)	($171.1)
INC	$0.0	$391.8	$0.0	($391.8)	$0.0	($388.1)	$0.0	$388.1	($3.7)
Internal Bilateral	$2,633.5	$2,633.5	$0.0	$0.0	$118.9	$118.9	$0.0	$0.0	$0.0
Total	$8,927.5	$9,111.4	$0.0	($184.0)	($138.1)	($201.5)	$0.0	$63.3	($120.6)

Table 11-47 Total PJM energy costs by transaction type by market (Dollars (Millions)): January 1 through March 31, 2016

	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	$256.1	$0.0	$0.0	$256.1	($246.1)	$0.0	$0.0	($246.1)	$10.0
Demand	$5,436.9	$0.0	$0.0	$5,436.9	$4.4	$0.0	$0.0	$4.4	$5,441.3
Demand Response	($0.2)	$0.0	$0.0	($0.2)	$0.2	$0.0	$0.0	$0.2	($0.0)
Export	$114.9	$0.0	$0.0	$114.9	$31.6	$0.0	$0.0	$31.6	$146.4
Generation	$0.0	$5,559.1	$0.0	($5,559.1)	$0.0	($175.8)	$0.0	$175.8	($5,383.3)
Import	$0.0	$102.0	$0.0	($102.0)	$0.0	$213.5	$0.0	($213.5)	($315.5)
INC	$0.0	$296.9	$0.0	($296.9)	$0.0	($283.4)	$0.0	$283.4	($13.5)
Internal Bilateral	$2,039.9	$2,039.9	$0.0	($0.0)	$127.1	$127.1	$0.0	($0.0)	($0.0)
Total	$7,847.5	$7,997.9	$0.0	($150.4)	($82.8)	($118.6)	$0.0	$35.8	($114.6)

Monthly Energy Costs

Table 11-48 shows a monthly summary of energy costs by market type for January 1, 2016 through March 31, 2017. Marginal total energy costs in the first three months of 2017 decreased from the first three months of 2016. Monthly total energy costs in the first three months of 2017 ranged from -$48.2 million in January to -$31.8 million in February.

Table 11-48 Monthly energy costs by market type (Dollars (Millions)): January 1, 2016 through March 31, 2017

	Energy Costs (Millions)							
	2016				2017			
	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total
Jan	($63.8)	$15.4	$0.6	($47.7)	($75.6)	$28.9	($1.5)	($48.2)
Feb	($50.0)	$11.1	$0.4	($38.5)	($48.3)	$16.5	$0.0	($31.8)
Mar	($36.6)	$9.3	($0.1)	($27.4)	($59.9)	$17.7	$0.2	($42.0)
Apr	($43.6)	$12.7	$0.3	($30.6)				
May	($37.4)	$11.5	($0.3)	($26.1)				
Jun	($50.9)	$17.6	($0.6)	($33.8)				
Jul	($74.3)	$17.5	($0.9)	($57.8)				
Aug	($72.9)	$18.2	($1.2)	($55.9)				
Sep	($54.0)	$14.8	($1.2)	($40.5)				
Oct	($42.7)	$16.4	($3.5)	($29.9)				
Nov	($43.9)	$16.7	($1.5)	($28.8)				
Dec	($70.4)	$22.9	($1.8)	($49.4)				
Total	($640.6)	$184.0	($9.8)	($466.3)	($183.8)	$63.2	($1.3)	($121.9)

Figure 11-8 shows PJM monthly energy costs for January 1, 2009 through March 31, 2017.

Figure 11-8 PJM monthly energy costs (Millions): January 1, 2009 through March 31, 2017

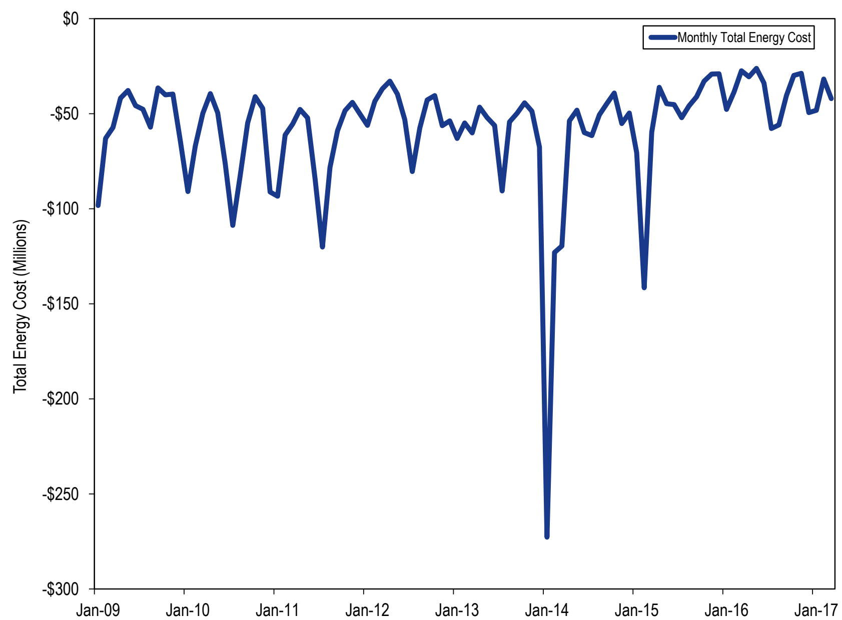


Table 11-49 and Table 11-50 show the monthly total energy costs for each virtual transaction type in the first three months of 2017 and the first three months of 2016. In the first three months of 2017, DECs paid $322.0 million in energy costs in the day-ahead market, were paid $320.7 million in energy credits in the balancing energy market and paid $1.2 million in net payment for energy. In the first three months of 2017, INCs were paid $391.8 million in energy credits in the day-ahead market, paid $388.1 million in energy cost in the balancing market and received $3.7 million in net payment for energy. In the first three months of 2016, DECs paid $256.1 million in energy costs in the day-ahead market, were paid $246.1 million in energy credits in the balancing energy market and paid $10.0 million in net payment for energy. In the first three months of 2016, INCs were paid $296.9 million in energy credits in the day-ahead market, paid $283.4 million in energy cost in the balancing energy market and received $13.5 million in net payment for energy.

Table 11-49 Monthly PJM energy costs by virtual transaction type and by market (Dollars (Millions)): January 1 through March 31, 2017

	Energy Costs (Millions)						
	Day-Ahead			Balancing			
	DEC	INC	Virtual Total	DEC	INC	Virtual Total	Virtual Grand Total
Jan	$115.3	($134.8)	($19.5)	($116.4)	$135.6	$19.2	($0.3)
Feb	$82.8	($107.0)	($24.2)	($79.8)	$103.3	$23.5	($0.7)
Mar	$123.9	($150.0)	($26.1)	($124.5)	$149.2	$24.7	($1.4)
Total	$322.0	($391.8)	($69.8)	($320.7)	$388.1	$67.4	($2.4)

Table 11-50 Monthly PJM energy costs by virtual transaction type and by market (Dollars (Millions)): 2016

	Energy Costs (Millions)						
	Day-Ahead			Balancing			
	DEC	INC	Virtual Total	DEC	INC	Virtual Total	Virtual Grand Total
Jan	$102.0	($109.3)	($7.2)	($101.0)	$106.1	$5.1	($2.1)
Feb	$85.5	($87.5)	($2.1)	($81.3)	$84.3	$3.0	$1.0
Mar	$68.6	($100.2)	($31.6)	($63.8)	$93.0	$29.2	($2.4)
Apr	$84.9	($109.3)	($24.3)	($86.5)	$112.0	$25.6	$1.2
May	$78.3	($87.2)	($8.9)	($79.4)	$86.1	$6.8	($2.1)
Jun	$105.0	($91.0)	$14.0	($110.0)	$94.5	($15.5)	($1.5)
Jul	$139.7	($130.5)	$9.2	($128.9)	$119.4	($9.6)	($0.3)
Aug	$138.1	($119.8)	$18.3	($145.6)	$123.4	($22.2)	($3.8)
Sep	$124.7	($104.7)	$20.0	($124.3)	$104.0	($20.4)	($0.3)
Oct	$111.4	($110.5)	$1.0	($107.4)	$106.9	($0.5)	$0.5
Nov	$84.6	($100.7)	($16.1)	($82.9)	$98.5	$15.6	($0.6)
Dec	$131.2	($124.7)	$6.5	($128.2)	$122.2	($6.1)	$0.4
Total	$1,254.0	($1,275.2)	($21.2)	($1,239.3)	$1,250.4	$11.1	($10.2)

Generation and Transmission Planning

Overview

Planned Generation and Retirements

- **Planned Generation.** As of March 31, 2017, 99,325.3 MW of capacity were in generation request queues for construction through 2024, compared to an average installed capacity of 195,870.3 MW as of March 31, 2017. Of the capacity in queues, 9,586.4 MW, or 9.7 percent, are uprates and the rest are new generation. Wind projects account for 15,494.6 MW of nameplate capacity or 15.6 percent of the capacity in the queues. Natural gas fired projects account for 64,672.3 MW of capacity or 65.1 percent of the capacity in the queues.
- **Generation Retirements.** As shown in Table 12-5, 32,314.5 MW have been, or are planned to be, retired between 2011 and 2020. Of that, 8,007.3 MW are planned to retire after the first three months of 2017. In the first three months of 2017, 209.0 MW were retired. Of the 8,007.3 MW pending retirement, 6,516.0MW are coal units. The coal unit retirements were a result of low gas prices, low capacity prices and the investments required for compliance with 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. There are 291.0 MW of coal fired steam capacity and 64,672.3 MW of gas fired capacity in the queue. The replacement of coal steam units by units burning natural gas will 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, 3,441 projects, representing 455,032.7 MW, have entered the queue process since its inception. Of those, 700 projects, 47,521.8 MW, went into service. Of the projects that entered the queue process, 67.4 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, which resulted in revisions to the PJM Open Access Transmission Tariff, effective October 31, 2016.[2] [3] On December 15, 2016, the Commission issued a notice of proposed rulemaking proposing additional queue reforms intended to improve certainty, promote more informed interconnection, and enhance interconnection processes.[4]
- 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."[5] 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

1 See 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 Letter Order, ER16-2518-000 (Oct. 7, 2016).
4 157 FERC ¶ 61,212 (2016).
5 See OATT § 1 (Transmission Owner).

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.[6] [7] On August 5, 2016, PJM announced that the Artificial Island project was to be suspended immediately due to unanticipated project complexities and significant cost overruns. On March 3, 2017, PJM held a special Transmission Expansion Advisory Committee (TEAC) meeting to discuss their updated analysis of the Artificial Island project. PJM staff presented updated assumptions that went into the new project analysis. In consultation with project developers and stakeholders, PJM made several major revisions to the project. These included switching the interconnection point from the Salem Substation to the Hope Creek Substation, removal of the New Freedom switched vertical circuit (SVC) from the project scope, and removal of the optical ground wire (OPGW) from the project scope. These revisions led to a revised total project cost estimate of $280 million, $240 million less than the previous $420 million project cost estimate released in February 2016. On April 6, 2017, the PJM Board lifted a suspension of the project. It is expected to be in service by June 2020.
- 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. The allocation process has been upheld by the FERC despite repeated challenges.[8]

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 are currently three backbone projects under development, Surry Skiffes Creek 500kV, the Northern New Jersey 345 kV Upgrades, and Byron Wayne 345 kV.[9]

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 or late and whether or not they will allow the outage.[10]
- There were 4,516 transmission outage requests submitted in the first three months of 2017. Of the requested outages, 73.9 percent were planned for five days or shorter and 11.4 percent were planned for longer than 30 days. Of the requested outages, 54.2 percent were late according to the rules in PJM's Manual 3.

6 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>.

7 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>.

8 See 155 FERC ¶ 61,090 (2016); 155 FERC ¶ 61,089 (2016); 155 FERC ¶ 61,088 (2016); see also Order No. 1000, FERC Stats. & Regs. ¶ 31,323 (2011), *order on reh'g*, Order No. 1000-A, 139 FERC ¶ 61,132, *order on reh'g and clarification*, Order No. 1000-B, 141 FERC ¶ 61,044 (2012), *aff'd sub nom.* 762 F.3d 41, 412 (D.C. Cir. 2014); 142 FERC ¶ 61,074 (2013) (accepting the proposed PJM cost allocation method, effective February 1, 2013, subject to the outcome of PJM's Order No. 1000 regional compliance filing proceeding); 142 FERC ¶ 61,214 (2013), *order on reh'g and compliance*, 147 FERC ¶ 61,128 (2014), *order on reh'g and compliance*, 150 FERC ¶ 61,038 (2015), *order on reh'g and compliance*, 151 FERC ¶ 61,250 (2015).

9 See "2016 RTEP Process Scope and Input Assumptions White Paper," P 23. <http://www.pjm.com/~/media/documents/reports/2016-rtep-process-scope-and-input-assumptions.ashx> Accessed November 7, 2016.

10 PJM. "Manual 03: Transmission Operations," Revision 50 (Dec. 1, 2016), Section 4.

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. First reported 2015. 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.[11] (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 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 2015. Status: Not adopted.)
- The MMU recommends consideration of changing the minimum distribution factor in the allocation from 0.01 to 0.00 and adding a threshold minimum usage impact on the line. (Priority: Medium. First reported 2015. 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

11 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>.

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. First reported 2015. 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 2014. Status: Partially adopted.)

Conclusion

The goal of PJM market design should be to enhance competition and to ensure that competition is the driver for all the key elements of PJM markets. But transmission investments have not been fully incorporated into competitive markets. The construction of new transmission facilities has significant impacts on the energy and capacity markets. But when generating units retire or load increases, there is no market mechanism in place that would require direct competition between transmission and generation to meet loads in the affected area. In addition, despite 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 March 31, 2017, 99,325.3 MW of capacity were in generation request queues for construction through 2024, compared to an average installed capacity of 195,870.3 MW as of March 31, 2017. Although it is clear that not all generation in the queues will be built, PJM has added capacity.[12] In the first three months of 2017, 2,462.4 MW of nameplate capacity went into service in PJM.

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 AC2 closed on March 31, 2017. Queue AD1 began on April 1, 2017.

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.[13] 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.[14]

Table 12-1 shows MW in queues by expected completion date and MW changes in the queues between December 31, 2016, and March 31 2017, for ongoing projects, i.e. projects with the status active, under construction or suspended.[15] Projects that are already in service are not included here. The total MW in queues increased by 17,386.0 MW, or 21.2 percent, from 81,936.3 MW at the end of 2015.

Table 12-1 Queue comparison by expected completion year (MW): March 31, 2016 to March 31, 2017[16]

			Three Month Change	
Year	As of 12/31/2016	As of 3/31/2017	MW	Percent
2016	21,064.0	0.0	(21,064.0)	0.0%
2017	12,957.0	18,388.4	5,431.4	29.5%
2018	14,859.6	25,891.8	11,032.2	42.6%
2019	18,416.5	25,435.8	7,019.3	27.6%
2020	10,869.3	17,001.1	6,131.8	36.1%
2021	1,925.9	10,761.3	8,835.4	82.1%
2022	250.0	1,230.0	980.0	79.7%
2023	0.0	614.0	614.0	100.0%
2024	1,594.0	0.0	(1,594.0)	0.0%
Total	81,936.3	99,322.3	17,386.0	21.2%

12 See Monitoring Analytics, "New Generation in the PJM Capacity Market: MW and Funding Sources for Delivery Years 2007/2008 through 2018/2019," <http://www.monitoringanalytics.com/reports/Reports/2016/New_Generation_in_the_PJM_Capacity_Market_20160504.pdf>.

13 See PJM. Manual 14C "Generation and Transmission Interconnection Process," Revision 10 (October 1, 2016) Section 3.7 <http://www.pjm.com/~/media/documents/manuals/m14c.ashx>.

14 PJM does not track the duration of suspensions or PJM termination of projects.

15 Expected completion dates are entered when the project enters the queue. Actual completion dates are generally different than expected completion dates.

16 Wind and solar capacity in Table 12-2 through Table 12-5 have not been adjusted to reflect derating.

Table 12-2 shows the yearly project status changes in more detail and how scheduled queue capacity has changed between December 31, 2016, and March 31, 2017. For example, 8,668.4 MW entered the queue in the first three months of 2017 and 21.1 of these MW have been withdrawn in the first three months of 2017. Of the total 71,567.0 MW marked as active at the beginning of 2017, 749.6 MW were withdrawn, 85.0 MW were suspended, 661.3 MW started construction, and 28.0 MW went into service by the end of the quarter. The Under Construction column shows that 776.4 MW came out of suspension and 661.3 MW began construction in the first three months of 2017, in addition to the 20,406.5 MW of capacity that maintained the status under construction from the previous year.

Table 12-2 Change in project status (MW): December 31, 2016 to March 31, 2017

		Status at 3/31/2017				
Status at 12/31/2016	Total at 12/31/2016	Active	Suspended	Under Construction	In Service	Withdrawn
(Entered in 2017)		8,668.4	0.0	0.0	0.0	21.1
Active	71,567.0	61,392.2	85.0	661.3	28.0	749.6
Suspended	5,790.0	0.0	4,925.7	776.4	0.0	87.9
Under Construction	24,045.3	0.0	2,409.8	20,406.5	1,089.8	130.3
In Service	46,436.0	0.0	0.0	0.0	46,404.0	0.0
Withdrawn	305,900.6	0.0	0.0	0.0	0.0	305,900.6
Total at 12/31/2016		70,060.6	7,420.5	21,844.2	47,521.8	306,889.5

Table 12-3 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-M are either in service or have been withdrawn. As of March 17, 2017, there are 99,325.3 MW of capacity in queues that are not yet in service, of which 7.5 percent are suspended, 22.0 percent are under construction and 69.5 percent have not begun construction.

Table 12-3 Capacity in PJM queues (MW): At March 31, 2017[17]

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	15,656.7	20,302.2
C Expired 31-Jul-99	0.0	531.0	0.0	0.0	3,474.8	4,005.8
D Expired 31-Jan-00	0.0	850.6	0.0	0.0	7,369.0	8,219.6
E Expired 31-Jul-00	0.0	795.2	0.0	0.0	8,033.8	8,829.0
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	17,980.8	19,170.4
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	3,738.3	3,841.3
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	485.3	584.2
L Expired 31-Jan-04	0.0	256.5	0.0	0.0	4,033.7	4,290.2
M Expired 31-Jul-04	0.0	504.8	0.0	0.0	3,705.6	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	0.0	3,037.3	253.0	0.0	5,320.5	8,610.8
Q Expired 31-Jul-06	0.0	3,147.9	0.0	0.0	11,385.7	14,533.6
R Expired 31-Jan-07	0.0	1,986.4	60.0	1,288.3	19,420.6	22,755.3
S Expired 31-Jul-07	0.0	3,549.5	120.0	70.0	12,396.5	16,136.0
T Expired 31-Jan-08	0.0	2,814.0	1,408.0	300.0	23,013.3	27,535.3
U Expired 31-Jan-09	200.0	837.3	949.9	520.0	30,829.6	33,336.8
V Expired 31-Jan-10	590.0	2,745.6	39.1	561.0	12,877.6	16,813.3
W Expired 31-Jan-11	944.0	2,118.9	1,071.9	824.8	19,107.2	24,066.7
X Expired 31-Jan-12	1,689.0	3,798.2	4,068.9	2,369.5	18,418.8	30,344.5
Y Expired 30-Apr-13	833.5	719.1	4,737.6	794.2	18,655.2	25,739.5
Z Expired 30-Apr-14	1,044.0	588.1	5,676.6	135.2	6,866.8	14,310.7
AA1 Expired 31-Oct-14	4,588.1	141.7	1,677.7	244.8	5,349.6	12,001.9
AA2 Expired 30-Apr-15	8,016.4	36.1	341.3	221.1	7,451.4	16,066.3
AB1 Expired 31-Oct-15	12,646.0	52.2	807.5	71.9	6,720.9	20,298.5
AB2 Expired 31-Mar-16	12,283.9	10.0	157.7	19.8	625.6	13,097.0
AC1 Through 30-Sep-16	18,203.7	0.0	0.0	0.0	211.1	18,414.7
AC2 Through 30-Apr-17	9,022.0	0.0	0.0	0.0	591.7	9,613.7
Total	70,060.6	47,521.8	21,844.2	7,420.5	306,889.5	453,736.6

17 Projects listed as partially in service are counted as in service for the purposes of this analysis.

Distribution of Units in the Queues

Table 12-4 shows the projects under construction, suspended, or active, by unit type, and control zone.[18] As of March 31, 2017, 99,325.3 MW of capacity were in generation request queues for construction through 2024, compared to 81,963.3 MW at December 31, 2016.[19] Table 12-4 also shows the planned retirements for each zone.

Table 12-4 Queue capacity by LDA, control zone and fuel (MW): At March 31, 2017[20]

LDA	Zone	BioMass	CC	CT	Diesel	Fuel Cell	Hydro	Nuclear	Solar	Steam	Storage	Wind	Total Queue Capacity	Planned Retirements
EMAAC	AECO	0.0	1,667.0	469.0	0.0	1.9	0.0	0.0	99.1	0.0	20.0	175.0	2,432.1	303.0
	DPL	16.0	742.0	57.0	32.8	0.0	0.0	0.0	1,547.7	0.0	26.0	499.6	2,921.1	34.0
	JCPL	0.0	2,047.2	0.0	0.0	0.4	0.0	0.0	255.2	0.0	95.0	0.0	2,397.9	614.5
	PECO	0.0	1,256.0	0.0	6.6	0.0	0.0	94.0	20.0	0.0	0.0	0.0	1,376.6	50.8
	PSEG	0.0	2,659.5	788.0	10.6	1.3	0.0	0.0	88.7	24.0	2.5	0.0	3,574.6	1,863.0
	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	16.0	8,371.7	1,314.0	50.0	3.6	0.0	94.0	2,010.8	24.0	143.5	674.6	12,702.2	2,865.3
SWMAAC	BGE	0.0	0.0	0.0	1.3	0.0	0.4	30.3	104.1	0.0	0.1	0.0	136.2	135.0
	Pepco	0.0	1,713.5	0.0	0.0	0.0	0.0	0.0	2.5	0.0	0.0	0.0	1,716.0	0.0
	SWMAAC Total	0.0	1,713.5	0.0	1.3	0.0	0.4	30.3	106.6	0.0	0.1	0.0	1,852.2	135.0
WMAAC	Met-Ed	0.0	497.0	34.1	0.0	0.0	0.0	0.0	158.0	30.0	0.0	0.0	719.1	6.0
	PENELEC	0.0	1,333.0	521.1	141.0	0.0	17.0	0.0	63.5	590.0	0.0	458.8	3,124.4	0.0
	PPL	16.0	5,800.0	19.9	0.0	0.0	0.0	0.0	30.0	0.0	30.0	266.2	6,162.1	0.0
	WMAAC Total	16.0	7,630.0	575.1	141.0	0.0	17.0	0.0	251.5	620.0	30.0	725.0	10,005.6	6.0
Non-MAAC	AEP	0.0	11,006.0	394.0	21.4	0.0	46.5	28.0	4,280.5	241.0	120.0	7,457.1	23,594.4	0.0
	AP	0.0	7,050.1	30.0	100.7	0.0	15.0	0.0	662.9	10.0	58.5	1,158.7	9,085.8	0.0
	ATSI	0.0	5,153.0	0.0	0.9	0.0	0.0	0.0	385.0	0.0	0.0	815.7	6,354.5	776.0
	ComEd	0.0	8,733.3	1,207.0	32.1	0.0	22.7	0.0	227.0	64.0	87.1	3,446.5	13,819.7	510.0
	DAY	0.0	1,150.0	0.0	0.0	0.0	0.0	0.0	841.9	12.0	39.9	300.0	2,343.8	2,941.0
	DEOK	0.0	.	0.0	4.8	0.0	0.0	0.0	290.0	20.0	19.8	0.0	334.6	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	8,299.4	155.0	8.0	0.0	0.0	0.0	8,567.6	14.0	134.0	917.1	18,157.6	728.0
	EKPC	0.0	614.0	0.0	0.0	0.0	0.0	0.0	160.0	0.0	0.0	0.0	774.0	0.0
	Non-MAAC Total	62.5	42,210.8	1,786.0	167.8	0.0	84.2	28.0	15,414.8	361.0	479.3	14,095.0	74,689.4	4,955.0
Total in PJM		94.5	59,926.0	3,675.1	360.1	3.6	101.6	152.3	17,783.7	1,005.0	652.9	15,494.6	99,249.3	7,961.3

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. As of March 31, 2017, there were 16,207.9 MW of gas fired capacity under construction in PJM. As of March 31, 2017, there were only 120.0 MW of coal fired steam capacity under construction in PJM. With respect to retirements, 6,663.5 MW of coal fired steam capacity and 208.8 MW of natural gas capacity are

18 Unit types designated as reciprocating engines are classified as diesel.
19 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 namplate capacity until actual generation data are available. Beginning with Queue U, PJM derates wind resources to 13 percent of nameplate capacity until there is operational data to support a different conclusion. PJM derates solar resources to 38 percent of nameplate capacity. Based on the derating of 15,494.6 MW of wind resources and 17,783.7 MW of solar resources, the 99,325.3 MW currently active in the queue would be reduced to 74.819.2 MW.
20 This data includes only projects with a status of active, under-construction, or suspended.

slated for deactivation between now and 2020. The replacement of coal steam units by natural gas units could significantly affect future congestion, the role of firm and interruptible gas supply, and natural gas supply infrastructure.

Planned Retirements

As shown in Table 12-5, 32,314.5 MW have been, or are planned to be, retired between 2011 and 2020.[21] Of that, 8,007.3 MW are planned to retire after the first three months of 2017. In the first three months of 2017, 209.0 MW were retired. Of the 8,007.3 MW pending retirement, 6,516.0 MW are coal units. The coal unit retirements were a result of low gas prices, low capacity prices and the investments required for compliance with the EPA's Mercury and Air Toxics Standards (MATS) for some units.

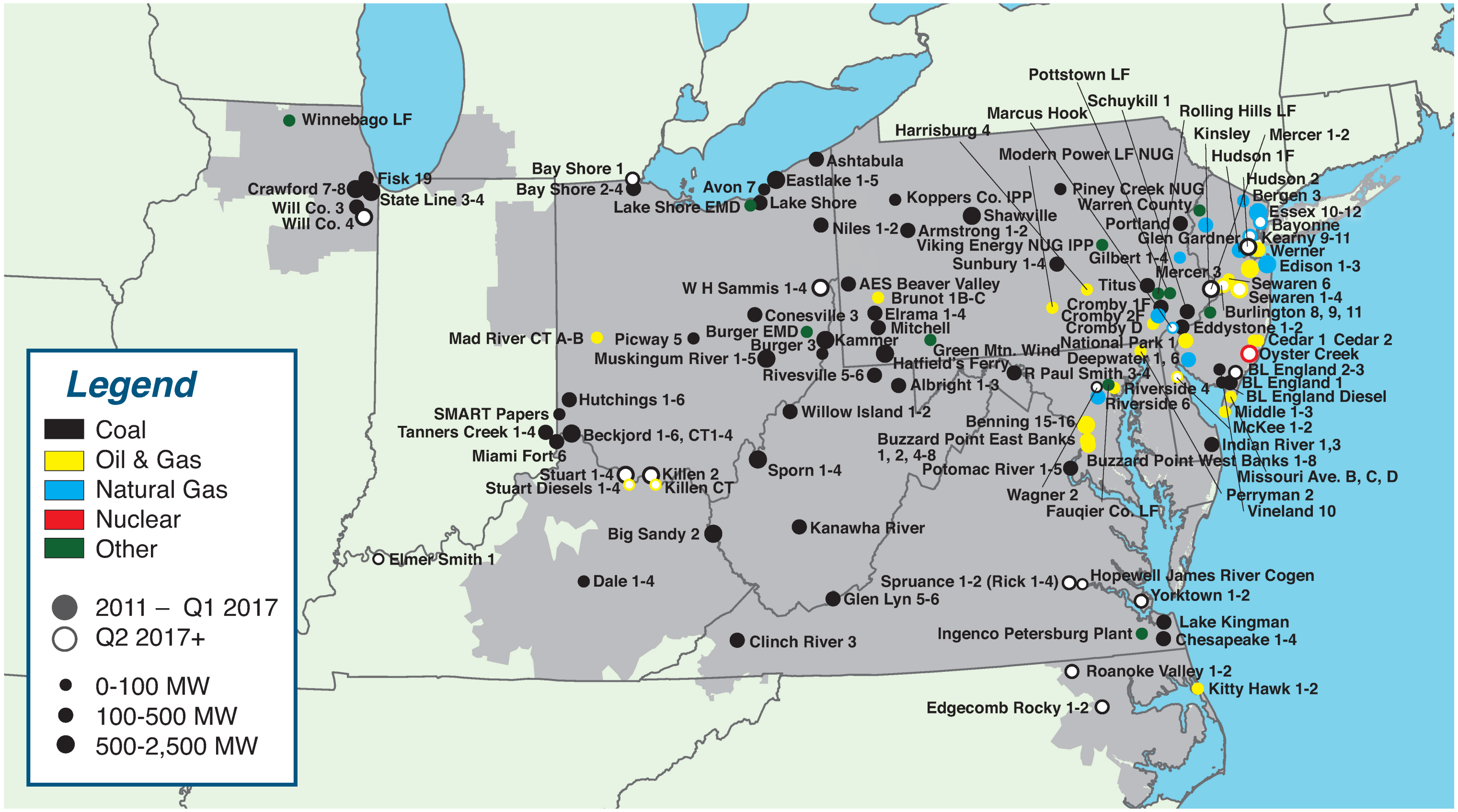
Table 12-5 Summary of PJM unit retirements by fuel (MW): 2011 through 2020

	Coal	Diesel	Heavy Oil	Hydro	Kerosene	Landfill Gas	Light Oil	Natural Gas	Nuclear	Wind	Wood Waste	Total
Retirements 2011	543.0	0.0	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	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	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	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	0.0	644.2	2.0	212.0	1,239.0	0.0	10.4	0.0	9,779.7
Retirements 2016	243.0	59.0	74.0	0.5	0.0	11.0	14.0	0.0	0.0	0.0	0.0	401.5
Retirements 2017 (Jan-Mar)	209.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	209.0
Planned Retirements for April 2017 and Later	6,516.0	2.4	182.0	0.0	0.0	0.0	30.6	661.8	614.5	0.0	0.0	8,007.3
Total	26,097.6	124.6	422.0	0.5	828.2	32.1	1,193.3	2,967.3	614.5	10.4	24.0	32,314.5

A map of the retirements between 2011 and 2020 is shown in Figure 12-1.

21 See PJM "Generator Deactivation Summary Sheets," at <http://www.pjm.com/planning/generation-deactivation/gd-summaries.aspx> (June 2, 2016).

Figure 12-1 Map of PJM unit retirements: 2011 through 2020



The list of pending retirements is shown in Table 12-6.

Table 12-6 Planned retirement of PJM units: as of March 31, 2017

Unit	Zone	ICAP (MW)	Fuel	Unit Type	Projected Deactivation Date
Yorktown 1-2	Dominion	323.0	Coal	Steam	15-Apr-17
McKee 1-2	DPL	34.0	Heavy Oil	Combustion Turbine	31-May-17
Hopewell James River Cogen	Dominion	89.0	Coal	Steam	31-May-17
Hudson 2	PSEG	620.0	Coal	Steam	01-Jun-17
Mercer 1-2	PSEG	632.0	Coal	Steam	01-Jun-17
Edgecomb Rocky 1-2	Dominion	115.5	Coal	Steam	01-Jun-17
Spruance 1-2 (Rich 1-4)	Dominion	200.0	Coal	Steam	01-Jun-17
Sewaren 1-4	PSEG	453.0	Kerosene	Combustion Turbine	01-Jun-18
Killen 2	DAY	600.0	Coal	Steam	01-Jun-18
Killen CT	DAY	24.0	Heavy Oil	Combustion Turbine	01-Jun-18
Stuart 1-4	DAY	2,308.0	Coal	Steam	01-Jun-18
Stuart Diesels 1-4	DAY	9.0	Light Oil	Diesel	01-Jun-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
BL England 2-3	AECO	303.0	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
Will County 4	ComEd	510.0	Coal	Steam	31-May-20
W H Sammis 1-4	ATSI	640.0	Coal	Steam	31-May-20
Wagner 2	BGE	135.0	Coal	Steam	01-Jun-20
Bay Shore 1	ATSI	136.0	Coal	Steam	01-Oct-20
Total		8,006.8			

Table 12-7 shows the capacity, average size, and average age of units retiring in PJM, from 2011 through 2020, while Table 12-8 shows these retirements by state. The majority, 80.8 percent, of all MW retiring during this period are coal steam units. These units have an average age of 53.9 years and an average size of 169.5 MW. Over half of them, 55.9 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 2016.

Table 12-7 Retirements by fuel type: 2011 through 2020

	Number of Units	Avg. Size (MW)	Avg. Age at Retirement (Years)	Total MW	Percent
Coal	154	169.5	53.9	26,097.6	80.8%
Diesel	8	15.6	43.5	124.6	0.4%
Heavy Oil	5	84.4	55.0	422.0	1.3%
Hydro	1	0.5	100.0	0.5	0.0%
Kerosene	20	41.4	45.5	828.2	2.6%
Landfill Gas	9	3.6	14.0	32.1	0.1%
Light Oil	20	59.7	43.7	1,193.3	3.7%
Natural Gas	47	63.1	46.6	2,967.3	9.2%
Nuclear	1	614.5	50.0	614.5	1.9%
Wind	1	10.4	15.0	10.4	0.0%
Wood Waste	2	12.0	23.5	24.0	0.1%
Total	268	120.6	49.4	32,314.5	100.0%

Table 12-8 Retirements (MW) by fuel type and state: 2011 through 2020

State	Coal	Diesel	Hydro	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	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	0.0	288.0
IL	2,134.0	0.0	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	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	0.0	1,047.0
MD	250.0	51.0	74.0	0.0	0.0	0.0	0.0	115.0	0.0	0.0	0.0	490.0
NC	324.5	0.0	0.0	0.0	0.0	0.0	31.0	0.0	0.0	0.0	0.0	355.5
NJ	1,543.0	8.0	148.0	0.5	828.2	7.7	212.0	2,600.5	614.5	0.0	0.0	5,962.4
OH	9,436.6	62.7	0.0	0.0	0.0	0.0	30.6	0.0	0.0	0.0	0.0	9,529.9
PA	5,145.0	0.0	166.0	0.0	0.0	16.0	131.7	251.8	0.0	10.4	24.0	5,744.9
VA	2,340.5	2.9	0.0	0.0	0.0	2.0	0.0	0.0	0.0	0.0	0.0	2,345.4
WV	2,641.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,641.0
Total	26,097.6	124.6	422.0	0.5	828.2	32.1	1,193.3	2,967.3	614.5	10.4	24.0	32,314.5

Generation Deactivations in 2017

Table 12-9 shows the units that were deactivated in the first three months of 2017.

Table 12-9 Unit deactivations in January through March, 2017

Company	Unit Name	ICAP (MW)	Primary Fuel	Zone Name	Average Age (Years)	Retirement Date
Exelon Corporation	Roanoke Valley 1	165.0	Coal	Dominion	22	01-Mar-17
Exelon Corporation	Roanoke Valley 2	44.0	Coal	Dominion	21	01-Mar-17
Total		209.0				

Generation Mix

As of March 31, 2017, PJM had an installed capacity of 195,870.3 MW (Table 12-10). 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 12-10 Existing PJM capacity: At March 31, 2017 (By zone and unit type (MW))[22]

Zone	CC	CT	Diesel	Fuel Cell	Hydroelectric	Nuclear	Solar	Steam	Storage	Wind	Total
AECO	901.9	570.7	14.6	0.0	0.0	0.0	41.7	815.9	0.0	7.5	2,352.3
AEP	6,100.0	3,682.2	80.3	0.0	1,071.9	3,211.0	10.1	18,897.8	6.0	2,204.0	35,263.3
APS	1,129.0	1,226.9	47.9	0.0	129.2	0.0	36.1	5,409.0	47.4	1,088.5	9,114.0
ATSI	1,570.5	1,618.3	67.7	0.0	0.0	2,134.0	0.0	5,719.0	0.0	0.0	11,109.5
BGE	0.0	789.0	18.4	0.0	0.0	1,716.0	0.0	2,921.5	0.0	0.0	5,444.9
ComEd	3,146.1	7,244.0	109.1	0.0	0.0	10,473.5	9.0	5,166.1	107.5	2,781.9	29,037.2
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	112.0	0.0	0.0	3,567.0	20.0	0.0	4,400.2
DLCO	244.0	15.0	0.0	0.0	6.3	1,777.0	0.0	660.0	0.0	0.0	2,702.3
Dominion	7,651.6	3,761.7	151.8	0.0	3,589.3	3,581.3	157.8	7,775.0	0.0	208.0	26,876.5
DPL	1,498.5	1,820.4	96.1	30.0	0.0	0.0	100.0	1,620.0	0.0	0.0	5,165.0
EKPC	0.0	774.0	0.0	0.0	70.0	0.0	0.0	1,687.0	0.0	0.0	2,531.0
JCPL	2,682.5	763.1	16.1	0.0	400.0	614.5	164.1	10.0	0.0	0.0	4,650.3
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	834.0	2.9	0.0	1,642.0	4,546.8	3.0	979.1	1.0	0.0	11,217.8
PENELEC	850.0	407.5	150.0	0.0	512.8	0.0	0.0	6,793.5	10.4	969.2	9,693.4
Pepco	955.0	1,091.7	9.9	0.0	0.0	0.0	0.0	3,649.1	0.0	0.0	5,705.7
PPL	2,657.9	602.2	55.5	0.0	706.6	2,520.0	15.0	5,169.9	20.0	219.7	11,966.8
PSEG	3,846.3	1,132.0	11.1	0.0	5.0	3,493.0	152.6	2,050.1	2.0	0.0	10,692.1
RECO	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	38,600.5	28,761.7	920.3	30.0	8,264.1	34,872.1	690.5	75,998.0	254.3	7,478.8	195,870.3

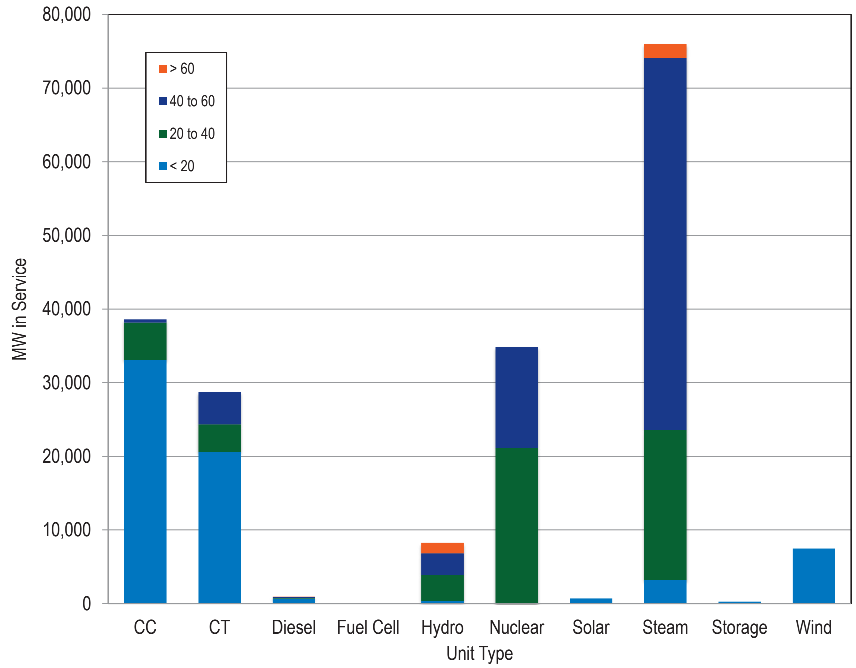
Figure 12-2 and Table 12-11 show the age of PJM generators by unit type. Units older than 40 years comprise 75,616.4 MW, or 38.6 percent, of the total capacity of 195,870.3 MW.

Table 12-11 PJM capacity (MW) by age (years): At March 31, 2017

Age (years)	CC	CT	Diesel	Fuel Cell	Hydroelectric	Nuclear	Solar	Steam	Storage	Wind	Total
Less than 20	33,074.0	20,563.3	663.9	30.0	338.8	0.0	690.5	3,225.4	254.3	7,478.8	66,319.0
20 to 40	5,084.5	3,768.4	98.8	0.0	3,563.2	21,117.9	0.0	20,302.1	0.0	0.0	53,934.9
40 to 60	442.0	4,430.0	155.6	0.0	2,915.0	13,754.2	0.0	50,558.5	0.0	0.0	72,255.3
More than 60	0.0	0.0	2.0	0.0	1,447.1	0.0	0.0	1,912.0	0.0	0.0	3,361.1
Total	38,600.5	28,761.7	920.3	30.0	8,264.1	34,872.1	690.5	75,998.0	254.3	7,478.8	195,870.3

22 The capacity described in this section refers to all capacity in PJM at nameplate ratings, regardless of whether the capacity entered the RPM auction. This table previously included external units.

Figure 12-2 PJM capacity (MW) by age (years): At March 31, 2017



Generation and Transmission Interconnection Planning Process

PJM made changes to the queue process in May 2012.[23] 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.[24] The Earlier Queue Submittal Task Force (EQSTF) was established in August 2015, to further address the issue.[25]

The Earlier Queue Submittal Task Force

In 2015 and 2016, participants of the Earlier Queue Submittal Task Force (EQSTF) drafted rule changes to the Interconnection Queue process meant to address high levels of deficient project applications being submitted to PJM for review.

To discourage incomplete interconnection project requests, the EQSTF proposed to only assign queue positions for project applications that had submitted all required project elements including site control. In addition, all project applications would be required to remedy any deficiencies by the end of the queue window in order to be considered in feasibility studies or be terminated and withdrawn. Queue positions had historically been assigned to project developers that paid the study deposit and submitted a project application by the appropriate submission deadline. Project applications with missing information were assigned queue numbers so long as these two criteria were met.

The EQSTF also proposed rule changes to interconnection study fee structures that would discourage the submission of speculative or incomplete queue projects. Under the old rules, deposits provided by developers for interconnection studies could not be charged until after a queue position was accepted. Under the new rules, these deposits would be available for charging before a queue position is assigned.

In addition, rather than socializing the study costs for deficient applications from project developers, the EQSTF proposed that these project costs be assigned directly to the developer that submitted the project. This would significantly increase the cost burden that developers would experience if a project is found to be deficient in the review process.

23 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>.

24 See presentation by Dave Egan to the PJM Planning Committee, at <http://www.pjm.com/~/media/committees-groups/committees/pc/20150611/20150611-item-09-queue-status-update.ashx>.

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

The EQSTF proposed to change the timing of queue windows and Feasibility Study dates to enable more generation projects to participate in the PJM Base Residual Auction. The EQSTF proposed shifting start dates for the queue windows back a month from May 1 to April 1 and Nov 1 to October 1. The EQSTF also proposed shifting feasibility study dates from Dec 1 to Nov 1 and June 1 to May 1.

Revisions to the OATT developed by the EQSTF were approved by the FERC effective October 31, 2016.[26]

On December 15, 2016, the Commission issued a notice of proposed rulemaking proposing additional queue reforms intended to improve certainty, promote more informed interconnection, and enhance interconnection processes.

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 12-12 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.[27] 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 12-13 and Table 12-14.

Table 12-13 shows the milestone status when projects were withdrawn, for all withdrawn projects. Of the projects withdrawn, 49.5 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.[28] [29] Withdrawing at or beyond this point is uncommon; only 245 projects, or 13.2 percent, of all projects withdrawn were withdrawn after reaching this milestone.

Table 12-12 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

26 See Letter Order, ER16-2518-000 (Oct. 7, 2016).

27 See PJM Manual 14B. "PJM Region Transmission Planning Process," Revision 33 (May 5, 2016), p.70.
28 "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 10 (October 1, 2016), p.8.
29 See PJM. "Manual 14C: Generation and Transmission Interconnection Facility Construction," Revision 10 (October 1, 2016), p.22.

Table 12-13 Last milestone at time of withdrawal: January 1, 1997 through March 31, 2017

Milestone Completed	Projects Withdrawn	Percent	Average Days	Maximum Days
Never Started	106	5.7%	163	1,235
Feasibility Study	814	43.8%	318	3,238
System Impact Study	442	23.8%	591	3,174
Facilities Study	253	13.6%	1,271	4,210
Construction Service Agreement (CSA) or beyond	245	13.2%	1,313	4,249
Total	1,860	100.0%		

Table 12-14 and Table 12-15 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 991 days, or 2.7 years, between entering a queue and going into service. For withdrawn projects, there is an average time of 635 days, or 1.7 years, between entering a queue and withdrawing.

Table 12-14 Average project queue times (days): At March 31, 2017

Status	Average (Days)	Standard Deviation	Minimum	Maximum
Active	886	538	2	3,745
In-Service	991	715	1	4,024
Suspended	2,095	1,176	610	5,108
Under Construction	1,684	985	427	4,652
Withdrawn	635	665	1	4,249

Table 12-15 presents information on the time in the stages of the queue for those projects not yet in service. Of the 858 projects in the queue as of March 31, 2017, 83 had a completed feasibility study and 166 were under construction.

Table 12-15 PJM generation planning summary: At March 31, 2017

Milestone Reached	Number of Projects	Percent of Total Projects	Average Days	Maximum Days
Under Review	418	48.7%	767	2,540
Feasibility Study	83	9.7%	976	1,943
System Impact Study	107	12.5%	985	3,651
Facilities Study	84	9.8%	1,925	4,260
Construction Service Agreement (CSA) or beyond	166	19.3%	2,078	5,108
Total	858	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 12-16 shows the number of projects that entered the queue by year. The number of queue entries has increased during the past three years, primarily by renewable projects (solar, hydro, storage, biomass, wind). Of the 844 projects entered in 2014, 2015, and 2016, 594, 70.3 percent, were renewable. Of the 163 projects entered 2016, 135, 82.8 percent, were renewable.

Table 12-16 Number of projects entered in the queue as of March 31, 2017

	Fuel Group			
Year Entered	Nuclear	Renewable	Traditional	Grand Total
1997	2	0	11	13
1998	0	0	18	18
1999	1	5	85	91
2000	2	3	79	84
2001	4	6	83	93
2002	3	14	33	50
2003	1	35	17	53
2004	4	17	32	53
2005	3	78	51	132
2006	9	78	70	157
2007	9	68	142	219
2008	3	114	99	216
2009	10	113	50	173
2010	5	381	55	441
2011	6	265	78	349
2012	2	73	80	155
2013	1	78	73	152
2014	0	122	68	190
2015	0	191	114	305
2016	2	265	67	334
2017	2	135	26	163
Total	69	2,041	1,331	3,441

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 35.2 percent of the nameplate MW currently active in the queue (Table 12-17).

Table 12-17 Queue details by fuel group: March 31, 2017

Fuel Group	Number of Projects	Percent of Projects	MW	Percent MW
Nuclear	8	0.9%	152.3	0.2%
Renewable	613	69.7%	35,423.3	35.2%
Traditional	258	29.4%	65,045.8	64.6%
Total	879	100.0%	100,621.4	100.0%

Table 12-18 shows the current status of all generation queue projects by fuel type and project classification from January 1, 1997, through March 31, 2017. For example, between January 1, 1997 and March 31, 2017, 140 nameplate capacity upgrades at natural gas fired facilities have completed the queue process and are in service.

Since 1997, there have been a total of 3,441 projects in PJM generation queues. A total of 2,810 projects have been classified as new generation and 631 projects have been classified as upgrades. Wind, solar and natural gas projects have accounted for 2,690 projects, or 78.2 percent, of all 3,441 generation queue projects. A total of 145 new projects from either project classification entered the generation queue in the first three months of 2017.

Table 12-18 Status of all generation queue projects: January 1, 1997 through March 31, 2017

		Number of Projects												
Project Status	Project Classification	Natural Gas	Wind	Coal	Solar	Nuclear	Hydro	Oil	Biomass	Storage	Other	LFG	Diesel	TOTAL
In Service	New Generation	91	61	9	104	1	10	4	7	16	3	71	6	383
	Upgrade	140	15	45	16	42	16	14	5	3	4	15	2	317
Under Construction	New Generation	31	26	-	62	-	4	-	-	28	-	6	-	157
	Upgrade	30	-	5	3	-	1	-	2	2	-	-	-	43
Suspended	New Generation	14	16	1	28	-	-	-	1	6	-	1	-	67
	Upgrade	5	3	-	-	-	-	-	-	3	-	-	-	11
Withdrawn	New Generation	406	372	54	633	9	40	9	32	65	10	76	12	1,718
	Upgrade	65	14	12	9	9	2	13	1	7	2	8	2	144
Active	New Generation	75	43	-	336	1	1	-	2	22	-	5	-	485
	Upgrade	74	7	5	11	7	1	-	1	4	3	-	3	116
Total Projects	New Generation	617	518	64	1,163	11	55	13	42	137	13	159	18	2,810
	Upgrade	314	39	67	39	58	20	27	9	19	9	23	7	631

Table 12-19 Status of all generation queue projects as percent of total projects by classification: January 1, 1997 through March 31, 2017

		Percent of Total Projects by Classification											
Project Status	Project Classification	Natural Gas	Wind	Coal	Solar	Nuclear	Hydro	Oil	Biomass	Storage	Other	LFG	Diesel
In Service	New Generation	14.7%	11.8%	14.1%	8.9%	9.1%	18.2%	30.8%	16.7%	11.7%	23.1%	44.7%	33.3%
	Upgrade	44.6%	38.5%	67.2%	41.0%	72.4%	80.0%	51.9%	55.6%	15.8%	44.4%	65.2%	28.6%
Under Construction	New Generation	5.0%	5.0%	0.0%	5.3%	0.0%	7.3%	0.0%	0.0%	20.4%	0.0%	3.8%	0.0%
	Upgrade	9.6%	0.0%	7.5%	7.7%	0.0%	5.0%	0.0%	22.2%	10.5%	0.0%	0.0%	0.0%
Suspended	New Generation	2.3%	3.1%	1.6%	2.4%	0.0%	0.0%	0.0%	2.4%	4.4%	0.0%	0.6%	0.0%
	Upgrade	1.6%	7.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	15.8%	0.0%	0.0%	0.0%
Withdrawn	New Generation	65.8%	71.8%	84.4%	54.4%	81.8%	72.7%	69.2%	76.2%	47.4%	76.9%	47.8%	66.7%
	Upgrade	20.7%	35.9%	17.9%	23.1%	15.5%	10.0%	48.1%	11.1%	36.8%	22.2%	34.8%	28.6%
Active	New Generation	12.2%	8.3%	0.0%	28.9%	9.1%	1.8%	0.0%	4.8%	16.1%	0.0%	3.1%	0.0%
	Upgrade	23.6%	17.9%	7.5%	28.2%	12.1%	5.0%	0.0%	11.1%	21.1%	33.3%	0.0%	42.9%

Table 12-19 shows the MW in Table 12-18 by share by classification as new generation or upgrade. Within a fuel type the shares of upgrades add to 100 percent and the shares of new generation add to 100 percent. For example, 80.0 percent of all hydro projects classified as upgrades are currently in service in PJM, 10.0 percent of hydro upgrades were withdrawn, 5.0 percent of hydro upgrades are under construction, and 5.0 percent of hydro upgrades are active in the queue. From January 1, 1997, through March 31, 2017, solar projects have had the lowest completion rate across all technology types for projects classified as new generation and storage projects have had the lowest completion rate across all technology types for projects classified as upgrades. Landfill gas projects have had the highest completion rate across all technology types for projects classified as new generation and hydro projects have had the highest completion rate across all technology types for projects classified as upgrades.

Table 12-20 shows the nameplate generating capacity of projects in the PJM generation queue by technology type and project classification. For example, the 372 new generation wind projects that have been withdrawn from the queue as of March 31, 2017 listed in Table 12-18 constitute 58,499.7 MW of nameplate capacity. The 472 new generation and upgrade natural gas projects that have been withdrawn in the same time period constitute 188,622.0 MW of nameplate capacity.

Table 12-20 Status of all generation capacity (MW) in the PJM generation queue: January 1, 1997 through March 31, 2017

		Project MW												
Project Status	Project Classification	Natural Gas	Wind	Coal	Solar	Nuclear	Hydro	Oil	Biomass	Storage	Other	LFG	Diesel	TOTAL
In Service	New Generation	24,046.1	6,671.2	1,378.0	824.2	9.0	565.6	607.0	225.7	155.4	50.0	382.6	69.5	34,984.2
	Upgrade	6,363.4	33.7	755.5	19.4	3,912.8	605.6	125.8	58.8	36.4	547.5	53.4	25.3	12,537.5
Under Construction	New Generation	14,553.8	3,989.9	0.0	1,188.2	0.0	35.6	0.0	0.0	71.1	0.0	35.5	0.0	19,874.1
	Upgrade	1,654.1	0.0	120.0	64.5	0.0	17.0	0.0	62.5	52.0	0.0	0.0	0.0	1,970.1
Suspended	New Generation	3,487.8	2,867.4	80.0	322.0	0.0	0.0	0.0	16.0	75.8	0.0	0.9	0.0	6,849.8
	Upgrade	365.7	175.0	0.0	0.0	0.0	0.0	0.0	0.0	30.0	0.0	0.0	0.0	570.7
Withdrawn	New Generation	180,030.6	58,499.7	33,431.6	8,391.8	8,161.0	1,988.0	1,721.0	1,027.7	720.1	843.8	426.5	63.9	295,305.6
	Upgrade	8,591.4	367.0	815.0	48.9	916.0	56.0	589.0	12.1	92.1	24.0	43.4	29.0	11,583.9
Active	New Generation	38,821.3	8,201.5	0.0	16,849.9	28.0	15.0	0.0	12.0	344.5	0.0	39.0	0.0	64,311.1
	Upgrade	5,789.6	260.8	91.0	655.2	124.3	34.0	0.0	4.0	79.5	1.1	0.0	6.1	7,045.6
Total Projects	New Generation	260,939.6	80,229.7	34,889.6	27,576.0	8,198.0	2,604.2	2,328.0	1,281.4	1,366.9	893.8	884.4	133.4	421,324.9
	Upgrade	**22,764.2**	**836.4**	**1,781.5**	**788.0**	**4,953.1**	**712.6**	**714.8**	**137.4**	**290.0**	**572.6**	**96.8**	**60.4**	**33,707.8**

Figure 12-3 shows the project MW that have entered the PJM generation queue by fuel type and year of entry. In 2015 and 2016, natural gas, wind, and solar projects accounted for the majority of all new projects entering the generation queue. The increase in solar projects entering the queue in 2016 from 2015 was primarily a result of new projects in Dominion. The increase in solar projects entering the queue in the first three months of 2017 was primarily a result of new projects in AEP.

Figure 12-3 Queue project MW by fuel type and queue entry year: January 1, 1997 through March 31, 2017

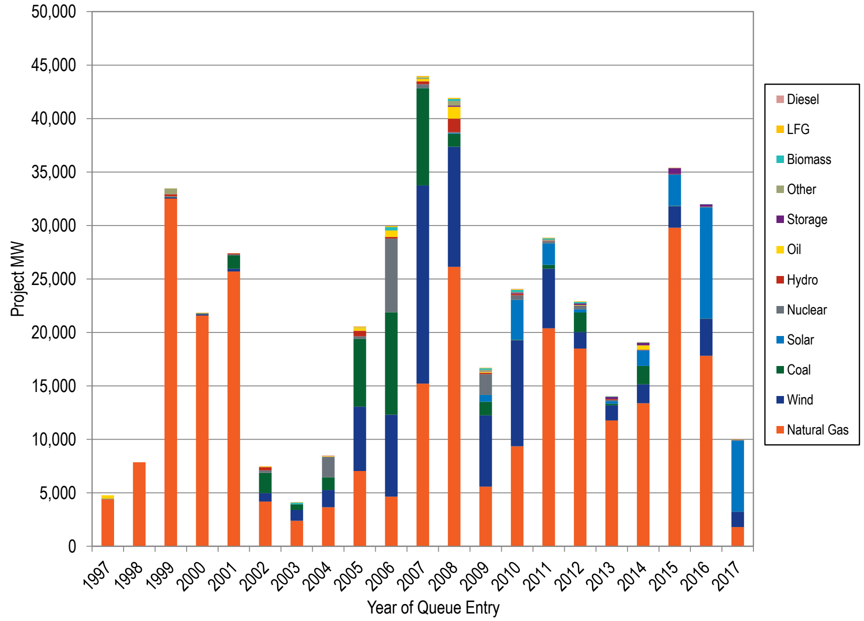


Table 12-21 shows the MW in Table 12-20 by share by classification as new generation or upgrade. Within a fuel type the shares of upgrades add to 100 percent and the shares of new generation add to 100 percent. For example, 72.9 percent of wind projects classified as new generation have been withdrawn from the queue between January 1, 1997, and March 31, 2017.

Table 12-22 shows the status of all natural gas projects by number of projects that entered PJM generation queues from January 1, 1997 through March 31, 2017, by zone. Of the 149 natural gas projects classified either as new generation or upgrade currently active in the PJM generation queue, 72 projects, 48.3 percent, are located within AEP, ComEd and AP.

Table 12-21 Status of all generation queue projects as percent of total MW in project classification: January 1, 1997 through March 31, 2017

		Percent of Total Project MW by Classification											
Project Status	Project Classification	Natural Gas	Wind	Coal	Solar	Nuclear	Hydro	Oil	Biomass	Storage	Other	LFG	Diesel
In Service	New Generation	9.2%	8.3%	3.9%	3.0%	0.1%	21.7%	26.1%	17.6%	11.4%	5.6%	43.3%	52.1%
	Upgrade	28.0%	4.0%	42.4%	2.5%	79.0%	85.0%	17.6%	42.8%	12.6%	95.6%	55.2%	41.9%
Under Construction	New Generation	5.6%	5.0%	0.0%	4.3%	0.0%	1.4%	0.0%	0.0%	5.2%	0.0%	4.0%	0.0%
	Upgrade	7.3%	0.0%	6.7%	8.2%	0.0%	2.4%	0.0%	45.5%	17.9%	0.0%	0.0%	0.0%
Suspended	New Generation	1.3%	3.6%	0.2%	1.2%	0.0%	0.0%	0.0%	1.2%	5.5%	0.0%	0.1%	0.0%
	Upgrade	1.6%	20.9%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	10.3%	0.0%	0.0%	0.0%
Withdrawn	New Generation	69.0%	72.9%	95.8%	30.4%	99.5%	76.3%	73.9%	80.2%	52.7%	94.4%	48.2%	47.9%
	Upgrade	37.7%	43.9%	45.7%	6.2%	18.5%	7.9%	82.4%	8.8%	31.8%	4.2%	44.8%	48.0%
Active	New Generation	14.9%	10.2%	0.0%	61.1%	0.3%	0.6%	0.0%	0.9%	25.2%	0.0%	4.4%	0.0%
	Upgrade	25.4%	31.2%	5.1%	83.1%	2.5%	4.8%	0.0%	2.9%	27.4%	0.2%	0.0%	10.1%

Table 12-22 Status of all natural gas generation queue projects: January 1, 1997 through March 31, 2017

		Number of Projects																				
Project Status	Project Classification	AECO	AEP	AP	ATSI	BGE	ComEd	DAY	DEOK	Dominion	DPL	DLCO	EKPC	JCPL	Met-Ed	PECO	PENELEC	Pepco	PPL	PSEG	RECO	TOTAL
In Service	New Generation	7	2	7	1	6	2	0	1	4	7	0	0	8	4	7	8	7	9	11	0	91
	Upgrade	7	9	8	1	3	9	6	0	30	13	0	0	5	1	8	6	4	6	24	0	140
Under Construction	New Generation	3	4	3	1	1	0	0	0	4	0	1	0	1	0	2	1	2	5	3	0	31
	Upgrade	2	3	2	1	0	6	0	0	3	0	0	0	1	0	3	0	1	4	4	0	30
Suspended	New Generation	2	2	2	0	0	0	0	0	0	1	0	0	1	0	0	5	1	0	0	0	14
	Upgrade	0	1	0	0	0	0	0	0	2	0	0	0	1	0	0	1	0	0	0	0	5
Withdrawn	New Generation	24	11	39	13	11	9	0	1	17	18	2	2	23	25	41	47	32	34	55	2	406
	Upgrade	5	1	4	3	0	1	0	1	7	4	0	0	5	7	2	4	3	4	14	0	65
Active	New Generation	4	11	9	4	0	12	1	0	3	2	0	1	2	1	1	9	0	4	11	0	75
	Upgrade	2	17	7	2	0	16	0	0	11	1	0	0	1	4	3	2	0	4	4	0	74
Total Projects	New Generation	40	30	60	19	18	23	1	2	28	28	3	3	35	30	51	70	42	52	80	2	617
	Upgrade	16	31	21	7	3	32	6	1	53	18	0	0	13	12	16	13	8	18	46	0	314

Table 12-23 shows the status of all gas projects by MW that entered PJM generation queues from January 1, 1997 through March 31, 2017, by zone. Of the 44,610.9 MW of natural gas projects classified either as new generation or upgrade currently active in the PJM generation queue, 23,622.8 MW, 52.9 percent, are located within AEP, ComEd and Dominion.

Table 12-23 Status of all natural gas generation capacity (MW) in the PJM generation queue: January 1, 1997 through March 31, 2017

		Project MW																				
Project Status	Project Classification	AECO	AEP	AP	ATSI	BGE	ComEd	DAY	DEOK	Dominion	DPL	DLCO	EKPC	JCPL	Met-Ed	PECO	PENELEC	Pepco	PPL	PSEG	RECO	TOTAL
In Service	New Generation	1,016.2	1,615.0	1,701.0	16.5	390.0	629.0	0.0	20.0	3,211.0	1,122.2	0.0	0.0	2,070.3	2,052.0	2,464.3	1,267.1	840.0	3,576.6	2,054.9	0.0	24,046.1
	Upgrade	265.7	244.0	812.7	40.0	6.5	849.5	60.0	0.0	1,446.7	189.0	0.0	0.0	224.0	10.0	715.0	103.0	105.1	327.3	964.9	0.0	6,363.4
Under Construction	New Generation	453.5	2,729.0	954.4	800.0	1.3	0.0	0.0	0.0	3,655.1	0.0	205.0	0.0	0.4	0.0	760.5	590.0	755.0	3,074.0	575.6	0.0	14,553.8
	Upgrade	41.0	21.0	45.0	161.0	0.0	112.6	0.0	0.0	225.0	0.0	0.0	0.0	0.0	0.0	206.0	0.0	64.5	524.0	254.0	0.0	1,654.1
Suspended	New Generation	606.0	1,110.0	39.8	0.0	0.0	0.0	0.0	0.0	0.0	291.0	0.0	0.0	440.0	0.0	0.0	107.0	894.0	0.0	0.0	0.0	3,487.8
	Upgrade	0.0	20.0	0.0	0.0	0.0	0.0	0.0	0.0	144.1	0.0	0.0	0.0	200.0	0.0	0.0	1.6	0.0	0.0	0.0	0.0	365.7
Withdrawn	New Generation	6,932.2	5,535.0	15,941.0	5,420.7	4,792.1	3,958.0	0.0	134.5	11,066.0	5,651.4	665.0	377.8	11,286.0	12,486.5	23,270.0	16,557.0	19,769.2	13,576.7	22,604.7	6.9	180,030.6
	Upgrade	122.8	610.0	567.0	86.0	0.0	10.0	0.0	36.0	305.3	668.0	0.0	0.0	253.0	1,730.0	205.0	1,040.6	85.0	480.0	2,392.7	0.0	8,591.4
Active	New Generation	805.4	6,959.0	5,695.8	4,047.0	0.0	7,383.3	1,150.0	0.0	3,544.5	508.0	0.0	614.0	1,267.2	450.0	220.0	1,795.5	0.0	1,878.9	2,502.7	0.0	38,821.3
	Upgrade	232.0	603.0	444.7	145.0	0.0	2,537.0	0.0	0.0	885.7	60.0	0.0	0.0	140.0	111.1	70.0	91.0	0.0	343.0	127.1	0.0	5,789.6
Total Projects	New Generation	9,813.3	17,948.0	24,332.0	10,284.2	5,183.4	11,970.3	1,150.0	154.5	21,476.6	7,572.6	870.0	991.8	15,063.9	14,988.5	26,714.8	20,316.6	22,258.2	22,106.2	27,737.9	6.9	260,939.6
	Upgrade	661.5	1,498.0	1,869.4	432.0	6.5	3,509.1	60.0	36.0	3,006.8	917.0	0.0	0.0	817.0	1,851.1	1,196.0	1,236.2	254.6	1,674.3	3,738.7	0.0	22,764.2

Table 12-24 shows the status of all wind generation projects that entered PJM generation queues from January 1, 1997 through March 31, 2017, by zone. Of the 76 wind projects to achieve in service status, 65 projects, 85.5 percent are located within ComEd, AEP, AP and PENELEC. Of the 50 wind projects currently active in the PJM generation queue, 39 projects, 78.0 percent are located within AEP, ComEd and AP.

Table 12-25 shows the wind project capacity in MW of all wind generation projects that have entered the PJM generation queue from January 1, 1997 through March 31, 2017, by zone. Of the 6,704.9 MW of wind generation capacity to achieve in service status, 6,370.3 MW, or 95.0 percent of nameplate capacity is located within ComEd, AEP, AP and PENELEC. Of the 8,462.3 MW of wind generation capacity currently active in the PJM generation queue, 7,045.5 MW of generation capacity or 83.2 percent is located within AEP, ComEd and AP.

Table 12-24 Status of all wind generation queue projects: January 1, 1997 through March 31, 2017

		Number of Projects																				
Project Status	Project Classification	AECO	AEP	AP	ATSI	BGE	ComEd	DAY	DEOK	Dominion	DPL	DLCO	EKPC	JCPL	Met-Ed	PECO	PENELEC	Pepco	PPL	PSEG	RECO	TOTAL
In Service	New Generation	1	8	11	0	0	17	0	0	0	0	0	0	1	1	0	18	0	4	0	0	61
	Upgrade	0	0	3	0	0	2	0	0	0	0	0	0	0	0	0	6	0	4	0	0	15
Under Construction	New Generation	1	9	7	0	0	4	0	0	4	0	0	0	0	0	0	1	0	0	0	0	26
	Upgrade	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Suspended	New Generation	1	7	1	1	0	1	2	0	0	0	0	0	0	0	0	2	0	1	0	0	16
	Upgrade	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3
Withdrawn	New Generation	15	82	41	6	0	92	13	0	13	9	0	1	1	0	0	59	0	39	1	0	372
	Upgrade	1	0	7	0	0	1	0	0	1	0	0	0	0	0	0	2	0	2	0	0	14
Active	New Generation	0	20	2	2	0	12	0	0	2	2	0	0	0	0	0	1	0	2	0	0	43
	Upgrade	0	0	3	0	0	2	0	0	0	0	0	0	0	0	0	2	0	0	0	0	7
Total Projects	New Generation	18	126	62	9	0	126	15	0	19	11	0	1	2	1	0	81	0	46	1	0	518
	Upgrade	2	1	14	0	0	5	0	0	1	0	0	0	0	0	0	10	0	6	0	0	39

Table 12-25 Status of all wind generation capacity (MW) in the PJM generation queue: January 1, 1997 through March 31, 2017

		Project MW																				
Project Status	Project Classification	AECO	AEP	AP	ATSI	BGE	ComEd	DAY	DEOK	Dominion	DPL	DLCO	EKPC	JCPL	Met-Ed	PECO	PENELEC	Pepco	PPL	PSEG	RECO	TOTAL
In Service	New Generation	7.5	2,052.0	1,004.0	0.0	0.0	2,413.5	0.0	0.0	0.0	0.0	0.0	0.0	30.6	70.0	0.0	894.4	0.0	199.2	0.0	0.0	6,671.2
	Upgrade	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	0.0	0.0	6.4	0.0	27.3	0.0	0.0	33.7
Under Construction	New Generation	150.0	1,318.3	782.6	0.0	0.0	978.5	0.0	0.0	690.5	0.0	0.0	0.0	0.0	0.0	0.0	70.0	0.0	0.0	0.0	0.0	3,989.9
	Upgrade	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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Suspended	New Generation	20.0	1,198.3	69.1	500.0	0.0	500.0	300.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	180.0	0.0	100.0	0.0	0.0	2,867.4
	Upgrade	5.0	100.0	70.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	175.0
Withdrawn	New Generation	3,626.4	15,573.1	3,010.1	645.6	0.0	21,515.8	1,828.0	0.0	2,156.5	2,310.0	0.0	150.3	60.0	0.0	0.0	4,897.6	0.0	2,706.3	20.0	0.0	58,499.7
	Upgrade	0.0	0.0	199.0	0.0	0.0	4.0	0.0	0.0	78.0	0.0	0.0	0.0	0.0	0.0	0.0	80.0	0.0	6.0	0.0	0.0	367.0
Active	New Generation	0.0	4,840.5	217.0	315.7	0.0	1,798.0	0.0	0.0	226.6	499.6	0.0	0.0	0.0	0.0	0.0	138.0	0.0	166.2	0.0	0.0	8,201.5
	Upgrade	0.0	0.0	20.0	0.0	0.0	170.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	70.8	0.0	0.0	0.0	0.0	260.8
Total Projects	New Generation	3,803.9	24,982.2	5,082.8	1,461.3	0.0	27,205.8	2,128.0	0.0	3,073.6	2,809.6	0.0	150.3	90.6	70.0	0.0	6,180.0	0.0	3,171.7	20.0	0.0	80,229.7
	Upgrade	5.0	100.0	289.0	0.0	0.0	174.0	0.0	0.0	78.0	0.0	0.0	0.0	0.0	0.0	0.0	157.1	0.0	33.3	0.0	0.0	836.4

Table 12-26 shows the status of all solar generation projects that have entered the PJM generation queue from January 1, 1997 through March 31, 2017, by zone. Out of a total of 1,199 solar projects in the PJM generation queue, 503 projects or 42.0 percent have been located in JCPL, AECO and PSEG, all zones in New Jersey. Of these three zones, AECO has the lowest completion rates for new generation and upgrade solar projects. Excluding currently active projects, only 5.1 percent of solar projects classified as new generation or upgrades in AECO are either in service or under construction. Of these three zones, PSEG has the highest completion rates. Excluding currently active projects, 44.1 percent of solar projects classified as either new generation or upgrades in PSEG are either in service or under construction.

The number of currently active new generation solar projects is also highly concentrated in several zones. Out of 344 active new generation solar projects, 125 projects, or 36.3 percent of all currently active new generation solar projects are located in Dominion. Out of 344 active new generation solar projects, 68, or 21.7 percent of all currently active new generation solar projects are located in AEP.

Table 12-27 shows the status of all solar generation project MW that have entered the PJM generation queue from January 1, 1997 through March 31, 2017, by zone. Out of a total of 28,264.0 MW of solar nameplate capacity in the PJM generation queue, 4,226.3 MW or 15.0 percent have been located in JCPL, AECO and PSEG, all of which are zones in New Jersey. Solar projects in Dominion have accounted for 11,153.0 MW or 39.5 percent of all solar project nameplate capacity in the PJM queue from January 1, 1997 through March 31, 2017. Solar projects in DPL have accounted for 2,833.6 MW or 10.0 percent of all solar project nameplate capacity in the PJM queue from January 1, 1997 through March 31, 2017.

Table 12-26 Status of all solar generation queue projects: January 1, 1997 through March 31, 2017

	Project	Number of Projects																				
Project Status	Classification	AECO	AEP	AP	ATSI	BGE	ComEd	DAY	DEOK	Dominion	DPL	DLCO	EKPC	JCPL	Met-Ed	PECO	PENELEC	Pepco	PPL	PSEG	RECO	TOTAL
In Service	New Generation	5	4	2	0	1	1	1	0	7	9	0	0	35	0	1	0	0	2	36	0	104
	Upgrade	0	0	0	0	0	0	0	0	2	8	0	0	6	0	0	0	0	0	0	0	16
Under Construction	New Generation	3	4	7	0	2	0	1	0	18	6	0	0	12	0	0	0	0	0	9	0	62
	Upgrade	0	0	0	0	0	0	0	0	2	1	0	0	0	0	0	0	0	0	0	0	3
Suspended	New Generation	0	3	12	0	0	0	1	0	1	2	0	0	5	1	0	1	0	0	2	0	28
	Upgrade	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Withdrawn	New Generation	147	17	44	6	4	7	4	5	51	81	0	0	153	11	5	10	6	27	55	0	633
	Upgrade	1	1	0	0	0	0	0	0	1	0	0	0	5	0	0	0	0	1	0	0	9
Active	New Generation	12	71	10	4	6	14	12	4	118	53	1	3	7	3	1	2	1	2	9	0	333
	Upgrade	0	0	1	0	0	0	0	1	7	1	0	0	0	0	0	0	0	0	1	0	11
Total Projects	New Generation	167	99	75	10	13	22	19	9	195	151	1	3	212	15	7	13	7	31	111	0	1160
	Upgrade	1	1	1	0	0	0	0	1	12	10	0	0	11	0	0	0	0	1	1	0	39

Table 12-27 Current status of all solar generation capacity (MW) in the PJM generation queue: January 1, 1997 through March 31, 2017

	Project	Project MW																				
Project Status	Classification	AECO	AEP	AP	ATSI	BGE	ComEd	DAY	DEOK	Dominion	DPL	DLCO	EKPC	JCPL	Met-Ed	PECO	PENELEC	Pepco	PPL	PSEG	RECO	TOTAL
In Service	New Generation	38.5	14.7	34.0	0.0	1.1	9.0	2.5	0.0	172.0	118.4	0.0	0.0	234.3	0.0	3.3	0.0	0.0	15.0	181.4	0.0	824.2
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.1	0.0	0.0	0.0	16.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	19.4
Under Construction	New Generation	20.8	40.0	81.3	0.0	22.0	0.0	3.4	0.0	753.0	49.0	0.0	0.0	167.6	0.0	0.0	0.0	0.0	0.0	51.2	0.0	1,188.2
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	64.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	64.5
Suspended	New Generation	0.0	49.9	143.4	0.0	0.0	0.0	20.0	0.0	5.0	25.5	0.0	0.0	52.0	3.0	0.0	13.5	0.0	0.0	9.7	0.0	322.0
	Upgrade	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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Withdrawn	New Generation	1,628.8	332.3	750.1	60.1	9.2	84.8	51.5	83.0	1,791.2	1,167.5	0.0	0.0	1,249.4	367.0	50.1	34.3	58.1	283.7	390.6	0.0	8,391.8
	Upgrade	10.0	6.0	0.0	0.0	0.0	0.0	0.0	0.0	8.0	0.0	0.0	0.0	23.8	0.0	0.0	0.0	0.0	1.1	0.0	0.0	48.9
Active	New Generation	78.3	4,540.6	428.2	385.0	22.1	367.0	818.5	264.9	7,807.3	1,453.2	15.0	160.0	35.7	155.0	20.0	130.0	2.5	30.0	36.5	0.0	16,749.9
	Upgrade	0.0	0.0	10.0	0.0	0.0	0.0	0.0	75.0	548.9	20.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.3	0.0	655.2
Total Projects	New Generation	1,766.5	4,977.4	1,437.0	445.1	54.4	460.8	895.9	347.9	10,528.5	2,813.6	15.0	160.0	1,738.9	525.0	73.4	177.8	60.6	328.7	669.5	0.0	27,476.0
	Upgrade	10.0	6.0	10.0	0.0	0.0	0.0	0.0	75.0	624.5	20.0	0.0	0.0	40.1	0.0	0.0	0.0	0.0	1.1	1.3	0.0	788.0

Table 12-28 shows the relationship between the project developer and Transmission Owner for all project MW that have entered the PJM generation queue from January 1, 1997 through March 31, 2017 by zone and technology type. A project where the developer is or is affiliated with the Transmission Owner is classified as related. A project where the developer is not affiliated with the Transmission Owner is classified as unrelated. For example, 36.0 MW of natural gas fired generation projects that have entered the PJM generation queue in DEOK were projects developed by Duke Energy or subsidiaries of Duke Energy, the Transmission Owner for DEOK. These project MW are classified as "related." There have been 154.5 MW of natural gas fired projects that have entered the PJM generation queue in DEOK by developers not affiliated with Duke Energy. These project MW are classified as "unrelated."

Table 12-28 Relationship between project developer and Transmission Owner for all interconnection queue projects MW by fuel type: January 1, 1997 through March 31, 2017

				MW by Fuel Type										
Parent Company	Transmission Owner	Related To Developer	Number of Projects	Biomass	Coal	Diesel	Hydro	Landfill Gas	Natural Gas	Nuclear	Other	Solar	Wind	Total MW
AEP	AEP	Related	49	0.0	3,965.0	0.0	34.0	3.0	3,027.0	214.0	0.0	74.7	0.0	7,317.7
		Unrelated	364	501.1	10,292.0	7.5	448.4	83.8	19,493.0	0.0	66.0	4,913.7	25,178.8	60,984.3
AES	DAY	Related	16	0.0	1,347.5	0.0	0.0	0.0	51.0	0.0	0.0	24.0	0.0	1,422.5
		Unrelated	35	1.9	0.0	0.0	0.0	10.0	9.0	0.0	0.0	471.9	2,128.0	2,620.8
DLCO	DLCO	Related	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	20	0.0	2,810.0	0.0	106.0	19.2	870.0	1,879.0	0.0	0.0	0.0	5,684.2
Dominion	Dominion	Related	83	64.0	301.0	0.0	340.0	0.0	13,215.0	1,944.0	0.0	251.4	142.0	16,257.4
		Unrelated	287	343.7	20.0	10.0	29.5	184.0	12,051.1	0.0	156.3	13,335.6	2,913.0	29,043.2
Duke	DEOK	Related	4	0.0	0.0	0.0	0.0	0.0	36.0	0.0	0.0	0.0	0.0	36.0
		Unrelated	18	0.0	70.0	0.0	112.0	4.8	154.5	0.0	0.0	373.0	0.0	714.3
EKPC	EKPC	Related	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	8	0.0	0.0	0.0	0.0	0.0	2,141.8	0.0	0.0	160.0	150.3	2,452.1
Exelon	AECO	Related	3	0.0	0.0	0.0	0.0	0.0	730.0	0.0	0.0	0.0	0.0	730.0
		Unrelated	268	29.8	15.0	13.0	0.0	31.0	9,783.6	0.0	0.0	1,786.3	3,808.9	15,467.6
	BGE	Related	14	0.0	10.0	0.0	0.0	0.0	1,037.0	3,373.3	0.0	20.0	0.0	4,440.3
		Unrelated	59	0.0	0.0	29.0	140.4	9.5	4,152.9	0.0	132.0	34.4	0.0	4,498.2
	ComEd	Related	18	0.0	0.0	0.0	0.0	0.0	0.0	1,185.0	0.0	9.0	396.0	1,590.0
		Unrelated	253	90.0	1,926.0	42.0	22.7	112.9	15,479.4	0.0	20.0	311.8	27,379.8	45,384.6
	DPL	Related	10	0.0	0.0	0.0	0.0	0.0	1,716.0	0.0	0.0	31.4	0.0	1,747.4
		Unrelated	252	62.2	653.0	0.0	0.0	58.4	6,773.6	0.0	30.0	2,954.9	2,809.6	13,341.7
	PECO	Related	29	0.0	7.0	0.0	45.0	0.0	6,420.0	437.8	0.0	0.0	0.0	6,909.8
		Unrelated	78	0.0	0.0	12.1	220.0	18.7	21,490.8	0.0	0.0	73.4	0.0	21,815.0
	Pepco	Related	1	0.0	0.0	0.0	0.0	0.0	0.0	1,640.0	0.0	0.0	0.0	1,640.0
		Unrelated	63	0.0	0.0	0.0	0.0	12.5	22,623.9	0.0	0.0	58.1	0.0	22,694.5
First Energy	AP	Related	14	0.0	1,745.0	0.0	252.0	0.0	4,790.0	0.0	0.0	0.0	0.0	6,787.0
		Unrelated	303	177.2	4,057.0	53.8	371.3	125.8	21,427.9	0.0	96.0	1,491.9	5,282.7	33,083.5
	ATSI	Related	8	0.0	0.0	0.0	0.0	0.0	1,678.0	16.0	0.0	0.6	0.0	1,694.6
		Unrelated	50	0.0	0.0	0.0	0.0	35.3	9,021.7	0.0	135.0	444.5	1,461.3	11,097.8
	JCPL	Related	2	0.0	0.0	0.0	20.0	0.0	100.0	0.0	0.0	0.0	0.0	120.0
		Unrelated	310	30.0	0.0	0.0	1.6	24.4	15,780.9	0.0	0.0	1,797.4	90.6	17,724.8
	Met-Ed	Related	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	89	90.4	0.0	8.0	0.0	57.9	16,839.6	93.0	11.0	525.0	70.0	17,694.9
	PENELEC	Related	8	0.0	1,860.0	0.0	32.0	0.0	1,174.0	0.0	0.0	0.0	0.0	3,066.0
		Unrelated	214	0.0	561.0	8.0	53.3	50.9	20,396.8	0.0	621.0	97.8	6,454.1	28,242.8
PPL	PPL	Related	36	0.0	139.0	0.0	0.0	7.7	2,294.0	1,988.0	0.0	0.0	0.0	4,428.7
		Unrelated	187	28.5	6,868.6	10.4	2.6	95.4	21,486.5	0.0	152.5	329.8	3,205.0	32,179.2
PSEG	PSEG	Related	101	0.0	24.0	0.0	0.0	11.7	12,802.1	381.0	0.0	125.2	0.0	13,344.0
		Unrelated	164	0.0	0.0	0.0	1,000.0	24.4	18,673.2	0.0	45.5	535.1	20.0	20,298.2
Consolidated Edison, Inc.	RECO	Related	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	2	0.0	0.0	0.0	0.0	0.0	6.9	0.0	0.0	0.0	0.0	6.9
Total		Related	396	64.0	9,398.5	0.0	723.0	22.4	49,070.1	11,179.1	0.0	536.3	538.0	71,531.4
		Unrelated	3,024	1,354.8	27,272.6	193.8	2,507.8	958.8	238,657.0	1,972.0	1,465.3	29,694.4	80,952.0	385,028.5

Table 12-29 shows the relationship between the project developer and Transmission Owner for all solar project MW that have entered the PJM generation queue from January 1, 1997 through March 31, 2017, by zone and project status. Of the 1,318.7 solar project MW that have achieved in service or under construction status during this time period, 186.9 MW, or 16.5 percent have been developed by Transmission Owners building in their own service territory. Of that 186.9 MW of solar projects, 115.8 MW or 62.0 percent have been developed by PSEG in the PSEG Zone and 20.0 MW or 10.7 percent have been developed by Dominion in the Dominion Zone.

Table 12-29 Relationship between project developer and Transmission Owner for all solar project MW in PJM interconnection queue: January 1, 1997 through March 31, 2017

			MW by Project Status					
Parent Company	Transmission Owner	Related To Developer	In Service	Under Construction	Suspended	Withdrawn	Active	Total MW
AEP	AEP	Related	2.5	12.2	0.0	0.0	60.0	74.7
		Unrelated	0.0	20.0	51.7	336.5	4,505.6	4,913.7
AES	DAY	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	2.5	23.4	0.0	51.5	418.5	495.9
DLCO	DLCO	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0
Dominion	Dominion	Related	20.0	0.0	0.0	7.0	224.4	251.4
		Unrelated	140.1	122.9	205.0	1,511.2	11,356.4	13,335.6
Duke	DEOK	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	0.0	83.0	290.0	373.0
EKPC	EKPC	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	0.0	0.0	160.0	160.0
Exelon	AECO	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	38.5	20.8	0.0	1,638.8	88.1	1,786.3
	BGE	Related	0.0	20.0	0.0	0.0	0.0	20.0
		Unrelated	1.1	2.0	0.0	9.2	22.1	34.4
	ComEd	Related	9.0	0.0	0.0	0.0	0.0	9.0
		Unrelated	0.0	0.0	0.0	84.8	227.0	311.8
	DPL	Related	7.4	0.0	0.0	24.0	0.0	31.4
		Unrelated	21.0	159.5	0.0	1,094.5	1,679.9	2,954.9
	PECO	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	3.3	0.0	0.0	50.1	20.0	73.4
	Pepco	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	0.0	58.1	0.0	58.1
First Energy	AP	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	34.0	32.5	38.9	692.2	694.3	1,491.9
	ATSI	Related	0.0	0.0	0.0	0.6	0.0	0.6
		Unrelated	0.0	0.0	0.0	59.5	385.0	444.5
	JCPL	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	204.1	175.5	92.9	1,235.2	89.7	1,797.4
	Met-Ed	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	3.0	367.0	155.0	525.0
	PENELEC	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	13.5	34.3	50.0	97.8
PPL	PPL	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	15.0	16.0	0.0	268.8	30.0	329.8
PSEG	PSEG	Related	105.8	10.0	0.0	8.2	1.2	125.2
		Unrelated	53.8	46.2	9.7	382.5	42.9	535.1
Consolidated Edison, Inc.	RECO	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0
Total		Related	144.7	42.2	0.0	39.8	285.6	512.3
		Unrelated	513.4	618.8	414.7	7,957.0	20,214.5	29,718.4

Table 12-30 shows the relationship between the project developer and Transmission Owner for all natural gas fired project MW that have entered the PJM generation queue from January 1, 1997 through March 31, 2017, by zone and project status. Of the 46,198.0 natural gas project MW that have achieved in service or under construction status during this time period, 10,382.0 MW, or 22.5 percent have been developed by Transmission Owners building in their own service territory. Of that 10,382.0 MW of natural gas projects, 5,571.0 MW or 53.7 percent have been developed by Dominion in the Dominion zone and 1,972.0 MW or 19.0 percent have been developed by PSEG in the PSEG Zone.

Table 12-30 Relationship between project developer and Transmission Owner for all natural gas project MW in PJM interconnection queue: January 1, 1997 through March 31, 2017

			MW by Project Status					
Parent Company	Transmission Owner	Related To Developer	In Service	Under Construction	Suspended	Withdrawn	Active	Total MW
AEP	AEP	Related	717.0	0.0	0.0	0.0	2,310.0	3,027.0
		Unrelated	1,142.0	3,355.0	525.0	6,145.0	8,326.0	19,493.0
AES	DAY	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	60.0	0.0	0.0	0.0	0.0	60.0
DLCO	DLCO	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	205.0	0.0	665.0	0.0	870.0
Dominion	Dominion	Related	3,823.0	1,748.0	0.0	7,476.0	168.0	13,215.0
		Unrelated	771.7	1,799.1	0.0	3,895.3	5,585.0	12,051.1
Duke	DEOK	Related	0.0	0.0	0.0	36.0	0.0	36.0
		Unrelated	20.0	0.0	0.0	134.5	0.0	154.5
EKPC	EKPC	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	0.0	377.8	1,764.0	2,141.8
Exelon	AECO	Related	0.0	0.0	0.0	730.0	0.0	730.0
		Unrelated	1,281.9	460.5	606.0	6,324.8	1,110.4	9,783.6
	BGE	Related	367.0	0.0	0.0	670.0	0.0	1,037.0
		Unrelated	29.5	1.3	0.0	4,122.1	0.0	4,152.9
	ComEd	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	1,478.5	112.6	0.0	3,958.0	9,930.3	15,479.4
	DPL	Related	411.0	0.0	0.0	1,305.0	0.0	1,716.0
		Unrelated	900.2	0.0	291.0	5,014.4	568.0	6,773.6
	PECO	Related	5.0	0.0	0.0	6,415.0	0.0	6,420.0
		Unrelated	3,174.3	892.5	0.0	17,060.0	364.0	21,490.8
	Pepco	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	160.1	2,498.5	0.0	19,854.2	111.1	22,623.9
First Energy	AP	Related	701.0	0.0	0.0	4,089.0	0.0	4,790.0
		Unrelated	1,796.7	962.5	70.1	12,393.1	6,205.5	21,427.9
	ATSI	Related	0.0	0.0	0.0	1,678.0	0.0	1,678.0
		Unrelated	40.0	961.0	0.0	3,808.8	4,211.9	9,021.7
	JCPL	Related	0.0	0.0	0.0	100.0	0.0	100.0
		Unrelated	2,294.3	440.0	200.0	10,879.0	1,967.6	15,780.9
	Met-Ed	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	2,062.0	0.0	0.0	14,216.5	561.1	16,839.6
	PENELEC	Related	5.0	0.0	0.0	1,169.0	0.0	1,174.0
		Unrelated	1,267.8	88.7	59.7	16,408.7	2,571.9	20,396.8
PPL	PPL	Related	633.0	0.0	0.0	1,661.0	0.0	2,294.0
		Unrelated	2,420.9	3,924.0	0.0	12,395.7	2,745.9	21,486.5
PSEG	PSEG	Related	1,972.0	0.0	0.0	9,871.1	959.0	12,802.1
		Unrelated	1,047.8	167.6	0.0	14,905.3	2,552.5	18,673.2
Consolidated Edison, Inc.	RECO	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	0.0	6.9	0.0	6.9
		Related	8,634.0	1,748.0	0.0	35,200.1	3,437.0	49,019.1
Total		Unrelated	19,947.7	15,868.3	1,751.8	152,565.0	48,575.2	238,708.0

Table 12-31 shows the relationship between the project developer and Transmission Owner for all wind project MW that have entered the PJM generation queue from January 1, 1997 through March 31, 2017, by zone and project status. Of the 10,584.3 wind project MW that have achieved in service or under construction status during this time period, 408.0 MW, or 3.9 percent have been developed by Transmission Owners building in their own service territory. Of that 408.0 MW of wind projects, 396.0 MW or 97.1 percent have been developed by Exelon in the ComEd Zone.

Table 12-31 Relationship between project developer and Transmission Owner for all wind project MW in PJM interconnection queue: January 1, 1997 through March 31, 2017

			MW by Project Status					
Parent Company	Transmission Owner	Related To Developer	In Service	Under Construction	Suspended	Withdrawn	Active	Total MW
AEP	AEP	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	2,052.0	966.6	1,650.0	14,383.8	6,126.4	25,178.8
AES	DAY	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	300.0	1,828.0	0.0	2,128.0
DLCO	DLCO	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0
Dominion	Dominion	Related	0.0	12.0	0.0	130.0	0.0	142.0
		Unrelated	0.0	673.9	300.0	1,730.9	208.2	2,913.0
Duke	DEOK	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0
EKPC	EKPC	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	0.0	150.3	0.0	150.3
Exelon	AECO	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	7.5	150.0	25.0	3,626.4	0.0	3,808.9
	BGE	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0
	ComEd	Related	396.0	0.0	0.0	0.0	0.0	396.0
		Unrelated	2,238.5	802.5	710.0	20,859.8	2,769.0	27,379.8
	DPL	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	100.0	0.0	2,210.0	499.6	2,809.6
	PECO	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0
	Pepco	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0
First Energy	AP	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	1,031.4	426.0	130.0	3,027.5	667.8	5,282.7
	ATSI	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	500.0	0.0	645.6	315.7	1,461.3
	JCPL	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	30.6	0.0	0.0	60.0	0.0	90.6
	Met-Ed	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	70.0	0.0	0.0	0.0	0.0	70.0
	PENELEC	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	862.5	38.3	150.0	4,927.6	475.8	6,454.1
PPL	PPL	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	226.5	0.0	100.0	2,443.8	434.7	3,205.0
PSEG	PSEG	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	0.0	20.0	0.0	20.0
Consolidated Edison, Inc.	RECO	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0
Total		Related	396.0	12.0	0.0	130.0	0.0	538.0
		Unrelated	6,519.0	3,657.3	3,365.0	55,913.7	11,497.1	80,952.0

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.[30] When one of the reportable transmission facilities needs to be taken out of service, the TO is required to submit an outage request as early as possible. The specific timeline is shown in Table 12-33.[31]

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.[32] Table 12-32 shows that 73.9 percent of the requested outages were planned for less than or equal to five days and 11.4 percent of requested outages were planned for greater than 30 days in the first three months of 2017. All of the outage data in this section except in the analysis for the FTR market are for outages scheduled to occur in the first three months of 2016 and 2017, regardless of when they were initially submitted.[33] The outage data in the analysis for the FTR market are for outages scheduled to occur in the planning periods 2015 to 2016 and 2016 to 2017.

30 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 12 (September 30, 2016).

31 See PJM. "Manual 3: Transmission Operations," Revision 50 (December 1, 2016), p.68.

32 See PJM. "Manual 3: Transmission Operations," Revision 50 (December 1, 2016), p.70.

33 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.

Table 12-32 Transmission facility outage request summary by planned duration: January 1 through March 31, 2016 and 2017

	2016 (Jan - Mar)		2017 (Jan - Mar)	
Planned Duration (Days)	Outage Requests	Percent	Outage Requests	Percent
<=5	3,496	74.4%	3,338	73.9%
>5 & <=30	688	14.6%	665	14.7%
>30	514	10.9%	513	11.4%
Total	4,698	100.0%	4,516	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 and outage planned duration. The received status can be On Time or Late, as defined in Table 12-33.[34]

The purpose of the rules defined in Table 12-33 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.[35]

Table 12-33 PJM transmission facility outage request received status definition

Planned Duration (Calendar Days)	Request Submitted	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
> 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
>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

34 See PJM. "Manual 3: Transmission Operations," Revision 50 (December 1, 2016), p.69 and p.70.

35 *See* "Report of PJM Interconnection, L.L.C. on Transmission Oversight Procedures," Docket No. EL01-122-000 (November 2, 2001).

Table 12-34 shows a summary of requests by received status. In the first three months of 2017, 54.2 percent of outage requests received were late.

Table 12-34 Transmission facility outage request summary by received status: January 1 through March 31, 2016 and 2017

	2016 (Jan - Mar)				2017 (Jan - Mar)			
Planned Duration (Days)	On Time	Late	Total	Percent Late	On Time	Late	Total	Percent Late
<=5	1,616	1,880	3,496	53.8%	1,659	1,679	3,338	50.3%
>5 & <=30	321	367	688	53.3%	261	404	665	60.8%
>30	169	345	514	67.1%	147	366	513	71.3%
Total	2,106	2,592	4,698	55.2%	2,067	2,449	4,516	54.2%

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 late unless the request is an emergency.

Outages with emergency status will be approved even if submitted late 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.[36] Table 12-35 is a summary of outage requests by emergency status. Of all outage requests scheduled to occur in the first three months of 2017, 16.0 percent were for emergency outages. Of all outage requests scheduled to occur in the first three months of 2016, 15.8 percent were for emergency outages.

Table 12-35 Transmission facility outage request summary by emergency: January 1 through March 31, 2016 and 2017

	2016 (Jan - Mar)				2017 (Jan - Mar)			
Planned Duration (Days)	Emergency	Non Emergency	Total	Percent Emergency	Emergency	Non Emergency	Total	Percent Emergency
<=5	567	2,929	3,496	16.2%	527	2,811	3,338	15.8%
>5 & <=30	110	578	688	16.0%	116	549	665	17.4%
>30	64	450	514	12.5%	81	432	513	15.8%
Total	741	3,957	4,698	15.8%	724	3,792	4,516	16.0%

36 PJM. "Manual 3: Transmission Operations," Revision 50 (December 1, 2016), p. 80.

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 are not expected to cause congestion on the PJM system and do not jeopardize the reliability of the PJM system. Each outage is studied and if it is expected to cause a constraint to exceed a limit, PJM will flag the outage ticket as "congestion expected."[37]

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 12-36 is a summary of outage requests by congestion status. Of all outage requests submitted to occur in the first three months of 2017, 7.6 percent were expected to cause congestion. Of all the outage requests that were expected to cause congestion, 1.2 percent (4 out of 345) were denied by PJM in the first three months of 2017 and 18.6 percent (64 out of 345) were cancelled (Table 12-38).

Table 12-36 Transmission facility outage request summary by congestion: January 1 through March 31, 2016 and 2017

	2016 (Jan - Mar)				2017 (Jan - Mar)			
Planned Duration (Days)	Congestion Expected	No Congestion Expected	Total	Percent Congestion Expected	Congestion Expected	No Congestion Expected	Total	Percent Congestion Expected
<=5	247	3,249	3,496	7.1%	239	3,099	3,338	7.2%
>5 & <=30	84	604	688	12.2%	66	599	665	9.9%
>30	47	467	514	9.1%	40	473	513	7.8%
Total	378	4,320	4,698	8.0%	345	4,171	4,516	7.6%

Table 12-37 shows the outage requests summary by received status, congestion status and emergency status. In the first three months of 2017, 38.3 percent of requests were submitted late and were nonemergency while 1.7 (75 out of 4,516) percent of requests were late, nonemergency, and expected to cause congestion.

37 PJM added this definition to Manual 38 in February 2017. PJM. "Manual 38: Operations Planning," Revision 10 (February 1, 2017), p. 17.

Table 12-37 Transmission facility outage requests that by received status, congestion and emergency: January 1 through March 31, 2016 and 2017

		2016 (Jan - Mar)				2017 (Jan - Mar)			
Submission Status		Congestion Expected	No Congestion Expected	Total	Percent	Congestion Expected	No Congestion Expected	Total	Percent
Late	Emergency	18	719	737	15.7%	29	691	720	15.9%
	Non Emergency	90	1,765	1,855	39.5%	75	1,654	1,729	38.3%
On Time	Emergency	0	4	4	0.1%	0	4	4	0.1%
	Non Emergency	270	1,832	2,102	44.7%	241	1,822	2,063	45.7%
Total		378	4,320	4,698	100.0%	345	4,171	4,516	100.0%

Once PJM processes an outage request, the outage request is labelled as Submitted, Received, Denied, Approved, Cancelled by Company, PJM Admin Closure, Revised, Active or Complete according to the processed stage of a request.[38] Table 12-38 shows the detailed process status for outage requests only for the outage requests that are expected to cause congestion. Status Submitted and status Received are in the In Process category and status Cancelled by Company and status PJM Admin Closure are in the Cancelled category in Table 12-38. Table 12-38 shows that of all the outage requests that were expected to cause congestion, 1.2 percent (4 out of 345) were denied by PJM in the first three months of 2017, 75.7 percent were complete and 18.6 percent (64 out of 345) were cancelled.

Table 12-38 Transmission facility outage requests that might cause congestion status summary: January 1 through March 31, 2016 and 2017

		2016 (Jan - Mar)						2017 (Jan - Mar)					
Submission Status		Cancelled	Complete	In Process	Denied	Congestion Expected	Percent Complete	Cancelled	Complete	In Process	Denied	Congestion Expected	Percent Complete
Late	Emergency	0	18	0	0	18	100.0%	5	22	2	0	29	75.9%
	Non Emergency	17	65	0	8	90	72.2%	9	59	5	2	75	78.7%
On Time	Emergency	0	0	0	0	0	0.0%	0	0	0	0	0	0.0%
	Non Emergency	72	193	0	5	270	71.5%	50	180	9	2	241	74.7%
Total		89	276	0	13	378	73.0%	64	261	16	4	345	75.7%

There are clear rules defined for assigning On Time or Late status for submitted outage requests in both the PJM Tariff and PJM Manuals.[39] However, the On Time or Late status only affects the priority that PJM assigns for processing the outage request. Many (78.7 percent or 59 out of 75) outages that were nonemergency, expected to cause congestion, and 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.

38 See PJM. "Outage Information," <http://www.pjm.com/markets-and-operations/etools/oasis/system-information/outage-info.aspx> (November 1, 2015).

39 OA Schedule 1 § 1.9.2 (Planned Outages).

Rescheduling Transmission Facility Outage Requests

A TO can reschedule or cancel an outage after initial submission. Table 12-39 is a summary of all the outage requests planned for the first three months of 2016 and 2017 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 the first three months of 2017, 7.9 percent of transmission outage requests were approved by PJM and then rescheduled by the TOs, and 4.3 percent of the transmission outages were approved by PJM and subsequently cancelled by the TOs.

Table 12-39 Rescheduled and cancelled transmission outage request summary: January 1 through March 31, 2016 and 2017

	2016 (Jan - Mar)					2017 (Jan - Mar)				
Days	Outage Requests	Approved and Rescheduled	Percent Approved and Rescheduled	Approved and Cancelled	Percent Approved and Cancelled	Outage Requests	Approved and Rescheduled	Percent Approved and Rescheduled	Approved and Cancelled	Percent Approved and Cancelled
<=5	3,496	210	6.0%	338	9.7%	3,338	143	4.3%	310	9.3%
>5 & <=30	688	14	2.0%	26	3.8%	665	37	5.6%	31	4.7%
>30	514	21	4.1%	14	2.7%	513	13	2.5%	16	3.1%
Total	4,698	245	5.2%	378	8.0%	4,516	193	4.3%	357	7.9%

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 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.[40] This rule allows a TO to reschedule within the same month with very little notice.

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.[41] 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 nine 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 12-33) 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 12-40 shows that there were 3,683 transmission equipment planned outages in the first three months of 2017, of which 469 were planned outages longer than 30 days, and of which 14 or 0.4 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.

40 PJM. "Manual 3: Transmission Operations," Revision 50 (December 1, 2016), p. 70.

41 PJM. "Manual 3: Transmission Operations," Revision 50 (December 1, 2016), p. 70.

Table 12-40 Transmission outage summary: January 1 through March 31, 2016 and 2017

		2016 (Jan - Mar)		2017 (Jan - Mar)	
Duration	Divided into Shorter Periods	Number of Outages	Percent	Number of Outages	Percent
> 30 Days	No	483	12.9%	469	12.7%
	Yes	20	0.5%	14	0.4%
<= 30 Days		3,233	86.5%	3,200	86.9%
Total		3,736	100.0%	3,683	100.0%

Table 12-41 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 the first three months of 2017, 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 more than 31 days and less than 62 days.

Table 12-41 Summary of potentially long duration (> 30 days) outages: January 1 through March 31, 2016 and 2017

	2016 (Jan - Mar)		2017 (Jan - Mar)	
Days	Number of Outages	Percent	Number of Outages	Percent
<=31	1	5.0%	0	0.0%
>31 & <=62	12	60.0%	5	35.7%
>62 and <=93	6	30.0%	9	64.3%
>93	1	5.0%	0	0.0%
Total	20	100.0%	14	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 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 12-33). 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 12-45 shows that 977 outage requests with a duration of two weeks or longer but shorter than two months were late, and only two of them were denied by PJM and 10.2 percent were cancelled. Table 12-45 also shows that 470 outage requests with a duration of two months or longer were late and none of them were denied by PJM and 10.9 percent were cancelled in the 2016 to 2017 planning year.

There are Long Term, Annual and Monthly Balance of Planning Period auctions in the FTR market. When determining transmission outages to be modeled 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 may exercise significant discretion in selecting outages to be modeled. PJM posts an FTR outage list to the FTR web page usually at least one week before the auction bidding opening day.[42]

Table 12-42 shows that 87.4 percent of the outage requests for outages expected to occur during the planning period 2016 to 2017 had a planned duration of less than two weeks and that 48.1 (9,458 out of 19,675) percent of all outage requests for the planning period were submitted late according to outage submission rules.

Table 12-42 Transmission facility outage requests by received status: Planning periods 2015 to 2016 and 2016 to 2017

	2015/2016				2016/2017			
Planned Duration	On Time	Late	Total	Percent	On Time	Late	Total	Percent
<2 weeks	8,797	8,810	17,607	87.0%	9,191	8,011	17,202	87.4%
>=2 weeks & <2 months	853	1,022	1,875	9.3%	832	977	1,809	9.2%
>=2 months	225	525	750	3.7%	194	470	664	3.4%
Total	9,875	10,357	20,232	100.0%	10,217	9,458	19,675	100.0%

42 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 12-43 shows late outage requests summary by emergency status. Of all outage requests for outages expected to occur in the 2016 to 2017 planning year and submitted late, 73.4 percent were for nonemergency outages.

Table 12-43 Late transmission facility outage requests by emergency: Planning periods 2015 to 2016 and 2016 to 2017

		2015/2016				2016/2017			
	Planned Duration	Emergency	Non Emergency	Total	Percent Non Emergency	Emergency	Non Emergency	Total	Percent Non Emergency
On Time	<2 weeks	16	8,781	8,797	99.8%	15	9,176	9,191	99.8%
	>=2 weeks & <2 months	4	849	853	99.5%	2	830	832	99.8%
	>=2 months	0	225	225	100.0%	0	194	194	100.0%
	Total	20	9,855	9,875	99.8%	17	10,200	10,217	99.8%
Late	<2 weeks	2,399	6,411	8,810	72.8%	2,239	5,772	8,011	72.1%
	>=2 weeks & <2 months	174	848	1,022	83.0%	182	795	977	81.4%
	>=2 months	103	422	525	80.4%	99	371	470	78.9%
	Total	2,676	7,681	10,357	74.2%	2,520	6,938	9,458	73.4%

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 12-44 shows a summary of requests by expected congestion and received status. Overall, 4.9 percent of all outage requests for outages expected to occur in the 2016 to 2017 planning year and submitted late were expected to cause congestion.

Table 12-44 Late transmission facility outage requests by congestion: Planning periods 2015 to 2016 and 2016 to 2017

		2015/2016				2016/2017			
	Planned Duration	Congestion Expected	No Congestion Expected	Total	Percent Congestion Expected	Congestion Expected	No Congestion Expected	Total	Percent Congestion Expected
On Time	<2 weeks	1,151	7,646	8,797	13.1%	1,091	8,100	9,191	11.9%
	>=2 weeks & <2 months	172	681	853	20.2%	149	683	832	17.9%
	>=2 months	46	179	225	20.4%	33	161	194	17.0%
	Total	1,369	8,506	9,875	13.9%	1,273	8,944	10,217	12.5%
Late	<2 weeks	371	8,439	8,810	4.2%	389	7,622	8,011	4.9%
	>=2 weeks & <2 months	49	973	1,022	4.8%	59	918	977	6.0%
	>=2 months	18	507	525	3.4%	15	455	470	3.2%
	Total	438	9,919	10,357	4.2%	463	8,995	9,458	4.9%

Table 12-45 shows that 84.4 percent of late outage requests with a duration of two weeks or longer but shorter than two months were active or completed, two was denied by PJM and 10.2 percent were cancelled in the 2016 to 2017 planning year. Table 12-45 also shows that 86.2 percent of late outage requests with duration of two months or longer were active or completed, none of them was denied, and 10.9 percent were cancelled in the 2016 to 2017 planning year.

Table 12-45 Transmission facility outage requests by received status and processed status: Planning periods 2015 to 2016 and 2016 to 2017

		2015/2016				2016/2017			
Planned Duration	Processed Status	On Time	Percent	Late	Percent	On Time	Percent	Late	Percent
<2 weeks	In Progress	0	0.0%	0	0.0%	1,407	15.3%	262	3.3%
	Denied	39	0.4%	36	0.4%	36	0.4%	51	0.6%
	Approved	0	0.0%	0	0.0%	134	1.5%	80	1.0%
	Cancelled	2,432	27.6%	1,202	13.6%	2,076	22.6%	968	12.1%
	Revised	0	0.0%	0	0.0%	18	0.2%	3	0.0%
	Active	0	0.0%	1	0.0%	26	0.3%	26	0.3%
	Completed	6,326	71.9%	7,571	85.9%	5,494	59.8%	6,621	82.6%
Total Submission		8,797	100.0%	8,810	100.0%	9,191	100.0%	8,011	100.0%
>=2 weeks & <2 months	In Progress	0	0.0%	0	0.0%	87	10.5%	41	4.2%
	Denied	0	0.0%	0	0.0%	2	0.2%	2	0.2%
	Approved	0	0.0%	0	0.0%	11	1.3%	9	0.9%
	Cancelled	236	27.7%	105	10.3%	202	24.3%	100	10.2%
	Revised	0	0.0%	0	0.0%	0	0.0%	0	0.0%
	Active	0	0.0%	0	0.0%	72	8.7%	82	8.4%
	Completed	617	72.3%	917	89.7%	458	55.0%	743	76.0%
Total Submission		853	100.0%	1,022	100.0%	832	100.0%	977	100.0%
>=2 months	In Progress	0	0.0%	0	0.0%	4	2.1%	13	2.8%
	Denied	0	0.0%	0	0.0%	0	0.0%	0	0.0%
	Approved	0	0.0%	0	0.0%	0	0.0%	1	0.2%
	Cancelled	45	20.0%	57	10.9%	52	26.8%	51	10.9%
	Revised	0	0.0%	0	0.0%	0	0.0%	0	0.0%
	Active	4	1.8%	20	3.8%	32	16.5%	120	25.5%
	Completed	176	78.2%	448	85.3%	106	54.6%	285	60.6%
Total Submission		225	100.0%	525	100.0%	194	100.0%	470	100.0%

Table 12-46 shows that there were 977 outage requests with a duration of two weeks or longer but shorter than two months submitted late, of which 55 were nonemergency and expected to cause congestion in the 2016 to 2017 planning year. Of the 55 such requests, three were in process, one was denied, eight were cancelled, and 43 were active or complete. For the outages planned for two months or longer, there were 470 total outages submitted late, of which 14 requests were nonemergency. Of those requests, two were in process, three were cancelled and nine were active or complete.

Table 12-46 Transmission facility outage requests by received status, processed status, emergency and congestion: Planning periods 2015 to 2016 and 2016 to 2017

		2015/2016						2016/2017					
		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	0	0	0.0%	0	0	0.0%	129	1,407	9.2%	14	262	5.3%
	Denied	32	39	82.1%	18	36	50.0%	27	36	75.0%	34	51	66.7%
	Approved	0	0	0.0%	0	0	0.0%	18	134	13.4%	5	80	6.3%
	Cancelled	305	2,432	12.5%	62	1,202	5.2%	206	2,076	9.9%	45	968	4.6%
	Revised	0	0	0.0%	0	0	0.0%	3	18	16.7%	0	3	0.0%
	Active	0	0	0.0%	0	1	0.0%	2	26	7.7%	1	26	3.8%
	Completed	811	6,326	12.8%	205	7,571	2.7%	704	5,494	12.8%	186	6,621	2.8%
Total Submission		1,148	8,797	13.0%	285	8,810	3.2%	1,089	9,191	11.8%	285	8,011	3.6%
>=2 weeks & <2 months	In Progress	0	0	0.0%	0	0	0.0%	24	87	27.6%	3	41	7.3%
	Denied	0	0	0.0%	0	0	0.0%	2	2	100.0%	1	2	50.0%
	Approved	0	0	0.0%	0	0	0.0%	3	11	27.3%	0	9	0.0%
	Cancelled	31	236	13.1%	6	105	5.7%	17	202	8.4%	8	100	8.0%
	Revised	0	0	0.0%	0	0	0.0%	0	0	0.0%	0	0	0.0%
	Active	0	0	0.0%	0	0	0.0%	14	72	19.4%	5	82	6.1%
	Completed	141	617	22.9%	39	917	4.3%	89	458	19.4%	38	743	5.1%
Total Submission		172	853	20.2%	45	1,022	4.4%	149	832	17.9%	55	977	5.6%
>=2 months	In Progress	0	0	0.0%	0	0	0.0%	0	4	0.0%	2	13	15.4%
	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%	0	0	0.0%	0	1	0.0%
	Cancelled	3	45	6.7%	2	57	3.5%	6	52	11.5%	3	51	5.9%
	Revised	0	0	0.0%	0	0	0.0%	0	0	0.0%	0	0	0.0%
	Active	0	4	0.0%	0	20	0.0%	7	32	21.9%	3	120	2.5%
	Completed	43	176	24.4%	15	448	3.3%	20	106	18.9%	6	285	2.1%
Total Submission		46	225	20.4%	17	525	3.2%	33	194	17.0%	14	470	3.0%

Even if an outage were submitted on time according to the transmission outage rules, it would not be modeled in the FTR model if it were submitted after the Annual FTR Auction bidding opening date. Table 12-47 shows that 64.7 percent of outage requests with duration longer than two weeks and shorter than two months labelled on time according to rules were submitted or rescheduled after the Annual FTR Auction bidding opening date in the 2016 to 2017 planning year. It also shows that 36.1 percent of outage requests with duration longer than or equal to two months labelled on time according to rules were submitted or rescheduled after the Annual FTR Auction bidding opening date in the 2016 to 2017 planning year.

Table 12-47 Transmission facility outage requests by received status and bidding opening date: Planning periods 2015 to 2016 and 2016 to 2017

	2015/2016						2016/2017					
	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	766	8,031	91.3%	181	8,629	97.9%	788	8,403	91.4%	158	7,853	98.0%
>=2 weeks & <2 months	316	537	63.0%	126	896	87.7%	294	538	64.7%	72	905	92.6%
>=2 months	131	94	41.8%	189	336	64.0%	124	70	36.1%	166	304	64.7%
Total	1,213	8,662	87.7%	496	9,861	95.2%	1,206	9,011	88.2%	396	9,062	95.8%

Table 12-48 shows that 80.7 percent of late outage requests which were submitted or rescheduled after the Annual FTR Auction bidding opening date were approved and complete in the 2016 to 2017 planning.

Table 12-48 Late transmission facility outage requests that are submitted after annual bidding opening date: Planning periods 2015 to 2016 and 2016 to 2017

	2015/2016			2016/2017		
Planned Duration	Completed Outages	Total	Percent	Completed Outages	Total	Percent
<2 weeks	7,407	8,629	85.8%	6,474	7,853	82.4%
>=2 weeks & <2 months	799	896	89.2%	684	905	75.6%
>=2 months	291	336	86.6%	159	304	52.3%
Total	8,497	9,861	86.2%	7,317	9,062	80.7%

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. By requiring all long-duration transmission outages to be submitted before February 1, PJM outage submission rules only prevent long-duration transmission outages from being submitted late. The rule does not address the situation in which long-duration transmission outages are submitted on-time, but are rescheduled so that they are late. The Annual FTR Auction model may consider transmission outages planned for longer than two weeks but less than two months. Those outages not only include long-duration but also include outages shorter than 30 days. In those cases, PJM outage submission rules failed to prevent long-duration transmission outages submitted late. The MMU recommends that PJM modify the rules to reduce or eliminate the approval of late outage requests submitted or rescheduled after the Annual FTR Auction bidding opening date.

Transmission Facility Outage Analysis in the Day-Ahead Energy 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 so that market participants can understand market conditions and so that PJM can accurately model market conditions in the day-ahead market. PJM requires transmission owners to submit changes to outages scheduled for the next two days no later than 09:30 am. [43]

In order to analyze the market impact, the outage requests that affect the operating day are compared: before the day-ahead market is closed; when the day-ahead market save cases are created; and during the operating day. The list of approved or active outage requests before the day-ahead market is closed is the view of outages available to market participants. The day-ahead market model uses a list of outages as an input. The list of outages that actually occurred during the operating day are the outages that affect the real-time market. If the three sets of outages are the same, there is no potential

43 PJM. "Manual 3: Transmission Operations," Revision 50 (December 1, 2016), p. 74

impact on markets. If the three sets of outages differ, there is a potential impact on markets.

For example for the operating day of November 23, 2016, Figure 12-4 shows that: there were 421 approved or active outages seen by market participants before the day-ahead market was closed; there were 282 outage requests included in the day-ahead market model; there were 273 outage request included in both sets of outage; there were 148 outage requests approved or active before the day-ahead market was closed but not included as inputs in day-ahead market model; and there were 9 outage requests included in day-ahead market model but not available to market participants prior to the day-ahead market.

Figure 12-4 Illustration of day-ahead market analysis on November 22, 2016

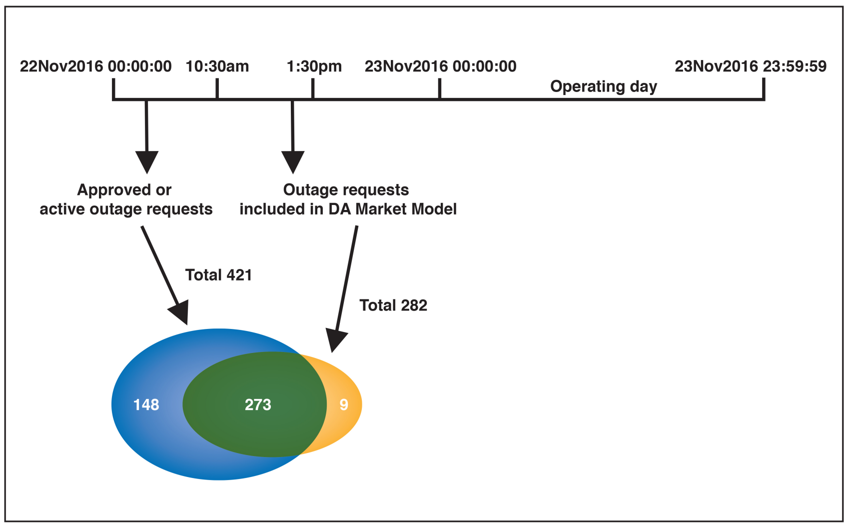


Figure 12-5 compares the weekly average number of active or approved outages available to market participants prior to the close of the day-ahead market with the outages included as inputs to the day-ahead market by PJM.

Figure 12-5 Weekly average number of approved or active outage requests comparing day-ahead market model outages: January 1, 2015 through March 31, 2017

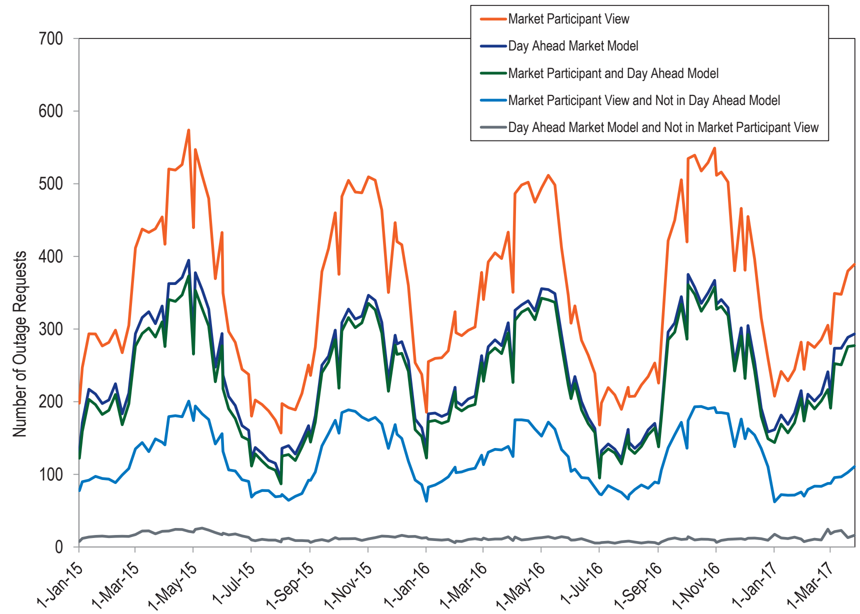


Figure 12-6 compares the weekly average number of outages included as inputs to the day-ahead market by PJM with the outages that actually occurred during the operating day.

Figure 12-6 Weekly average number of day-ahead market model outages comparing outages occurred on operating day: January 1, 2015 through March 31, 2017

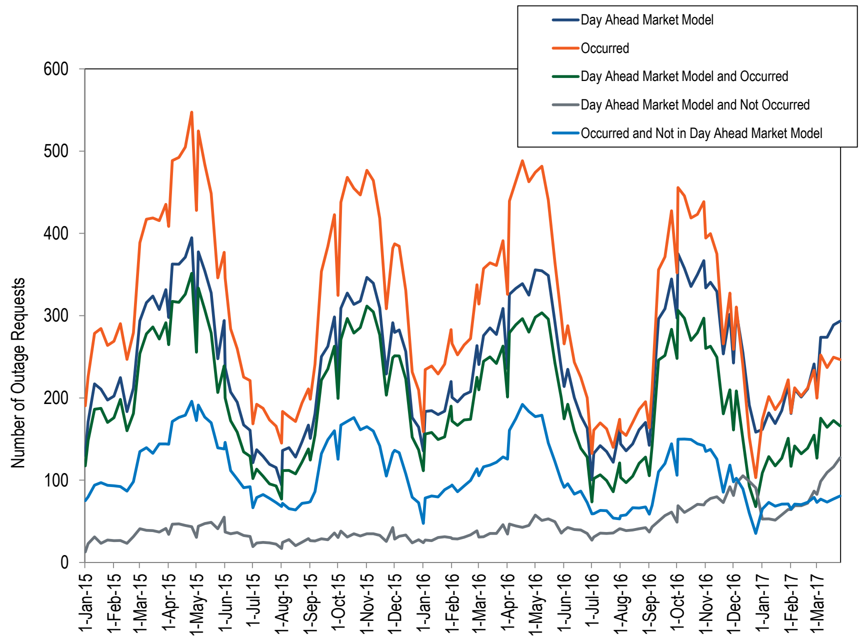


Figure 12-7 compares the weekly average number of active or approved outages available to market participants prior to the close of the day-ahead market with the outages that actually occurred during the operating day.

Figure 12-7 Weekly average number of approved or active outage requests comparing outages occurred on operating day: January 1, 2015 through March 31, 2017

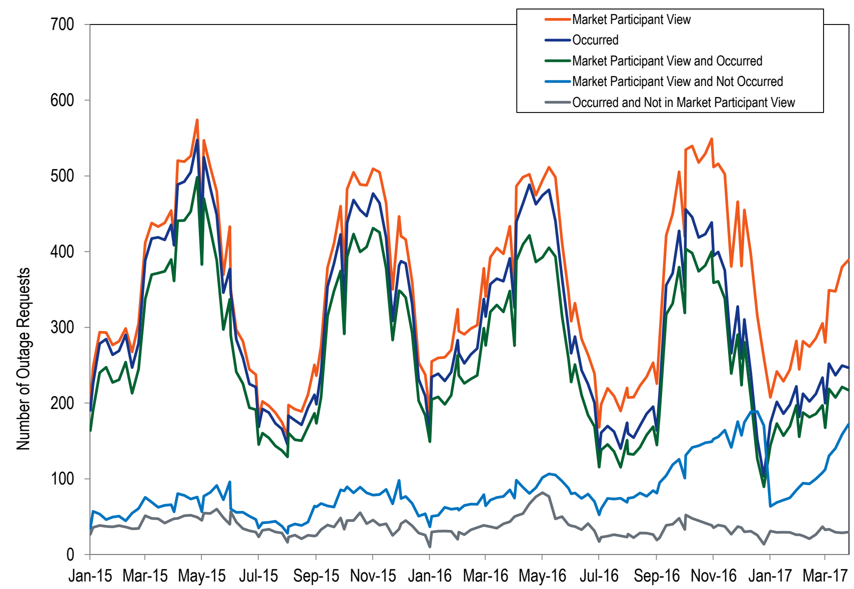


Figure 12-5, Figure 12-6, and Figure 12-7 show that on a weekly average basis, the active or approved outages available to day-ahead market participants, the outages included as inputs in the day-ahead market model and the outages that actually occurred in real time are not consistent. The active or approved outages available to day-ahead market participants are more consistent with the outages that actually occurred in real time than with the outages included in the day-ahead market model.

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 received the low cost generation.

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 April 1, 1999, FTRs were introduced with the LMP market, there was a real-time market but no day-ahead market, and FTRs returned real-time congestion revenue to load. Effective June 1, 2000, the day-ahead market was introduced and FTRs returned total congestion including day-ahead and balancing congestion to load. 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 86.5 percent of total congestion costs including congestion in the Day-Ahead Energy Market and the balancing energy market for the 15/16 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 a nodal, network system with locational marginal pricing. 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.

1 *See* 81 FERC ¶ 61,257, at 62,241 (1997).
2 *See Id.* at 62, 259–62,260 & n. 123.

On September 15, 2016, FERC ordered PJM to address the allocation of congestion credits in the FTR market, portfolio netting within the FTR market and the use of historical resources for the Annual ARR allocation process.[3] PJM made a compliance filing on November 14, 2016, outlining their plans to address these issues.[4] Under the order, PJM will allocate the costs of balancing congestion and market-to-market payments to load and exports. PJM will allocate all excess congestion revenue from the day-ahead market to FTR holders. PJM will allocate excess auction revenue, which is what FTR holders were willing to pay for FTRs in excess of what is provided to ARR holders, to FTR holders. FERC ordered the continued use of portfolio netting with the corresponding cross subsidies among participants in the FTR market. FERC directed PJM to replace generation to load paths based on retired generation with generation to load paths based on existing generation resources.

If the original PJM FTR design had been designed to return congestion revenues to load without use of the generation to load paths, 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.

The *2017 Quarterly State of the Market Report for PJM: January through March* focuses on the 16/17 Monthly Balance of Planning Period FTR Auctions for the 15/16 and 16/17 planning periods, covering January 1, 2017, through March 31, 2017.

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

3 See 156 FERC ¶ 61,180 (2016).

4 See Compliance Filing concerning Modifications to ARR and FTR Provisions, Docket No. EL16-6 (November 14, 2016).

- 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. But it is not clear, in a competitive market, why FTR purchases by financial entities remain persistently profitable.
- Market design was evaluated as flawed because there are significant flaws with the basic ARR/FTR design. The market design is not an efficient way to ensure that all congestion revenues are returned to load.

Overview

Auction Revenue Rights

Market Structure

- **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 first 10 months of the 16/17 planning period, PJM allocated a total of 28,451.4 MW of residual ARRs, down from 30,118.1 MW in the first 10 months of the 15/16 planning period, with a total target allocation of $6.6 million for the first 10 months of the 16/17 planning period, down from $7.7 million for the first 10 months of the 15/16 planning period.
- **ARR Reassignment for Retail Load Switching.** There were 53,343 MW of ARRs associated with $503,400 of revenue that were reassigned in the

first 10 months of the 15/16 planning period. There were 38,194 MW of ARRs associated with $426,200 of revenue that were reassigned for the first 10 months of the 16/17 planning period.

Market Performance

- **Revenue Adequacy.** For the 16/17 planning period, the ARR target allocations, which are based on the nodal price differences from the Annual FTR Auction, were $913.8 million, while PJM collected $940.3 million from the combined Long Term, Annual and Monthly Balance of Planning Period FTR Auctions, making ARRs revenue adequate. For the 15/16 planning period, the ARR target allocations were $931.6 million while PJM collected $968.1 million from the combined Long Term, Annual and Monthly Balance of Planning Period FTR Auctions. The year over year decrease in ARR target allocations and auction revenue is a result of decreased prices from the previous planning period resulting from continued reduced allocation of Stage 1B and Stage 2 ARRs. ARR revenue adequacy is also affected by PJM's clearing of additional counter flow FTRs to alleviate infeasibilities from Stage 1A.
- **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, which include congestion in the Day-Ahead Energy Market and the balancing energy market, for the 14/15 planning period. In the first 10 months of the 16/17 planning period, total ARR and self scheduled FTR revenues offset 92.4 percent of total congestion costs. The total offset for the last six planning periods is 72.4 percent. The goal of the design should be to return 100 percent of the congestion revenues to the load.

Financial Transmission Rights

Market Structure

- **Supply.** In the Monthly Balance of Planning Period FTR Auctions for the first 10 months of the 16/17 planning period, total participant FTR sell offers were 3,965,903 MW, down from 4,500,555 MW for the same period during the 15/16 planning period.
- **Demand.** The total FTR buy bids from the Monthly Balance of Planning Period FTR Auctions for the first 10 months of the 16/17 planning period decreased 19.8 percent from 23,243,499 MW for the same time period of the prior planning period, to 18,651,410 MW.
- **Patterns of Ownership.** For the Monthly Balance of Planning Period Auctions, financial entities purchased 74.0 percent of prevailing flow and 79.2 percent of counter flow FTRs for January through March of 2017. Financial entities owned 63.7 percent of all prevailing and counter flow FTRs, including 53.4 percent of all prevailing flow FTRs and 77.4 percent of all counter flow FTRs during the period from January through March 2017.

Market Behavior

- **FTR Forfeitures.** Total forfeitures for the first 10 months of the 16/17 planning period were $0.5 million for Increment Offers, Decrement Bids and UTC Transactions using PJM's method. FTR forfeitures were not billed after January 19, 2017.
- **Credit Issues.** There were no defaults in the first three months of 2017.

Market Performance

- **Volume.** In the first 10 months of the 16/17 planning period Monthly Balance of Planning Period FTR Auctions cleared 2,074,581 MW (11.1 percent) of FTR buy bids and 897,198 MW (22.6 percent) of FTR sell offers cleared.
- **Price.** The weighted average buy bid cleared FTR price in the Monthly Balance of Planning Period FTR Auctions for the first 10 months of the 16/17 planning period was $0.13, down from $0.21 per MW for the same period in the 15/16 planning period.
- **Revenue.** The Monthly Balance of Planning Period FTR Auctions generated $31.3 million in net revenue for all FTRs for the first 10 months of the

16/17 planning period, up from $31.1 million for the same time period in the 15/16 planning period.

- **Revenue Adequacy.** FTRs were paid at 100 percent of the target allocation level for the first 10 months of the 16/17 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 decision to include more outages and PJM's decision to include additional constraints (closed loop interfaces) in the model, 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 the first three months of 2017, physical entities lost money on FTRs, with -$21.4 million in profits, and financial entities had profits of $2.7 million.

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
2017/2020 Long Term	6/1/2016	12/5/2016
2016/2017 ARR	2/29/2016	3/29/2016
2016/2017 Annual	4/5/2016	4/28/2016

Recommendations

- The MMU recommends that the ARR/FTR design be modified to ensure that the rights to all congestion revenues are assigned to load. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that all FTR auction revenue be distributed to ARR holders. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that FTR auction revenues not be used to buy counter flow FTRs for the purpose of improving FTR payout ratios.[5] (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that all historical generation to load paths be eliminated as a basis for allocating ARRs. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that counter flow FTRs be eliminated. (Priority: High. First reported 2015. 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.)
- 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 implement a seasonal ARR and FTR allocation system to better represent outages. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM 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.)
- 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.)

5 See "PJM Manual 6: Financial Transmission Rights," Rev. 17 (June 1, 2016) at 55.

- 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 report correct monthly payout ratios to reduce understatement of payout ratios on a monthly basis. (Priority: Low. First reported 2012. Status: Adopted 2016.)

Conclusion

The annual ARR allocation should be designed to ensure that the rights to all congestion revenues are assigned to firm transmission service customers, without requiring contract path physical transmission rights that are 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 the benefits of firm low cost generation delivered using the transmission system in the form of revenues which offset congestion. Financial transmission rights and the associated revenues were directly provided to loads in recognition of the fact that loads pay for the transmission system which permits low cost generation to be delivered to load and loads pay congestion. 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 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 the rights to all the congestion revenues and 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 14/15 planning period. For the 15/16 planning period, ARRs and self scheduled FTRs offset 86.5 percent of total congestion costs. For the first 10 months of the 16/17 planning period, ARRs and self scheduled FTRs offset 92.4 percent of total congestion costs.

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.

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

The Commission's order will shift substantial revenue from load to the holders of FTRs and reduce the ability of load to offset congestion. If these rules had been in place for the first 10 months of the 16/17 planning period, and ARR/FTR allocations had remained constant, ARR holders would have gone from an offset of 92.4 percent under the current rule, to 86.3 percent under the new rule, a loss of $57.5 million for the first 10 months. FTR holders would have received a corresponding windfall and revenues to FTR holder would have exceeded target allocations by $158.1 million.

If these rules had been in place beginning with the 11/12 planning period, ARR holders would have received $1,010.3 million less in congestion offsets from the 11/12 through the 16/17 planning period. The total overpayment to FTR holders for the 11/12 through 16/17 planning period would have been $923.5 million. The underpayment to load and the overpayment to FTR holders is a result of several factors in the new rules all of which mean the transfer of revenues to FTR holders and the shifting of costs to load. Load is now required to pay for balancing congestion, which significantly increases costs to load and significantly increases revenues paid to FTR holders. PJM will continue to clear counter flow FTRs using excess auction revenues in order to make it possible to sell more prevailing flow FTRs. FTR holders will receive excess day-ahead congestion revenues in excess of target allocations. FTR holders will receive excess auction revenue, which is what FTR holders were willing to pay for FTRs in excess of what is provided to ARR 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 balancing 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.

PJM used a more conservative approach to modeling the transmission capability for the 14/15 through 16/17 planning periods compared to the 13/14 planning period. PJM simply used 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 10/11 planning period through the 13/14 planning period. The market response to lower revenue adequacy was to reduce bid prices and to increase bid volumes and offer volumes. In the 14/15 and 15/16 planning periods, due to reduced ARR allocations, FTR volume decreased relative to the 13/14 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 13/14 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 13/14 planning period from the reported 72.8 percent to 91.0 percent. For the 14/15 and 15/16 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 are 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. There is a reason that transmission is not built to address the Stage 1A overallocation issue. PJM's transmission planning process (RTEP) does not identify a need for new transmission because there is, in fact, no need for new transmission associated with Stage 1A ARRs. The Stage 1A overallocation issue is a fiction based on the use of outdated and irrelevant generation to load paths to assign Stage 1A rights that have nothing to do with actual power flows.

The result of removing portfolio netting, applying a payout ratio to counter flow FTRs and eliminating Stage 1A ARR overallocation in the 13/14 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 different line ratings, 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; the payment of congestion revenues to UTCs; 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.

It is not clear, in a competitive market, why FTR purchases by financial entities remain persistently profitable. In a competitive market, it would be expected that profits would be competed away.

For the 14/15 and 15/16 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 a 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 the rights to all the congestion revenues, and 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. The MMU recommends that all FTR auction revenues be 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 03/04 planning period. The initial allocation covered the Mid-Atlantic Region and the AP Control Zone. For the 06/07 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 07/08 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.

ARR Allocation

For the 07/08 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 zonal base load, based on generation to load paths that reflect generation resources that had served load prior to markets 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.

8 "PJM Manual 6: Financial Transmission Rights," Rev. 17 (June 1, 2016) at 31; "IARRs for RTEP Upgrades Allocated for 2016/2017 Planning Period," <http://www.pjm.com/~/media/markets-ops/ftr/annual-arr-allocation/2016-2017/2016-2017-iarrs-for-rtep-upgrades-allocated.ashx>.

9 See *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," Rev. 17 (June 1, 2016) at 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 zonal peak load, based on generation to load paths that reflect generation resources that had served load prior to markets 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 15/16 planning period, when residual zone pricing was 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 issues. 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.

FERC Order on EL16-121: Stage 1A ARR Allocation

FERC ordered PJM to more accurately represent system usage when allocating Stage 1A ARRs by removing retired resources from their allocation methodology.[15] PJM made a compliance filing, accepted by FERC, stating that

11 See "PJM Manual 6: Financial Transmission Rights," Rev. 17 (June 1, 2016) at 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>.
13 "PJM Manual 6: Financial Transmission Rights," Rev. 17 (June 1, 2016) at 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>.
15 156 FERC ¶ 61,180 (2016).

retired units would be replaced with qualified replacement resources (QRRs).[16] PJM proposed to categorize QRRs as built under a rate base approach or a non-rate base (market) approach. PJM proposed to give priority to load delivery from their own rate based units in deciding between competing ARR claims.

Under the new allocation methodology, PJM will replace retired units or units whose ICAP is less than their historical capacity with QRRs. A QRR will be a unit, or combination of units, whose ICAP value can meet the historically allocated MW quantity that was allocated based on the retired resource. QRRs will be classified as rate base or non-rate base units and ranked by rate base/non-rate base and by economics within each category. Participants will have to provide evidence that a unit is a rate-base unit to qualify for the designation in the Stage 1A ARR allocation. PJM will assign the historical MW to rate base QRRs within the zone, and then intra zonally to all generation units to replace retired resource capacity. These reassignments must all pass the simultaneous feasibility test.

The method PJM has proposed continues to rely on a contract path based approach. PJM is not applying this method to all Stage 1A units, so over allocations may persist. Existing, non-retired, Stage 1A resources will still be given their current allocations, while ARR allocations to QRRs that replace retired Stage 1A resources will be prorated based on the feasibility of these of ARRs after existing resources are allocated. As a result of this proration, the new ARRs will have lower priority than the non-retired Stage 1A resources, which could affect the value of the newly assigned ARRs.

FTR Revenue Adequacy and Stage 1B/Stage 2 ARR Allocations

For the 14/15 and 15/16 planning periods, FTR revenue adequacy was over 100 percent. Not every month was revenue adequate, but there was excess revenue from other months to ensure that the planning period was revenue adequate. The last time there were four months of consecutive funding of 100 percent or more was in the 09/10 planning period.

16 See FERC Docket No. EL16-6-003.

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 use 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 cannot be prorated.

Figure 13-1 shows the historic allocations for Stage 1B and Stage 2 ARRs from the 11/12 to 16/17 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 13/14 planning period to the 14/15 planning period. Total Stage 1B and Stage 2 ARR allocations increased slightly in the 15/16 planning year over the 14/15 planning year allocations, from 3,497.6 MW to 5,219.6 MW. But the ARR allocations for the 15/16 planning year were still 78.8 percent below 13/14 planning period volumes of 34,444.0 MW. For the 16/17 planning period there was another relatively small increase in available Stage 1B and Stage 2 capacity from 5,319.6 MW to 12,821.6 MW, but available ARRs were still 48.9 percent below 13/14 planning period volumes.

Figure 13-1 Historic Stage 1B and Stage 2 ARR Allocations from the 11/12 through 16/17 planning periods

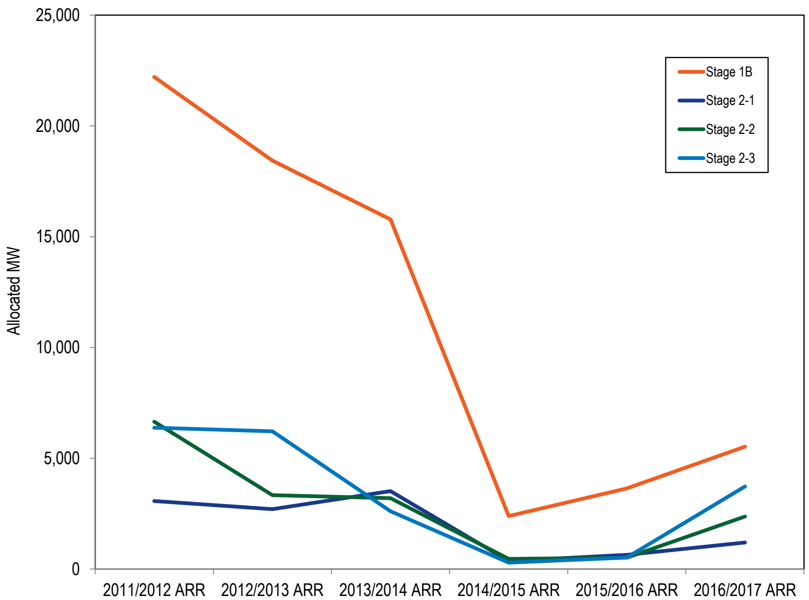


Table 13-3 shows the ARR allocations for the 11/12 through 16/17 planning periods. Stage 1A allocations cannot be prorated and have been slowly increasing. Stage 1B and Stage 2 allocations can be prorated. Stage 1B and Stage 2 allocations were steadily declining over the 11/12 through 13/14 planning periods, but were very significantly reduced in the 14/15 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 14/15 planning period to the 15/16 planning period and a small increase for the 16/17 planning period. These incremental increases are the result of PJM making more ARRs available based on excess revenue in the previous planning period.

Table 13-3 Historic Stage 1B and Stage 2 ARR Allocations from the 11/12 through 16/17 planning periods

Stage	2011/2012 ARR	2012/2013 ARR	2013/2014 ARR	2014/2015 ARR	2015/2016 ARR	2016/2017 ARR
Stage 1A	64,159.9	67,299.6	67,861.4	68,837.7	71,874.0	69,089.1
Stage 1B	22,208.3	18,431.7	15,782.0	2,389.6	3,643.1	5,525.7
Stage 2-1	3,072.5	2,700.6	3,519.2	360.9	643.8	1,197.1
Stage 2-2	6,652.6	3,334.3	3,200.0	455.9	511.2	2,368.8
Stage 2-3	6,382.6	6,218.7	2,611.8	291.2	521.5	3,730.0
Total Stage 2	16,107.7	12,253.6	9,331.0	1,108.0	1,676.5	7,295.9
Total Allocations	102,475.9	97,984.9	92,974.4	72,335.3	77,193.6	81,910.7

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.[17] ARR reassignment occurs daily only if the LSE losing load has ARRs with a net positive economic value to that control zone. An LSE gaining load in the same control zone is allocated a proportional share of positively valued ARRs within the control zone based on the shifted load. ARRs are reassigned to the nearest 0.001 MW and any MW of load may be reassigned multiple times over a planning period. Residual ARRs are also subject to the rules of ARR reassignment. This practice supports competition by ensuring that the offset to congestion follows load, thereby removing a barrier to competition among LSEs and, by ensuring that only ARRs with a positive value are reassigned, preventing an LSE from assigning poor ARR choices to other LSEs. However, when ARRs are self scheduled as FTRs, these underlying self-scheduled FTRs do not follow load that shifts while the ARRs do follow load that shifts, and this may result in lower value of the ARRs for the receiving LSE compared to the total value held by the original ARR holder.

There were 55,638 MW of ARRs associated with $659,000 of revenue that were reassigned in the 15/16 planning period. There were 38,194 MW of ARRs associated with $426,200 of revenue that were reassigned for the first 10 months of the 16/17 planning period.

17 See "PJM Manual 6: Financial Transmission Rights," Rev. 17 (June 1, 2016) at 28.

Table 13-4 summarizes ARR MW and associated revenue automatically reassigned for network load in each control zone where changes occurred between June 2015 and March 2017.

Table 13-4 ARRs and ARR revenue automatically reassigned for network load changes by control zone: June 1, 2015, through March 31, 2017

	ARRs Reassigned (MW-day)		ARR Revenue Reassigned [Dollars (Thousands) per MW-day]	
Control Zone	2015/2016 (12 months)	2016/2017 (10 months)	2015/2016 (12 months)	2016/2017 (10 months)
AECO	594	357	$4.5	$3.2
AEP	7,145	1,654	$72.0	$9.9
AP	2,171	1,367	$51.8	$28.1
ATSI	7,077	7,284	$66.7	$39.5
BGE	3,044	2,061	$95.7	$122.4
ComEd	5,433	2,769	$133.0	$91.4
DAY	624	593	$1.3	$1.7
DEOK	6,489	2,118	$31.5	$12.5
DLCO	6,179	5,136	$13.1	$12.2
DPL	1,628	1,436	$55.2	$29.2
Dominion	20	55	$0.3	$0.2
EKPC	0	0	$0.0	$0.0
JCPL	1,629	900	$12.4	$3.0
Met-Ed	1,081	757	$9.4	$6.2
PECO	4,189	3,248	$23.8	$8.1
PENELEC	1,277	1,076	$21.8	$16.2
PPL	3,341	3,811	$18.6	$4.6
PSEG	1,569	1,334	$37.5	$18.6
Pepco	2,098	2,182	$10.4	$19.0
RECO	52	58	$0.0	$0.1
Total	55,638	38,194	$659.0	$426.2

Residual ARRs

Residual ARRs are available if 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. Residual ARRs are a separate product from incremental ARRs.

Only ARR holders that had their Stage 1 ARRs prorated are eligible to receive Residual ARRs which cannot be declined, with positive or negative target allocations. Stage 1 ARR holders have a priority right to 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 13-5 shows the Residual ARRs automatically allocated to eligible participants, along with the target allocations from the effective month. In the first 10 months of the 16/17 planning period planning period, PJM allocated a total of 28,452.4 MW of residual ARRs, down from 30,118.1 MW for the first 10 months of the 15/16 planning period. Residual ARRs had a total target allocation of $6.6 million for the first 10 months of the 16/17 planning period, down from $7.7 million for the first 10 months of the 15/16 planning period. 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 13-5 Residual ARR allocation volume and target allocation: 2017

Month	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Target Allocation
Jan-17	3,253.4	2,186.7	67.2%	$1,148,805
Feb-17	5,885.1	2,273.7	38.6%	$905,697
Mar-17	9,304.9	2,391.6	25.7%	$286,710
Total	18,443.4	6,852.0	37.2%	$2,341,212

Market Performance

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 to ensure 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.[18]

There is a reason that transmission is not actually built to address the Stage 1A overallocation issue. PJM's transmission planning process (RTEP) does not identify a need for new transmission because there is, in fact, no need for new transmission associated with Stage 1A ARRs. The Stage 1A overallocation issue is a fiction based on the use of outdated and irrelevant generation to load paths to assign Stage 1A rights that have nothing to do with actual power flows.

For the 16/17 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 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.

18 "PJM Manual 6: Financial Transmission Rights," Rev. 17 (June 1, 2016) at 22.

The result of this required increased 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.

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.

ARR holders received $968.1 million in credits from the FTR auctions during the 15/16 planning period before accounting for self scheduling, load shifts or residual ARRs. The FTR auction revenue collected pays ARR holders' credits. During the first 10 months of the 16/17 planning period, ARR holders received $940.3 million in ARR credits.

Table 13-6 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 15/16 planning period and the first 10 months of the 16/17 planning periods.

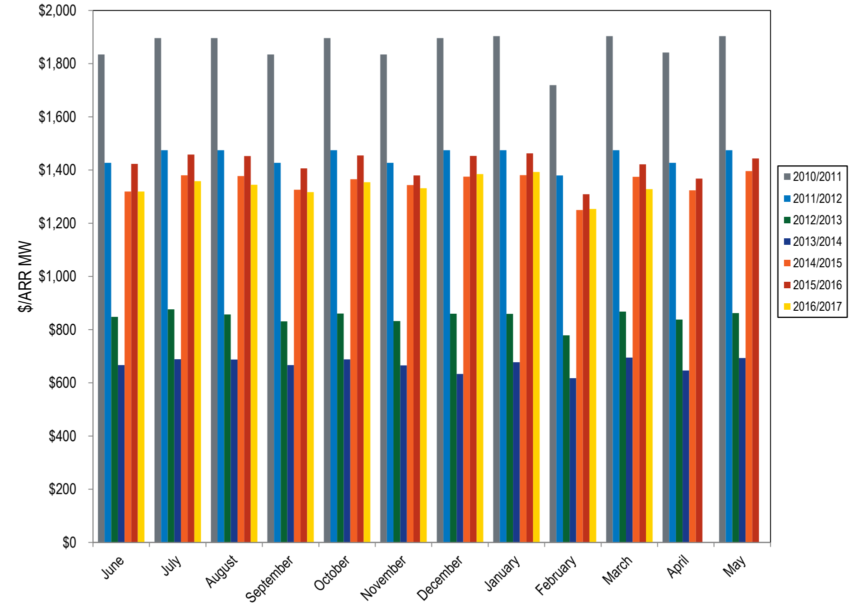
Table 13-6 Projected ARR revenue adequacy (Dollars (Millions)): Planning periods 15/16 and 16/17

	2015/2016	2016/2017
Total FTR auction net revenue	$968.1	$940.3
Annual FTR Auction net revenue	$936.3	$909.0
Monthly Balance of Planning Period FTR Auction net revenue*	$31.8	$31.3
ARR target allocations	$931.6	$913.8
ARR credits	$931.6	$913.8
Surplus auction revenue	$36.5	$26.5
ARR payout ratio	100%	100%
FTR payout ratio*	100%	100%

* Shows twelve months for 2015/2016 and ten months for 2016/2017.

Figure 13-2 shows the dollars per ARR MW held for each month of the 10/11 planning period through the first 10 months of the 16/17 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 14/15 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 14/15 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 15/16 planning period, the dollars per MW of ARR allocation was $10,641.54. For the first 10 months of the 16/17 planning period, the dollars per MW of ARR allocation were $9,337.48 down from $9,608.25 in the first 10 months of the 15/16 planning period. Total dollars per MW were down slightly in the 16/17 planning period due to increased Stage 1B and Stage 2 ARR volume.

Figure 13-2 Dollars per ARR MW paid to ARR holders: Planning periods 10/11 through 16/17



Excess Auction Revenue

Figure 13-3 shows the monthly excess auction revenue from the 11/12 through 15/16 planning periods. Excess auction revenue is the revenue collected each month from FTR auctions in excess of ARR target allocations.

Beginning with the 14/15 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.[19] This allows PJM to use the excess auction revenue to pay prevailing flow FTRs without increasing prevailing flow obligations. The result is to increase FTR funding. This action removes money from the ARR revenue stream and caused the decrease in excess ARR revenue beginning in

19 *See* "PJM Manual 6: Financial Transmission Rights," Rev. 17 (June 1, 2016) at 55.

June 2014. Excess auction revenue is allocated pro rata to FTR holders at the end of the planning period, instead of being distributed to ARR holders.

Figure 13-3 Monthly excess ARR revenue: Planning periods 11/12 through 16/17

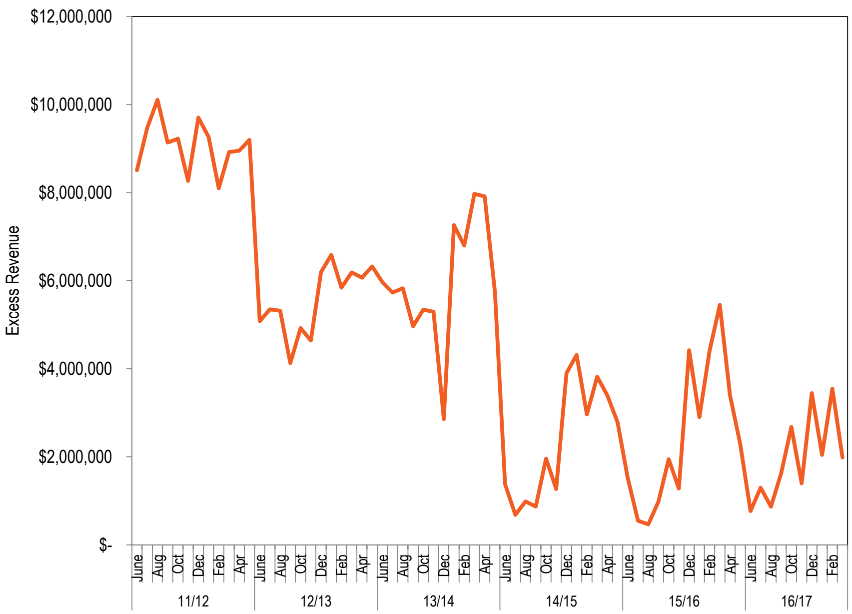


Table 13-7 shows the excess auction revenue, by planning period, for planning periods 10/11 through 16/17.

Table 13-7 Excess Auction Revenue: Planning periods 10/11 through 16/17

Planning Period	Excess Auction Revenue
2010/2011	$29,704,562
2011/2012	$80,083,695
2012/2013	$66,652,822
2013/2014	$71,687,937
2014/2015*	$29,045,590
2015/2016	$29,612,591
2016/2017**	$19,671,517
Total	$326,458,714

*Start of counter flow "buy back"

**Through March 31, 2017

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 total congestion revenue including day-ahead and balancing congestion. The value of the day-ahead congestion price differences, termed the FTR target allocation, defines the maximum, but not guaranteed, payout for FTRs. The target allocation of an FTR reflects the difference in day-ahead 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. 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. 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. 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 by ARR holders are available only as obligations and 24-hour product class, consistent with the associated ARRs, and only in the Annual FTR Auction.

Market Structure

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.[20] FTRs

20 See "PJM Manual 6: Financial Transmission Rights," Rev. 17 (June 1, 2016) at 38.

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 transmission capacity in the model on the affected facilities. The capacity modeled in the Annual ARR Allocation is used as the capacity for the Annual FTR Auction to simultaneously accommodate 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 starting in the 14/15 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.[21] 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 goals.

21 See "PJM Manual 6: Financial Transmission Rights," Rev. 17 (June 1, 2016) at 55.

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.

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

22 See "PJM Manual 6: Financial Transmission Rights," Rev. 17 (June 1, 2016) at 39.

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 entire 15/16 planning period and the first 10 months of the 16/17 planning period were 25,686,865 MW and 18,651,410 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 13-8 presents the Monthly Balance of Planning Period FTR Auction cleared FTRs for 2017 by trade type, organization type and FTR direction. Financial entities purchased 74.0 percent of prevailing flow FTRs, up 0.7 percent, and 79.2 percent of counter flow FTRs, up 4.7 percent, for the year, with the result that financial entities purchased 76.4 percent, up 1.9 percent, of all prevailing and counter flow FTR buy bids in the Monthly Balance of Planning Period FTR Auction cleared FTRs for 2017.

Table 13-8 Monthly Balance of Planning Period FTR Auction patterns of ownership by FTR direction: 2017

		FTR Direction		
Trade Type	Organization Type	Prevailing Flow	Counter Flow	All
Buy Bids	Physical	26.0%	20.8%	23.6%
	Financial	74.0%	79.2%	76.4%
	Total	100.0%	100.0%	100.0%
Sell Offers	Physical	17.9%	16.9%	17.6%
	Financial	82.1%	83.1%	82.4%
	Total	100.0%	100.0%	100.0%

Table 13-9 presents the average daily net position ownership for all FTRs for 2017, by FTR direction.

Table 13-9 Daily FTR net position ownership by FTR direction: 2017

	FTR Direction		
Organization Type	Prevailing Flow	Counter Flow	All
Physical	46.6%	22.6%	36.3%
Financial	53.4%	77.4%	63.7%
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]

23 See "PJM Manual 6: Financial Transmission Rights," Rev. 17 (June 1, 2016) at 56.

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]

Table 13-10 provides the Monthly Balance of Planning Period FTR Auction market volume for the entire 15/16 planning period and the first 10 months of the 16/17 planning period. There were 15,071,895 MW of FTR obligation buy bids and 2,017,735 MW of FTR obligation sell offers for all bidding periods in the first 10 months of the 16/17 planning period. The Monthly Balance of Planning Period FTR Auction cleared 2,017,735 MW (13.4 percent) of FTR obligation buy bids and 752,120 MW (21.4 percent) of FTR obligation sell offers.

There were 3,579,515 MW of FTR option buy bids and 459,474 MW of FTR option sell offers for all bidding periods in the Monthly Balance of Planning Period FTR Auctions for the first 10 months of the 16/17 planning period. The monthly auctions cleared 56,845 MW (1.6 percent) of FTR option buy bids, and 145,078 MW (31.6 percent) of FTR option sell offers.

24 *id.*

Table 13-10 Monthly Balance of Planning Period FTR Auction market volume: 2017

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-17	Obligations	Buy bids	241,099	1,077,550	123,675	11.5%	953,876	88.5%
		Sell offers	96,626	234,411	54,042	23.1%	180,370	76.9%
	Options	Buy bids	3,709	228,387	2,199	1.0%	226,187	99.0%
		Sell offers	7,276	28,852	11,745	40.7%	17,107	59.3%
Feb-17	Obligations	Buy bids	260,651	1,042,481	131,660	12.6%	910,821	87.4%
		Sell offers	94,844	208,036	48,565	23.3%	159,471	76.7%
	Options	Buy bids	2,826	190,661	2,187	1.1%	188,474	98.9%
		Sell offers	6,148	26,709	8,897	33.3%	17,812	66.7%
Mar-17	Obligations	Buy bids	259,179	1,004,570	166,466	16.6%	838,104	83.4%
		Sell offers	105,362	261,780	55,611	21.2%	206,168	78.8%
	Options	Buy bids	2,403	136,494	5,659	4.1%	130,835	95.9%
		Sell offers	6,941	32,989	10,691	32.4%	22,298	67.6%
2015/2016*	Obligations	Buy bids	4,076,728	21,836,340	2,366,860	10.8%	19,469,480	89.2%
		Sell offers	1,582,528	4,385,972	1,088,967	24.8%	3,297,005	75.2%
	Options	Buy bids	157,638	3,850,526	92,957	2.4%	3,757,569	97.6%
		Sell offers	112,395	505,471	137,873	27.3%	367,598	72.7%
2016/2017**	Obligations	Buy bids	3,550,288	15,071,895	2,017,735	13.4%	13,054,160	86.6%
		Sell offers	1,709,127	3,506,429	752,120	21.4%	2,754,309	78.6%
	Options	Buy bids	80,436	3,579,515	56,845	1.6%	3,522,669	98.4%
		Sell offers	111,876	459,474	145,078	31.6%	314,396	68.4%

* Shows twelve months for 2015/2016; ** Shows ten months ended March 31 for 2016/2017

Table 13-11 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 2017 was 143,948.4 MW. The average monthly cleared volume for 2016 was 219,630.6 MW.

Table 13-11 Monthly Balance of Planning Period FTR Auction buy-bid, bid and cleared volume (MW per period): 2017

Monthly Auction	MW Type	Prompt Month	Second Month	Third Month	Q1	Q2	Q3	Q4	Total
Jan-17	Bid	614,939	263,340	198,667				228,991	1,305,937
	Cleared	72,086	25,184	10,841				17,763	125,874
Feb-17	Bid	617,074	230,889	201,187				183,993	1,233,142
	Cleared	82,727	24,497	13,321				13,302	133,847
Mar-17	Bid	582,068	237,341	219,040				102,614	1,141,063
	Cleared	100,495	34,460	27,873				9,297	172,125

Figure 13-4 shows cleared auction volumes as a percent of the total FTR cleared volume by calendar months for June 2004 through March 2017, 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 a corresponding increase in the share of Annual FTRs.

Figure 13-4 Cleared auction volume (MW) as a percent of total FTR cleared volume by calendar month: June 1, 2004 through March 31, 2017

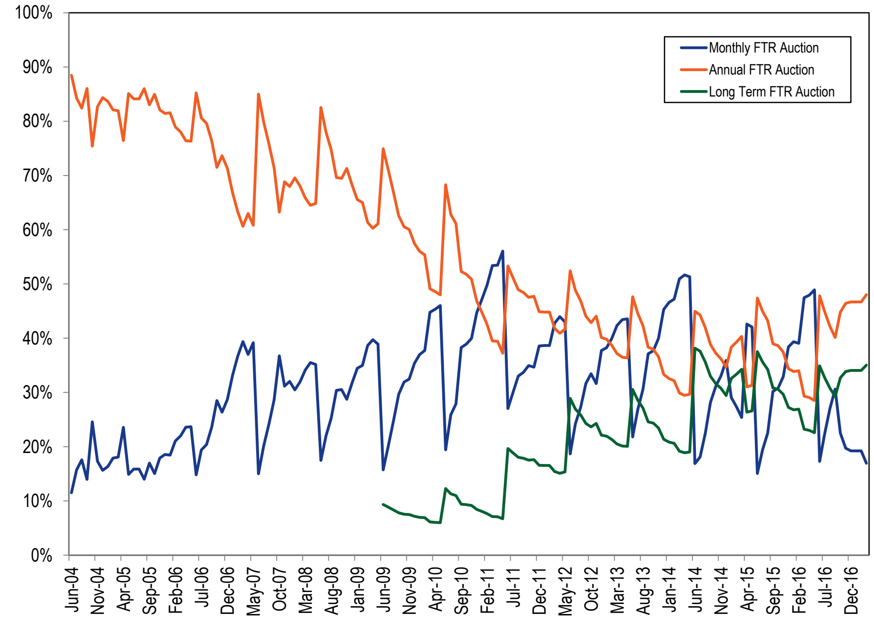


Table 13-12 provides the secondary bilateral FTR market volume for the entire 15/16 and 16/17 planning periods.

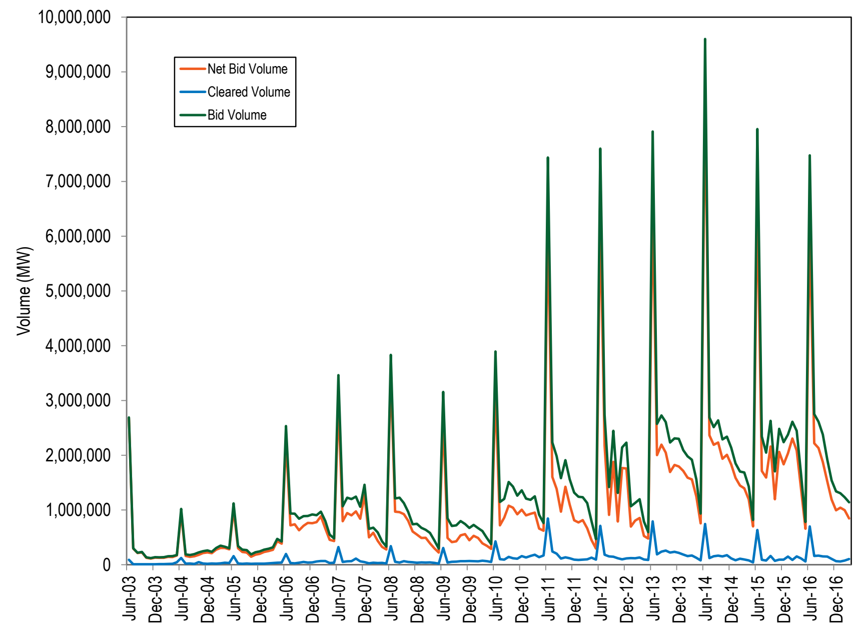
Table 13-12 Secondary bilateral FTR market volume: Planning periods 15/16 and 16/17[25]

Planning Period	Type	Class Type	Volume (MW)
2015/2016	Obligation	24-Hour	667.6
		On Peak	40,207.5
		Off Peak	27,652.4
		Total	68,527.5
	Option	24-Hour	0.0
		On Peak	8,765.5
		Off Peak	6,157.1
		Total	14,922.6
2016/2017	Obligation	24-Hour	538.5
		On Peak	13,955.7
		Off Peak	7,414.4
		Total	21,908.6
	Option	24-Hour	0.0
		On Peak	678.0
		Off Peak	104.5
		Total	782.5

Figure 13-5 shows the FTR bid, cleared and net bid volume from June 2003 through March 2017 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.

25 The 15/16 planning period covers bilateral FTRs that are effective for any time between June 1, 2015 through May 31, 2016, which originally had been purchased in a Long Term FTR Auction, Annual FTR Auction or Monthly Balance of Planning Period FTR Auction
26 The data for this table are available in *2016 State of the Market Report for PJM*, Volume 2, Appendix H.

Figure 13-5 Long Term, Annual and Monthly FTR Auction bid and cleared volume: June 1, 2003 through March 31, 2017



Price

Table 13-13 shows the weighted-average cleared buy-bid price in the Monthly Balance of Planning Period FTR Auctions by bidding period for January through March 2017. For example, for the January 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 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 March 2017 was $0.13 per MW, down from $0.12 per MW in the same time last year, a 8.3 percent increase in FTR prices. The cleared weighted-average price for the current planning period was $0.13, down 35.0 percent from $0.20 for the same time period during the previous planning period.

Table 13-13 Monthly Balance of Planning Period FTR Auction cleared, weighted-average, buy-bid price per period (Dollars per MW): January 1 through March 31, 2017

Monthly Auction	Prompt Month	Second Month	Third Month	Q1	Q2	Q3	Q4	Total
Jan-17	$0.14	$0.23	$0.05				$0.09	$0.13
Feb-17	$0.07	$0.09	$0.05				$0.06	$0.07
Mar-17	$0.09	$0.12	$0.13				$0.02	$0.09

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 for financial entities regardless of the payout ratio raises questions about the competitiveness of the market. It is not clear, in a competitive market, why FTR purchases by financial entities remain persistently profitable. In a competitive market, it would be expected that profits would be competed to zero or a de mimimis level.

Table 13-14 lists FTR profits by organization type and FTR direction for the period from January through March, 2017. Some participants classified as physical, such as a company that holds one generator, are not eligible for ARRs but do have a physical presence on the PJM system. Such entities would be under the Physical category, while any entity that holds an ARR will be under the Physical ARR Holder category. Separating physical into those participants with and without FTRs allows a better view into the profits ARR holders are making through the FTR market. FTR profits are the sum of the daily FTR target allocations, including for self-scheduled FTRs, adjusted by the payout ratio 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 FTR credits also do not include any excess congestion revenue distributions made at the end of the planning period. 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. FTR profitability is the difference between the revenue received for an FTR and the cost of the FTR. In the first three months of 2017, physical entities lost money on FTRs, with -$21.4 million in profits, and financial entities had profits of $2.7 million.

Table 13-14 FTR profits by organization type and FTR direction: 2017

	FTR Direction				
Organization Type	Prevailing Flow	Self Scheduled Prevailing Flow	Counter Flow	Self Scheduled Counter Flow	All
Financial	($81,473,560.05)	NA	$84,164,908	NA	$2,691,348
Physical	($21,621,158.22)	NA	$14,995,939	NA	($6,625,219)
Physical ARR Holder	($64,055,593.66)	$36,219,117	$13,195,571	($106,997)	($14,747,902)
Total	($167,150,311.94)	$36,219,117	$112,356,418	($106,997)	($18,681,774)

Table 13-15 lists the monthly FTR profits in 2017 by organization type.

Table 13-15 Monthly FTR profits by organization type: 2017

	Organization Type			
Month	Physical	Physical ARR Holders	Financial	Total
Jan	($1,519,199)	($10,870,707)	$82,092	($12,307,814)
Feb	($2,227,836)	($1,645,130)	$3,282,949	($590,017)
Mar	($2,878,185)	($2,232,065)	($673,693)	($5,783,943)
Total	($6,625,219)	($14,747,902)	$2,691,348	($18,681,774)

Table 13-16 lists the historical profits by calendar year by organization type beginning January 2011.

Table 13-16 Yearly FTR profits by organization type: 2011 through 2016

Calendar Year	Physical	Financial	Total
2011	$340,260,261	$125,697,493	$465,957,753
2012	($7,634,041)	$78,762,923	$71,128,882
2013	$170,180,569	$177,494,506	$347,675,076
2014	$873,909,275	$543,642,102	$1,417,551,377
2015	$453,547,398	$182,282,134	$635,829,532
2016	$244,139,718	$47,537,492	$291,677,210

Revenue

Monthly Balance of Planning Period FTR Auction Revenue

Table 13-17 shows Monthly Balance of Planning Period FTR Auction revenue by trade type, type and class type for January through March 2017. The Monthly Balance of Planning Period FTR Auctions for the 16/17 planning period netted $31.3 million in revenue, the difference between buyers paying $151.1 million and sellers receiving $119.8 million for the first 10 months of the 16/17 planning period. For the entire 2015 to 2016 planning period, the Monthly Balance of Planning Period FTR Auctions netted $31.8 million in revenue with buyers paying $263.5 million and sellers receiving $231.7 million.

Table 13-17 Monthly Balance of Planning Period FTR Auction revenue: 2017

Monthly			Class Type			
Auction	Type	Trade Type	24-Hour	On Peak	Off Peak	All
Jan-17	Obligations	Buy bids	$2,064,395	$3,326,398	$1,880,556	$7,271,349
		Sell offers	($1,166,330)	$2,100,570	$568,999	$1,503,239
	Options	Buy bids	$0	$436,831	$124,595	$561,427
		Sell offers	$14,107	$2,241,105	$1,851,251	$4,106,463
Feb-17	Obligations	Buy bids	$19,605	$2,333,806	$1,386,196	$3,739,608
		Sell offers	($73,596)	($379,460)	($408,832)	($861,888)
	Options	Buy bids	$0	$112,477	$48,121	$160,598
		Sell offers	$10,443	$1,587,969	$1,091,908	$2,690,320
Mar-17	Obligations	Buy bids	($931,344)	$4,194,358	$2,656,930	$5,919,943
		Sell offers	($28,037)	$3,554,009	$632,253	$4,158,225
	Options	Buy bids	$0	$281,337	$130,792	$412,129
		Sell offers	$5,795	$1,219,568	$675,806	$1,901,170
2015/2016*	Obligations	Buy bids	$19,822,319	$132,789,349	$90,651,090	$243,262,758
		Sell offers	($3,279,132)	$105,708,110	$76,816,631	$179,245,609
	Options	Buy bids	$34,213	$12,353,013	$7,822,858	$20,210,083
		Sell offers	$237,496	$30,375,844	$21,799,523	$52,412,863
	Net Total		$22,898,168	$9,058,407	($142,207)	$31,814,368
2016/2017**	Obligations	Buy bids	$33,393,379	$70,378,863	$32,313,828	$136,086,071
		Sell offers	$1,496,596	$51,547,110	$20,478,015	$73,521,721
	Options	Buy bids	$370,191	$9,202,101	$5,440,931	$15,013,224
		Sell offers	$580,881	$28,195,652	$17,532,111	$46,308,645
	Net Total		$31,686,093	($161,798)	($255,367)	$31,268,928

* Shows Twelve Months; ** Shows Ten 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 first 10 months of the 16/17 planning period. Figure 13-6 shows the 10 largest positive and negative FTR target allocations, summed by sink, for the first 10 months of the 16/17 planning period. The top 10 sinks that produced financial benefit accounted for 48.8 percent of total positive target allocations during the first 10 months of the 16/17 planning period with the Northern Illinois Hub accounting for 15.3 percent of all positive target allocations. The top 10 sinks that created liability accounted for 17.5 percent of total negative target allocations with the PSEG Zone accounting for 2.9 percent of all negative target allocations.

Figure 13-6 Ten largest positive and negative FTR target allocations summed by sink: 16/17 planning period

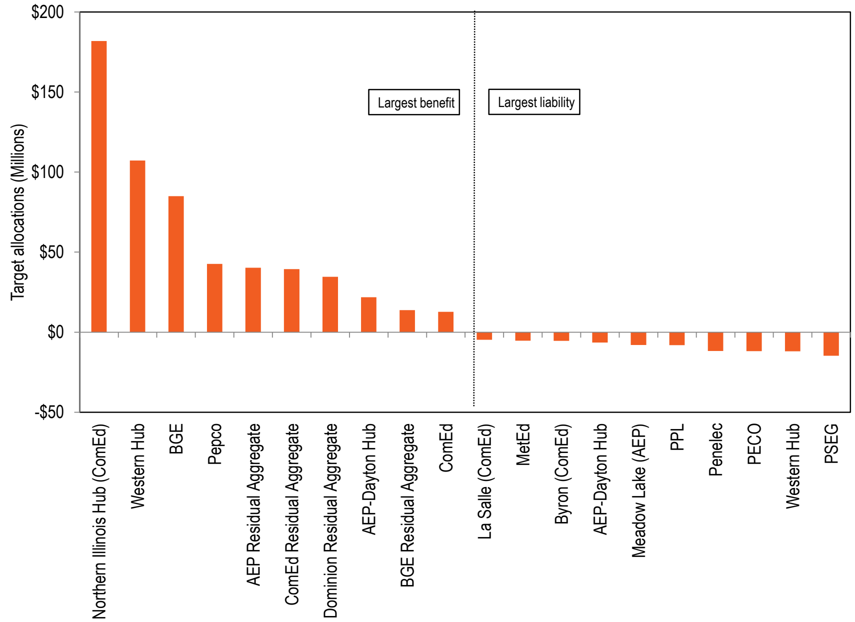


Figure 13-7 Ten largest positive and negative FTR target allocations summed by source: 16/17 planning period

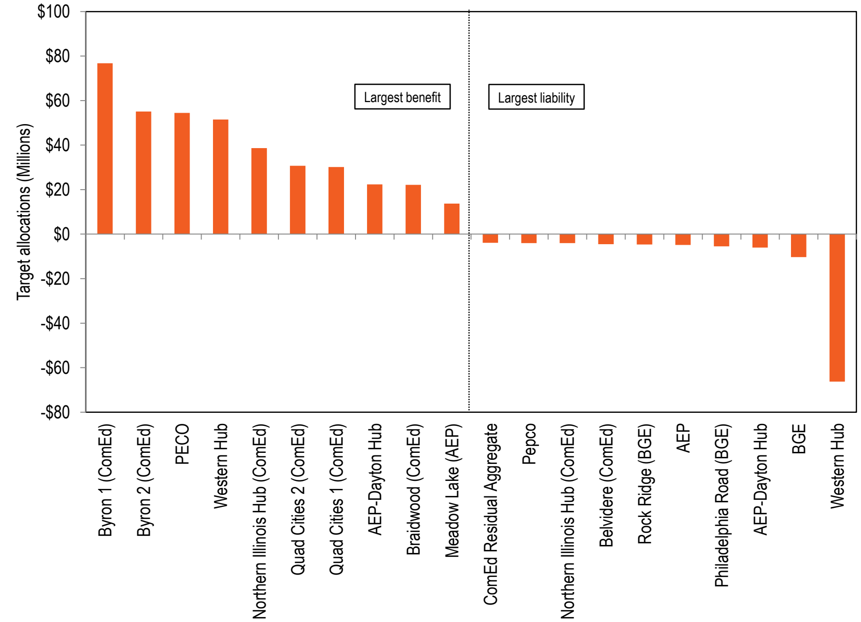


Figure 13-7 shows the 10 largest positive and negative FTR target allocations, summed by source, for the first 10 months of the 16/17 planning period. The top 10 sources with a positive target allocation accounted for 33.3 percent of total positive target allocations with Byron accounting for 6.5 percent of total positive target allocations. The top 10 sources with a negative target allocation accounted for 22.6 percent of all negative target allocations, with the Western Hub accounting for 13.1 percent.

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. 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, is assigned 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. If PJM allocated FTRs equal to the transmission capability into constrained areas, FTR payouts would equal the sum of congestion.

Revenue adequacy must be distinguished from the adequacy of ARRs/FTRs as an offset against total congestion. Revenue adequacy is a narrower concept that compares total congestion revenues, including day-ahead and balancing congestion, to the total target allocations, based only on day-ahead congestion, 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 ARRs/FTRs as an offset for load against congestion compares ARR and self-scheduled FTR revenues to total congestion on the system.

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 was 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 revenues, which equal the difference between ARR target allocations and FTR auction revenues, and negative FTR target allocations, which are a source of revenue from FTRs with a negative target allocation. Competing use revenues are based on the Unscheduled Transmission Service Agreement between the New York Independent System Operator (NYISO) and PJM. This agreement sets forth the terms and conditions under which compensation is provided for transmission service in connection with transactions not scheduled directly or otherwise prearranged between NYISO and PJM. Congestion revenues appearing in Table 13-18 include both congestion charges associated with PJM facilities and those associated with reciprocal, coordinated flowgates (M2M flowgates) in MISO and NYISO whose operating limits are respected by PJM.[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 nonmonitoring RTO's real-time market flow is greater than their FFE plus the approved MW adjustment from day-ahead coordination, then the nonmonitoring RTO will pay the monitoring RTO based on the difference between their market flow and their FFE. If the nonmonitoring 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 nonmonitoring RTO for congestion relief provided by the non-monitoring RTO based on the difference between the nonmonitoring RTO's market flow and their FFE.

For the 14/15, 15/16 and the first 10 months of the 16/17 planning periods, PJM paid MISO and NYISO a combined $33.2 million, $41.5 million and $26.4 million for redispatch on the designated M2M flowgates. 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.

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."

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)

FTRs were paid at 100 percent of the target allocation level for the 14/15 and 15/16 planning periods. Congestion revenues are allocated to FTR holders based on FTR target allocations. PJM collected $1,457.1 million, $1,003.3 million and $775.1 million of FTR revenues during the 14/15, 15/16 and first 10 months of the 16/17 planning periods. 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 15/16 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.

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 14/15 planning period, Stage 1B and Stage 2 ARR allocations were reduced by 84.9 percent and 88.1 percent from the 13/14 planning period. For the 15/16 planning period, Stage 1B and Stage 2 ARR allocations were reduced by 76.9 percent and 82.0 percent from the 13/14 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 impact on total ARR target allocations is shown in Table 13-18 and on dollars per MW in Figure 13-2.

Table 13-18 presents the PJM FTR revenue detail for the 15/16 planning period and the first 10 months of the 16/17 planning period.

Table 13-18 Total annual PJM FTR revenue detail (Dollars (Millions)): Planning periods 15/16 and 16/17

Accounting Element	2015/2016	2016/2017
ARR information		
ARR target allocations	$963.5	$779.0
FTR auction revenue	$993.1	$798.7
ARR excess	$29.6	$19.7
FTR targets		
Positive target allocations	$1,148.8	$945.3
Negative target allocations	($209.1)	($146.7)
FTR target allocations	$939.7	$680.9
Adjustments:		
Adjustments to FTR target allocations	($0.3)	($0.5)
Total FTR targets	$939.4	$680.9
FTR revenues		
ARR excess	$29.6	$19.7
Congestion		
Net Negative Congestion (enter as negative)	($25.2)	($11.0)
Hourly congestion revenue	$1,021.0	$775.3
Midwest ISO M2M (credit to PJM minus credit to Midwest ISO)	($41.5)	($26.4)
Adjustments:		
Excess revenues carried forward into future months	$21.5	$17.6
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	$21.5	$17.6
Net Negative Congestion charged to DA Operating Reserves	$0.0	$0.0
Total FTR congestion credits	$1,003.3	$775.1
Total congestion credits on bill (includes CEPSW and end-of-year distribution)	$1,003.3	$775.1
Remaining deficiency	($39.2)	($85.5)

FTR target allocations are based on hourly prices in the Day-Ahead Energy Market for FTR paths and are defined to be the revenue required to compensate FTR holders for day-ahead congestion on those paths. FTR credits are paid to FTR holders and, depending on market conditions, can be less than the target allocations. Table 13-19 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 13-19 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. September 2016 and October 2016 had revenue shortfalls totaling $2.6 million and $6.1 million, but were fully funded using excess revenue from previous months.

Table 13-19 Monthly FTR accounting summary (Dollars (Millions)): Planning period 15/16 and 16/17

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-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)
Jan-16	$105.7	$102.1	100.0%	$102.1	100.0%	($3.7)
Feb-16	$110.5	$103.7	100.0%	$103.7	100.0%	($6.8)
Mar-16	$75.4	$80.2	94.1%	$80.2	100.0%	$4.7
Apr-16	$71.4	$82.6	86.4%	$82.6	100.0%	$11.3
May-16	$49.2	$51.6	95.4%	$51.6	100.0%	$2.4
Summary for Planning Period 2015 to 2016						
Total	$981.6	$939.6		$990.8	100.0%	$57.7
Jun-16	$60.5	$55.1	100.0%	$60.5	100.0%	($5.4)
Jul-16	$112.1	$87.1	100.0%	$112.1	100.0%	($24.9)
Aug-16	$110.9	$82.2	100.0%	$110.9	100.0%	($28.7)
Sep-16	$117.7	$120.4	97.7%	$120.4	100.0%	$2.6
Oct-16	$104.9	$110.9	94.5%	$110.9	100.0%	$6.1
Nov-16	$45.7	$38.2	100.0%	$45.7	100.0%	($7.4)
Dec-16	$52.9	$42.3	100.0%	$52.9	100.0%	($10.7)
Jan-17	$61.1	$44.0	100.0%	$61.1	100.0%	($17.1)
Feb-17	$47.5	$51.8	91.7%	$51.8	100.0%	$0.0
Mar-17	$44.4	$48.9	90.8%	$48.9	100.0%	$0.0
Summary for Planning Period 2016 to 2017						
Total	$757.7	$680.8		$775.1		($85.5)

Figure 13-8 shows the original PJM reported FTR payout ratio by month, excluding excess revenue distribution, for January 2004 through March 2017. The months with payout ratios above 100 percent have excess congestion revenue and the months with payout ratios under 100 percent are revenue inadequate. Figure 13-8 also shows the payout ratio after distributing excess revenue across months within the planning period. If there are excess revenues in a given month, the excess is distributed to other months within the planning period that were revenue deficient. The payout 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 13-8 FTR payout ratio by month, excluding and including excess revenue distribution: January 1, 2004 through March 31, 2017

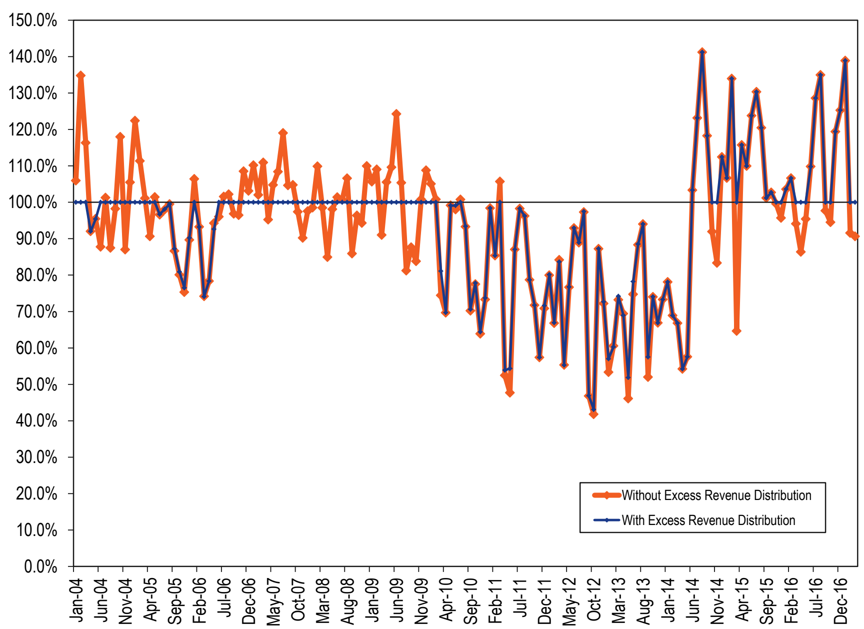


Table 13-20 shows the FTR payout ratio by planning period from the 2003 to 2004 planning period forward. Planning period 2013 to 2014 includes the additional revenue from unallocated congestion charges from Balancing Operating Reserves. For the 2014 to 2015 and 2015 to 2016 planning periods, there was excess congestion revenue to pay target allocations resulting in a payout ratio of 116.2 percent and 106.8 percent for the planning periods. This excess will be distributed to all FTR participants, pro rata, based on their net positive target allocations.

Table 13-20 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%
2016/2017	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 13-21 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 10 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 13-21 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)	$0.00	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

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. There are several reasons for the disconnect between congestion revenues and ARR/FTR revenues. The reasons include unavoidable modeling differences, avoidable modeling differences, such as outage modeling decisions, cross subsidies among and between FTR participants ARR holders and the construction of the Stage 1A ARR system which is based on historical, rather than physical, pathways.

The issuance of the September 15, 2016, FERC order increases the gap between congestion revenue and ARR/FTR revenue collected. Allocating balancing congestion and M2M payments, along with allocating excess congestion revenue to FTR holders solely, increases revenue adequacy for FTRs, but reduces payments to load and increases costs to load, undermining the ability of load to offset their congestion costs. Supporting FTR portfolio netting leads to cross subsidies among FTR participants. Restructuring Stage 1A allocations using QRRs for retired resources is an attempt to fix a flawed system, but retains the core problem which is reliance on contract path congestion revenue rights. The accepted rule change does not address the problem with using contract paths, does not address the deficiencies for active units and gives priority to units based on financial, not physical, determinations. The purpose of the FTR/ARR system is to return congestion revenue to load. The current and newly accepted rules do not meet this goal.

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 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 13-22 shows an example of the effects of calculating FTR payouts on a per FTR basis rather than the current method of portfolio netting for four hypothetical organizations for an example hour. 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 13-22 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 13-23 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. September 2016 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.

Table 13-23 Monthly positive and negative target allocations and payout ratios with and without hourly netting: Planning period 15/16 and 16/17

	Net Positive Target Allocations	Net Negative Target Allocations	Per FTR Positive Target Allocations	Per FTR Negative Target Allocations	Total Congestion Revenue	Reported Payout Ratio (Current)	No Netting Payout Ratio (Proposed)
Jun-16	$66,890,503	($11,761,810)	$145,725,072	($90,578,663)	$60,547,574	100.0%	100.0%
Jul-16	$103,067,704	($15,947,225)	$234,908,328	($147,750,891)	$112,060,353	100.0%	100.0%
Aug-16	$106,463,071	($24,309,023)	$270,738,798	($188,528,046)	$110,872,528	100.0%	100.0%
Sep-16	$143,711,526	($23,349,848)	$334,869,805	($214,320,300)	$120,361,723	100.0%	100.0%
Oct-16	$140,704,976	($29,766,159)	$322,466,349	($211,484,113)	$110,938,816	100.0%	100.0%
Nov-16	$50,418,317	($12,156,919)	$124,242,433	($85,964,032)	$45,658,421	100.0%	100.0%
Dec-16	$58,101,556	($15,818,469)	$164,917,652	($122,634,566)	$52,937,720	100.0%	100.0%
Jan-17	$57,634,209	($13,628,839)	$155,454,345	($111,435,198)	$61,102,571	100.0%	100.0%
Feb-17	$62,493,872	($10,637,939)	$164,114,064	($112,258,132)	$51,847,372	100.0%	100.0%
Mar-17	$61,368,268	($12,419,714)	$178,782,835	($129,836,815)	$58,898,455	100.0%	100.0%
2015/2016 Total	$1,148,845,079	($206,167,602)	$2,970,405,028	($2,030,832,071)	$1,003,307,668	100.0%	100.0%
2016/2017* Total	$850,854,002	($169,795,945)	$2,096,219,680	($1,414,790,755)	$785,225,532	100.0%	100.0%

*First ten months of 2016 to 2017 planning period

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 13-24 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	-

Table 13-24 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.

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 13-26 shows the effects on a participant with and without portfolio netting under three distinct scenarios. Table 13-25 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 13-25 Nodal day-ahead CLMPs

Node	DA CLMP
A	$20
B	$25
C	$40
D	$100
E	$10

Table 13-26 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

FERC Order on FTRs: Portfolio Netting

On September 15, 2016, FERC decided that PJM's current practice of portfolio netting was just and reasonable.[30] FERC did not agree that portfolio netting led to subsidization of portfolios with counterflow positions. The Market Monitor and PJM demonstrated that eliminating portfolio netting would eliminate a cross subsidy among FTR portfolios without changing the amount of total revenue available revenue to pay to portfolios.

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.

30 See 156 FERC ¶ 61,180 (2016).

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 13-27 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 13-27 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 13-28 shows the monthly positive, negative and total target allocations.[31] Table 13-28 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 14/15, 15/16 or 16/17 planning periods. 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 as a slight difference in the total revenue and adjusted counter flow total revenue columns for February and March 2017 that were not revenue adequate. The result of this would be $4.3 million in additional revenue generated for 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 13-9 shows the FTR surplus, collected day-ahead, balancing and total congestion payments from January 2005 through March 2017. May 2016 had positive total balancing congestion of $7.5 million. March 2015 had balancing congestion of -$70.0 million.

Figure 13-9 FTR surplus and the collected day-ahead, balancing and total congestion: January 1, 2005 through March 31, 2017

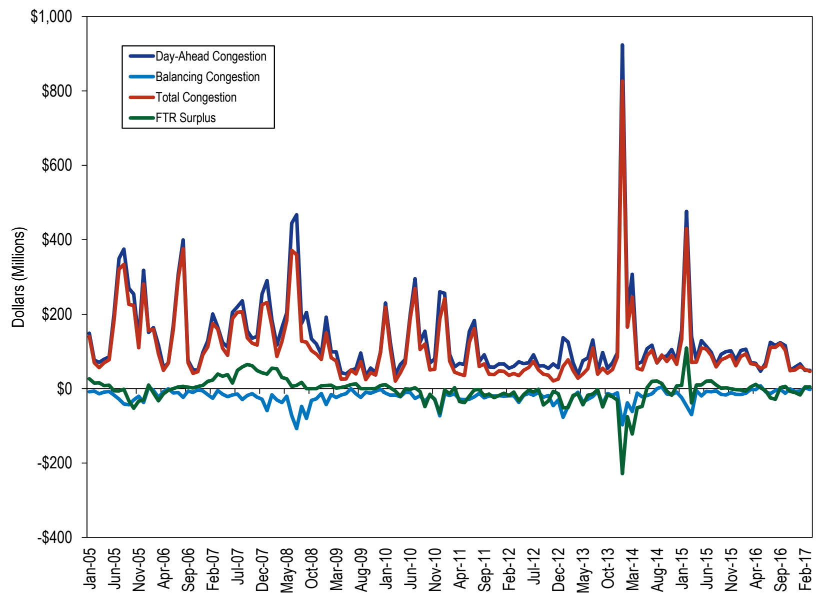


Table 13-28 Counter flow FTR payout ratio adjustment impacts: Planning period 15/16 and 16/17

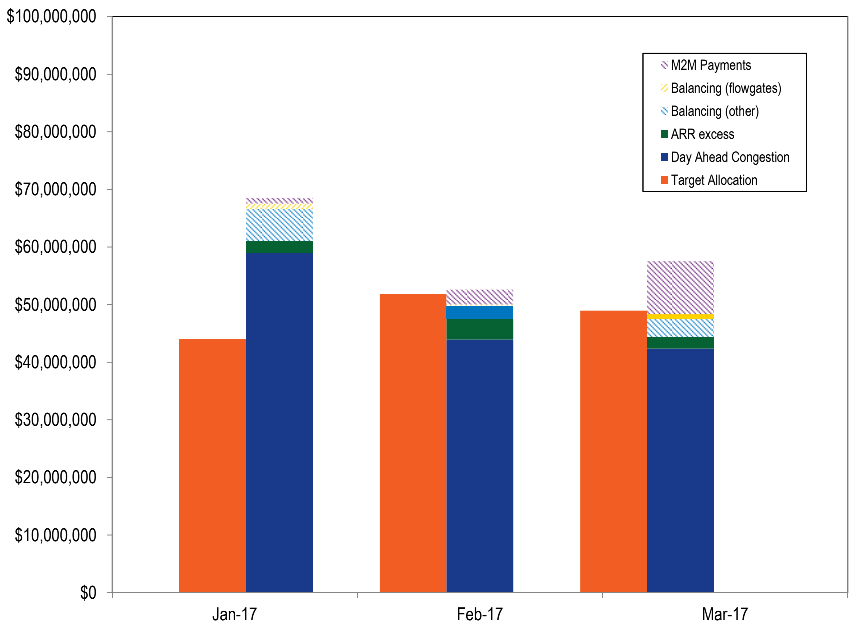
	Positive Target Allocations	Negative Target Allocations	Total Target Allocations	Total Congestion Revenue	Reported Payout Ratio*	Total Revenue Available	Adjusted Prevailing Flow Payout Ratio	Adjusted Counter Flow Payout Ratio	Adjusted Counter Flow Revenue Available	Additional Revenue Generated
Jan-17	$155,454,345	($111,435,198)	$44,019,146	$61,102,571	100.0%	$172,537,769	100.0%	100.0%	$172,537,769	$0
Feb-17	$164,114,064	($112,258,132)	$51,855,933	$51,847,372	100.0%	$164,105,504	100.0%	100.0%	$164,108,362	$2,858
Mar-17	$178,782,835	($129,836,814)	$48,946,021	$48,898,455	99.9%	$178,735,269	100.0%	100.0%	$178,751,090	$15,821
Total 2015/2016	$2,970,404,365	($2,030,831,660)	$939,572,706	$1,002,235,633	100.0%	$3,033,067,292	100.0%	100.0%	$3,037,387,376	$4,320,084
Total 2016/2017	$2,096,219,680	($1,414,790,754)	$681,428,926	$775,225,487	100.0%	$2,190,016,242	100.0%	100.0%	$2,096,025,661	$93,355

* Reported payout ratios may vary due to rounding differences when netting

31 Reported payout ratio may differ between Table 13-23 and Table 13-28 due to rounding differences when netting target allocations and considering each FTR individually.

Figure 13-10 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 2017 was revenue inadequate by $4.4 million. March was revenue inadequate by $4.6 million, but there was enough excess revenue in other months in the planning period to fully fund both months.

Figure 13-10 FTR target allocation compared to sources of positive and negative congestion revenue



ARRs as an Offset to Congestion for Load

Load pays for the transmission system and contributes 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 13-29 compares the revenue received by ARR holders and total congestion for the 2011 to 2012 through the first four months of the 16/17 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 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 13-29 shows the offset provided by ARRs and self scheduled FTRs for the entire 11/12 through the 16/17 planning period. This offset reflects the share of congestion revenues returned to loads. ARR and FTR revenues offset 44.7 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 2015 to 2016 planning period ARRs and self scheduled FTRs offset 86.5 percent of total congestion costs. For the first 10 months of the 16/17 planning period ARRs and self scheduled FTRs offset 92.4 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. The current allocation of congestion revenue resulted in a total of $1,731.8 million in unreturned congestion revenue to ARR holders, and a 72.4 percent congestion offset, over the last six planning periods.

Table 13-29 ARR and FTR total congestion offset (in millions) for ARR holders: Planning periods 11/12 through 16/17

Planning Period	ARR Credits	FTR Credits	Total Congestion	Total ARR/ FTR Offset	Percent Offset	Unreturned Revenue
2011/2012	$512.2	$249.8	$770.6	$762.0	98.9%	$8.5
2012/2013	$349.5	$181.9	$575.8	$531.4	92.3%	$44.4
2013/2014	$337.7	$456.4	$1,777.1	$794.0	44.7%	$983.1
2014/2015	$482.4	$404.4	$1,390.9	$886.8	63.8%	$504.1
2015/2016	$635.3	$223.4	$992.6	$858.8	86.5%	$133.8
2016/2017	$533.8	$169.6	$761.2	$703.4	92.4%	$57.8
Total	$2,850.9	$1,685.5	$6,268.1	$4,536.4	72.4%	$1,731.8

FERC Order on FTRs: Balancing Congestion and M2M Payment Allocation

On September 15, 2016, FERC issued an order removing balancing congestion and market to market (M2M) payments from the FTR funding equation and assigned them, on a load ratio basis, to load and exports.[32] The MMU has petitioned the U.S. Court of Appeals for the District of Columbia Circuit to reverse the order and restore the longstanding approach to calculating congestion revenues.[33] The has been consolidated with appeals filed by others and is now pending.

The new rule for calculating congestion revenues will go into effect on June 1, 2017, for the 2017 to 2018 planning period.

In its compliance filing PJM redefined balancing congestion as balancing congestion plus market to market (M2M) payments between MISO and NYISO. Under the order, load and exports will pay balancing congestion and M2M payments proportionally. On average from the 2011 to 2012 planning period on, load comprises 94.7 percent of all demand. From the 2011 to 2012 planning period onward, total balancing congestion and M2M payments were $1,516.0 million, so load would have been responsible for an additional $$1,010.3 million in charges to subsidize FTR holders.

In addition, FERC ordered that all excess congestion revenue, which includes day-ahead congestion in excess of FTR target allocations and excess FTR auction revenue, belongs to FTR holders. PJM initially proposed returning excess day-ahead and excess FTR auction revenue to ARR holders, but that proposal was rejected by FERC. Under this new rule, for the 11/12 through 16/17 planning period FTR holders would have receive an additional $923.5 million over their target allocations.

The Market Monitor continues to propose that excess FTR auction revenue should be allocated to ARR holders and all congestion rents, including balancing congestion, should be allocated to FTRs.

The reallocation of balancing congestion and M2M payments from FTR holders to load, and the allocation of excess auction revenues to FTR holders subsidizes FTR holders at the expense of ARR holders. It is inconsistent with the logic that FTRs are a day-ahead only product because excess auction revenues are not day-ahead revenues.

Table 13-30 shows the share of total congestion that is offset by ARRs and FTRs for load for the 11/12 through 16/17 planning periods. Table 13-30 shows the congestion offset available to load under the current rules. Table 13-30 also shows what the congestion offset available to load would be under the new rules, the change in the congestion offset available to load and the overpayment to FTRs under the new rules. The new congestion offset is calculated as the ARR credits and the FTR credits excluding balancing congestion and M2M payments, divided by the total congestion and the load share of balancing and M2M payments. The proposed new revenue is the sum of the ARR credits, adjusted FTR credits and the load share of balancing congestion and M2M payments. The FTR over payment is the excess day-

32 See 156 FERC ¶ 61,180 (2016), *reh'g denied*, 156 FERC ¶ 61,093 (2017).
33 Case No. 17-1106.

ahead congestion revenue and excess auction revenue FTR holders received over their FTR target allocations.

If these rules had been in place beginning with the 11/12 planning period, ARR holders would have received $1,010.3 million less in congestion offsets from the 11/12 through the 16/17 planning period. The total overpayment to FTR holders for the 11/12 through 16/17 planning period would have been $923.5 million. The underpayment to load and the overpayment to FTR holders is a result of several factors in the new rules all of which mean the transfer of revenues to FTR holders and the shifting of costs to load. Load is now required to pay for balancing congestion, which significantly increases costs to load and significantly increases revenues paid to FTR holders. PJM will continue to clear counter flow FTRs using excess auction revenues in order to make it possible to sell more prevailing flow FTRs. FTR holders will receive excess day-ahead congestion revenues in excess of target allocations. FTR holders will receive excess auction revenue, which is what FTR holders were willing to pay for FTRs in excess of what is provided to ARR holders.

Table 13-30 ARR and FTR total congestion offset (in millions) for ARR holders under PJM's proposed FTR funding: Planning periods 11/12 through 16/17

	Old					Proposed				
Planning Period	ARR Credits	FTR Credits	Total Congestion	Total ARR/ FTR Offset	Percent Offset	New Offset	Old Revenue Received	New Revenue Received	ARR Holder Change	FTR Over Payment
2011/2012	$512.2	$249.8	$770.6	$762.0	98.9%	83.3%	$762.0	$598.6	($163.4)	$113.9
2012/2013	$349.5	$181.9	$575.8	$531.4	92.3%	68.0%	$531.4	$275.9	($255.5)	$62.1
2013/2014	$337.7	$456.4	$1,777.1	$794.0	44.7%	43.2%	$794.0	$574.1	($219.9)	$0.0
2014/2015	$482.4	$404.4	$1,390.9	$886.8	63.8%	57.2%	$886.8	$686.6	($200.2)	$400.6
2015/2016	$635.3	$223.4	$992.6	$858.8	86.5%	78.2%	$858.8	$744.8	($113.9)	$188.9
2016/2017	$533.8	$169.6	$761.2	$703.4	92.4%	86.3%	$703.4	$645.9	($57.5)	$158.1
Total	$2,850.9	$1,685.4	$6,268.1	$4,536.4	72.4%	64.4%	$4,536.4	$3,526.1	($1,010.3)	$923.5

Credit Issues

There were no defaults in the first three months of 2017.

FTR Forfeitures

FERC Order on FTR Forfeitures

On January 19, 2017, FERC determined that the application of the current FTR forfeiture rule to INCs, DECs and UTCs was unjust and unreasonable.[34] In their determination, FERC ordered that a method should be developed to consider the net impact of a participant's entire portfolio of virtual bids on a constraint related to an FTR position. The new rule will be more transparent and will depend on an individual participant's net impact on a constraint. FERC also explicitly ordered counter flow FTRs to be considered for FTR forfeiture.

In response to this, PJM determined that no FTR forfeitures will be billed to participants after January 19, 2017, under the prior rules. Instead, participants will be retroactively billed their FTR forfeiture amounts based on the new FTR forfeiture rule once it is in place.

Until January 19, 2017, 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.

34 See 158 FERC ¶ 61,038 (2017).

Figure 13-11 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 13-11, 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 13-11 Illustration of INC/DEC FTR forfeiture rule

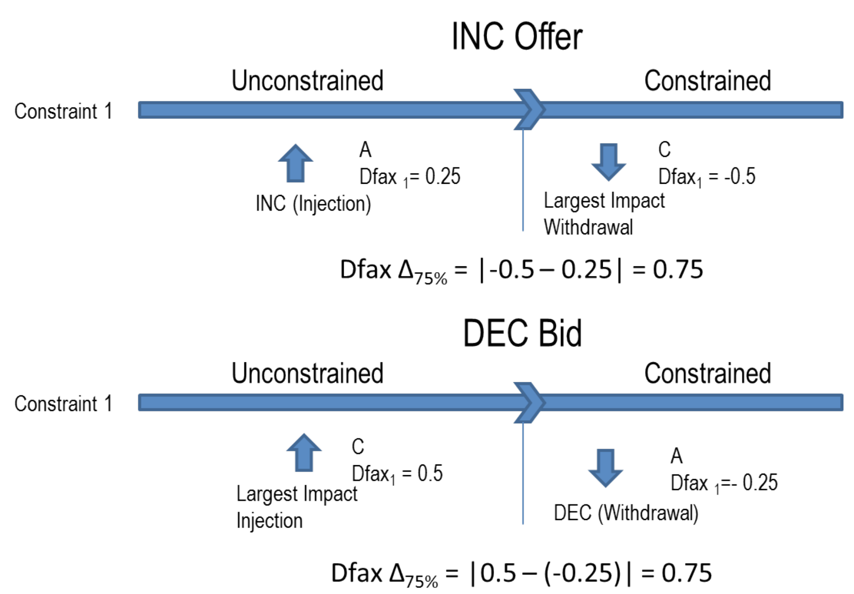
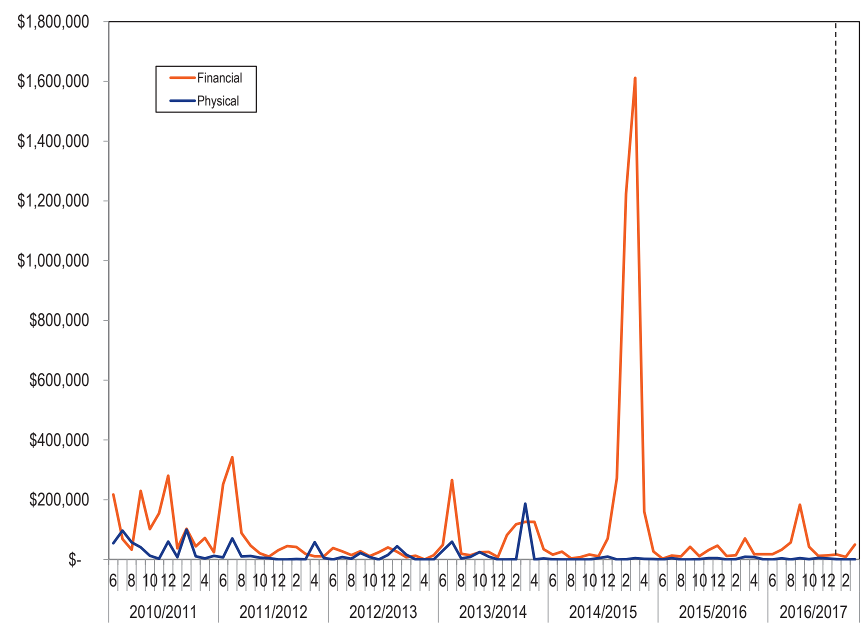


Figure 13-12 shows the FTR forfeiture values for both physical and financial participants for each month of June 2010 through March 2017. Currently, counter flow FTRs are not subject to forfeiture regardless of INC or DEC positions. Total forfeitures for the first 10 months of the 16/17 planning period were \$0.4 million (0.07 percent of total FTR target allocations). The dashed vertical line represents January 2017, which is the final month PJM will assess FTR forfeitures using the method described above.

Figure 13-12 Monthly FTR forfeitures for physical and financial participants: June 2010 through March 2017



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 13-13 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 13-13 Illustration of UTC FTR forfeiture rule

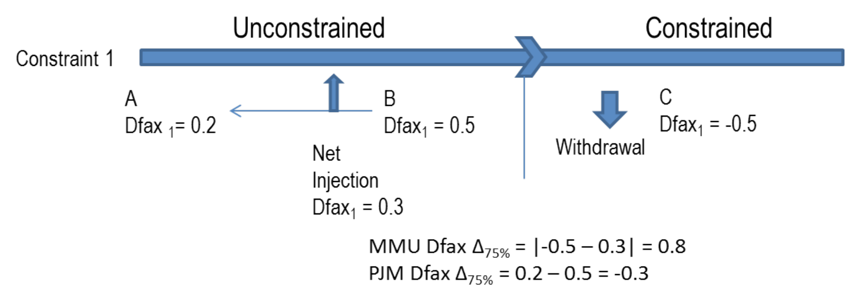
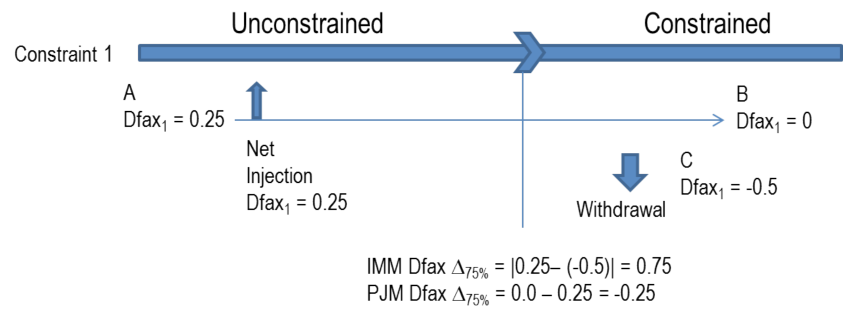


Figure 13-14 demonstrates where the assumption of contract path for UTCs in PJM's method does not hold with actual system conditions when either the source or sink of the UTC does not have any impact on the constraint being considered. In this case, the UTC is effectively an INC or a DEC relative to 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 13-14, 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 13-14 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.