# State of the Market Report for PJM

## Volume 2: Detailed Analysis

Monitoring Analytics, LLC
Independent Market Monitor for PJM

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# Preface

The PJM Market Monitoring Plan provides:

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

Accordingly, Monitoring Analytics, LLC, which serves as the Market Monitoring Unit (MMU) for PJM Interconnection, L.L.C. (PJM),[2] and is also known as the Independent Market Monitor for PJM (IMM), submits this *2017 State of the Market Report for PJM*.[3]

1 PJM Open Access Transmission Tariff (OATT) Attachment M (PJM Market Monitoring Plan) § VI.A. Capitalized terms used herein and not otherwise defined have the meaning provided in the OATT, PJM Operating Agreement, PJM Reliability Assurance Agreement or other tariff that PJM has on file with the Federal Energy Regulatory Commission (FERC or Commission).

2 OATT Attachment M.

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 State of the Market Report for PJM*.

# TABLE OF CONTENTS

# Introduction

## 2017 in Review

The results of the energy market and the results of the capacity market were competitive in 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, reliability and resilience, 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. Changing LMP to increase revenues to preferred technologies is also tempting and no more consistent with markets than cost of service regulation.

It is essential that any approach to the PJM markets incorporate a consistent view of how the preferred market design is expected 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 market assets that are uneconomic as a result of competition. Subsidies are an effort to reverse market outcomes with no commitment to a regulatory model and no attempt to mitigate negative impacts on competition. 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 continued to evolve in 2017. These subsidies are not directly part of the PJM market design but nonetheless threaten the foundations of the PJM capacity market and the PJM energy market, as well as the competitiveness of PJM markets overall.

The Ohio subsidy proceedings, the Illinois ZEC subsidy proceeding, the request in Pennsylvania to subsidize the Three Mile Island nuclear power plant, the request in New Jersey to subsidize the Salem and Hope Creek nuclear power plants, and the DOE Grid Resilience Proposal (NOPR), 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 new 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.

The proponents of subsidies and of the concomitant significant alterations to the PJM capacity market and energy market designs have not demonstrated that there is a systematic problem rather than an uneconomic unit specific problem. Proponents have not demonstrated that the technologies in question actually need subsidies or higher revenues from market design changes.

An evaluation of the economics of the PJM nuclear fleet based on public data shows that some nuclear plants are at risk of retirement. The exact number depends on the evaluation criteria. Using historical data, between six nuclear plants with a total capacity of 7,058 MW and nine plants with a total capacity of 14,027 MW did not recover their avoidable costs in two of the last three years. Based on forward prices for energy and the known forward prices for capacity, all but four nuclear plants with a total capacity of 3,554 MW would cover their annual avoidable costs on average over the next three years (2018 through 2020) including 100 percent of nuclear plant capital expenditures estimated by the Nuclear Energy Institute (NEI). Given that Oyster Creek has been scheduled to retire since 2015, there are three nuclear plants with a total capacity of 2,939 MW that would not cover avoidable costs on this basis. These three plants are all single unit nuclear plants which have higher costs than multiple unit sites.

An evaluation of the economics of the PJM coal fleet shows that a significant number of coal units are at risk of retirement based on historical data. If the coal units at risk are defined to be units receiving less than 90 percent of their avoidable costs, the total coal MW at risk would be 17,302 MW.

Based on these criteria, 22,929 MW, primarily of coal and nuclear capacity in PJM, are at risk of retirement, in addition to the units that are currently planning to retire, primarily coal and nuclear units. Based on more conservative criteria, 30,785 MW are at risk of retirement.

There are some nuclear power plants in PJM that are not economic at expected levels of energy and capacity market clearing prices. There are coal plants that are not economic at recent levels of energy and capacity market clearing prices. The decisions on how to proceed belong to the owners of those plants. The fact that some plants are uneconomic does not call into question the fundamentals of PJM markets. Many generating plants have retired in PJM since the introduction of markets and many generating plants have been built since the introduction of markets.

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.

In addition, artificially retaining uneconomic units in the market through the use of subsidies suppresses energy and capacity market prices and puts other units with relatively weak economics at risk. That is what makes subsidies contagious. Subsidies to uneconomic units will make additional units uneconomic which will create the request for additional subsidies and the process will continue, eventually implicating even highly efficient units and new entry. Competition in the markets could be replaced by competition to receive subsidies. PJM markets have no protection against this emergent threat.

The PJM markets have worked to provide incentives to entry and to retaining capacity. PJM has excess reserves of more than 10,000 MW on June 1, 2017, and will have excess reserves of more than 17,000 MW on June 1, 2018, based on current positions. Capacity investments in PJM were generally financed by market sources. Of the 24,889.8 MW of additional capacity that cleared in RPM auctions for the 2007/2008 through 2016/2017 delivery years, 18,140.5 MW (72.9 percent) were based on market funding. Of the 18,030.9 MW of additional capacity that cleared in RPM auctions for the 2017/2018 through 2020/2021 delivery years, 15,324.7 MW (85 percent) are based on market funding. Those investments were made based on the assumption that markets would be allowed to work and that inefficient units would exit.

A comparison of the total units at risk and the current excess capacity in PJM suggests that, ignoring local reliability issues, the current and expected excess capacity is of the same order of magnitude as the units at risk.

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 (the minimum offer price rule or MOPR) 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. An extended MOPR (MOPR-Ex) is the best means currently available to PJM 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-Ex is a simple and straightforward approach to ensuring that the impact of state subsidies on markets is limited and the impact on other states is limited and that there is a disincentive for such subsidies. MOPR-Ex, with exemptions for competitive entry, for self supply by cost of service utilities, for self supply by public power entities and for competitive RPS programs is a practical and narrowly targeted approach to protecting competitive wholesale power markets. An extended MOPR is a better way to maintain PJM markets than the PJM proposal to permit subsidized units to displace competitive units 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 extended 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 overall market outcomes are subject to legitimate criticism is that the capacity market has not been permitted to reveal the underlying supply and demand fundamentals in prices. Before market outcomes are rejected in favor of nonmarket choices, the capacity market 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.

The proponents of subsidies are also proposing changes to the PJM market design to increase revenues to specific technologies. 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 is just another manifestation of the goal to change market outcomes and should also be resisted. The PJM supply curve is not flat. One of the lessons of the history of PJM capacity market design is that design changes based on short term, nonmarket considerations can have long term, significant, negative unintended consequences. The logic of LMP is fully consistent with efficient and competitive markets. The basic logic of LMP should not be modified in order to increase prices, or off peak prices or revenues. The shape of the supply curve does not affect the basic logic of LMP and LMP should not be arbitrarily 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 the market design should be made when consistent with the basic market design logic, including better pricing when transmission constraints are violated and better and more locational scarcity pricing and improved incentives for flexible units by ending the practice of paying uplift to units based on inflexible operating parameters.

Prices in PJM are not too low. There is no evidence to support the need for a significant change to the calculation of LMP. The underlying problem that fast start pricing and PJM's convex hull pricing approach are attempting to address is actually scarcity pricing, including the impact of operator actions on the definition of scarcity. Prices do not reflect market conditions when the market is tight. Rather than undercutting the basic LMP logic that is core to market efficiency, it would make more sense to directly address scarcity pricing, operator actions and the design of reserve markets.

The objective of efficient short run price signals is to minimize system production costs, not to minimize uplift. Repricing the market to reflect commitment costs would create a tradeoff between minimizing production costs and reduction of uplift. The tradeoff would exist because when commitment costs are included in prices, the price signal no longer equals the short run marginal cost and therefore no longer provides the correct signal for efficient behavior for market participants making decisions on the margin, whether resources, load, interchange transactions, or virtual traders. This tradeoff would be created by PJM's fast start pricing proposal and in a much more extensive form by PJM's modified convex hull pricing proposal.

The fast start pricing and convex hull solutions would undercut LMP logic rather than directly addressing the design of scarcity pricing. The solution is not to accept that the inflexible CT should be paid or set price based on its commitment costs rather than its short run marginal costs. The question of why units make inflexible offers should be addressed directly. Are units inflexible because they are old and inefficient, because owners have not invested in increased flexibility or because they serve as a mechanism for the exercise of market power? The question of why this unit was built, whether it was built under cost of service regulation and whether it is efficient to retain the unit should be answered directly. The question of how to provide market incentives for investment in flexible units and for investment in increased flexibility of existing units should be addressed directly. The question of whether inflexible units should be paid uplift at all should be addressed directly. Marginal cost pricing without paying excess uplift to inflexible units would create incentives for market participants to provide flexible solutions including replacing inefficient units with flexible, efficient units.

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. As part of ensuring that a grid that relies on gas, coal and nuclear for very similar shares of energy, PJM should continue to evolve its approaches to evaluating reliability and extend those to the gas infrastructure, the coal infrastructure and the nuclear infrastructure. Risks associated with gas deliverability, with coal deliverability and availability to produce energy and with nuclear common mode issues could all be part of this evaluation.

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.

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 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. This is evidence of generally competitive behavior, although the behavior of some participants raises concerns about economic withholding. The performance of the PJM markets under high load conditions and rapidly changing 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 2017 compared to 2016. The load-weighted average real-time LMP was 6.0 percent higher in 2017 than in 2016, $30.99 per MWh versus $29.23 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 markup component of LMP increased from 0.9 percent of the real-time load-weighted average

LMP in 2016 to 8.2 percent in 2017. Participant behavior was evaluated as competitive because marginal units generally made offers at, or close to, their short run marginal costs. But the increased markup results are a reminder that aggregate market power remains an issue when market conditions are tight and that market design choices must account for the potential to exercise aggregate market power. There are 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. Net revenues are significantly affected by fuel prices, energy prices and capacity prices. Energy prices and fuel prices were higher in 2017 than in 2016 and capacity prices lower on average. Natural gas prices increased more than energy prices and CTs and CCs ran with lower margins as a result. Coal prices increased more than energy prices but less than gas prices and CPs ran for slightly more hours and margins varied by zone. In 2017, a new CC would have been profitable in 11 of 20 zones while a new CT, a new coal plant and a new nuclear plant would have been significantly unprofitable. In 2017, average energy market net revenues decreased by 54 percent for a new CT, 9 percent for a new CC, 2 percent for a new coal plant, and 4 percent for a new solar installation compared to 2016. Average energy market net revenues increased by 49 percent for a new diesel unit, 11 percent for a new nuclear plant, and 11 percent for a new wind installation compared to 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 of $1,771.4 million in unreturned congestion revenue to ARR holders, and a 74.0 percent congestion offset over the last seven planning periods.

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: 2016 and 2017[1 2]

| | 2016 | 2017 | Percent Change |
|---|---|---|---|
| Peak Load (MW) | 152,177 | 145,636 | (4.3%) |
| Installed Capacity at December 31 (MW) | 182,449 | 183,882 | 0.8% |
| Load Weighted Average Real Time LMP ($/MWh) | $29.23 | $30.99 | 6.0% |
| Total Congestion Costs ($ Million) | $1,023.70 | $697.60 | (31.9%) |
| Total Uplift Charges ($ Million) | $136.70 | $129.10 | (5.6%) |
| Total PJM Billing ($ Billion) | $39.05 | $40.17 | 2.9% |

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."

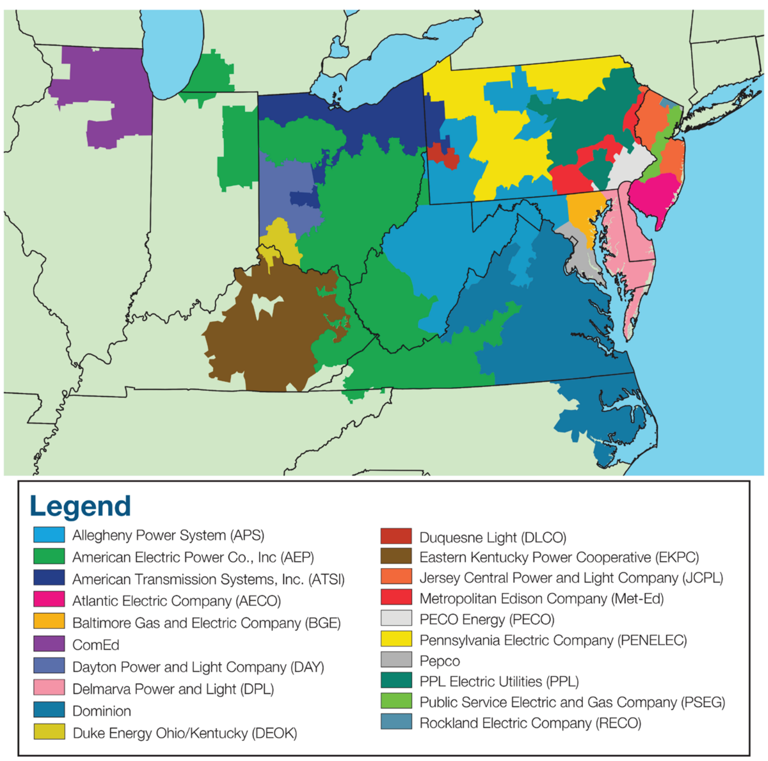
 

## PJM Market Background

The PJM Interconnection, L.L.C. (PJM) operates a centrally dispatched, competitive wholesale electric power market that, as of December 31, 2017, had installed generating capacity of 183,882 megawatts (MW) and 1,031 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.

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




In 2017, PJM had total billings of $40.17 billion, an increase of 2.9 percent from $39.05 billion in 2016.[6]

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.

3 See PJM. "Member List," which can be accessed at: <http://pjm.com/about-pjm/member-services/member-list.aspx>.
4 See PJM. "Who We Are," which can be accessed at: <http://pjm.com/about-pjm/who-we-are.aspx>.
5 See the *2017 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.

6 Monthly and year to date billing values are provided by PJM.
7 See also the *2017 State of the Market Report for PJM*, Volume 2, 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 *2017 State of the Market Report for PJM*, Volume 2, Appendix A: "PJM Geography."

## Conclusions

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

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 2017:

### Energy Market Conclusion

**Table 1-2 The energy market results were competitive**

| Market Element | Evaluation | Market Design |
|---|---|---|
| Market Structure: Aggregate Market | Partially Competitive | |
| Market Structure: Local Market | Not Competitive | |
| Participant Behavior | Competitive | |
| **Market Performance** | **Competitive** | **Effective** |

- The aggregate market structure was evaluated as partially competitive because the aggregate market power test based on pivotal suppliers indicates that the aggregate day-ahead market structure was not competitive on every day. The hourly HHI (Herfindahl-Hirschman Index) results indicate that by FERC standards, the PJM energy market in 2017 was unconcentrated. Average HHI was 919 with a minimum of 696 and a maximum of 1205 in 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. As demonstrated for the day-ahead market, 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 number of pivotal suppliers in the energy market is a more precise measure of structural market power than the HHI. The HHI is not a definitive measure of structural market power. 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 and local reliability issues.

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 are 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.

## Capacity Market Conclusion

### 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. But the net CONE times B offer cap under the capacity performance design, in the absence of performance assessment hours, exceeds the competitive level and should be reevaluated for each BRA. 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.

11 In the 2008/2009 RPM Third Incremental Auction, 18 participants in the RTO market passed the TPS test. In the 2018/2019 RPM Second Incremental Auction, 35 participants in the RTO market passed the 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.

## Tier 2 Synchronized Reserve Market Conclusion

### 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.

## Day-Ahead Scheduling Reserve Market Conclusion

### 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 15.4 percent of all cleared hours in 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 2,373 hours (27.1 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.

## Regulation Market Conclusion

### 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 2017 because the PJM Regulation Market failed the three pivotal supplier (TPS) test in 85.7 percent of the hours in 2017.
- Participant behavior in the PJM Regulation Market was evaluated as competitive for 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.

## FTR Auction Market Conclusion

### 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. But it is not clear, in a competitive market, why the ownership structure of Long Term FTRs is so highly concentrated.
- Participant behavior was evaluated as competitive because there was no evidence of anticompetitive 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 or effective way to ensure that all congestion revenues are returned to load. ARR holders' rights to congestion revenues are not defined clearly enough. ARR holders cannot determine the price at which they are willing to sell rights to congestion revenue. PJM defines the share of system capability made available for sale as FTRs.

# 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

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).

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 market structure, participant conduct and market performance for the 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 refer 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 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

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 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.

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

The MMU also monitors transmission planning, interconnections and rules for vertical market power issues, and with the introduction of competitive transmission development policy in Order No. 1000, horizontal market power issues.[30]

## 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.[31] The MMU initiates and proposes changes to the design of such markets or the PJM Market Rules in stakeholder or regulatory proceedings.[32] 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.[33] 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.[34] The MMU may provide in its annual, quarterly and other reports "recommendations regarding any matter within its purview."[35]

# New Recommendations

Consistent with its core function to "[e]valuate existing and proposed market rules, tariff provisions and market design elements and recommend proposed rule and tariff changes,"[36] 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 State of the Market Report for PJM*, the MMU includes 15 new recommendations made in 2017.[37]

## New Recommendation from Section 3, Energy Market

- The MMU recommends that PJM increase the interaction of outage and operational restrictions data submitted by Market Participants via eDART/eGADs and offer data submitted via Markets Gateway. (Priority: Low. New recommendation. Status: Not adopted.)

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–Appendix § II(p).
29 OATT Attachment M–Appendix § III.
30 OA Schedule 6 § 1.5.
31 OATT Attachment M § IV.D.
32 *Id.*
33 *Id.*
34 *Id.*
35 OATT Attachment M § VI.A.
36 18 CFR § 35.28(g)(3)(ii)(A); see also OATT Attachment M § IV.D.
37 New recommendations include all MMU recommendations that were reported for the first time in the *2017 State of the Market Report for PJM* or in any of the three quarterly state of the market reports that were published in 2017.

## New Recommendations from Section 5, Capacity Market

- The MMU recommends that PJM offer to sell back capacity in incremental auctions only at the BRA clearing price for the relevant delivery year. (Priority: Medium. First reported Q1, 2017. Status: Not adopted.)
- The MMU recommends that PJM clear the capacity market based on nodal capacity resource locations and the characteristics of the transmission system consistent with the actual electrical facts of the grid. The current nested LDA structure used in the capacity market does not adequately represent all the capacity transfers that are feasible among LDAs. Absent a fully nodal capacity market clearing process, the MMU recommends that PJM use a nonnested model for all LDAs and specify a VRR curve for each LDA separately. Each LDA requirement should be met with the capacity resources located within the LDA and exchanges from neighboring LDAs up to the transmission limit. LDAs should price separate if that is the result of the LDA supply curves and the transmission constraints. (Priority: Medium. First reported Q3, 2017. Status: Not adopted.)
- The MMU recommends that the RPM market power mitigation rule be modified to apply offer caps in all cases when the three pivotal supplier test is failed and the sell offer is greater than the offer cap. This will ensure that market power does not result in an increase in make whole payments. (Priority: Medium. First reported Q3, 2017. Status: Not adopted.)
- The MMU recommends that PJM develop a forward looking estimate for the expected number of Performance Assessment Hours (H) to use in calculating the Non-Performance Charge Rate. The MMU recommends that PJM develop a forward looking estimate for the Balancing Ratio (B) during Performance Assessment Hours to use in calculating the default offer cap. Both H and B parameters should be included in the annual review of planning parameters for the Base Residual Auction. (Priority: High. First reported Q3, 2017. Status: Not adopted.)
- The MMU recommends that when expected H and B are not the same as the assumed levels used to calculate the default market seller offer cap of Net CONE*B, the offer cap be recalculated for each BRA using the fundamental economic logic for a competitive offer of a CP resource. (Priority: High. New Recommendation. Status: Not adopted.)
- The MMU recommends elimination of the cost of service recovery rate in OATT Section 119, and that RMR service should be provided under the deactivation avoidable cost rate in Part V. The MMU also recommends specific improvements to the DACR provisions. (Priority: Medium. New recommendation. Status: Not adopted.)

## New Recommendations from Section 6, Demand Response

- The MMU recommends that the maximum offer for demand resources be the same as the maximum offer for generation resources. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends the Relative Root Mean Squared Test be required for all demand resources with a CBL. (Priority: Low. New recommendation. Status: Partially adopted.)
- The MMU recommends that PRD be required to respond during a PAH to be consistent with all CP resources. (Priority: High. New recommendation. Status: Not adopted.)

## New Recommendations from Section 10, Ancillary Services

- The MMU recommends that for oil tanks which are shared with other resources only a proportionate share of the minimum tank suction level (MTSL) be allocated to black start service. The MMU further recommends that the PJM tariff be updated to clearly state how the MTSL will be calculated for black start units sharing oil tanks. (Priority: Medium. First reported Q3, 2017. Status: Not adopted.)
- The MMU recommends that capability to operate under the proposed deadband (+/- 0.036 HZ) and droop (5 percent) settings be mandated as a condition of interconnection and that such capability be required of both new and existing resources. The MMU recommends that no additional compensation be provided as the current PJM market design provides adequate compensation. (Priority: Low. New recommendation. Status: Not adopted.)

## New Recommendation from Section 12, Generation and Transmission Planning

- The MMU recommends that PJM limit the scope of supplemental projects that can obtain exceptions to the Order No. 1000 process to ensure maximum competition. (Priority: Medium. New recommendation. Status: Not adopted.)

## New Recommendations from Section 13, Financial Transmission and Auction Revenue Rights

- The MMU recommends that Long Term FTRs be modified to include only a one year ahead FTR. (Priority: High. First reported Q2, 2017. Status: Not adopted.)
- The MMU recommends that the full transmission capacity of the system be allocated as ARRs prior to sale as FTRs. (The MMU recommends that all requested ARR rights for each delivery year be reserved for ARR holders during the Long Term FTR Auction.) (Priority: High. New recommendation. Status: Not adopted.)

# Total Price of Wholesale Power

The total price of wholesale power is the total price per MWh of purchasing wholesale electricity from PJM markets. The total price is an average price and actual prices vary by location. The total price includes the price of energy, capacity, ancillary services, and transmission service, administrative fees, regulatory support fees and uplift charges billed through PJM systems. Table 1-8 shows the average price, by component, for 2016 and 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.[38]
- The Energy Uplift (Operating Reserves) component is the average price per MWh of day-ahead and balancing operating reserves and synchronous condensing charges.[39]
- The Reactive component is the average cost per MWh of reactive supply and voltage control from generation and other sources.[40]
- The Regulation component is the average cost per MWh of regulation procured through the PJM Regulation Market.[41]
- The PJM Administrative Fees component is the average cost per MWh of PJM's monthly expenses for a number of administrative services, including Advanced Control Center ($AC^2$) and OATT Schedule 9 funding of FERC, OPSI, CAPS and the MMU.
- The Transmission Enhancement Cost Recovery component is the average cost per MWh of PJM billed (and not otherwise collected through utility rates) costs for transmission upgrades and projects, including annual recovery for the TrAIL and PATH projects.[42]
- The 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.[43]
- The Emergency Load Response component is the average cost per MWh of the PJM Emergency Load Response Program.[44]
- 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.[45]

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

- The Transmission Owner (Schedule 1A) component is the average cost per MWh of transmission owner scheduling, system control and dispatch services charged to transmission customers.[46]
- The Synchronized Reserve component is the average cost per MWh of synchronized reserve procured through the Synchronized Reserve Market.[47]
- The Black Start component is the average cost per MWh of black start service.[48]
- The RTO Startup and Expansion component is the average cost per MWh of charges to recover AEP, ComEd and DAY's integration expenses.[49]
- The NERC/RFC component is the average cost per MWh of NERC and RFC charges, plus any reconciliation charges.[50]
- The Economic Load Response component is the average cost per MWh of day ahead and real time economic load response program charges to LSEs.[51]
- The Transmission Facility Charges component is the average cost per MWh of Ramapo Phase Angle Regulators charges allocated to PJM Mid-Atlantic transmission owners.[52]
- The nonsynchronized reserve component is the average cost per MWh of non-synchronized reserve procured through the Nonsynchronized Reserve Market.[53]
- The Emergency Energy component is the average cost per MWh of emergency energy.[54]

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 97.3 percent of the total price per MWh in 2017.

### Table 1-8 Total price per MWh by category: 2016 and 2017[55]

| Category | 2016 $/MWh | 2016 Percent of Total | 2017 $/MWh | 2017 Percent of Total | Percent Change |
|---|---|---|---|---|---|
| Load Weighted Energy | $29.23 | 58.5% | $30.99 | 58.2% | 6.0% |
| Capacity | $10.96 | 21.9% | $11.23 | 21.1% | 2.5% |
| Capacity | $10.96 | 21.9% | $11.23 | 21.1% | 2.5% |
| Capacity (FRR) | $0.00 | 0.0% | $0.00 | 0.0% | 0.0% |
| Transmission | $8.42 | 16.8% | $9.57 | 18.0% | 13.7% |
| Transmission Service Charges | $7.81 | 15.6% | $8.84 | 16.6% | 13.1% |
| Transmission Enhancement Cost Recovery | $0.52 | 1.0% | $0.64 | 1.2% | 24.2% |
| Transmission Owner (Schedule 1A) | $0.09 | 0.2% | $0.10 | 0.2% | 3.4% |
| Transmission Facility Charges | $0.00 | 0.0% | $0.00 | 0.0% | (100.0%) |
| Ancillary | $0.72 | 1.4% | $0.78 | 1.5% | 8.9% |
| Reactive | $0.38 | 0.8% | $0.44 | 0.8% | 14.8% |
| Regulation | $0.11 | 0.2% | $0.14 | 0.3% | 26.8% |
| Black Start | $0.09 | 0.2% | $0.09 | 0.2% | 4.3% |
| Synchronized Reserves | $0.05 | 0.1% | $0.06 | 0.1% | 5.5% |
| Non-Synchronized Reserves | $0.01 | 0.0% | $0.01 | 0.0% | 1.1% |
| Day Ahead Scheduling Reserve (DASR) | $0.07 | 0.1% | $0.05 | 0.1% | (38.7%) |
| Administration | $0.47 | 0.9% | $0.52 | 1.0% | 9.6% |
| PJM Administrative Fees | $0.44 | 0.9% | $0.48 | 0.9% | 10.0% |
| NERC/RFC | $0.03 | 0.1% | $0.03 | 0.1% | 4.2% |
| RTO Startup and Expansion | $0.00 | 0.0% | $0.00 | 0.0% | 3.3% |
| Energy Uplift (Operating Reserves) | $0.17 | 0.3% | $0.14 | 0.3% | (16.9%) |
| Demand Response | $0.01 | 0.0% | $0.01 | 0.0% | (35.3%) |

46 OATT Schedule 1A.
47 OA Schedule 1 § 3.2.3A.01; PJM OATT Schedule 6.
48 OATT Schedule 6A. The line item in Table 1-8 includes all Energy Uplift (Operating Reserves) charges for Black Start.
49 OATT Attachments H-13, H-14 and H-15 and Schedule 13.
50 OATT Schedule 10-NERC and OATT Schedule 10-RFC.
51 OA Schedule 1 § 3.6.
52 OA Schedule 1 § 5.3b.
53 OA Schedule 1 § 3.2.3A.001.
54 OA Schedule 1 § 3.2.6.
55 Note: The totals in this table include after the fact billing adjustments and may not match totals presented in past reports.

| | | | | | |
|---|---|---|---|---|---|
| Load Response | $0.01 | 0.0% | $0.01 | 0.0% | (35.3%) |
| 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 | $49.99 | 100.0% | $53.24 | 100.0% | 6.5% |

Table 1-9 shows the inflation adjusted average price, by component, for 2016 and 2017. To obtain the inflation adjusted average prices, the individual components' prices are deflated using the US Consumer Price Index for all items, Urban Consumers (with a base period of January 1998), as published by *Bureau of Labor Statistics*.[56]

### Table 1-9 Inflation adjusted total price per MWh by category: 2016 and 2017[57]

| Category | 2016 $/MWh | 2016 Percent of Total | 2017 $/MWh | 2017 Percent of Total | Percent Change |
|---|---|---|---|---|---|
| Load Weighted Energy | $19.68 | 58.5% | $20.43 | 58.2% | 3.8% |
| Capacity | $7.39 | 21.9% | $7.40 | 21.1% | 0.2% |
| Capacity | $7.39 | 21.9% | $7.40 | 21.1% | 0.2% |
| Capacity (FRR) | $0.00 | 0.0% | $0.00 | 0.0% | 0.0% |
| Transmission | $5.67 | 16.8% | $6.31 | 18.0% | 11.3% |
| Transmission Service Charges | $5.26 | 15.6% | $5.82 | 16.6% | 10.8% |
| Transmission Enhancement Cost Recovery | $0.35 | 1.0% | $0.42 | 1.2% | 21.6% |
| Transmission Owner (Schedule 1A) | $0.06 | 0.2% | $0.06 | 0.2% | 1.4% |
| Transmission Facility Charges | $0.00 | 0.0% | $0.00 | 0.0% | (100.0%) |
| Ancillary | $0.48 | 1.4% | $0.51 | 1.5% | 6.7% |
| Reactive | $0.26 | 0.8% | $0.29 | 0.8% | 12.4% |
| Regulation | $0.07 | 0.2% | $0.09 | 0.3% | 24.1% |
| Black Start | $0.06 | 0.2% | $0.06 | 0.2% | 2.2% |
| Synchronized Reserves | $0.04 | 0.1% | $0.04 | 0.1% | 3.4% |
| Non-Synchronized Reserves | $0.01 | 0.0% | $0.01 | 0.0% | (1.6%) |
| Day Ahead Scheduling Reserve (DASR) | $0.05 | 0.1% | $0.03 | 0.1% | (39.8%) |
| Administration | $0.32 | 0.9% | $0.34 | 1.0% | 7.3% |
| PJM Administrative Fees | $0.30 | 0.9% | $0.32 | 0.9% | 7.6% |
| NERC/RFC | $0.02 | 0.1% | $0.02 | 0.1% | 1.9% |
| RTO Startup and Expansion | $0.00 | 0.0% | $0.00 | 0.0% | 5.0% |
| Energy Uplift (Operating Reserves) | $0.12 | 0.3% | $0.09 | 0.3% | (18.7%) |
| Demand Response | $0.01 | 0.0% | $0.00 | 0.0% | (36.2%) |
| Load Response | $0.01 | 0.0% | $0.00 | 0.0% | (36.2%) |
| 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 | $33.66 | 100.0% | $35.10 | 100.0% | 4.3% |

Table 1-10 shows the average price, by component of the total wholesale power price per MWh, for calendar years 1999 through 2017.

56 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> (January 12, 2018)

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

## Table 1-10 Total price per MWh by category: Calendar Years 1999 through 2017[58]

| 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 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 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 |
| 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 | $10.24 |
| 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 |
| 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 |
| Transmission | $3.49 | $4.13 | $3.56 | $3.46 | $3.64 | $3.38 | $2.80 | $3.27 | $3.55 | $3.83 | $4.22 | $4.33 | $4.86 |
| 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 |
| 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 |
| 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 |
| 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 |
| Ancillary | $0.41 | $0.68 | $0.75 | $0.63 | $0.91 | $0.91 | $1.19 | $0.92 | $1.00 | $1.15 | $0.78 | $0.90 | $0.90 |
| 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 |
| 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 |
| 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 |
| 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 |
| 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 |
| 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 |
| Administration | $0.23 | $0.26 | $0.73 | $0.86 | $1.05 | $1.00 | $0.73 | $0.75 | $0.75 | $0.41 | $0.34 | $0.39 | $0.40 |
| 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 | $0.37 |
| 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 |
| 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 |
| 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 |
| Demand Response | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.03 | $0.06 | $0.05 | $0.01 | $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 |
| 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 |
| 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 |
| Total Price | $38.92 | $36.98 | $43.22 | $37.39 | $47.83 | $50.66 | $69.30 | $58.82 | $71.20 | $85.01 | $55.66 | $66.95 | $63.16 |

| Category | 2012 $/MWh | 2013 $/MWh | 2014 $/MWh | 2015 $/MWh | 2016 $/MWh | 2017 $/MWh |
|---|---|---|---|---|---|---|
| Load Weighted Energy | $35.23 | $38.66 | $53.14 | $36.16 | $29.23 | $30.99 |
| Capacity | $6.57 | $7.24 | $9.21 | $11.25 | $10.96 | $11.23 |
| Capacity | $6.05 | $7.13 | $9.01 | $11.12 | $10.96 | $11.23 |
| Capacity (FRR) | $0.52 | $0.11 | $0.20 | $0.13 | $0.00 | $0.00 |
| Transmission | $5.32 | $5.65 | $6.46 | $7.69 | $8.42 | $9.57 |
| Transmission Service Charges | $4.90 | $5.21 | $5.96 | $7.09 | $7.81 | $8.84 |
| Transmission Enhancement Cost Recovery | $0.34 | $0.36 | $0.41 | $0.51 | $0.52 | $0.64 |
| Transmission Owner (Schedule 1A) | $0.08 | $0.08 | $0.09 | $0.09 | $0.09 | $0.10 |
| Transmission Facility Charges | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 |
| Ancillary | $0.84 | $1.24 | $0.99 | $0.91 | $0.72 | $0.78 |
| Reactive | $0.46 | $0.76 | $0.40 | $0.37 | $0.38 | $0.44 |
| Regulation | $0.26 | $0.25 | $0.33 | $0.23 | $0.11 | $0.14 |
| Black Start | $0.04 | $0.14 | $0.08 | $0.08 | $0.09 | $0.09 |
| Synchronized Reserves | $0.04 | $0.04 | $0.12 | $0.11 | $0.05 | $0.06 |
| Non-Synchronized Reserves | $0.00 | $0.00 | $0.02 | $0.02 | $0.01 | $0.01 |
| Day Ahead Scheduling Reserve (DASR) | $0.05 | $0.06 | $0.05 | $0.10 | $0.07 | $0.05 |
| Administration | $0.46 | $0.45 | $0.46 | $0.46 | $0.47 | $0.52 |
| PJM Administrative Fees | $0.42 | $0.41 | $0.43 | $0.43 | $0.44 | $0.48 |
| NERC/RFC | $0.02 | $0.02 | $0.03 | $0.03 | $0.03 | $0.03 |
| RTO Startup and Expansion | $0.01 | $0.01 | $0.01 | $0.01 | $0.00 | $0.00 |
| Energy Uplift (Operating Reserves) | $0.74 | $0.55 | $1.15 | $0.38 | $0.17 | $0.14 |
| Demand Response | $0.03 | $0.08 | $0.08 | $0.02 | $0.01 | $0.01 |
| Load Response | $0.02 | $0.01 | $0.03 | $0.02 | $0.01 | $0.01 |
| Emergency Load Response | $0.01 | $0.06 | $0.06 | $0.00 | $0.00 | $0.00 |
| Emergency Energy | $0.00 | $0.00 | $0.01 | $0.00 | $0.00 | $0.00 |
| Total Price | $49.20 | $53.87 | $71.49 | $56.87 | $49.99 | $53.24 |

Table 1-11 shows the inflation adjusted average price, by component of the total wholesale power price per MWh, for calendar years 1999 through 2017.[59]

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

59 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> (January 12, 2018).

## Table 1-11 Inflation adjusted total price per MWh by category: Calendar Years 1999 through 2017[60]

| 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 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Load Weighted Energy | $33.04 | $28.80 | $33.45 | $28.35 | $36.24 | $37.91 | $52.37 | $42.73 | $48.06 | $53.27 | $29.46 | $35.83 | $33.01 |
| Capacity | $0.13 | $0.23 | $0.24 | $0.11 | $0.07 | $0.08 | $0.02 | $0.02 | $2.73 | $5.85 | $8.11 | $9.00 | $7.37 |
| Capacity | $0.13 | $0.23 | $0.24 | $0.11 | $0.07 | $0.08 | $0.02 | $0.02 | $2.73 | $5.85 | $8.11 | $9.00 | $6.99 |
| 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 | $0.38 |
| Transmission | $3.38 | $3.88 | $3.25 | $3.10 | $3.20 | $2.88 | $2.32 | $2.62 | $2.76 | $2.87 | $3.18 | $3.21 | $3.49 |
| Transmission Service Charges | $3.31 | $3.79 | $3.17 | $3.04 | $3.13 | $2.80 | $2.24 | $2.55 | $2.69 | $2.76 | $3.04 | $2.99 | $3.23 |
| Transmission Enhancement Cost Recovery | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.04 | $0.08 | $0.15 | $0.20 |
| Transmission Owner (Schedule 1A) | $0.07 | $0.08 | $0.07 | $0.06 | $0.06 | $0.08 | $0.07 | $0.07 | $0.07 | $0.07 | $0.06 | $0.07 | $0.06 |
| 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 |
| Ancillary | $0.40 | $0.64 | $0.68 | $0.56 | $0.80 | $0.77 | $0.98 | $0.74 | $0.78 | $0.86 | $0.59 | $0.66 | $0.64 |
| Reactive | $0.25 | $0.27 | $0.20 | $0.18 | $0.21 | $0.22 | $0.21 | $0.23 | $0.23 | $0.25 | $0.27 | $0.33 | $0.29 |
| Regulation | $0.15 | $0.37 | $0.48 | $0.38 | $0.44 | $0.43 | $0.66 | $0.42 | $0.49 | $0.52 | $0.26 | $0.27 | $0.23 |
| Black Start | $0.00 | $0.00 | $0.00 | $0.00 | $0.01 | $0.01 | $0.02 | $0.02 | $0.02 | $0.02 | $0.02 | $0.01 | $0.01 |
| Synchronized Reserves | $0.00 | $0.00 | $0.00 | $0.01 | $0.13 | $0.11 | $0.09 | $0.07 | $0.05 | $0.06 | $0.04 | $0.05 | $0.07 |
| 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 |
| 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 | $0.04 |
| Administration | $0.22 | $0.24 | $0.66 | $0.77 | $0.93 | $0.85 | $0.61 | $0.60 | $0.58 | $0.31 | $0.25 | $0.29 | $0.29 |
| PJM Administrative Fees | $0.22 | $0.25 | $0.65 | $0.77 | $0.92 | $0.79 | $0.60 | $0.59 | $0.56 | $0.29 | $0.23 | $0.27 | $0.26 |
| NERC/RFC | $0.00 | -$0.00 | $0.01 | $0.01 | $0.01 | $0.01 | $0.00 | -$0.00 | $0.01 | $0.01 | $0.01 | $0.02 | $0.01 |
| RTO Startup and Expansion | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.05 | $0.00 | $0.01 | $0.01 | $0.01 | $0.01 | $0.01 | $0.01 |
| Energy Uplift (Operating Reserves) | $0.50 | $0.87 | $1.15 | $0.65 | $0.78 | $0.81 | $0.88 | $0.38 | $0.51 | $0.48 | $0.36 | $0.59 | $0.56 |
| Demand Response | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.02 | $0.05 | $0.03 | $0.00 | $0.02 | $0.02 |
| Load Response | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.02 | $0.05 | $0.03 | $0.00 | $0.01 | $0.01 |
| 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 | $0.01 | $0.01 |
| 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 |
| Total Price | $37.75 | $34.68 | $39.44 | $33.54 | $42.04 | $43.32 | $57.20 | $47.12 | $55.47 | $63.68 | $41.96 | $49.62 | $45.39 |

| Category | 2012 $/MWh | 2013 $/MWh | 2014 $/MWh | 2015 $/MWh | 2016 $/MWh | 2017 $/MWh |
|---|---|---|---|---|---|---|
| Load Weighted Energy | $24.80 | $26.82 | $36.37 | $24.69 | $19.68 | $20.43 |
| Capacity | $4.63 | $5.02 | $6.29 | $7.66 | $7.39 | $7.40 |
| Capacity | $4.26 | $4.94 | $6.15 | $7.58 | $7.39 | $7.40 |
| Capacity (FRR) | $0.37 | $0.07 | $0.14 | $0.09 | $0.00 | $0.00 |
| Transmission | $3.74 | $3.92 | $4.41 | $5.24 | $5.67 | $6.31 |
| Transmission Service Charges | $3.45 | $3.61 | $4.07 | $4.84 | $5.26 | $5.82 |
| Transmission Enhancement Cost Recovery | $0.24 | $0.25 | $0.28 | $0.34 | $0.35 | $0.42 |
| Transmission Owner (Schedule 1A) | $0.06 | $0.06 | $0.06 | $0.06 | $0.06 | $0.06 |
| Transmission Facility Charges | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 |
| Ancillary | $0.59 | $0.86 | $0.67 | $0.62 | $0.48 | $0.51 |
| Reactive | $0.32 | $0.53 | $0.27 | $0.25 | $0.26 | $0.29 |
| Regulation | $0.18 | $0.17 | $0.22 | $0.16 | $0.07 | $0.09 |
| Black Start | $0.03 | $0.10 | $0.05 | $0.05 | $0.06 | $0.06 |
| Synchronized Reserves | $0.03 | $0.03 | $0.08 | $0.08 | $0.04 | $0.04 |
| Non-Synchronized Reserves | $0.00 | $0.00 | $0.01 | $0.01 | $0.01 | $0.01 |
| Day Ahead Scheduling Reserve (DASR) | $0.03 | $0.04 | $0.03 | $0.07 | $0.05 | $0.03 |
| Administration | $0.32 | $0.31 | $0.32 | $0.32 | $0.32 | $0.34 |
| PJM Administrative Fees | $0.30 | $0.29 | $0.29 | $0.29 | $0.30 | $0.32 |
| NERC/RFC | $0.02 | $0.02 | $0.02 | $0.02 | $0.02 | $0.02 |
| RTO Startup and Expansion | $0.01 | $0.01 | $0.01 | $0.00 | $0.00 | $0.00 |
| Energy Uplift (Operating Reserves) | $0.52 | $0.38 | $0.79 | $0.26 | $0.12 | $0.09 |
| Demand Response | $0.02 | $0.05 | $0.05 | $0.01 | $0.01 | $0.00 |
| Load Response | $0.01 | $0.01 | $0.02 | $0.01 | $0.01 | $0.00 |
| Emergency Load Response | $0.01 | $0.04 | $0.04 | $0.00 | $0.00 | $0.00 |
| Emergency Energy | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 |
| Total Price | $34.63 | $37.37 | $48.90 | $38.81 | $33.66 | $35.10 |

Table 1-12 shows the percent of average price, by component of the wholesale power price per MWh, for calendar years 1999 through 2017.

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

## Table 1-12 Percent of total price per MWh by category: Calendar Years 1999 through 2017[61]

| 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 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 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% |
| Capacity | 0.4% | 0.7% | 0.6% | 0.3% | 0.2% | 0.2% | 0.0% | 0.0% | 5.0% | 9.2% | 19.4% |
| Capacity | 0.4% | 0.7% | 0.6% | 0.3% | 0.2% | 0.2% | 0.0% | 0.0% | 5.0% | 9.2% | 19.4% |
| Capacity (FRR) | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| Transmission | 9.0% | 11.2% | 8.2% | 9.3% | 7.6% | 6.7% | 4.0% | 5.6% | 5.0% | 4.5% | 7.6% |
| 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% |
| 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% |
| 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% |
| 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% |
| Ancillary | 1.1% | 1.8% | 1.7% | 1.7% | 1.9% | 1.8% | 1.7% | 1.6% | 1.4% | 1.4% | 1.4% |
| Reactive | 0.7% | 0.8% | 0.5% | 0.5% | 0.5% | 0.5% | 0.4% | 0.5% | 0.4% | 0.4% | 0.7% |
| Regulation | 0.4% | 1.1% | 1.2% | 1.1% | 1.1% | 1.0% | 1.1% | 0.9% | 0.9% | 0.8% | 0.6% |
| Black Start | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| Synchronized Reserves | 0.0% | 0.0% | 0.0% | 0.0% | 0.3% | 0.3% | 0.2% | 0.1% | 0.1% | 0.1% | 0.1% |
| 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% |
| 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% |
| Administration | 0.6% | 0.7% | 1.7% | 2.3% | 2.2% | 2.0% | 1.1% | 1.3% | 1.1% | 0.5% | 0.6% |
| 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% |
| NERC/RFC | 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% |
| 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% |
| Demand Response | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.1% | 0.1% | 0.0% |
| Load Response | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.1% | 0.1% | 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% |
| Emergency Energy | 0.2% | 0.1% | 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% |

| Category | 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 | Percent of Total Charges 2017 |
|---|---|---|---|---|---|---|---|---|
| Load Weighted Energy | 72.2% | 72.7% | 71.6% | 71.8% | 74.3% | 63.6% | 58.5% | 58.2% |
| Capacity | 18.1% | 16.2% | 13.4% | 13.4% | 12.9% | 19.8% | 21.9% | 21.1% |
| Capacity | 18.1% | 15.4% | 12.3% | 13.2% | 12.6% | 19.6% | 21.9% | 21.1% |
| Capacity (FRR) | 0.0% | 0.8% | 1.1% | 0.2% | 0.3% | 0.2% | 0.0% | 0.0% |
| Transmission | 6.5% | 7.7% | 10.8% | 10.5% | 9.0% | 13.5% | 16.8% | 18.0% |
| Transmission Service Charges | 6.0% | 7.1% | 10.0% | 9.7% | 8.3% | 12.5% | 15.6% | 16.6% |
| Transmission Enhancement Cost Recovery | 0.3% | 0.4% | 0.7% | 0.7% | 0.6% | 0.9% | 1.0% | 1.2% |
| Transmission Owner (Schedule 1A) | 0.1% | 0.1% | 0.2% | 0.2% | 0.1% | 0.2% | 0.2% | 0.2% |
| Transmission Facility Charges | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| Ancillary | 1.3% | 1.4% | 1.7% | 2.3% | 1.4% | 1.6% | 1.4% | 1.5% |
| Reactive | 0.7% | 0.6% | 0.9% | 1.4% | 0.6% | 0.7% | 0.8% | 0.8% |
| Regulation | 0.5% | 0.5% | 0.5% | 0.5% | 0.5% | 0.4% | 0.2% | 0.3% |
| Black Start | 0.0% | 0.0% | 0.1% | 0.3% | 0.1% | 0.1% | 0.2% | 0.2% |
| Synchronized Reserves | 0.1% | 0.1% | 0.1% | 0.1% | 0.2% | 0.2% | 0.1% | 0.1% |
| Non-Synchronized Reserves | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| Day Ahead Scheduling Reserve (DASR) | 0.0% | 0.1% | 0.1% | 0.1% | 0.1% | 0.2% | 0.1% | 0.1% |
| Administration | 0.6% | 0.6% | 0.9% | 0.8% | 0.6% | 0.8% | 0.9% | 1.0% |
| PJM Administrative Fees | 0.5% | 0.6% | 0.9% | 0.8% | 0.6% | 0.8% | 0.9% | 0.9% |
| NERC/RFC | 0.0% | 0.0% | 0.1% | 0.0% | 0.0% | 0.1% | 0.1% | 0.1% |
| RTO Startup and Expansion | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| Energy Uplift (Operating Reserves) | 1.2% | 1.2% | 1.5% | 1.0% | 1.6% | 0.7% | 0.3% | 0.3% |
| Demand Response | 0.0% | 0.0% | 0.1% | 0.1% | 0.1% | 0.0% | 0.0% | 0.0% |
| Load Response | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| Emergency Load Response | 0.0% | 0.0% | 0.0% | 0.1% | 0.1% | 0.0% | 0.0% | 0.0% |
| Emergency Energy | 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% |

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

Figure 1-2 shows the contributions of load-weighted energy, capacity and transmission service charges to the total price of wholesale power for each quarter since 1999.

### Figure 1-2 Top three components of quarterly total price ($/MWh): 1999 through 2017[62]

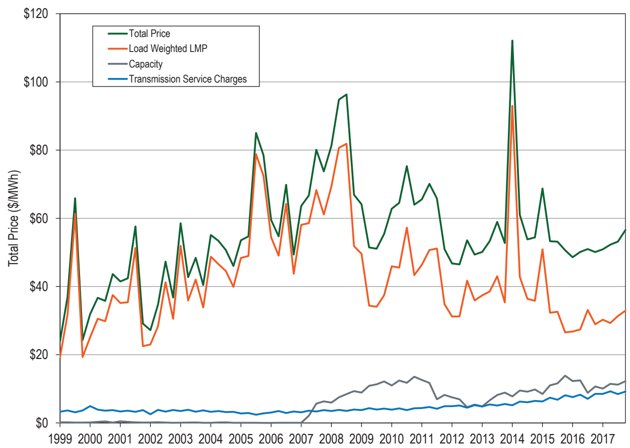



Figure 1-3 shows the inflation adjusted contributions of load-weighted energy, capacity and transmission service charges to the total price of wholesale power for each quarter since 1999.[63]

### Figure 1-3 Inflation adjusted top three components of quarterly total price ($/MWh): 1999 through 2017[64]

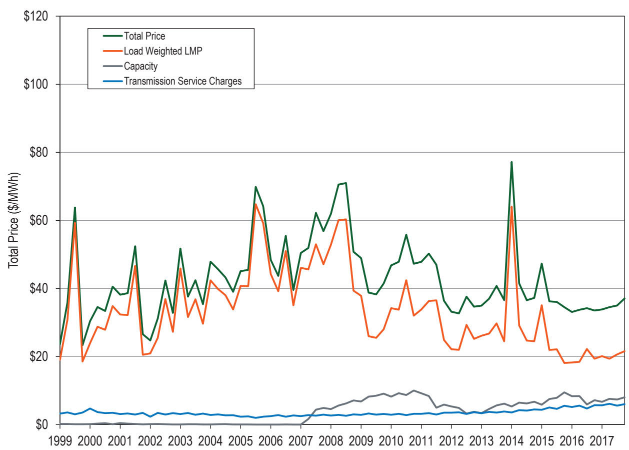



Figure 1-4 shows the total price of wholesale power and the inflation adjusted total price of wholesale power for each quarter since 1999.[65]

### Figure 1-4 Quarterly total price and quarterly inflation adjusted total price ($/MWh): 1999 through 2017[66 67]


# 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 increased by 2,551 MW, or 1.5 percent, from 171,300 MW in the summer of 2016 to 173,851 MW in the summer of 2017. In 2017, 5,244.3 MW of new resources were added, 8,391.8 MW were retired.

  PJM average real-time cleared generation in 2017 decreased by 0.4 percent in 2016, from 91,304 MW to 90,944 MW.

  PJM average day-ahead cleared supply in 2017, including INCs and up to congestion transactions, decreased by 0.8 percent in 2016, from 131,634 MW to 130,601 MW.

- **Aggregate Pivotal Suppliers.** The PJM energy market at times requires generation from pivotal suppliers

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

63 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> (January 12, 2018).

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

65 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> (January 12, 2018).

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

67 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> (January 12, 2018).

to meet the daily peak load, resulting in aggregate market power even when the HHI level indicates that the aggregate market is unconcentrated.

- **Generation Fuel Mix.** In 2017, coal units provided 31.8 percent, nuclear units 35.6 percent and natural gas units 26.8 percent of total generation. Compared to 2016, generation from coal units decreased 6.8 percent, generation from natural gas units increased 0.8 percent and generation from nuclear units increased 2.9 percent.
- **Fuel Diversity.** In 2017, the fuel diversity of energy generation, measured by the fuel diversity index for energy (FDIe), increased 0.8 percent over the FDI for 2016.
- **Marginal Resources.** In the PJM Real-Time Energy Market, in 2017, coal units were 32.3 percent of marginal resources and natural gas units were 53.3 percent of marginal resources. In 2016, coal units were 46.4 percent and natural gas units were 42.6 percent of the marginal resources.

  In the PJM Day-Ahead Energy Market, in 2017, up to congestion transactions were 79.9 percent of marginal resources, INCs were 5.5 percent of marginal resources, DECs were 10.2 percent of marginal resources, and generation resources were 4.3 percent of marginal resources. In 2016, up to congestion transactions were 82.4 percent of marginal resources, INCs were 4.2 percent of marginal resources, DECs were 8.6 percent of marginal resources, and generation resources were 4.7 percent of marginal resources.
- **Demand.** Demand includes physical load and exports and virtual transactions. The PJM accounting peak load during 2017 was 145,636 MW in the HE 1700 on July 19, 2017, which was 6,541 MW, 4.3 percent, lower than the PJM peak load for 2016, which was 152,177 MW in the HE 1500 on August 11, 2016.

  PJM average real-time load in 2017 decreased by 2.2 percent from 2016, from 88,601 MW to 86,618 MW. PJM average day-ahead demand in 2017, including DECs and up to congestion transactions, decreased by 1.3 percent of 2016, from 127,390 MW to 125,792 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 2017, 14.4 percent of real-time load was supplied by bilateral contracts, 27.5 percent by spot market purchases and 58.9 percent by self-supply. Compared to 2016, reliance on bilateral contracts increased by 1.6 percentage points, reliance on spot market purchases increased by 3.5 percentage points and reliance on self-supply decreased by 4.4 percentage points.
- **Supply and Demand: Scarcity.** Five minute shortage pricing was triggered on one day in 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 2016 to 0 percent in 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 2016 to 0.3 percent in 2017.

  In 2017, 12 control zones experienced congestion resulting from one or more constraints binding for 100 or more hours. The analysis of the application of the TPS test to local markets demonstrates that it is working successfully to identify pivotal owners when the market structure is noncompetitive and to ensure that owners are not subject to offer capping when the market structure is competitive. There are, however, identified issues with the application of market power mitigation to resources whose owners fail the TPS test that can result in the exercise of local market power. These issues need to be addressed.
- **Offer Capping for Reliability.** PJM also offer caps units that are committed for reliability reasons, specifically for black start service and reactive service. In the Day-Ahead Energy Market, for units committed for reliability reasons, offer-capped unit hours increased from 0 percent in 2016 to 0.1 percent in 2017. In the Real-Time Energy Market,

for units committed for reliability reasons, offer-capped unit hours remained at 0.1 percent in 2016 and 2017.

- **Markup Index.** The markup index is a summary measure of participant offer behavior for individual marginal units. In 2017, in the PJM Real-Time Energy Market, 91.5 percent of marginal units had offer prices less than $50 per MWh. The average dollar markup of units with offer prices less than $25 was zero when using unadjusted cost-based offers. The average dollar markup of units with offer prices between $25 and $50 was positive when using unadjusted cost-based 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-based offers, the highest markup for any marginal unit in 2017 was more than $700 per MWh while the highest markup in 2016 was more than $200 per MWh.

  In 2017, in the PJM Day-Ahead Energy Market, 92.8 percent of marginal generating units had offer prices less than $50 per MWh. The average dollar markup of units with offer prices less than $25 was positive when using unadjusted cost-based offers. The average dollar markup of units with offer prices between $25 and $50 was positive when using unadjusted cost-based offers. Using the unadjusted cost-based offers, the highest markup for any marginal unit in 2017 was more than $60 per MWh, while the highest markup in 2016 was more than $160 per MWh.

- **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 2017, the average hourly increment offers submitted MW increased by 11.1 percent from 7,175 MW in 2016 to 7,968 MW in 2017, and cleared MW decreased by 2.4 percent from 4,675 MW in 2016 to 4,562 MW in 2017. In 2017, the average hourly decrement bids submitted MW increased by 14.5 percent from 6,879 MW in 2016 to 7,874 MW in 2017, and cleared MW decreased by 0.3 percent from 4,051 MW in 2016 to 4,035 MW in 2017. In 2017, the average hourly up to congestion submitted MW decreased by 3.3 percent from 142,075 MW in 2016 to 137,419 MW in 2017, and cleared MW increased by 1.6 percent from 34,387 MW in 2016 to 34,927 MW in 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 2017, 54.9 percent were offered as available for economic dispatch, 3.8 percent were offered as emergency dispatch, 20.1 percent were offered as self scheduled, and 21.2 percent were offered as self scheduled and dispatchable.

## Market Performance

- **Prices.** PJM LMPs are a direct measure of market performance. Price level is a good, general indicator of market performance, although the number of factors influencing the overall level of prices means it must be analyzed carefully. Among other things, overall average prices reflect 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 2017 compared to 2016. The load-weighted, average real-time LMP was 6.0 percent higher in 2017 than in 2016, $30.99 per MWh versus $29.23 per MWh.

PJM day-ahead energy market prices increased in 2017 compared to 2016. The load-weighted, average day-ahead LMP was 3.9 percent higher in 2017 than in 2016, $30.85 per MWh versus $29.68 per MWh.

- **Components of LMP.** In the PJM Real-Time Energy Market, in 2017, 28.9 percent of the load-weighted LMP was the result of coal costs, 39.2 percent was the result of gas costs and 1.79 percent was the result of the cost of emission allowances.

  In the PJM Day-Ahead Energy Market, in 2017, 21.1 percent of the load-weighted LMP was the result of coal costs, 23.7 percent was the result of DEC bid costs, 18.4 percent was the result of gas costs, 22.2 percent was the result of INC bid costs, and 3.1 percent was the result of up to congestion transaction costs.

- **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 2017, the adjusted markup component of LMP was $4.94 per MWh or 16.0 percent of the PJM load-weighted, average LMP. May had the highest adjusted peak markup component, $8.23 per MWh, or 21.72 percent of the real-time, peak hour load-weighted, average LMP. There were 50 hours in 2017 where the positive markup contribution to the PJM system wide, load-weighted, average LMP exceeded $48.33 per MWh.

  In the PJM Day-Ahead Energy Market, INCs, DECs and UTCs have zero markups. In 2017, the adjusted markup component of LMP resulting from generation resources was $2.04 per MWh or 6.6 percent of the PJM day-ahead load-weighted average LMP. September had the highest adjusted markup component, $2.98 per MWh or 9.4 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 -$0.53 per MWh in 2016 and -$0.06 per MWh in 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

- PJM implemented five minute shortage pricing beginning May 11, 2017. Five minute shortage pricing was triggered for one day, September 21, 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. The MMU recommends that the level of incremental costs includable in cost-based offers not exceed the short run marginal cost of the unit. (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 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-based offers based on short run marginal costs and the correct calculation of cost-based offers. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends removal of all use of 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-based offers, and 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 price-based non-PLS 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. (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. Stakeholder process.)
- The MMU recommends that Market Sellers not be allowed to designate any portion of an available Capacity Resource's ICAP equivalent of cleared UCAP capacity commitment as a Maximum Emergency offer at any time during the delivery year.[68] (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: Adopted, 2012.)
- 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.[69] There is currently no PJM documentation in the tariff or manuals explaining how hubs are created and how their definitions are changed.[70] (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that all buses with a net withdrawal be treated as load 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.)

68 This recommendation was accepted by PJM and filed with FERC in 2014 as part of the capacity performance updates to the RPM. See Schedule 1, Section 1.10.1A(d), Revisions to the PJM Open Access Transmission Tariff and PJM Operating Agreement (Marked/Redline Format), EL15-29-000 (December 12, 2014). FERC rejected the proposed change in Order 151FERC¶61,208 at 476 (June 9, 2015).

69 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.

70 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 require all generating units to identify the fuel type associated with each of their offered schedules. (Priority: Low. First reported 2014. Status: Adopted 2014.)
- The MMU recommends that PJM increase the interaction of outage and operational restrictions data submitted by Market Participants via eDART/eGADs and offer data submitted via Markets Gateway. (Priority: Low. New recommendation. Status: Not adopted.)

## Section 3 Conclusion

The MMU analyzed key elements of PJM energy market structure, participant conduct and market performance in 2017, including aggregate supply and demand, concentration ratios, aggregate pivotal supplier results, local three pivotal supplier test results, offer capping, participation in demand response programs, loads and prices.

PJM average real-time cleared generation decreased by 360 MW, 0.4 percent, and peak load decreased by 6,541 MW, 4.3 percent, in 2017 compared to 2016. 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. The market structure of the PJM aggregate energy market is partially competitive because aggregate market power does exist for a significant number of hours. The HHI is not a definitive measure of structural market power. The number of pivotal suppliers in the energy market is a more precise measure of structural market power than the HHI. It is possible to have pivotal suppliers in the aggregate market even when the HHI level is not in the highly concentrated range. The current market power mitigation rules for the PJM energy market rely on the assumption that the ownership structure of the aggregate market ensures competitive outcomes. This assumption requires that the total demand for energy can be met without the supply from any individual supplier or without the supply from a small group of suppliers. This assumption is not correct. There are pivotal suppliers in the aggregate energy market at times. High markups for some units demonstrate the potential to exercise market power during high demand conditions. The existing market power mitigation measures do not address aggregate market power. The MMU is developing an aggregate market power test and will propose market power mitigation rules to address aggregate market power.

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.[71] 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. These issues can be resolved by simple rule changes.

The enforcement of market power mitigation rules is undermined if the definition of a competitive offer is not correct. A competitive offer is equal to short run marginal costs. 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 rule changes to incorporate a clear and accurate definition of short run marginal costs.

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 to serve load in each market interval. 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 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

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

incentives for unit owners to take all necessary actions to acquire fuel and operate rather than take an outage.

Prices in PJM are not too low. There is no evidence to support the need for a significant change to the calculation of LMP. The underlying problem that fast start pricing and PJM's convex hull pricing approach are attempting to address is actually scarcity pricing, including the impact of operator actions on the definition of scarcity. Prices do not reflect market conditions when the market is tight. Rather than undercutting the basic LMP logic that is core to market efficiency, it would make more sense to directly address scarcity pricing, operator actions and the design of reserve markets.

The objective of efficient short run price signals is to minimize system production costs, not to minimize uplift. Repricing the market to reflect commitment costs would create a tradeoff between minimizing production costs and reduction of uplift. The tradeoff would exist because when commitment costs are included in prices, the price signal no longer equals the short run marginal cost and therefore no longer provides the correct signal for efficient behavior for market participants making decisions on the margin, whether resources, load, interchange transactions, or virtual traders. This tradeoff would be created by PJM's fast start pricing proposal and in a much more extensive form by PJM's modified convex hull pricing proposal.

The fast start pricing and convex hull solutions would undercut LMP logic rather than directly addressing the underlying issues. The solution is not to accept that the inflexible CT should be paid or set price based on its commitment costs rather than its short run marginal costs. The question of why units make inflexible offers should be addressed directly. Are units inflexible because they are old and inefficient, because owners have not invested in increased flexibility or because they serve as a mechanism for the exercise of market power? The question of why this unit was built, whether it was built under cost of service regulation and whether it is efficient to retain the unit should be answered directly. The question of how to provide market incentives for investment in flexible units and for investment in increased flexibility of existing units should be addressed directly. The question of whether inflexible units should be paid uplift at all should be addressed directly. Marginal cost pricing without paying excess uplift to inflexible units would create incentives for market participants to provide flexible solutions including replacing inefficient units with flexible, efficient units.

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. However, the explicit balancing mechanism that included net revenues directly in unit offers in the prior capacity market design is not present in the Capacity Performance design. The nature of a direct and explicit scarcity pricing net revenue true up mechanism should be addressed if scarcity revenues are expected to increase. PJM implemented scarcity pricing rules in 2012. PJM implemented five minute scarcity pricing on May 11, 2017, and implemented two step operating reserve demand curves on July 12, 2017. 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 2017 or prior years. This is evidence of generally competitive behavior and competitive market outcomes, although the behavior of some participants during high demand periods is consistent with economic withholding. Markups were higher in 2017. Given the structure of the energy market which can permit the exercise of aggregate market power at times of high demand, the change in some participants' behavior is a source of concern in the energy market and provides a reason to use correctly defined short run marginal 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 2017.

## Overview: Section 4, Energy Uplift

### Energy Uplift Results

- **Energy Uplift Charges.** Total energy uplift charges decreased by $7.5 million, or 5.5 percent, in 2017 compared to 2016, from $136.7 million to $129.1 million.
- **Energy Uplift Charges Categories.** The decrease of $7.5 million in 2017 is comprised of a $32.6 million decrease in day-ahead operating reserve charges, a $7.2 million increase in balancing operating reserve charges and a $17.9 million increase in reactive services charges.
- **Average Effective Operating Reserve Rates in the Eastern Region.** Day-ahead load paid $0.030 per MWh, real-time load paid $0.037 per MWh, a DEC paid $0.386 per MWh and an INC and any load, generation or interchange transaction deviation paid $0.355 per MWh.
- **Average Effective Operating Reserve Rates in the Western Region.** Day-ahead load paid $0.030 per MWh, real-time load paid $0.028 per MWh, a DEC paid $0.357 per MWh and an INC and any load, generation or interchange transaction deviation paid $0.327 per MWh.
- **Reactive Services Rates.** The ComEd, PENELEC, and DPL control zones had the three highest local voltage support rates: $0.139, $0.099 and $0.073 per MWh.

### Characteristics of Credits

- **Types of units.** Coal units received 78.7 percent of all day-ahead generator credits. Combustion turbines received 76.3 percent of all balancing generator credits. Combustion turbines and diesels received 70.3 percent of the lost opportunity cost credits.
- **Concentration of Energy Uplift Credits.** The top 10 units receiving energy uplift credits received 33.1 percent of all credits. The top 10 organizations received 77.9 percent of all credits. Concentration indexes for energy uplift categories classify them as highly concentrated. Day-ahead operating reserves HHI was 7486, balancing operating reserves HHI was 3334 and lost opportunity cost HHI was 5538.
- **Economic and Noneconomic Generation.** In 2017, 85.1 percent of the day-ahead generation eligible for operating reserve credits was economic and 73.1 percent of the real-time generation eligible for operating reserve credits was economic.
- **Day-Ahead Unit Commitment for Reliability.** In 2017, 1.2 percent of the total day-ahead generation MWh was scheduled as must run by PJM, of which 54.9 percent received energy uplift payments.

### Geography of Charges and Credits

- In 2017, 89.2 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 6.4 percent by interchange transactions at interfaces.
- Generators in the Eastern Region received 50.7 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.
- Generators in the Western Region received 47.4 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.
- External generators received 1.9 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. Pending before FERC.)
- 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. Pending before FERC.)

- 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 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 must 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 consistent with pricing at short run marginal cost 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 10 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.[72] 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.

It is not appropriate to accept that inflexible units should be paid or set price based on short run marginal costs plus no load. The question of why units make inflexible offers should be addressed directly. Are units inflexible because they are old and inefficient, because owners have not invested in increased flexibility or because they serve as a mechanism for the exercise of market power. The question of why this unit was built, whether it was built under cost of service regulation and whether it is efficient to retain the unit should be answered directly. The question of how to provide market incentives for investment in flexible units and for investment in increased flexibility of existing units should be addressed directly. The question of whether inflexible units should be paid uplift at all should be addressed directly. Marginal cost pricing without paying uplift to inflexible units would create incentives for market participants to provide flexible solutions including replacing inefficient units with flexible, efficient units.

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. The same is true of fast start pricing and of convex hull pricing.

Accurate short run price signals, equal to the short run marginal cost of generating power, provide market incentives for cost minimizing production to all economically dispatched resources and provide market incentives to load based on the marginal cost of additional consumption. The objective of efficient short run price signals is to minimize system production costs, not to minimize uplift. Repricing the market to reflect commitment costs would create a tradeoff between minimizing production costs and reduction of uplift. The tradeoff would exist because when commitment costs are included in prices, the price signal no longer equals the short run marginal cost and therefore no longer provides the correct signal for efficient behavior for market participants making decisions on the margin, whether resources, load, interchange transactions, or virtual traders. This tradeoff would be created in more limited form by PJM's fast start pricing proposal and in extensive form by PJM's modified convex hull pricing proposal.

## 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.[73]

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.[74] 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.[75] Also

72 On October 17, 2017, PJM filed with FERC to begin charging uplift to UTC transactions and eliminating the netting of deviations with internal bilateral transactions. See FERC Docket No. ER18-86-000.

73 The terms *PJM Region*, *RTO Region* and *RTO* are synonymous in this report and include all capacity within the PJM footprint.

74 See 126 FERC ¶ 61,275 (2009) at P 86.

75 See Letter Order, FERC Docket No. ER10-366-000 (January 22, 2010).

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.[76]

The 2017/2018 RPM Third Incremental Auction, the 2020/2021 RPM Base Residual Auction, the 2018/2019 RPM Second Incremental Auction, and the 2019/2020 RPM First Incremental Auction were conducted in 2017.

On June 9, 2015, FERC accepted changes to the PJM capacity market rules proposed in PJM's Capacity Performance (CP) filing.[77] 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.[78] 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 nonperformance 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.[79] 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 2017, PJM installed capacity increased 1,470.9 MW or 0.8 percent, from 182,410.7 MW on January 1 to 183,881.6 MW on December 31. Installed capacity includes net capacity imports and exports and can vary on a daily basis.
- **PJM Installed Capacity by Fuel Type.** Of the total installed capacity on December 31, 2017, 35.4 percent was coal; 36.8 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 0.2 percent was solar.
- **Supply.** Total internal capacity available to offer in the Base Residual Auction for the relevant delivery year decreased 7,225.8 MW from 200,848.1 MW on June 1, 2016, to 193,622.3 MW on June 1, 2017. This decrease was the result of new generation (5,179.3 MW), reactivated generation (1,025.7 MW),

76 See 126 FERC ¶ 61,275 (2009) at P 88.
77 See 151 FERC ¶ 61,208 (2015).
78 See "PJM Manual 18: PJM Capacity Market," Rev. 38 (July 27, 2017) at 9.
79 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.

net generation capacity modifications (cap mods) (-7,943.1 MW), demand resource (DR) modifications (-3,472.4 MW), energy efficiency (EE) modifications (158.9 MW), the EFORd effect due to higher sell offer EFORds (-2,167.1 MW), and lower load management UCAP conversion factor (-7.1 MW).

- **Demand.** There was a 787.1 MW decrease in the RPM reliability requirement from 180,332.2 MW on June 1, 2016, to 179,545.1 MW on June 1, 2017. The 787.1 MW decrease in the RTO Reliability Requirement was a result of a 1,017.4 MW decrease in the forecast peak load in UCAP terms holding the Forecast Pool Requirement (FPR) constant at the 2016/2017 level offset by a 230.3 MW increase attributable to the change in FPR. On June 1, 2017, PJM EDCs and their affiliates maintained a large market share of load obligations under RPM, together totaling 63.6 percent, down from 64.1 percent on June 1, 2016.
- **Market Concentration.** In the 2018/2019 RPM Second Incremental Auction, 35 participants in the RTO passed the three pivotal supplier (TPS) test. In the 2017/2018 RPM Base Residual Auction, 2017/2018 RPM First Incremental Auction, 2017/2018 RPM Second Incremental Auction, 2017/2018 RPM Third Incremental Auction, 2018/2019 RPM Base Residual Auction, 2018/2019 RPM First Incremental Auction, 2019/2020 RPM Base Residual Auction, 2019/2020 RPM First Incremental Auction, and the 2020/2021 RPM Base Residual Auction all participants in the total PJM market as well as the LDA RPM markets failed the three pivotal supplier (TPS) test.[80] The TPS test was not applied in the 2016/2017 Capacity Performance (CP) Transition Incremental Auction and the 2017/2018 CP Transition Incremental Auction. All offers in the CP Transition Auctions were subject to overall offer caps. Offer caps were applied to all sell offers for resources which were subject to mitigation when the Capacity Market Seller did not pass the test, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, increased the market clearing price.[81] [82] [83]
- **Imports and Exports.** Of the 4,961.8 MW of imports in the 2020/2021 RPM Base Residual Auction, 3,997.2 MW cleared. Of the cleared imports, 1,671.2 MW (41.8 percent) were from MISO.
- **Demand-Side and Energy Efficiency Resources.** Capacity in the RPM load management programs was 10,117.8 MW for June 1, 2017, as a result of cleared capacity for demand resources and energy efficiency resources in RPM Auctions for the 2017/2018 Delivery Year (13,793.0 MW) less replacement capacity from sources other than demand resources and energy efficiency (3,675.2 MW).

## Market Conduct

- **2017/2018 RPM Base Residual Auction.** Of the 1,202 generation resources that submitted offers, the MMU calculated offer caps for 531 generation resources (44.2 percent), of which 400 (33.3 percent) were based on the technology specific default (proxy) ACR values and 131 (10.9 percent) were unit-specific offer caps.
- **2017/2018 Capacity Performance Transition Incremental Auction.** All 785 generation resources which submitted offers in the 2017/2018 CP Transition Incremental Auction were subject to an offer cap of $210.83 per MW-day, which is 60 percent of the Net Cost of New Entry (CONE) used in the 2017/2018 RPM Base Residual Auction.
- **2017/2018 RPM First Incremental Auction.** Of the 118 generation resources that submitted offers, the MMU calculated offer caps for 53 generation resources (44.9 percent), of which 36 (30.5 percent) were based on the technology specific default (proxy) ACR values and 17 (14.4 percent) were unit-specific offer caps.
- **2017/2018 RPM Second Incremental Auction.** Of the 95 generation resources that submitted offers, the MMU calculated offer caps for 35 generation

80 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 § 5.10(a)(ii).

81 See OATT Attachment DD § 6.5.

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

83 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 (36.8 percent), of which 15 (15.8 percent) were based on the technology specific default (proxy) ACR values and 20 (21.1 percent) were unit-specific offer caps.

- **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 (1.6 percent) were based on the technology specific default (proxy) ACR values and four (1.3 percent) were unit-specific offer caps.
- **2018/2019 RPM Base Residual Auction.** Of the 473 generation resources that submitted Base Capacity offers, the MMU calculated offer caps for 219 generation resources (46.3 percent), of which 166 (35.1 percent) were based on the technology specific default (proxy) ACR values and 53 (11.2 percent) were unit-specific offer caps. Of the 992 generation resources that submitted Capacity Performance offers, the MMU calculated unit specific offer caps for 35 generation resources (3.5 percent).
- **2018/2019 RPM First Incremental Auction.** Of the 80 generation resources that submitted Base Capacity offers, the MMU calculated offer caps for 30 generation resources (37.5 percent), of which 18 (22.5 percent) were based on the technology specific default (proxy) ACR values and 12 (15.0 percent) were unit-specific offer caps. Of the 293 generation resources that submitted Capacity Performance offers, the MMU calculated unit specific offer caps for nine generation resources (3.1 percent).
- **2018/2019 RPM Second Incremental Auction.** Of the 68 generation resources that submitted Base Capacity offers, the MMU calculated offer caps for 23 generation resources (33.8 percent), of which 12 (17.6 percent) were based on the technology specific default (proxy) ACR values and 11 (16.2 percent) were unit-specific offer caps. Of the 344 generation resources that submitted Capacity Performance offers, the MMU calculated unit specific offer caps for five generation resources (1.5 percent).
- **2019/2020 RPM Base Residual Auction.** Of the 505 generation resources that submitted Base Capacity offers, the MMU calculated offer caps for 212 generation resources (42.0 percent), of which 171 (33.9 percent) were based on the technology specific default (proxy) ACR values and 41 (8.1 percent) were unit-specific offer caps. Of the 1,003 generation resources that submitted Capacity Performance offers, the MMU calculated unit specific offer caps for 25 generation resources (2.5 percent).
- **2019/2020 RPM First Incremental Auction.** Of the 81 generation resources that submitted Base Capacity offers, the MMU calculated offer caps for 28 generation resources (34.6 percent), of which 17 (21.0 percent) were based on the technology specific default (proxy) ACR values and 11 (13.6 percent) were unit-specific offer caps. Of the 382 generation resources that submitted Capacity Performance offers, the MMU calculated unit specific offer caps for six generation resources (1.6 percent).
- **2020/2021 RPM Base Residual Auction.** Of the 1,114 generation resources that submitted offers, the MMU calculated unit specific offer caps for 14 generation resources (1.3 percent).

## Market Performance

- The 2017/2018 RPM Third Incremental Auction, the 2020/2021 RPM Base Residual Auction, the 2018/2019 RPM Second Incremental Auction, and the 2019/2020 RPM First Incremental Auction were conducted in 2017. The weighted average capacity price for the 2017/2018 Delivery Year is $141.19 per MW-day, including all RPM Auctions for the 2017/2018 Delivery Year held through 2017. The weighted average capacity price for the 2018/2019 Delivery Year is $175.58, including all RPM auctions for the 2018/2019 Delivery Year held through 2017. The weighted average capacity price for the 2019/2020 Delivery Year is $113.41, including all RPM Auctions for the 2019/2020 Delivery Year held through 2017.
- 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 $141.19 per MW-day in 2017/2018.

## Reliability Must Run Service

- Of the seven companies (23 units) that have provided RMR service, two companies (seven units) filed to be paid for RMR service under the deactivation avoidable cost rate (DACR), the formula rate. The other five companies (16 units) filed to be paid for RMR service under the cost of service recovery rate.

## Generator Performance

- **Forced Outage Rates.** The average PJM EFORd for 2017 was 6.8 percent, an increase from 6.5 percent for 2016.[84]
- **Generator Performance Factors.** The PJM aggregate equivalent availability factor for 2017 was 84.1 percent, an increase from 83.4 percent for 2016.
- **Outages Deemed Outside Management Control (OMC).** In 2017, 2.9 percent of forced outages were classified as OMC outages.

## Section 5 Recommendations[85]

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.[86]

### Definition of Capacity

- 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.[87] [88] (Priority: High. First reported 2013. Status: Not adopted. Pending before FERC.)
- The MMU recommends that the definition of demand side resources be modified 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.)

### Market Design and Parameters

- 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 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.[89] [90] 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 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, unlike the situation when EE was first added to the capacity market. However, the MMU recommends that the PJM load forecast method should be modified so that EE impacts immediately affect the forecast without the long lag times incorporated in the current forecast method. 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

84 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 January 24, 2018. 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.

85 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 52.

86 151 FERC ¶ 61,208 (June 9, 2015).

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

88 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).

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

90 See the *2012 State of the Market Report for PJM*, Volume 2, Section 6: Net Revenue.

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 offer to sell back capacity in incremental auctions only at the BRA clearing price for the relevant delivery year. (Priority: Medium. First reported Q1, 2017. Status: Not adopted.)
- The MMU recommends that the use of the 2.5 percent demand adjustment (Short Term Resource Procurement Target) be terminated immediately. The 2.5 percent should be added back to the overall market demand curve. (Priority: Medium. First reported 2013. Status: Adopted 2015.)
- The MMU recommends changing the RPM solution method to explicitly incorporate the cost of make whole payments in the objective function. (Priority: Medium. First reported 2014. Status: Not adopted.)
- The MMU recommends that PJM clear the capacity market based on nodal capacity resource locations and the characteristics of the transmission system consistent with the actual electrical facts of the grid. The current nested LDA structure used in the capacity market does not adequately represent all the capacity transfers that are feasible among LDAs. Absent a fully nodal capacity market clearing process, the MMU recommends that PJM use a nonnested model for all LDAs and specify a VRR curve for each LDA separately. Each LDA requirement should be met with the capacity resources located within the LDA and exchanges from neighboring LDAs up to the transmission limit. LDAs should price separate if that is the result of the LDA supply curves and the transmission constraints. (Priority: Medium. First reported Q3, 2017. Status: Not adopted.)

## Offer Caps and Offer Floors

- The MMU recommends the extension of the minimum offer price rule (MOPR) to all existing and proposed units (MOPR-Ex) in order to protect competition in the capacity market from external subsidies. (Priority: High. First reported 2016. 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.[91] (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 the RPM market power mitigation rule be modified to apply offer caps in all cases when the three pivotal supplier test is failed and the sell offer is greater than the offer cap. This will ensure that market power does not result in an increase in make whole payments. (Priority: Medium. First reported Q3, 2017. Status: Not adopted.)
- The MMU recommends that PJM develop a forward looking estimate for the expected number of Performance Assessment Hours (H) to use in calculating the Non-Performance Charge Rate. The MMU recommends that PJM develop a forward looking estimate for the Balancing Ratio (B) during Performance Assessment Hours to use in calculating the default offer cap. Both H and B parameters should be included in the annual review of planning parameters for the Base Residual Auction. (Priority: High. First reported Q3, 2017. Status: Not adopted.)
- The MMU recommends that when expected H and B are not the same as the assumed levels used to calculate the default market seller offer cap of Net CONE*B, the offer cap be recalculated for each

91 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).

BRA using the fundamental economic logic for a competitive offer of a CP resource. (Priority: High. New Recommendation. Status: Not adopted.)

## Performance Incentive Requirements of RPM

- The MMU recommends that a unit which is not capable of supplying energy consistent with its day-ahead offer reflect an appropriate outage. (Priority: Medium. First reported 2009. Status: Not adopted. Pending before FERC.)
- The Market Monitor recommends that retroactive replacement transactions associated with a failure to perform during a PAH not be allowed and that, more generally, retroactive replacement capacity transactions not be permitted. (Priority: Medium. First reported 2016. Status: Not adopted.)
  - 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.[92] (Priority: Medium. First reported 2013. Status: Adopted 2015.)
- 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.)

## Capacity Imports and Exports

- 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 full substitutes for internal, physical capacity resources. (Priority: High. First reported 2014. Status: Adopted 2015.)
- 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 full substitutes for internal, physical capacity resources. 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 that all capacity imports have firm transmission to the PJM border prior to offering in an RPM auction. (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 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 the rules need additional clarification and operational details. (Priority: Low. First reported 2010. Status: Partially adopted.)

## Deactivations/Retirements

- 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

92 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, joint report, "*Capacity in the PJM Market*," (August 20, 2012).<http://www.monitoringanalytics.com/reports/Reports/2012/IMM_And_PJM_Capacity_White_Papers_On_OPSI_Issues_20120820.pdf>

analyses. (Priority: Low. First reported 2012. Status: Partially adopted.)

- The MMU recommends that RMR units recover all and only 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. Customers should bear no responsibility for paying previously incurred costs, including a return on or of prior investments. (Priority: Low. First reported 2010. Status: Not adopted.)
- The MMU recommends elimination of the cost of service recovery rate in OATT Section 119, and that RMR service should be provided under the deactivation avoidable cost rate in Part V. The MMU also recommends specific improvements to the DACR provisions. (Priority: Medium. New recommendation. Status: Not adopted.)

## Section 5 Conclusion

The analysis of PJM Capacity Markets begins with market structure, which provides the framework for the actual behavior or conduct of market participants. The analysis examines participant behavior within that market structure. In a competitive market structure, market participants are constrained to behave competitively. The analysis examines market performance, measured by price and the relationship between price and marginal cost, that results from the interaction of market structure and participant behavior.

The MMU found serious market structure issues, measured by the three pivotal supplier test results 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 exception was that some seasonal resources were paid additional make whole based on a failure of the market power rules to apply offer capping. 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.[93 94 95 96 97 98] 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 PJM markets have worked to provide incentives to entry and to retaining capacity. PJM has excess reserves of more than 10,000 MW on June 1, 2017, and will have excess reserves of more than 17,000 MW on June 1, 2018, based on current positions. Capacity investments in PJM were financed by market sources. Of the 24,889.8 MW of additional capacity that cleared in RPM auctions for the 2007/2008 through 2016/2017 delivery years, 18,140.5 MW (72.9 percent) were based on market funding. Of the 18,030.9 MW of additional capacity that cleared in RPM auctions for the 2017/2018 through 2020/2021 delivery years, 15,324.7 MW (85 percent) are based on market funding. Those investments were made based on the assumption that markets would be allowed to work and that inefficient units would exit.

The issue of external subsidies emerged more fully in 2017. 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, the Illinois ZEC subsidy proceeding, the request in Pennsylvania to subsidize the TMI nuclear power plant, the request in New Jersey to subsidize the Salem and Hope Creek nuclear power plants, and the DOE NOPR, all originate from the fact that competitive markets result in the exit of uneconomic

93 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).

94 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).

95 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).

96 See "Analysis of the 2020/2021 RPM Base Residual Auction," <<http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Analysis_of_the_20202021_RPM_BRA_20171117.pdf>> (November 11, 2017).

97 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).

98 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2017," <http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Report_on_Capacity_Replacement_Activity_4_20171214.pdf> (December 14, 2017).

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 new 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, the MOPR-Ex.

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 extended (MOPR-Ex) 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 activity includes economic demand response (economic resources), emergency and pre-emergency demand response (demand resources), synchronized reserves and regulation. Economic demand response participates in the energy market. Emergency and pre-emergency demand response participates in the capacity market and energy market.[99] Demand response resources participate in the Synchronized Reserve Market. Demand response resources participate in the regulation market.

In 2017, total demand response revenue decreased by $154.4 million, 23.5 percent, from $657.1 million in 2016 to $502.6 million in 2017. Emergency demand response revenue accounted for 98.5 percent of all demand response revenue, economic demand response for 0.5 percent, demand response in the Synchronized Reserve Market for 0.6 percent and demand response in the regulation for 0.4 percent.

Total emergency demand response revenue decreased by $153.8 million, 23.7 percent, from $649.0 million in 2016 to $495.2 million in 2017. This consisted entirely of a $153.8 million, 23.7 percent, reduction in capacity market revenue from $649.0 million in 2016 to $495.2 million in 2017.[100]

Economic demand response revenue decreased by $0.9 million, 26.3 percent, from $3.5 million in 2016 to $2.6 million in 2017.[101] Demand response revenue in the Synchronized Reserve Market decreased by $0.5 million, 13.4 percent, from $3.4 million in 2016 to $3.0 million in 2017. Demand response revenue in the regulation market increased by $0.8 million, 69.0 percent, from $1.1 million in 2016 to $1.8 million in 2017.

- **Demand Response Energy Payments are Uplift.** Energy payments to emergency and economic demand response resources are uplift. LMP does not cover energy payments although emergency and economic demand response can and does set LMP. Energy payments to emergency demand resources are paid by PJM market participants in proportion to their net purchases in the real-time market. Energy payments to economic demand resources are paid by real-time exports from PJM 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 or equal to the net benefits test price for that month.[102]

- **Demand Response Market Concentration.** The ownership of economic demand response resources was highly concentrated in 2016 and 2017. The HHI for economic resource reductions decreased from 7658 in 2016 to 7599 in 2017. The ownership of emergency demand response resources was moderately concentrated in 2017. The HHI for emergency demand response committed MW was 1433 for the 2017/2018 Delivery Year. In the 2017/2018 Delivery Year, the four largest companies contributed 69.6 percent of all committed emergency demand response MW.

- **Limited Locational Dispatch of Demand Resources.** Beginning with the 2014/2015 Delivery Year, demand resources are dispatchable for mandatory reductions 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. Nodal dispatch of demand resources in a nodal market would improve market efficiency. The goal should be nodal dispatch of demand resources with no advance notice required, as is the case for generation resources.

## Section 6 Recommendations

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

- The MMU recommends, as a preferred alternative to including demand resources as supply in the capacity market, that demand resources be on the demand side of the markets, that customers be able to avoid capacity and energy charges by not using capacity and energy at their discretion, that customer payments be determined only by metered load, and that PJM forecasts immediately incorporate the impacts of demand side behavior. (Priority: High. First reported 2014. Status: Not adopted.)

- The MMU recommends that the option to specify a minimum dispatch price (strike price) for demand resources 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.)

99 Emergency demand response refers to both emergency and pre-emergency demand response. With the implementation of the Capacity Performance design, there is no functional difference between the emergency and pre-emergency demand response resource.

100 The total credits and MWh numbers for demand resources were calculated as of February 19, 2018 and may change as a result of continued PJM billing updates.

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

102 "PJM Manual 28: Operating Agreement Accounting," Rev. 77 (Nov. 1, 2017) at 83.

- The MMU recommends that the maximum offer for demand resources be the same as the maximum offer for generation resources. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that the demand resources be treated as an economic resource, responding to economic price signals like other capacity resources. The MMU recommends that demand resources not be treated as emergency resources, not trigger a PJM emergency and not trigger a Performance Assessment Hour. (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.[103] (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.[104] (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: Partially 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

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

104 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 October 17, 2017) 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.

and must terminate or modify registrations that are no longer capable of responding to PJM dispatch directives at defined levels because load has been reduced or eliminated, 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 subzones 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 in the capacity market, with an obligation to respond when called for all hours of the year. (Priority: High. First reported 2011. Status: Partially adopted.[105])
- 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 setting 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 the Relative Root Mean Squared Test be required for all demand resources with a CBL. (Priority: Low. New recommendation. Status: Partially adopted.)
- The MMU recommends that PRD be required to respond during a PAH to be consistent with all CP resources. (Priority: High. New recommendation. Status: Not adopted.)
- The MMU recommends capping the baseline for measuring compliance under GLD, for the limited summer product, at the customers' PLC. (Priority: High. First reported 2010. Status: Adopted 2015.)
- The MMU recommends that demand resources whose technology type (load drop method) is designated as "Other" explicitly record the technology type. (Priority: Low. First reported 2013. Status: Adopted, 2014.)

105 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.

## 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. The Capacity Performance demand response product definition in the PJM Capacity Performance capacity market design is a significant step in that direction, although performance obligations are still not identical to other capacity resources.

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. The fact that PJM currently defines demand resources as emergency resources and the fact that calling on demand resources triggers a performance assessment hour under the Capacity Performance design, both serve as a significant disincentive to calling on demand resources. Demand resources should be treated as economic resources like any other capacity resource. Demand resources should be called when economic and paid the LMP rather than an inflated strike price up to $1,849 per MWh that is set by the seller.

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 or modify registrations that are no longer capable of responding to PJM dispatch directives at the specified level, 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 resources should be on the demand side of the capacity market rather than on the supply side. Rather than detailed 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 and the level of usage paid for would be defined by metered usage rather than a complex and inaccurate measurement protocol.

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 CP design in the capacity market. 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 2017 than in 2016. Gas prices increased more than energy prices and CTs and CCs ran with lower margins as a result. Coal prices increased more than energy prices but less than gas prices and CPs ran for slightly more hours in 2017 than in 2016 and margins varied by zone.
- In 2017, average energy market net revenues decreased by 54 percent for a new CT, 9 percent for a new CC, 2 percent for a new CP, and 4 percent for a new solar installation compared to 2016. Average energy market net revenues increased by 49 percent for a new DS, 11 percent for a new nuclear plant, and 11 percent for a new wind installation compared to 2016.
- The relative prices of fuel varied during 2017. While the marginal cost of the new CC was consistently below that of the new CP in 2017, the marginal cost of the new CT was above that of the new CP in January and December. As a result, CT hours dropped significantly and CP hours increased.
- Capacity revenue accounted for 65 percent of total net revenues for a new CT, 38 percent for a new CC, 62 percent for a new CP, 95 percent for a new DS, and 20 percent for a new nuclear plant.
- In 2017, a new CT would not have received sufficient net revenue to cover levelized total costs in any zone but would have covered 95 percent of levelized costs in the PSEG Zone, as a result of higher locational capacity market prices.
- In 2017, a new CC would have received sufficient net revenue to cover levelized total costs in three of the twenty zones and to cover 90 percent or more of levelized costs in 11 zones.
- In 2017, a new CP would not have received sufficient net revenue to cover levelized total costs in any zone.
- In 2017, a new nuclear plant would not have received sufficient net revenue to cover levelized total costs in any zone.
- In 2017, net revenues covered more than 44 percent of the annual levelized total costs of a new entrant wind installation in ComEd, 65 percent of the annual levelized total costs of a new entrant wind installation in PENELEC and 167 percent of the annual levelized total costs of a new entrant solar installation in PSEG. Renewable energy credits accounted for five percent of the total net revenue of a wind installation in ComEd and 37 percent of the total net revenue of a wind installation in PENELEC. Renewable energy credits accounted for 81 percent of the total net revenue of a solar installation in PSEG.
- In 2017, most units did not achieve full recovery of avoidable costs through net revenue from energy markets alone, illustrating the critical role of the PJM Capacity Market in providing incentives for continued operation and investment. In 2017, capacity revenues were sufficient to cover the

shortfall between energy revenues and avoidable costs for the majority of units and technology types in PJM, with the exception of some coal units and some nuclear units.

- The net revenue results show that there are between 108 and 118 units with between 22,929 MW and 30,785 MW of capacity in PJM at risk of retirement in addition to the units that are currently planning to retire. Coal and nuclear units account for most of the MW at risk. There are between 38 and 46 coal units, with between 17,302 MW and 21,039 MW, at risk. There are between three and five nuclear plants at risk, with between 2,939 MW and 7,058 MW at risk.

## 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 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 alone 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 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 2017, and have not covered their total costs in the ComEd Zone through 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.[106]
- **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

106 *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).

prohibit emissions that significantly interfere with the ability of another state to meet NAAQS.[107]

- **National Emission Standards for Reciprocating Internal Combustion Engines.** Provisions exempting 100 hours of run time for certain stationary reciprocating internal combustion engines (RICE) participating in emergency demand response programs have been eliminated. 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] 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] On October 10, 2017, the EPA proposed to repeal the Clean Power Plan based a determination that the Plan exceeds the EPA's authority under Section 111 of the EPAs Act.[112]
- **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]

## State Environmental Regulation

- **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 December 8, 2017, auction for the 2015–2017 compliance period was \$3.80 per ton. The clearing price is equivalent to a price of \$4.19 per metric tonne, the unit used in other carbon markets. The price decreased by \$0.55 per ton, 12.6 percent, from \$4.35 per ton from September 8, 2017, to \$3.80 per ton for December 8, 2017.
- **Carbon Price.** If the price of carbon were \$50.00 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).

## 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 December 31, 2018, 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.[114]

## 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 December 31, 2017, 93.0 percent of coal steam MW had some type of flue-gas desulfurization (FGD) technology to reduce $SO_2$ emissions, while 99.5 percent of coal steam MW had some type of particulate control, and 93.7 percent of fossil fuel fired capacity in PJM had $NO_X$ emission control technology.

107 CAA § 110(a)(2)(D)(i)(I).

108 EPA, Memorandum, Peter Tsirigotis Guidance on Vacatur of RICE NESHAP and NSPS Provisions for Emergency Engines (April 15, 2016).

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 *See Repeal of Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units*, Proposed Rule, EPA Docket No. EPA-HQ-OAR-2017-0355, 82 Fed. Reg. 48035 (October 16, 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 See Enr. Com. Sub. For H. B. No. 2001.

## Renewable Generation

Total wind and solar generation was 2.7 percent of total generation in PJM for 2017, total renewable generation was 4.8 percent of total generation in PJM and was 6.7 percent if coal and solid waste resources in the Tier II RECs programs are included.

## Section 8 Recommendation

- 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 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. 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.[115]

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.

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

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

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 efficient markets 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.

## Overview: Section 9, Interchange Transactions

### Interchange Transaction Activity

- **Aggregate Imports and Exports in the Real-Time Energy Market.** In 2017, PJM was a monthly net exporter of energy in the Real-Time Energy Market in all months.[116] In 2017, the real-time net interchange of -22,958.1 GWh was lower than the net interchange of -9,153.6 GWh in 2016.
- **Aggregate Imports and Exports in the Day-Ahead Energy Market.** In 2017, PJM was a monthly net exporter of energy in the Day-Ahead Energy Market in all months. In 2017, the total day-ahead net interchange of -19,550.1 GWh was lower than net interchange of -9,182.4 GWh in 2016.
- **Aggregate Imports and Exports in the Day-Ahead and the Real-Time Energy Market.** In 2017, gross imports in the Day-Ahead Energy Market were 184.9 percent of gross imports in the Real-Time Energy Market (135.4 percent in 2016). In 2017, gross exports in the Day-Ahead Energy Market were 125.4 percent of the gross exports in the Real-Time Energy Market (127.8 percent in 2016).
- **Interface Imports and Exports in the Real-Time Energy Market.** In 2017, there were net scheduled exports at 11 of PJM's 20 interfaces in the Real-Time Energy Market.
- **Interface Pricing Point Imports and Exports in the Real-Time Energy Market.** In 2017, there were net scheduled exports at 11 of PJM's 18 interface pricing points eligible for real-time transactions in the Real-Time Energy Market.[117]
- **Interface Imports and Exports in the Day-Ahead Energy Market.** In 2017, there were net scheduled exports at 12 of PJM's 20 interfaces in the Day-Ahead Energy Market.
- **Interface Pricing Point Imports and Exports in the Day-Ahead Energy Market.** In 2017, there were net scheduled exports at 12 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 2017, up to congestion transactions were net exports at four of PJM's 19 interface pricing points eligible for day-ahead transactions in the Day-Ahead Energy Market.
- **Inadvertent Interchange.** In 2017, net scheduled interchange was -22,958 GWh and net actual interchange was -23,147 GWh, a difference of 189 GWh. In 2016, the difference was 1,186 GWh. This difference is inadvertent interchange.
- **Loop Flows.** In 2017, the Wisconsin Energy Corporation (WEC) Interface had the largest loop flows of any interface with -1,934 GWh of net scheduled interchange and 9,387 GWh of net actual interchange, a difference of 11,321 GWh. In 2017, the SouthIMP interface pricing point had the largest loop flows of any interface pricing point with 8,015 GWh of net scheduled interchange and 24,457 GWh of net actual interchange, a difference of 16,442 GWh.

### Interactions with Bordering Areas

#### PJM Interface Pricing with Organized Markets

- **PJM and MISO Interface Prices.** In 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 56.9 percent of the hours.
- **PJM and New York ISO Interface Prices.** In 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 52.2 percent of the hours.
- **Neptune Underwater Transmission Line to Long Island, New York.** In 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 59.7 percent of the hours.
- **Linden Variable Frequency Transformer (VFT) Facility.** In 2017, the hourly flow (PJM to NYISO) was consistent with the real-time hourly price

116 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.
117 There is one interface pricing point eligible for day-ahead transaction scheduling only (NIPSCO).

differences between the PJM Linden Interface and the NYISO Linden bus in 53.5 percent of the hours.

- **Hudson DC Line.** In 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 9.0 percent of the hours.[118]

## Interchange Transaction Issues

- **PJM Transmission Loading Relief Procedures (TLRs).** PJM issued six TLRs of level 3a or higher in 2017, compared to nine such TLRs issued in 2016.
- **Up to congestion.** The average number of up to congestion bids submitted in the Day-Ahead Energy Market decreased by 11.2 percent, from 156,021 bids per day in 2016 to 138,489 bids per day in 2017. The average cleared volume of up to congestion bids submitted in the Day-Ahead Energy Market increased by 1.2 percent, from 824,885 MWh per day in 2016, to 838,258 MWh per day in 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.[119] [120] 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.[121]

## 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 authority to the MISO interface pricing point. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM monitor, and adjust as necessary, the weights applied to the components of the interfaces to ensure that the interface prices reflect ongoing changes in system conditions. The MMU also recommends that PJM review the mappings of external balancing authorities to individual interface pricing points to reflect changes to the impact of the external power source on PJM tie lines as a result of system topology changes. The MMU recommends that this review occur at least annually. (Priority: Low. First reported 2009. Status: Not adopted.)
- The MMU recommends that, 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

118 The Hudson line was out of service for all hours in the first nine months of 2017. In the first nine months of 2017, there were five hours with less than 1 MW of unscheduled flow across the Hudson line.

119 *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).

120 *See* Letter Order, Docket No. ER14-381-000 (June 30, 2014).

121 *See* joint statement of PJM and the MMU re Interchange Scheduling issued July 29, 2014, at: <http://www.monitoringanalytics.com/reports/Market_Messages/Messages/PJM_IMM_Statement_on_Interchange_Scheduling_20140729.pdf>.

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: Partially adopted, 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 2017.)

### 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.[122]

### 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).

122 See PJM. "Manual 10: Pre-Scheduling Operations," Rev. 36 (Dec. 22, 2017), p. 24.

- **Demand.** The PJM primary reserve requirement is 150 percent of the largest contingency. For 2017, the average primary reserve requirement was 2,211.6 MW in the RTO Zone and 2,027.4 MW in the MAD Subzone.

## 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 2017 there was an average hourly supply of 1,172.1 MW of tier 1 available in the RTO Zone. In 2017, there was an average hourly supply of 493.9 MW of tier 1 synchronized reserve available within the MAD Subzone and an additional 727.4 MW of tier 1 available to the MAD Subzone from the RTO Zone.
- **Demand.** The synchronized reserve requirement is calculated hourly as the largest contingency within both the RTO Zone and the MAD 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 per MW. This is the Synchronized Energy Premium Price.

  Of the Degree of Generator Performance (DGP) adjusted tier 1 synchronized reserve MW estimated at market clearing, 50.5 percent actually responded during the six synchronized reserve events with duration of 10 minutes or longer in 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. The tariff requires payment of the tier 2 synchronized reserve market clearing price to tier 1 resources whenever the nonsynchronized reserve market clearing price rises above zero. This requirement was unnecessary and inconsistent with efficient markets. This change 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 $2,197,514 in 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, that have penalties for failure to respond, 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 uses 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 2017, the supply of offered and eligible tier 2 synchronized reserve was 24,231.3 MW in the RTO Zone of which 6,561.8 MW (including 1,520.9 MW of DSR) was located in the MAD Subzone.
- **Demand.** The average hourly required synchronized reserve requirement was 1,504.8 MW in the RTO Reserve Zone and 1,493.3 MW for the Mid-Atlantic Dominion Reserve Subzone. The hourly average required tier 2 synchronized reserve was 323.0 MW in the MAD Subzone and 688.8 MW in the RTO.
- **Market Concentration.** 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 2017.

In 2017, the weighted average HHI for tier 2 synchronized reserve in the Mid-Atlantic Dominion Subzone was 5927, which is classified as highly concentrated. The MMU calculates that the three pivotal supplier test in the Mid-Atlantic Dominion Subzone would have been failed in 66.7 percent of hours.

In 2017, the weighted average HHI for cleared tier 2 synchronized reserve in the RTO Synchronized Reserve Zone was 6543, which is classified as highly concentrated. The MMU calculates that the three pivotal supplier test in the RTO Synchronized Reserve Zone would have been failed in 58.9 percent of hours.

### 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, unless the unit type is exempt. 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 $3.28 per MW in 2017, a decrease of $0.90 from 2016.

  The weighted average price for tier 2 synchronized reserve for all cleared hours in the RTO Synchronized Reserve Zone was $3.73 per MW in 2017, a decrease of $1.15 from 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. Generation owners do not submit supply offers. 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 (based on offer parameters), and on the resource opportunity costs calculated by PJM.

### Market Structure

- **Supply.** In 2017, the average hourly supply of eligible nonsynchronized reserve was 2,171.5 MW in the RTO Zone.
- **Demand.** Demand for nonsynchronized reserve equals the primary reserve requirement minus the tier 1 synchronized reserve estimate and minus the scheduled tier 2 synchronized reserve.[123] In the RTO Zone, the market cleared an hourly average of 1,053.2 MW of nonsynchronized reserve in 2017.
- **Market Concentration.** In 2017, the weighted average HHI for cleared nonsynchronized reserve in the RTO Zone was 4242, which is highly concentrated. The MMU calculates that the three pivotal supplier test would have been failed in 55.6 percent of hours.

### Market Conduct

- **Offers.** Generation owners do not submit supply offers. 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 hours in the RTO Reserve Zone $0.13 per MW in 2017. The price cleared above $0.00 only 1.7 percent of hours.

123 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Rev. 92 (Nov. 1, 2017), p. 81. "Because Synchronized Reserve may be utilized to meet the Primary Reserve requirement, there is no explicit requirement for non-synchronized reserves."

## 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. The Day-Ahead Scheduling Reserve Market (DASR) has no performance obligations except that a unit which clears the DASR market may not be on an outage in real time.[124] If DASR units are on an outage in real time or cleared DASR MW are not available, the DASR payment is not made.

### 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 30 minute energy ramp rate or the economic maximum MW minus the day-ahead dispatch point for all online units. In 2017, the average available hourly DASR was 36,547.8 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 5,608.8 MW per hour in 2017, compared to 6,072.5 MW per hour in 2016.
- **Concentration.** In 2017, the MMU estimates that the DASR Market would have failed the three pivotal supplier test in 15.9 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 2017, a daily average of 39.2 percent of units offered above $0.00. A daily average of 14.8 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 2017.

### Market Performance

- **Price.** In 2017, the weighted average DASR price for all hours when the DASRMCP was above $0.00 was $2.11.

## 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 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 fast ramp rates. In the Regulation Market RegD MW are converted to effective MW using a marginal rate of substitution (MRTS), called a marginal benefit function (MBF). Correctly implemented, the MBF would be 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 2017, the average hourly eligible supply of regulation for nonramp hours was 1,136.1 performance adjusted MW (869.0 effective MW).[125] This was a decrease of 90.7 performance adjusted MW (an increase of 7.8 effective MW) from 2016, when the average hourly eligible supply of regulation for nonramp hours was 1,226.8 performance adjusted MW (861.2 effective MW). In 2017, the average hourly eligible supply of regulation for ramp hours was 1,427.2 performance adjusted MW (1,183.4 effective MW). This was an increase of 230.9 performance adjusted MW (233.4 effective MW)

124 See PJM, "Manual 11: Energy & Ancillary Services Market Operations," Rev. 92 (Nov. 1, 2017), p. 155 §11.2.7.

125 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>.

from 2016, when the average hourly eligible supply of regulation was 1,196.3 performance adjusted MW (950.0 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.

- **Supply and Demand.** The nonramp regulation requirement of 525.0 effective MW was provided by a combination of RegA and RegD resources equal to 488.1 hourly average MW in 2017. This is a decrease of 28.1 MW from 2016, when the average hourly total regulation cleared MW for nonramp hours were 516.2 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 720.2 hourly average MW in 2017. This is an increase of 84.2 MW from 2016, where the average hourly regulation cleared MW for ramp hours were 636.0 MW.

  The ratio of the average hourly eligible supply of regulation to average hourly regulation demand for ramp hours was 1.98 in 2017. This is an increase of 5.4 percent from 2016, when the ratio was 1.88. The ratio of the average hourly eligible supply of regulation to average hourly regulation demand required for nonramp hours was 2.33 in 2017. This is a decrease of 2.0 percent from 2016, when the ratio was 2.38.

- **Market Concentration.** In 2017, the three pivotal supplier test was failed in 85.7 percent of hours. In 2017, the weighted average HHI of RegA resources was 2677, which is highly concentrated and the weighted average HHI of RegD resources was 1604, which is also highly concentrated. The weighted average HHI of all resources was 1136, 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.[126] In 2017, there were 221 resources following the RegA signal and 61 resources following the RegD signal.

## Market Performance

- **Price and Cost.** The weighted average clearing price for regulation was $16.78 per effective MW of regulation in 2017. This is an increase of $1.05 per MW, or 6.7 percent, from the weighted average clearing price of $15.73 per MW in 2016. The weighted average cost of regulation in 2017 was $23.03 per effective MW of regulation. This is an increase of $4.89 per MW, or 27.0 percent, from the weighted average cost of $18.14 per MW in 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 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 1.0, 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 average MBF is less than 1.0, resulting in persistent overpayment of RegD resources that creates an artificial incentive for inefficient entry of RegD resources. The MBF averaged less than 1.0 in six months of 2017, resulting in RegD resources being paid an average of $17.4 million (288.3 percent) more than they should have in 2017. In each month of 2016, the average MBF was less than 1.0, resulting in RegD resources being paid an average of $14.6 million (1,565.7 percent) more than they should have been.

- **Marginal Benefit Factor Function.** The marginal benefit factor (MBF) is intended to measure the

126 See the *2016 State of the Market Report for PJM*, Volume 2, Appendix F "Ancillary Services Markets."

operational substitutability of RegD resources for RegA resources. The marginal benefit factor function is incorrectly defined and applied in the PJM market clearing. 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.[127]

- **Changes to the Regulation Market.** 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. PJM made additional changes which went into effect on January 9, 2017. These include changing the definition of 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. The January 9 changes did not resolve the underlying issues. Effective July 31, 2017, PJM ended the use of excursion hours (hours ending 7:00, 8:00, 18:00-21:00), in which PJM had decided that more RegA was needed and PJM did not clear any RegD with an MBF less than 1.0.

## 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).[128]

In 2017, total black start charges were $69.5 million, including $69.3 million in revenue requirement charges and $0.257 million in operating reserve charges. Black start revenue requirements 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 2017 ranged from $0.06 per MW-day in the DLCO Zone (total charges were $51,114) to $4.28 per MW-day in the PENELEC Zone (total charges were $4,543,929).

## 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.[129] 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 2017, total reactive charges were $334.3 million, an 11.9 percent increase from $298.7 million in 2016. Reactive capability revenue requirement charges increased from $296.2 million in 2016 to $313.9 million in 2017 and reactive service charges increased from $2.4 million in 2016 to $20.4 million in 2017. Total reactive service charges in 2017 ranged from $1,239 in the RECO Zone to $47.5 million in the ComEd Zone.

127 The issues associated with over procurement were brought before the PJM Operating Committee in May of 2015. Regulation Performance Impacts, PJM Operating Committee, (May 26, 2015), which can be accessed at: <http://www.pjm.com/committees-and-groups/committees/oc.aspx>.

128 OATT Schedule 1 § 1.3BB.

129 OATT Schedule 2.

## Frequency Response

In response to a November 17, 2016 FERC NOPR,[130] PJM formed the Primary Frequency Response Senior Task Force (PFRSTF) to review primary frequency response and propose changes to its tariff and operating manuals, including consideration of compensation mechanisms if needed.

## Section 10 Recommendations

- The MMU recommends that the Regulation Market be modified to incorporate a consistent application of the marginal benefit factor (MBF) throughout the optimization, assignment and settlement process. The MBF should be defined as the Marginal Rate of Technical Substitution (MRTS) between RegA and RegD. (Priority: High. First reported 2012. Status: Not adopted. Pending before FERC.)
- 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. Pending before FERC.)
- The MMU recommends that the LOC calculation used in the Regulation Market be based on the resource's dispatched energy offer schedule, not the lower of its price or cost offer schedule. (Priority: Medium. First reported 2010. Status: Pending before FERC.)
- 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, to prevent gaming, 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. (Priority: Medium. First reported 2016. Status: Not adopted. Pending before FERC.)
- The MMU recommends the use of a single five minute clearing price based on actual five minute LMP and lost opportunity cost to improve the performance of the Regulation Market. (Priority: Medium. First reported 2010. Status: Adopted in 2012.)
- The MMU recommends that PJM be required to save data elements necessary for verifying the performance of the Regulation Market. (Priority: Medium. First reported 2010. Status: Not adopted.)
- The MMU recommends enhanced documentation of the implementation of the Regulation Market design. (Priority: Medium. First reported 2010. Status: Pending before FERC.)
- The MMU recommends that the rule requiring that tier 1 synchronized reserve resources are paid the tier 2 price when the nonsynchronized reserve price is above zero be eliminated immediately and that, under the current rule, 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: Partially 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 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, 2016.)
- 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

130 *Essential Reliability Services and the Evolving Bulk-Power System – Primary Frequency Response*, Notice of Proposed Rulemaking, 157 FERC ¶ 61,122 (Nov. 17, 2016) ("NOPR").

deselection process be published. (Priority: High. First reported 2014. Status: Adopted, 2014.)

- 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 PJM modify the DASR Market to ensure that all resources cleared incur a real-time performance obligation. (Priority: Low. First reported 2013. 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 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 that for oil tanks which are shared with other resources only a proportionate share of the minimum tank suction level (MTSL) be allocated to black start service. The MMU further recommends that the PJM tariff be updated to clearly state how the MTSL will be calculated for black start units sharing oil tanks. (Priority: Medium. First reported Q3, 2017. Status: Not adopted.)
- The MMU recommends that capability to operate under the proposed deadband (+/- 0.036 HZ) and droop (5 percent) settings be mandated as a condition of interconnection and that such capability be required of both new and existing resources. The MMU recommends that no additional compensation be provided as the current PJM market design provides adequate compensation. (Priority: Low. New recommendation. Status: Not adopted.)

## Section 10 Conclusion

The current PJM regulation market design that incorporates two signals using two resource types was a result of Commission Order No. 755 and subsequent orders that required a flawed design.[131]

The current design of the PJM Regulation Market is significantly flawed. The market design has failed to correctly incorporate the marginal rate of technical substitution (MRTS) in market clearing and settlement. The market design uses the marginal benefit factor (MBF) to incorrectly represent the MRTS and uses a mileage ratio instead of the MBF in settlement. This failure to correctly and consistently incorporate the MRTS 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.

To address these flaws, the MMU and PJM developed a joint proposal which was approved by the PJM Members Committee on July 27, 2017 and filed with FERC on October 17, 2017.[132] The PJM/MMU joint proposal addresses issues with the inconsistent application of the marginal benefit factor throughout the optimization and settlement process in the PJM Regulation Market.

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 six spinning events 10 minutes or longer in 2017, the response was 87.6 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

131 *Frequency Regulation Compensation in the Organized Wholesale Power Markets*, Order No. 755, 137 FERC ¶ 61,064 at PP 197–200 (2011)

132 18 CFR § 385.211 (2017)

windfall payment to the holders of tier 1 synchronized reserve resources. 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 already 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 $2,197,514 million in 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 $326.1 million or 31.9 percent, from $1,023.7 million in 2016 to $697.6 million in 2017.
- **Day-Ahead Congestion.** Day-ahead congestion costs decreased by $367.4 million or 33.4 percent, from $1,100.4 million in 2016 to $733.1 million in 2017.
- **Balancing Congestion.** Balancing congestion costs increased by $41.3 million or 53.8 percent, from -$76.8 million in 2016 to -$35.5 million in 2017.
- **Real-Time Congestion.** Real-time congestion costs decreased by $236.1 million or 22.4 percent, from $1,053.7 million in 2016 to $817.5 million in 2017.
- **Monthly Congestion.** Monthly total congestion costs in 2017 ranged from $30.1 million in August to $121.7 million in December.
- **Geographic Differences in CLMP.** Differences in CLMP among eastern, southern and western control zones in PJM were primarily a result of congestion on the Braidwood - East Frankfort Line, the Conastone - Peach Bottom Line, the Emilie – Falls Line, the Graceton - Safe Harbor Line and the 5004/5005 Interface.
- **Congestion Frequency.** Congestion frequency continued to be significantly higher in the Day-Ahead Energy Market than in the Real-Time Energy Market in 2017. The number of congestion event hours in the Day-Ahead Energy Market was about 13 times the number of congestion event hours in the Real-Time Energy Market.

  Day-ahead congestion frequency increased by 9.3 percent from 275,298 congestion event hours in 2016 to 300,923 congestion event hours in 2017.

  Real-time congestion frequency decreased by 15.1 percent from 26,370 congestion event hours in 2016 to 22,400 congestion event hours in 2017.
- **Congested Facilities.** Day-ahead, congestion-event hours increased on flowgates and transformers and decreased on interfaces and lines. Real-time, congestion-event hours increased on interfaces and decreased on lines, flowgates and transformers.

  The Braidwood - East Frankfort Line was the largest contributor to congestion costs in 2017. With $43.4 million in total congestion costs, it accounted for 6.2 percent of the total PJM congestion costs in 2017.
- **Zonal Congestion.** ComEd had the largest total congestion costs among all control zones in 2017. ComEd had $215.8 million in total congestion costs, comprised of -$237.5 million in total load congestion payments, -$460.2 million in total generation congestion credits and -$6.8 million in explicit congestion costs. The Braidwood – East Frankfort Line, the Cherry Valley Transformer, the Alpine – Belvidere Flowgate, the Brokaw - Leroy Flowgate and the Bryron – Cherry Valley Flowgate

contributed $89.6 million, or 41.5 percent of the total ComEd control zone congestion costs.

- **Ownership.** In 2017, financial entities were net receivers and physical entities were net payers of congestion charges. In 2017, financial entities were paid $19.9 million in congestion credits compared to $10.8 million received in congestion credits in 2016. In 2017, physical entities paid $717.5 million in congestion charges, a decrease of $316.9 million or 30.6 percent compared to 2016.

## Marginal Loss Cost

- **Total Marginal Loss Costs.** Total marginal loss costs decreased by $5.7 million or 0.8 percent, from $696.5 million in 2016 to $690.8 million in 2017. The loss MWh in PJM decreased by 233.8 GWh or 1.5 percent, from 15,153.9 GWh in 2016 to 14,920.1 GWh in 2017. The loss component of real-time LMP in 2017 was $0.0145, compared to $0.0144 in 2016.
- **Monthly Total Marginal Loss Costs.** Monthly total marginal loss costs in 2017 ranged from $44.2 million in April to $91.5 million in December.
- **Day-Ahead Marginal Loss Costs.** Day-ahead marginal loss costs decreased by $3.3 million or 0.4 percent, from $773.2 million in 2016 to $769.9 million in 2017.
- **Balancing Marginal Loss Costs.** Balancing marginal loss costs decreased by $2.4 million or 3.1 percent, from -$76.7 million in 2016 to -$79.1 million in 2017.
- **Total Marginal Loss Surplus.** The total marginal loss surplus decreased in 2017 by $12.6 million or 5.5 percent, from $227.2 million in 2016, to $214.6 million in 2017.

## Energy Cost

- **Total Energy Costs.** Total energy costs decreased by $8.9 million or 1.9 percent, from -$466.3 million in 2016 to -$475.2 million in 2017.
- **Day-Ahead Energy Costs.** Day-ahead energy costs decreased by $7.9 million or 1.2 percent, from -$640.6 million in 2016 to -$648.5 million in 2017.
- **Balancing Energy Costs.** Balancing energy costs decreased by $17.8 million or 9.7 percent, from $184.0 million in 2016 to $166.2 million in 2017.
- **Monthly Total Energy Costs.** Monthly total energy costs in 2017 ranged from -$61.9 million in December to -$31.0 million in April.

## 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, 86.5 and 98.1 percent of total congestion costs including congestion in the Day-Ahead Energy Market and the balancing energy market for the 2014/2015, 2015/2016 and 2016/2017 planning periods. For the first seven months of the 2017/2018 planning period ARRs and self scheduled FTRs offset 79.4 percent of total congestion costs.

# Overview: Section 12, Planning

## Planned Generation and Retirements

- **Planned Generation.** As of December 31, 2017, 99,452.5 MW of capacity were in generation request queues for construction through 2024, compared to an installed capacity of 201,496.5 MW as of December 31, 2017. Of the capacity in queues, 9,880.7 MW, or 9.9 percent, are uprates and the rest are new generation. Wind projects account for 18,287.9 MW of nameplate capacity or 18.4 percent of the capacity in the queues. Natural gas fired projects account for 59,999.8 MW of capacity or 60.3 percent of the capacity in the queues.
- **Generation Retirements.** 32,699.3 MW have been, or are planned to be, retired between 2011 and 2020. Of that, 6,935.9 MW are planned to retire after December 31, 2017. In 2017, 2,126.8 MW were retired. Of the 6,935.9 MW pending retirement, 4,620.0 MW (66.6 percent) 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 coal fired steam units retire. There are 199.0 MW of coal fired steam capacity and 59,999.8 MW of gas fired capacity in the queue. The replacement of coal fired 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.[133] PJM's process is designed to ensure that new generation is added in a reliable and systematic manner. 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. The queue process results in a substantial number of projects that drop out. Excluding currently active projects and projects currently under construction, 3,685 projects, representing 474,780.1 MW, have entered the queue process since its inception. Of those, 753 projects, representing 51,560.5 MW, went into service. Of the projects that entered the queue process, 68.2 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 associated with the submittal of large numbers of requests at the end of the queue window, which resulted in revisions to the PJM Open Access Transmission Tariff, effective October 31, 2016.[134] [135] 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.[136]
- 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."[137] 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)

- The Transmission Expansion Advisory Committee (TEAC) regularly reviews internal and external proposals to improve transmission reliability throughout PJM. These proposals are periodically presented to the PJM Board of Managers for authorization. In 2017, the PJM Board approved over $1.7 billion in upgrades.

133 See OATT Parts IV & VI.

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

135 See Letter Order, ER16-2518-000 (Oct. 7, 2016).

136 157 FERC ¶ 61,212 (2016).

137 See OATT § 1 (Transmission Owner).

- There are currently three backbone projects under development, Surry Skiffes Creek 500kV, and the conversion of the Marion-Bayonne and Bayway-Linden lines from 138 kV to 345 kV.[138]
- Through December 31, 2017, PJM has completed two market efficiency cycles. In the first cycle, PJM received 92 proposals for 11 identified issues. In the second market efficiency cycle, PJM received 96 proposals for four identified issues.
- The first Targeted Market Efficiency Process (TMEP) analysis included the investigation of congestion on 50 market to market flowgates. The study resulted in the evaluation of 13 potential upgrades, resulting in the recommendation of five TMEP projects. The five projects address $59 million in historical congestion, with a TMEP benefit of $99.6 million. The projects have a total cost of $20 million, with a 5.0 average benefit/cost ratio. PJM and MISO presented the five recommended projects to their boards in December, 2017, and both boards approved all five projects.[139]
- On April 6, 2017, the PJM Board lifted the suspension of the Artificial Island project. The project is expected to be in service by June 2020.

## 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.[140]
- There were 15,613 transmission outage requests submitted in the 2017/2018 planning period. Of the requested outages, 73.4 percent were planned for five days or shorter and 8.5 percent were planned for longer than 30 days. Of the requested outages, 43.7 percent were late according to the rules in PJM's Manual 3.

## Section 12 Recommendations

The MMU recommends improvements to the planning process.

- The MMU recommends that PJM continue to incorporate the principle that the goal of transmission planning should be the incorporation of transmission investment decisions into market driven processes as much as possible. (Priority: Low. First reported 2001. Status: Not adopted.)
- The MMU recommends the creation of a mechanism to permit a direct comparison, or competition, between transmission and generation alternatives, including which alternative is less costly and who bears the risks associated with each alternative. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that rules be implemented to permit competition to provide financing for transmission projects. This competition could reduce the cost of capital for transmission projects and significantly reduce total costs to customers. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that rules be implemented to require that project cost caps on new transmission projects be part of the evaluation of competing projects. (Priority: Low. 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.[141]

138 See "2017 RTEP Process Scope and Input Assumptions White Paper," P 25. <http://www.pjm.com/-/media/library/reports-notices/2017-rtep/20170731-rtep-input-assumptions-and-scope-whitepaper.ashx?la=en>.

139 See PJM. "*MISO PJM IPSAC*," (January 12, 2018) <http://www.pjm.com/-/media/committees-groups/stakeholder-meetings/ipsac/20180112/20180112-ipsac-presentation.ashx>.

140 PJM. "Manual 03: Transmission Operations," Rev. 52 (Dec. 22, 2017) Section 4.

141 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>.

(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.)
- The MMU recommends that PJM limit the scope of supplemental projects that can obtain exceptions to the Order No. 1000 process, to ensure maximum competition. (Priority: Medium. New recommendation. Status: Not adopted.)

## Section 12 Conclusion

The goal of PJM market design should be to enhance competition and to ensure that competition is the driver for all the key elements of PJM markets. But transmission investments have not been fully incorporated into competitive markets. The construction of new transmission facilities has significant impacts on the energy and capacity markets. But when generating units retire or load increases, there is no market mechanism in place that would require direct competition between transmission and generation to meet loads in the affected area. In addition, despite FERC Order No. 1000, there is not yet a transparent, robust and clearly defined mechanism to permit competition to build transmission projects, to ensure that competitors provide a total project cost cap, or to obtain least cost financing through the capital markets.

The addition of a planned transmission project changes the parameters of the capacity auction for the area, changes the amount of capacity needed in the area, changes the capacity market supply and demand fundamentals in the area and may effectively forestall the ability of generation to compete. But there is no mechanism to permit a direct comparison, let alone competition, between transmission and generation alternatives. There is no mechanism to evaluate whether the generation or transmission alternative is less costly, whether there is more risk associated with the generation or transmission alternatives, or who bears the risks associated with each alternative. Creating such a mechanism should be an explicit goal of PJM market design.

Managing the generation queues is a highly complex process. The PJM queue evaluation process has been substantially improved in recent years and it is more efficient and effective as a result. The PJM queue evaluation process should continue to be improved to help 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 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.

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. Residual ARRs with negative target allocations are not allocated to participants. Instead they are removed and the model is rerun.

  In the first seven months of the 2017/2018 planning period, PJM allocated a total of 23,506.1 MW of residual ARRs, up from 21,600.4 MW in the first seven months of the 2016/2017 planning period, with a total target allocation of $7.9 million for the first seven months of the 2017/2018 planning period, up from $4.2 million for the first seven months of the 2016/2017 planning period.

- **ARR Reassignment for Retail Load Switching.** There were 33,771 MW of ARRs associated with $245,600 of revenue that were reassigned in the first seven months of the 2017/2018 planning period. There were 27,920 MW of ARRs associated with $315,900 of revenue that were reassigned for the first seven months of the 2016/2017 planning period.

## Market Performance

- **Revenue Adequacy.** For the first seven months of the 2017/2018 planning period, the ARR target allocations, which are based on the nodal price differences from the Annual FTR Auction, were $555.5 million, while PJM collected $568.6 million from the combined Annual and Monthly Balance of Planning Period FTR Auctions, making ARRs revenue adequate. ARRs have historically been fully funded by the revenue collected from the Annual FTR Auction. As a result, ARRs do not receive revenue collected from the long term or monthly auctions. For the 2016/2017 planning period, the ARR target allocations were $914.2 million while PJM collected $941.5 million from the combined 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 74.5 percent of total congestion costs, which include congestion in the Day-Ahead Energy Market and the balancing energy market, for the 2011/2012 planning period through the 2017/2018 planning period. In the first seven months of the 2017/2018 planning period, in which balancing congestion and M2M payments were directly assigned to load, total ARR and self scheduled FTR revenues offset 79.4 percent of total congestion costs. Without the allocation of balancing congestion to load, the total offset offered by ARRs and FTRs would have been 90.5 percent. The goal of the FTR market design should be to ensure that load has the rights to 100 percent of the congestion revenues.

# Financial Transmission Rights

## Market Structure

- **Supply.** The principal binding constraints limiting the supply of FTRs in the 2017/2020 Long Term FTR Auction include the St. John's Transformer in Dominion and the Elliott-Rosewood Line in AEP. The principal binding constraints limiting the supply of FTRs in the Annual FTR Auction for the 2017/2018 planning period include the Bunsonville Flowgate in MISO and the Silver Lake-Silver Lake Line in ComEd.

  In a given auction round, market participants can sell FTRs that they have acquired in preceding auction rounds. In the 2017/2020 Long Term FTR Auction, total participant FTR sell offers were 208,405 MW, down from 327,980 in the 2016/2017 Long Term FTR Auction. In the 2017/2018 Annual FTR Auction, total participant sell offers were 276,844 MW, down from 378,431 MW in the 2016/2017 Annual FTR Auction. In the Monthly Balance of Planning Period FTR Auctions for the first seven months of the 2017/2018 planning period, total participant FTR sell offers were 3,228,291 MW, up from 3,173,126 MW for the same period during the 2016/2017 planning period.
- **Demand.** In the 2017/2020 Long Term FTR Auction, total FTR buy bids were 2,176,871 MW, down 11.5 percent from 2,459,946 MW the previous planning period. There were 2,306,063 MW of buy and self scheduled bids in the 2017/2018 Annual FTR Auction, down 11.0 percent from 2,592,183 MW the previous planning period. The total FTR buy bids from the Monthly Balance of Planning Period FTR Auctions for the first seven months of the 2017/2018 planning period decreased 8.9 percent from 14,971,267 MW for the same time period of the prior planning period, to 13,631,502 MW.
- **Patterns of Ownership.** For the 2017/2020 Long Term FTR Auction, financial entities purchased 77.5 percent of prevailing flow FTRs and 84.9 percent of counter flow FTRs. For the 2017/2018 Annual FTR Auction, financial participants purchased 60.1 percent of all prevailing flow FTRs and 76.7 percent of all counter flow FTRs. For the Monthly Balance of Planning Period Auctions, financial entities purchased 74.3 percent of prevailing flow and 82.7 percent of counter flow FTRs January through

December of 2017. Financial entities owned 59.6 percent of all prevailing and counter flow FTRs, including 50.4 percent of all prevailing flow FTRs and 71.9 percent of all counter flow FTRs during the period from January through December, 2017.

## Market Behavior

- **FTR Forfeitures.** FTR forfeitures were not billed after January 19, 2017, pending retroactive implementation of a new FTR forfeiture rule. As of the September bill, PJM has begun retroactive billing under the new FTR forfeiture rule. In the period without FTR forfeiture bills, no information on forfeitures was provided to participants and behavior could not be adjusted.
- **Credit Issues.** There were two collateral defaults in 2017, for a total of $318,746. Both defaults were cured reasonably promptly.

## Market Performance

- **Volume.** The 2017/2020 Long Term FTR Auction cleared 297,083 MW (13.6 percent) of FTR buy bids, up 7.1 percent from 277,397 MW (11.3 percent) in the 2016/2019 Long Term FTR Auction. The Long Term FTR Auction also cleared 36,782 MW (17.6 percent) of FTR sell offers, compared to 61,210 (18.7 percent), a 40.0 percent decrease.

  In the Annual FTR Auction for the 2017/2018 planning period 513,263 MW (22.3 percent) of buy and self schedule bids cleared, up 22.1 percent from 420,198 MW (16.2 percent) for the previous planning period. In the first seven months of the 2017/2018 planning period Monthly Balance of Planning Period FTR Auctions cleared 1,933,854 MW (14.2 percent) of FTR buy bids and 791,546 MW (24.5 percent) of FTR sell offers.
- **Price.** The weighted average buy bid FTR price in the 2017/2020 Long Term FTR Auction was $0.04 per MW, down from $0.05 per MW for the 2016/2019 planning period. The weighted average buy bid FTR price in the Annual FTR Auction for the 2017/2018 planning period was $0.51 per MW, up from $0.49 per MW in the 2016/2017 planning period. The weighted average buy bid cleared FTR price in the Monthly Balance of Planning Period FTR Auctions for the first seven months of the 2017/2018 planning period was $0.12, down from $0.13 per MW for the same period in the 2016/2017 planning period.
- **Revenue.** The 2017/2020 Long Term FTR Auction generated $26.7 million of net revenue for all FTRs, up from $23.2 million for the 2016/2019 Long Term FTR Auction. The 2017/2018 Annual FTR Auction generated $542.2 million in net revenue, down from $909.0 million for the 2016/2017 Annual FTR Auction. The Monthly Balance of Planning Period FTR Auctions generated $26.4 million in net revenue for all FTRs for the first seven months of the 2017/2018 planning period, down from $26.7 million for the same time period in the 2016/2017 planning period.
- **Revenue Adequacy.** FTRs were paid at 100 percent of the target allocation level for the first seven months of the 2017/2018 planning period. This high level of revenue adequacy was at least partially a result of FERC redefining the FTR congestion calculation to exclude balancing congestion and M2M payments.
- **Profitability.** FTR profitability is the difference between the revenue received for an FTR and the cost of the FTR. In the first seven months of the 2017/2018 planning period, physical entities made $32.1 million in profits, while receiving $85.5 million in returned congestion from self scheduled FTRs, and financial entities made $87.7 million in profits.

## 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 Long Term FTRs be modified to include only a one year ahead FTR. (Priority: High. First reported Q2, 2017. Status: Not adopted.)
- The MMU recommends that the full transmission capacity of the system be allocated as ARRs prior to sale as FTRs. (The MMU recommends that all requested ARR rights for each delivery year be reserved for ARR holders during the Long Term FTR Auction.) (Priority: High. New recommendation. Status: Not adopted.)

- The MMU recommends that all FTR auction revenue, including auction revenue from the sale of Long Term FTRs, 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.[142] (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 market 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 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: Adopted 2017)
- 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, including the use of probabilistic outage modeling. (Priority: Low. First reported 2013. Status: Not adopted.)
- 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: Partially adopted, 2014/2015 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 physically firm transmission service which results in the delivery of low cost generation which results, in an LMP system, 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 of congestion revenues in an LMP market. In other words, load payments in excess of generation revenues are the source of the funds used 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.

142 See "PJM Manual 6: Financial Transmission Rights," Rev. 18 (Sep. 1, 2017) at 55.

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. With the creation of ARRs and the creation of FTRs as a derivative product, the purchasers of FTRs do not pay for firm transmission service, do not have the right to financially firm transmission service and 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 63.8, 86.5 and 98.1 percent of total congestion costs including congestion in the Day-Ahead Energy Market and the balancing energy market for the 2014/2015, 2015/2016 and 2016/2017 planning periods. The results for 2016/2017 resulted from the FTR Market expecting higher congestion than was realized. Day-ahead congestion was down 19.3 percent and balancing congestion was down 41.9 percent between the 2015/2016 and 2016/2017 planning periods. The FTR auction cleared, relative to realized congestion, at a higher relative price in 2016/2017 than in 2014/2015.

In the 2014/2015, 2015/2016 and 2016/2017 planning periods, PJM limited the allocation of ARR capacity, and FTRs, through outage selection to manage FTR funding. This resulted in a surplus of congestion revenue relative to FTR target allocations. This also resulted in a significant redistribution of ARRs among ARR holders based on differences in allocations between Stage 1A and Stage 1B ARRs.

As of the 2017/2018 planning period, as a result of the FERC order, balancing congestion and M2M payments are assigned to load, rather than to FTR Holders. Load is significantly worse off as a result of the changes made to the FTR/ARR process by PJM based on the FERC order of September 15, 2016. ARR holders can expect a decrease in ARR revenues and an increase in the volatility of ARR revenues under the new rules. ARR revenues were significantly reduced for the 2017/2018 FTR Auction, the first auction under the new rules. ARRs and self scheduled FTRs offset 79.4 percent of total congestion costs for the first seven months of the 2017/2018 planning period rather than the 90.5 percent offset that would have occurred under the prior rules. The increase in ARR value from the reassignment of balancing congestion and M2M payments to load, as predicted by proponents of the reassignment, did not occur.

Load should never be required to subsidize payments to FTR Holders, regardless of the reason. Such subsidies have been suggested repeatedly.[143] The FERC order of September 15, 2016, introduced a subsidy to FTR Holders at the expense of ARR holders.[144] The order requires PJM to ignore balancing congestion when calculating total congestion dollars available to fund FTRs. This approach ignores 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. Eliminating balancing congestion from the FTR revenue calculation requires load to pay twice for congestion. Load will have to continue paying for the physical transmission system, will have to continue paying in excess of generator revenues and load will not have balancing congestion included in the calculation of congestion. These changes were made in order to increase the payout to holders of FTRs who are not loads. In other words, load will continue to be the source of all the funding for 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 shifts substantial revenue from load to the holders of FTRs and reduces the ability of load to offset congestion. Under the old allocation rule ARR holders would have had an effective offset of 90.5 percent of congestion in the first seven months of the 2017/2018 planning period rather than the 79.4 percent effective offset that resulted from the new rule, a loss of $36.5 million.

If these allocation rules had been in place beginning with the 2011/2012 planning period, ARR holders would have received a total of $1,034.2 million less in congestion offsets from the 2011/2012 through the 2016/2017 planning period. The total overpayment

143 See FERC Dockets Nos. EL13-47-000 and EL12-19-000.

144 See 156 FERC ¶ 61,180.

to FTR Holders for the 2011/2012 through 2016/2017 planning period would have been $944.4 million. The underpayment to load and the overpayment to FTR Holders is a result of several factors in the 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 while degrading the ability of ARRs to provide a predictable offset to congestion costs. PJM will continue to clear counter flow FTRs using auction revenues greater than the ARR target allocations in order to make it possible to sell more prevailing flow FTRs. FTR Holders will also receive day-ahead congestion revenues in excess of target allocations. FTR Holders will also receive additional auction revenue, which is what FTR Holders were willing to pay for FTRs above what is provided to ARR holders through ARR target allocations on defined paths.

Revenue adequacy has received a lot of attention in the PJM FTR Market. There are several factors that can affect the reporting, distribution of and quantity of funding in the FTR Market. Revenue adequacy is misunderstood. FTR Holders, with the creation of ARRs, do not have the right to financially firm transmission service and FTR Holders do not have the right to revenue adequacy 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.

PJM used a more conservative approach to modeling the transmission capability for the 2014/2015 through 2016/2017 planning periods compared to the 2013/2014 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, an increase in ARR target allocations and an increase in congestion revenues not assigned to ARRs. The market response to the reduced supply of FTRs was increased bid prices, increased clearing prices and reduced clearing quantities. For the 2017/2018 planning period PJM assigned all balancing congestion and M2M payments to load and exports. As a result, PJM also reversed course and increased the availability of Stage 1B and Stage 2 FTRs. The market response to the increased supply of FTRs was lower bid prices and clearing prices.

Clearing prices fell and cleared quantities increased from the 2010/2011 planning period through the 2013/2014 planning period. The market response to lower revenue adequacy was to reduce bid prices and to increase bid volumes and offer volumes. In the 2014/2015, 2015/2016 and 2016/2017 planning periods, due to reduced ARR allocations resulting from PJM's actions to manage FTR revenue, FTR volume decreased relative to the 2013/2014 planning period. The reduction in ARR allocations and resulting FTR volume caused, by definition, an improvement in revenue adequacy, and also resulted in an increase in the prices of FTRs. Increased FTR prices resulted in increased ARR target allocations, because ARR target allocations are based on the Annual FTR Auction nodal prices. In the 2017/2018 planning period, based on the reallocation of balancing congestion and M2M payments to load, PJM reduced outages in the Annual FTR Auction model. This increased FTR capability, but decreased ARR target allocations resulting from lower FTR clearing prices.

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

If netting within portfolios were eliminated and the payout ratio were calculated correctly, the payout ratio in the 2013/2014 planning period would have been 87.5 percent instead of the reported 72.8 percent. The MMU recommends that netting of positive and negative target allocations within portfolios be eliminated.

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

There is no reason to treat counter flow FTRs more favorably than prevailing flow FTRs. Counter flow FTRs should also be affected when the payout ratio is less than 100 percent. This would mean that counter flow FTRs would pay back an increased amount that mirrors the decreased payments to prevailing flow FTRs. The adjusted payout ratio would evenly divide the impact of lower payouts among counter flow FTR Holders and prevailing flow FTR Holders by increasing negative counter flow target allocations by the same amount it decreases positive target allocations. The FTR Market cannot work efficiently if FTR buyers do not receive payments consistent with the performance of their FTRs. Eliminating the counter flow subsidy would be another good step in that direction.

The result of removing portfolio netting and applying a payout ratio to counter flow FTRs would have increased the calculated payout ratio in the 2013/2014 planning period from the reported 72.8 percent to 91.0 percent. For the 2014/2015, 2015/2016 and 2016/2017 planning periods 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 reduced revenue and cross subsidy.

The MMU recommends that the basis for the Stage 1A assignments be reviewed and made explicit and that the role of out of date generation to load paths be reviewed beyond the replacement of retired generation that was implemented. 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.

In addition to addressing these issues, the approach to the question of FTR funding should also examine 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 annual and long term FTR auction models; 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; 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 FTR target allocations 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. It is also not clear, in a competitive market, why the ownership structure of long term FTRs is so highly concentrated for the three year product and why participation in the Long Term FTR Auction continues to be very low for the second and third year long term product. The apparent lack of competition to purchase Long Term FTRs (three year product), results in low prices when compared to the resale prices in Annual FTR Auctions. In a competitive market the price of Long Term FTRs would be expected to converge with the prices of Annual FTRs, but there has been a persistent, wide divergence that has made the purchase of Long Term FTRs persistently very profitable.

It has become increasingly clear that the long term FTR auction structure should be significantly modified. The value of congestion rights sold in the long term FTR auction are not available to load via ARRs. The Long Term FTR auction sells congestion rights that are not allocated to ARR holders. These congestion rights are not available to ARR holders in the annual ARR allocation because the outages included in the annual auction are not included in the long term FTR auction model and because scheduled system upgrades are not included in the annual FTR auction model but are included in the long term FTR auction model. Even the additional revenue from the sale of these congestion rights are not returned to ARR holders. Auction revenue from the sale of FTRs in the Long Term FTR Auction is not returned to ARR holders. An estimate of the value of these congestion rights is based on the difference in price for congestion rights between the annual auction and the long term auction for the same years. The prices in the Long Term FTR Auction are much lower than those in the Annual FTR Auction. The difference in revenue over the previous four planning periods was $337.2 million. There is no reason to continue to fail to assign congestion rights to load and to make it available solely to the purchasers of long term FTRs.

# 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. The MMU recognizes that PJM does not have the unilateral authority to implement changes to the tariff but PJM has a significant role in the issues PJM focuses on, in proposed changes to the PJM manuals, and in the recommendations PJM makes to the stakeholders and to FERC. 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, FERC, or court action, that status is noted.

This section of the report presents:

- **New Recommendations:** recommendations reported for the first time in 2017;[6]
- **History of MMU Recommendations:** summary status of all MMU recommendations from 1999 through 2017;
- **Current MMU Recommendations:** all current MMU recommendations;
- **Adopted Recommendations:** recommendations which have been adopted by PJM.

## New Recommendations

Consistent with its core function to "[e]valuate existing and proposed market rules, tariff provisions and market design elements and recommend proposed rule and tariff changes,"[7] the MMU recommends specific enhancements to existing market rules and implementation of new rules

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

6 New recommendations include all MMU recommendations that were reported for the first time in the *2017 State of the Market Report for PJM* or in any of the three quarterly state of the market reports that were published in 2017.
7 18 CFR § 35.28(g)(3)(ii)(A); see also OATT Attachment M § IV.D.

that are required for competitive results in PJM markets and for continued improvements in the functioning of PJM markets.

In this *2017 State of the Market Report for PJM*, the MMU includes 15 new recommendations made in 2017.[8]

## New Recommendation from Section 3, Energy Market

- The MMU recommends that PJM increase the interaction of outage and operational restrictions data submitted by Market Participants via eDART/eGADs and offer data submitted via Markets Gateway. (Priority: Low. New recommendation. Status: Not adopted.)

## New Recommendations from Section 5, Capacity Market

- The MMU recommends that PJM offer to sell back capacity in incremental auctions only at the BRA clearing price for the relevant delivery year. (Priority: Medium. First reported Q1, 2017. Status: Not adopted.)
- The MMU recommends that PJM clear the capacity market based on nodal capacity resource locations and the characteristics of the transmission system consistent with the actual electrical facts of the grid. The current nested LDA structure used in the capacity market does not adequately represent all the capacity transfers that are feasible among LDAs. Absent a fully nodal capacity market clearing process, the MMU recommends that PJM use a nonnested model for all LDAs and specify a VRR curve for each LDA separately. Each LDA requirement should be met with the capacity resources located within the LDA and exchanges from neighboring LDAs up to the transmission limit. LDAs should price separate if that is the result of the LDA supply curves and the transmission constraints. (Priority: Medium. First reported Q3, 2017. Status: Not adopted.)
- The MMU recommends that the RPM market power mitigation rule be modified to apply offer caps in all cases when the three pivotal supplier test is failed and the sell offer is greater than the offer cap. This will ensure that market power does not result in an increase in make whole payments. (Priority: Medium. First reported Q3, 2017. Status: Not adopted.)
- The MMU recommends that PJM develop a forward looking estimate for the expected number of Performance Assessment Hours (H) to use in calculating the Non-Performance Charge Rate. The MMU recommends that PJM develop a forward looking estimate for the Balancing Ratio (B) during Performance Assessment Hours to use in calculating the default offer cap. Both H and B parameters should be included in the annual review of planning parameters for the Base Residual Auction. (Priority: High. First reported Q3, 2017. Status: Not adopted.)
- The MMU recommends that when expected H and B are not the same as the assumed levels used to calculate the default market seller offer cap of Net CONE*B, the offer cap be recalculated for each BRA using the fundamental economic logic for a competitive offer of a CP resource. (Priority: High. New Recommendation. Status: Not adopted.)
- The MMU recommends elimination of the cost of service recovery rate in OATT Section 119, and that RMR service should be provided under the deactivation avoidable cost rate in Part V. The MMU also recommends specific improvements to the DACR provisions. (Priority: Medium. New recommendation. Status: Not adopted.)

## New Recommendations from Section 6, Demand Response

- The MMU recommends that the maximum offer for demand resources be the same as the maximum offer for generation resources. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends the Relative Root Mean Squared Test be required for all demand resources with a CBL. (Priority: Low. New recommendation. Status: Partially adopted.)
- The MMU recommends that PRD be required to respond during a PAH to be consistent with all CP resources. (Priority: High. New recommendation. Status: Not adopted.)

8 New recommendations include all MMU recommendations that were reported for the first time in the *2017 State of the Market Report for PJM* or in any of the three quarterly state of the market reports that were published in 2017.

## New Recommendations from Section 10, Ancillary Services

- The MMU recommends that for oil tanks that are shared with other resources, only a proportionate share of the minimum tank suction level (MTSL) be allocated to black start service. The MMU further recommends that the PJM tariff be updated to clearly state how the MTSL will be calculated for black start units sharing oil tanks. (Priority: Medium. First reported Q3, 2017. Status: Not adopted.)
- The MMU recommends that capability to operate under the proposed deadband (+/- 0.036 HZ) and droop (5 percent) settings be mandated as a condition of interconnection and that such capability be required of both new and existing resources. The MMU recommends that no additional compensation be provided as the current PJM market design provides adequate compensation. (Priority: Low. New recommendation. Status: Not adopted.)

## New Recommendation from Section 12, Generation and Transmission Planning

- The MMU recommends that PJM limit the scope of supplemental projects that can obtain exceptions to the Order No. 1000 process to ensure maximum competition. (Priority: Medium. New recommendation. Status: Not adopted.)

## New Recommendations from Section 13, Financial Transmission and Auction Revenue Rights

- The MMU recommends that Long Term FTRs be modified to include only a one year ahead FTR. (Priority: High. First reported Q2, 2017. Status: Not adopted.)
- The MMU recommends that the full transmission capacity of the system be allocated as ARRs prior to sale as FTRs. (The MMU recommends that all requested ARR rights for each delivery year be reserved for ARR holders during the Long Term FTR Auction.) (Priority: High. New recommendation. Status: Not adopted.)

# History of MMU Recommendations

The MMU began making recommendations to PJM in the 1999 State of the Market Report. Since that time, the MMU has made 240 recommendations in the State of the Market Reports. In 2014, the MMU began including a priority and status with each recommendation. In this *2017 State of the Market Report for PJM*, the MMU has reviewed all past recommendations, assigned priority and determined their current status.

For the review of past recommendations, the MMU has refined the status assigned to each recommendation. In addition to the definitions of Adopted, Partially Adopted, and Not Adopted described above, the MMU includes the following definitions:

- **Partially Adopted (Continued Recommendation):** PJM has implemented part of the recommendation made by the MMU, and the MMU continues to recommend total adoption of the recommendation. These recommendations continue to be included in the main sections of this report;
- **Partially Adopted (Recommendation Closed):** PJM has implemented part of the recommendation made by the MMU, and the MMU has chosen to discontinue making the recommendation going forward. These recommendations are no longer included in the main sections of this report;
- **Not Adopted (Pending before FERC):** PJM has not yet implemented any part of the recommendation made by the MMU, but the subject of the recommendation is pending FERC action;
- **Not Adopted (Stakeholder Process):** PJM has not yet implemented any part of the recommendation made by the MMU, but the subject of the recommendation is pending stakeholder action;
- **Replaced by Newer Recommendation:** a recommendation that was discontinued when the MMU modified the recommendation; and
- **Withdrawn:** The MMU no longer makes the recommendation.

Table 2-1 shows the status of all recommendations reported by the MMU from 1999 through 2017. Over that time, 23 percent of all MMU recommendations have been adopted, 35 percent have been adopted or partially adopted, and 61 percent are not adopted. Of the 66 high priority recommendations, 20 (30 percent) have been adopted. Table 2-1 includes past recommendations that are no longer included in this report.

### Table 2-1 Status of MMU reported recommendations: 1999 through 2017

| Status | Priority High | Priority Medium | Priority Low | Total | Percent of Total |
|---|---|---|---|---|---|
| Adopted | 20 | 15 | 19 | 54 | 22.5% |
| Partially Adopted (Continued Recommendation) | 5 | 7 | 6 | 18 | 7.5% |
| Partially Adopted (Recommendation Closed) | 2 | 4 | 5 | 11 | 4.6% |
| Partially Adopted (Total) | 7 | 11 | 11 | 29 | 12.1% |
| Not Adopted | 32 | 63 | 35 | 130 | 54.2% |
| Not Adopted (Pending before FERC) | 4 | 2 | 0 | 6 | 2.5% |
| Not Adopted (Stakeholder Process) | 2 | 6 | 2 | 10 | 4.2% |
| Not Adopted (Total) | 38 | 71 | 37 | 146 | 60.8% |
| Replaced by Newer Recommendation | 1 | 5 | 2 | 8 | 3.3% |
| Withdrawn | 0 | 1 | 2 | 3 | 1.3% |
| Total | 66 | 103 | 71 | 240 | 100.0% |

# Complete List of Current MMU Recommendations

The recommendations are explained 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. The MMU recommends that the level of incremental costs includable in cost-based offers not exceed the short run marginal cost of the unit. (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 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-based offers based on short run marginal costs and the correct calculation of cost-based offers. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends removal of all use of 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-based offers, and 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 price-based non-PLS 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. (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. Stakeholder process.)
- The MMU recommends that Market Sellers not be allowed to designate any portion of an available Capacity Resource's ICAP equivalent of cleared UCAP capacity commitment as a Maximum Emergency offer at any time during the delivery year.[9] (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.)

9 This recommendation was accepted by PJM and filed with FERC in 2014 as part of the capacity performance updates to the RPM. See Schedule 1, Section 1.10.1A(d), Revisions to the PJM Open Access Transmission Tariff and PJM Operating Agreement (Marked/Redline Format), EL15-29-000 (December 12, 2014). FERC rejected the proposed change in Order 151FERC¶61,208 at 476 (June 9, 2015).

- 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: 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.[10] There is currently no PJM documentation in the tariff or manuals explaining how hubs are created and how their definitions are changed.[11] (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that all buses with a net withdrawal be treated as load 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 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 2014.)
- The MMU recommends that PJM increase the interaction of outage and operational restrictions data submitted by Market Participants via eDART/eGADs and offer data submitted via Markets Gateway. (Priority: Low. New recommendation. Status: Not adopted.)

## Section 4, Energy Uplift

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

- The MMU recommends that PJM not use closed loop 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.)

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

11 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 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. Pending before FERC.)
- 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. Pending before FERC.)
- 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 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 must 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 Market

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

### Definition of Capacity

- The MMU recommends the enforcement of a consistent definition of capacity resource. The MMU recommends that the requirement to be a physical resource be enforced and enhanced. The requirement to be a physical resource should apply at the time of auctions and should also constitute a commitment to be physical in the relevant Delivery Year. The requirement to be a physical resource should be applied to all resource types, including planned generation, demand resources and imports.[13] [14] (Priority: High. First reported 2013. Status: Not adopted. Pending before FERC.)
- The MMU recommends that the definition of demand side resources be modified 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.)

12 151 FERC ¶ 61,208 (June 9, 2015).

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

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

## Market Design and Parameters

- 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 the net revenue calculation used by PJM to calculate the net Cost of New Entry (CONE) VRR parameter reflect the actual flexibility of units in responding to price signals rather than using assumed fixed operating blocks that are not a result of actual unit limitations.[15] [16] The result of reflecting the actual flexibility is higher net revenues, which affect the parameters of the RPM demand curve and market outcomes. (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that 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, unlike the situation when EE was first added to the capacity market. However, the MMU recommends that the PJM load forecast method should be modified so that EE impacts immediately affect the forecast without the long lag times incorporated in the current forecast method. 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 offer to sell back capacity in incremental auctions only at the BRA clearing price for the relevant delivery year. (Priority: Medium. First reported Q1, 2017. Status: Not adopted.)
- The MMU recommends that the use of the 2.5 percent demand adjustment (Short Term Resource Procurement Target) be terminated immediately. The 2.5 percent should be added back to the overall market demand curve. (Priority: Medium. First reported 2013. Status: Adopted 2015.)
- The MMU recommends changing the RPM solution method to explicitly incorporate the cost of make whole payments in the objective function. (Priority: Medium. First reported 2014. Status: Not adopted.)
- The MMU recommends that PJM clear the capacity market based on nodal capacity resource locations and the characteristics of the transmission system consistent with the actual electrical facts of the grid. The current nested LDA structure used in the capacity market does not adequately represent all the capacity transfers that are feasible among LDAs. Absent a fully nodal capacity market clearing process, the MMU recommends that PJM use a nonnested model for all LDAs and specify a VRR curve for each LDA separately. Each LDA requirement should be met with the capacity resources located within the LDA and exchanges from neighboring LDAs up to the transmission limit. LDAs should price separate if that is the result of the LDA supply curves and the transmission constraints. (Priority: Medium. First reported Q3, 2017. Status: Not adopted.)

## Offer Caps and Offer Floors

- The MMU recommends the extension of the minimum offer price rule (MOPR) to all existing and proposed units (MOPR-Ex) in order to protect competition in the capacity market from external subsidies. (Priority: High. First reported 2016. 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

15 See PJM Interconnection, L.L.C., Docket No. ER12-513-000 (December 1, 2011) ("Triennial Review").
16 See the *2012 State of the Market Report for PJM*, Volume 2, Section 6: Net Revenue.

of modeling assumptions.[17] (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 the RPM market power mitigation rule be modified to apply offer caps in all cases when the three pivotal supplier test is failed and the sell offer is greater than the offer cap. This will ensure that market power does not result in an increase in make whole payments. (Priority: Medium. First reported Q3, 2017. Status: Not adopted.)
- The MMU recommends that PJM develop a forward looking estimate for the expected number of Performance Assessment Hours (H) to use in calculating the Non-Performance Charge Rate. The MMU recommends that PJM develop a forward looking estimate for the Balancing Ratio (B) during Performance Assessment Hours to use in calculating the default offer cap. Both H and B parameters should be included in the annual review of planning parameters for the Base Residual Auction. (Priority: High. First reported Q3, 2017. Status: Not adopted.)
- The MMU recommends that when expected H and B are not the same as the assumed levels used to calculate the default market seller offer cap of Net CONE*B, the offer cap be recalculated for each BRA using the fundamental economic logic for a competitive offer of a CP resource. (Priority: High. New Recommendation. Status: Not adopted.)

## Performance Incentive Requirements of RPM

- The MMU recommends that a unit which is not capable of supplying energy consistent with its day-ahead offer reflect an appropriate outage. (Priority: Medium. First reported 2009. Status: Not adopted. Pending before FERC.)
- The Market Monitor recommends that retroactive replacement transactions associated with a failure to perform during a PAH not be allowed and that, more generally, retroactive replacement capacity transactions not be permitted. (Priority: Medium. First reported 2016. Status: Not adopted.)
  - 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.[18] (Priority: Medium. First reported 2013. Status: Adopted 2015.)
- 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.)

## Capacity Imports and Exports

- 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 full substitutes for internal, physical capacity resources. (Priority: High. First reported 2014. Status: Adopted 2015.)
- 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 full substitutes for internal, physical capacity resources.

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

18 See OATT Attachment DD § 10(e). For more on this issue and related incentive issues, see the MMU's White Paper included in: Monitoring Analytics, LLC and PJM Interconnection, LLC, joint report, "*Capacity in the PJM Market*," (August 20, 2012).<http://www.monitoringanalytics.com/reports/Reports/2012/IMM_And_PJM_Capacity_White_Papers_On_OPSI_Issues_20120820.pdf>.

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 that all capacity imports have firm transmission to the PJM border prior to offering in an RPM auction. (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 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 the rules need additional clarification and operational details. (Priority: Low. First reported 2010. Status: Partially adopted.)

## Deactivations/Retirements

- 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 that RMR units recover all and only 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. Customers should bear no responsibility for paying previously incurred costs, including a return on or of prior investments. (Priority: Low. First reported 2010. Status: Not adopted.)
- The MMU recommends elimination of the cost of service recovery rate in OATT Section 119, and that RMR service should be provided under the deactivation avoidable cost rate in Part V. The MMU also recommends specific improvements to the DACR provisions. (Priority: Medium. New recommendation. Status: Not adopted.)

## Section 6, Demand Response

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 December 31, 2017.

- The MMU recommends, as a preferred alternative to including demand resources as supply in the capacity market, that demand resources be on the demand side of the markets, that customers be able to avoid capacity and energy charges by not using capacity and energy at their discretion, that customer payments be determined only by metered load, and that PJM forecasts immediately incorporate the impacts of demand side behavior. (Priority: High. First reported 2014. Status: Not adopted.)
- The MMU recommends that the option to specify a minimum dispatch price (strike price) for demand resources 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 maximum offer for demand resources be the same as the maximum offer for generation resources. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that the demand resources be treated as an economic resource, responding to economic price signals like other capacity resources. The MMU recommends that demand resources not be treated as emergency resources, not trigger a PJM emergency and not trigger a Performance Assessment Hour. (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.[19] (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.[20] (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: Partially 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 must terminate or modify registrations that are no longer capable of responding to PJM dispatch directives at defined levels because load has been reduced or eliminated, 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 subzones 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 in the capacity market, with an obligation to respond when called for all

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

20 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 October 17, 2017) 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.

hours of the year. (Priority: High. First reported 2011. Status: Partially adopted.[21])

- 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 setting 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 the Relative Root Mean Squared Test be required for all demand resources with a CBL. (Priority: Low. New recommendation. Status: Partially adopted.)
- The MMU recommends that PRD be required to respond during a PAH to be consistent with all CP resources. (Priority: High. New recommendation. Status: Not adopted.)
- The MMU recommends capping the baseline for measuring compliance under GLD, for the limited summer product, at the customers' PLC. (Priority: High. First reported 2010. Status: Adopted 2015.)
- The MMU recommends that demand resources whose technology type (load drop method) is designated as "Other" explicitly record the technology type. (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.)

21 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.

## 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 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 recommends 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: Partially adopted, 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 2017.)

## Section 10, Ancillary Services

- The MMU recommends that the Regulation Market be modified to incorporate a consistent application of the marginal benefit factor (MBF) throughout the optimization, assignment and settlement process. The MBF should be defined as the Marginal Rate of Technical Substitution (MRTS) between RegA and RegD. (Priority: High. First reported 2012. Status: Not adopted. Pending before FERC.)
- 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. Pending before FERC.)
- The MMU recommends that the LOC calculation used in the Regulation Market be based on the resource's dispatched energy offer schedule, not the lower of its price or cost offer schedule. (Priority: Medium. First reported 2010. Status: Pending before FERC.)
- 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, to prevent gaming, 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. (Priority: Medium. First reported 2016. Status: Not adopted. Pending before FERC.)

- The MMU recommends the use of a single five minute clearing price based on actual five minute LMP and lost opportunity cost to improve the performance of the Regulation Market. (Priority: Medium. First reported 2010. Status: Adopted in 2012.)
- The MMU recommends that PJM be required to save data elements necessary for verifying the performance of the Regulation Market. (Priority: Medium. First reported 2010. Status: Not adopted.)
- The MMU recommends enhanced documentation of the implementation of the Regulation Market design. (Priority: Medium. First reported 2010. Status: Pending before FERC.)
- The MMU recommends that the rule requiring that tier 1 synchronized reserve resources are paid the tier 2 price when the nonsynchronized reserve price is above zero be eliminated immediately and that, under the current rule, 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: Partially 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 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, 2016.)
- 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.)
- 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 PJM modify the DASR Market to ensure that all resources cleared incur a real-time performance obligation. (Priority: Low. First reported 2013. 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 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 that for oil tanks which are shared with other resources only a proportionate share of the minimum tank suction level (MTSL) be allocated to black start service. The MMU further recommends that the PJM tariff be updated to clearly state how the MTSL will be calculated for black start units sharing oil tanks. (Priority: Medium. First reported Q3, 2017. Status: Not adopted.)
- The MMU recommends that capability to operate under the proposed deadband (+/- 0.036 HZ) and droop (5 percent) settings be mandated as a condition of interconnection and that such capability be required of both new and existing resources. The MMU recommends that no additional compensation be provided as the current PJM market design provides adequate compensation. (Priority: Low. New recommendation. Status: Not adopted.)

## Section 11, Congestion and Marginal Losses

There are no recommendations in this section.

## Section 12, Planning

- The MMU recommends that PJM continue to incorporate the principle that the goal of transmission planning should be the incorporation of transmission investment decisions into market driven processes as much as possible. (Priority: Low. First reported 2001. Status: Not adopted.)
- The MMU recommends the creation of a mechanism to permit a direct comparison, or competition, between transmission and generation alternatives, including which alternative is less costly and who bears the risks associated with each alternative. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that rules be implemented to permit competition to provide financing for transmission projects. This competition could reduce the cost of capital for transmission projects and significantly reduce total costs to customers. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that rules be implemented to require that project cost caps on new transmission projects be part of the evaluation of competing projects. (Priority: Low. 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.[22] (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends outsourcing interconnection studies to an independent party to avoid potential conflicts of interest. Currently, these studies are performed by incumbent transmission owners under PJM's direction. This creates potential conflicts of interest, particularly when transmission owners are vertically integrated and the owner of transmission also owns generation. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends 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.)

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

- The MMU recommends that 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.)
- The MMU recommends that PJM limit the scope of supplemental projects that can obtain exceptions to the Order No. 1000 process, to ensure maximum competition. (Priority: Medium. New recommendation. Status: Not 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 Long Term FTRs be modified to include only a one year ahead FTR. (Priority: High. First reported Q2, 2017. Status: Not adopted.)
- The MMU recommends that the full transmission capacity of the system be allocated as ARRs prior to sale as FTRs. (The MMU recommends that all requested ARR rights for each delivery year be reserved for ARR holders during the Long Term FTR Auction.) (Priority: High. New recommendation. Status: Not adopted.)
- The MMU recommends that all FTR auction revenue, including auction revenue from the sale of Long Term FTRs, 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.[23] (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 market 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 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: Adopted 2017)
- 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, including the use of probabilistic outage modeling. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM reduce FTR sales on paths with persistent overallocation of FTRs including clear rules for what defines persistent

23 See "PJM Manual 6: Financial Transmission Rights," Rev. 18 (Sep. 1, 2017) at 55.

overallocation and how the reduction will be applied. (Priority: High. First reported 2013. Status: Partially adopted, 2014/2015 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.)

## Adopted Recommendations

The following is the complete list of all MMU recommendations that have been adopted by PJM, including the priority, date of first report, and the section in the State of the Market Report in which the recommendation was made.

### Adopted 2017

- 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. Last reported 2017, Section 9, Interchange Transactions.)
- 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. Last reported 2017, Section 13, Financial Transmission and Auction Revenue Rights.)

### Adopted 2016

- 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. Last reported: 2016 Section 13, Financial Transmission and Auction Revenue Rights.)

### Adopted 2015

- 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 2009. Last reported: 2016 Section 3, Energy Market.)
- The MMU recommends including no load and startup costs as part of the total avoided costs in the calculation of lost opportunity cost credits paid to combustion turbines and diesels scheduled in the Day-Ahead Energy Market but not committed in real time. (Priority: Medium. First reported 2012. Last reported: 2016 Section 4, Energy Uplift.)
- 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. Last reported: 2016 Section 4, Energy Uplift.)
- The MMU recommends that all generation types face the same performance incentives. (Priority: High. First reported 2009. Last reported: 2012 Section 4, Capacity Market.)
- The existence of a capacity market that links payments for capacity to the level of unforced capacity and therefore to the forced outage rate creates an incentive to improve forced outage rates. The performance incentives in the RPM Capacity Market design need to be strengthened. (Priority: High. First reported 2009. Last reported: 2009 Section 5, Capacity Market.)
- The MMU recommends that the obligations of capacity resources be more clearly defined in the market rules. (Priority: High. First reported 2010. Last reported: 2011 Section 4, Capacity Market.)
- 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. Last reported: 2016 Section 5, Capacity Market.)
- The MMU recommends immediate elimination of lack of fuel as an acceptable basis for an OMC outage. (Priority: Medium. First reported 2012. Last reported: 2012 Section 4, Capacity Market.)
- PJM should scrutinize OMC outages for low Btu coal carefully. (Priority: Medium. First reported 2003. Last reported: 2009 Section 5, Capacity Market.)
- The MMU recommends that PJM eliminate the broad exception related to lack of gas during the winter period for single-fuel, natural gas-fired units. (Priority: Medium. First reported 2013. Last reported: 2016 Section 5, Capacity Market.)

- 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. Last reported: 2016 Section 5, Capacity Market.)
- The MMU recommends elimination of the exception related to a unit that runs less than 50 hours during the RPM peak period. (Priority: Low. First reported 2012. Last reported: 2012 Section 4, Capacity.)
- 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 2012. Last reported: 2016 Section 5 Capacity Market.)
- 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. Last reported: 2016 Section 5, capacity Market.)
- The MMU recommends that PJM increase the Capacity Resource Deficiency Charge, which is a penalty charge. (Priority: High. First reported 2013. Last reported: 2013 Section 5, Capacity Market.)
- The MMU recommends that all capacity have firm transmission to the PJM border acquired prior to the offering in an RPM auction. (Priority: High. First reported 2014. Last reported: 2016 Section 5, Capacity Market.)
- 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. Last reported: 2016 Section 5, Capacity Market.)
- The MMU recommends that all resources importing capacity into PJM accept a must offer requirement. (Priority: High. First reported 2014. Last reported: 2016 Section 5, Capacity Market.)
- 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. Last reported: 2016 Section 6, Demand Response.)
- Continued development of appropriate credit protections for transactions in PJM markets that are consistent with those available to participants in bilateral transactions. (Priority: Low. First reported 2002. Last reported: 2002 Section: Recommendations.)
- 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. Last reported: 2017, Section 4, Uplift.)

## 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. Last reported: 2016 Section 3, Energy Market.)
- Pending elimination of these DR products, the MMU recommends that PJM procure the maximum amount of Annual and Extended Summer capacity resources available during an RPM auction, without impacting the clearing price. Currently, PJM procures a minimum level of Extended Summer and Annual Resources, but could procure additional MW of these superior products without a change in the clearing price. (Priority: Medium. First reported 2012. Last reported: 2012 Section 4, Capacity Market.)
- 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. Last reported: 2016 Section 6, Demand Response.)

- The MMU recommends that the Enhanced energy Scheduler (EES) application be modified to require that transactions be scheduled for a constant MW level over the entire 45 minutes as soon as possible. This business rule is currently in the PJM Manuals, but is not being enforced. (Priority: Low. First reported 2009. Last reported: 2011 Section 8, Interchange Transactions.)
- The MMU recommends that the rules for compliance with calls to respond to actual spinning events be reevaluated. (Priority: Low. First reported 2011. Last reported: 2012 Section 9, Ancillary Service Markets.)
- 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. Last reported: 2016 Section 10, Ancillary Service Markets.)

## Adopted 2013

- The MMU recommends that the notification requirement for deactivations be modified to include required notification of six to twelve months prior to an auction in which the unit will not be offered due to deactivation. The purpose of this deadline is to allow adequate time for potential Capacity Market Sellers to offer new capacity in the auction. (Priority: Low. First reported 2012. Last reported: 2012 Section 4, Capacity Market.)
- The MMU recommends modifying the evaluation criteria via a change to PJM's market software, to ensure that not willing to pay congestion transactions are not permitted to flow in the presence of congestion. (Priority: Low. First reported 2009. Last reported: 2009 Section 4, Interchange Transactions.)
- The MMU recommends that PJM modify the not willing to pay congestion product to address the issues of uncollected congestion charges. The MMU recommends charging market participants for any congestion incurred while such transactions are loaded, regardless of their election of transmission service, and restricting the use of not willing to pay congestion transactions to transactions at interfaces (wheeling transactions). (Priority: Low. First reported 2010. Last reported: 2011 Section 8, Interchange Transactions.)
- The MMU recommends that PJM, FERC, reliability authorities and state regulators reevaluate the way in which black start service is procured in order to ensure that procurement is done in a least cost manner for the entire PJM market. PJM should have responsibility to prepare the black start restoration plan for the region, with Members playing an advisory role. PJM should have the responsibility to procure required black start service on a least cost basis through a transparent process. (Priority: Low. First reported 2009. Last reported: 2011 Section 9, Ancillary Service Markets.)
- The MMU recommends that PJM document the reasons each time it changes the Tier 1 synchronized reserve transfer capability into the Mid-Atlantic subzone market because of the potential impacts on the market. (Priority: Low. First reported 2011. Last reported: 2011 Section 9, Ancillary Service Markets.)

## Adopted 2012

- The MMU recommends that PJM should, on an expedited basis, request that the tariff be modified to permit allocation of day-ahead operating reserve charges consistent with the prior allocation of these charges in real time. This would be a short term solution to the issue created by shifting operating reserve charges to the Day-Ahead Energy Market and therefore changing the allocation of those charges. In addition, PJM should start a stakeholder process to consider the market design and cost allocation issues in detail and propose a permanent tariff change that results from the process. (Priority: High. First reported 2012. Last reported: 2012-Q3 Section 3, Operating Reserve.)
- The MMU recommends that the single clearing price for synchronized reserves be determined based on the actual LMP and not the forecast LMP. (Priority: Low. First reported 2010. Last reported: 2016 Section 6, Ancillary Service Markets.)
- The MMU recommends that PJM conduct a detailed review of the Day-Ahead Market software in order to address the issue of occasional anomalous loss factors and their effect on the day-ahead market results. (Priority: Low. First reported 2011. Last

reported: 2011 Section 10, Congestion and Marginal Losses.)

- 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. Last reported 2017 Section 3, Energy Market.)

## Adopted 2011

- The MMU recommends eliminating internal source and sink bus designations for external energy transactions in the Day-Ahead and Real-Time Energy Markets. (Priority: Low. First reported 2010. Last reported: 2011 Section 8, Interchange Transactions.)
- The MMU continues to recommend the complete elimination of unsecured credit, over an appropriate transition period, based on the MMU's view of PJM's role in evaluating the credit worthiness of complex corporate entities and due to a concern about inappropriate shifts of risks and costs among PJM members. (Priority: Low. First reported 2009. Last reported: 2010 Section 8, Financial Transmission and Auction Revenue Rights.)

## Adopted 2010

- Implementation of rules governing the definition of final prices to ensure certainty for market participants. (Priority: High. First reported 2008. Last reported: 2009 Section 1, Introduction.)
- The MMU recommends the implementation of improved cost-based data submission to permit better monitoring and better analysis of markets. (Priority: Medium. First reported 2002. Last reported: 2009 Section 1, Introduction.)

## Adopted 2009

- Retention and application of enhancements to rules governing the payment of operating reserve credits to generators and the allocation of operating reserves charges among market participants that were implemented on December 1, 2008. The new operating reserve rules represent positive steps towards the goals of removing the ability to exercise market power and refining the allocation of operating reserves charges to better reflect causal factors. (Priority: High. First reported 2006. Last reported: 2007 Section 1, Introduction.)
- The MMU recommends that the RPM market structure, definitions and rules be modified to improve the efficiency of market prices and to ensure that market prices reflect the forward locational marginal value of capacity. (Priority: High. First reported 2006. Last reported: 2011 Section 4, Capacity.)
- Retention and application of the improved market power mitigation rules in the Regulation Market to prevent the exercise of market power in the Regulation Market while ensuring appropriate economic signals when investment is required and an efficient market mechanism. The PJM Regulation Market continues to be characterized by structural market power. PJM's application of targeted, flexible real-time, market power mitigation in the Regulation Market addresses only the hours in which structural market power exists and therefore provides an incentive for the continued development of competition. (Priority: High. First reported 2006. Last reported: 2009 Section 1, Introduction.)

## Adopted 2008

- Consistent application of local market power rules to all constraints. (Priority: High. First reported 2006. Last reported: 2007 Section 1, Introduction.)
- Retention and application of the improved local market power mitigation rules to prevent the exercise of local market power in the Energy Market while ensuring appropriate economic signals when investment is required. (Priority: Medium. First reported 2003. Last reported: 2009 Section 1, Introduction.)
- Consistent application of local market power rules to all units, including those currently exempt from offer capping. (Priority: High. First reported 2006. Last reported: 2007 Section 1, Introduction.)

## Adopted 2006

- Modification of incentives in the capacity market to require all Load Serving Entities (LSEs) to meet their obligations to serve load on a longer-term basis and to require all capacity resources to be offered on a comparable longer term basis. (Priority: Medium. First reported 1999. 2000 Section: Summary.)

- Reevaluation of the criteria used to determine whether generating units qualify for capacity resource status. (Priority: Medium. First reported 1999. 1999 Section: Summary.)

## Adopted Date Not Determined

- Implementation of rules governing the definition of final prices to ensure certainty for market participants. (Priority: Low. First reported 2008. Last reported: 2009.)
- While it is reasonable to limit the authority of LSE/EDCs in the review of demand side settlements as the LSE/EDCs have economic incentives to deny settlements, LSE/EDCs should be able to initiate PJM settlement reviews. (Priority: Low. First reported 2009. Last reported: 2009 Section 2, Energy Market, Part 1.)
- The MMU recommends two ways to further improve the Economic program by increasing the probability that payments are made only for economic and deliberate load reducing activities in response to price. (Priority: Low. First reported 2009. Last reported: 2009 Section 2, Energy Market, Part 1.)
- Load reduction in response to price must be clearly defined in the business rules and verified in a transparent daily settlement screen. (Priority: Low. First reported 2009. Last reported: 2009 Section 2, Energy Market, Part 1.)
- The four steps in the normal operations review should be routinely applied to all registrations from the beginning of participation. This would include the ongoing evaluation of whether CBL accurately represents customer load for each customer; analysis of settlements to determine responsiveness to price and; required submission of detailed description of load reduction activities on specific days. (Priority: Low. First reported 2009. Last reported: 2009 Section 2, Energy Market, Part 1.)
- The definition of CBL should continue to be refined to ensure that it reflects the actual normal use of individual customers including normal daily and hourly fluctuations in usage and usage that is a function of measurable weather conditions. When used to determine compliance in Load Management testing for GLD customers, the CBL calculation should include adjustments for ambient conditions. (Priority: Low. First reported 2009. Last reported: 2009 Section 2, Energy Market, Part 1.)
- If, for any settlement, the number of consecutive hours showing load reduction is beyond a reasonable window for load reducing actions in response to price, it should initiate a CBL review and warrant further substantiation from the customer and CSP. (Priority: Low. First reported 2009. Last reported: 2009 Section 2, Energy Market, Part 1.)
- It is the MMU's recommendation that any settlement submitted with a consecutive 24 hour period of CBL greater than metered load should initiate a CBL review by PJM and that a customer should be required to provide documentation of load reduction actions taken prior to acceptance of such settlements. Further, in order for PJM or the MMU to assess the accuracy of the CBL for a particular customer or for the Program in general, more hourly load data is required than is currently captured by PJM. (Priority: Low. First reported 2009. Last reported: 2009 Section 2, Energy Market, Part 1.)

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

**Table 3-1 The energy market results were competitive**

| Market Element | Evaluation | Market Design |
|---|---|---|
| Market Structure: Aggregate Market | Partially Competitive | |
| Market Structure: Local Market | Not Competitive | |
| Participant Behavior | Competitive | |
| **Market Performance** | **Competitive** | **Effective** |

- The aggregate market structure was evaluated as partially competitive because the aggregate market power test based on pivotal suppliers indicates that the aggregate day-ahead market structure was not competitive on every day. The hourly HHI (Herfindahl-Hirschman Index) results indicate that by FERC standards, the PJM energy market in 2017 was unconcentrated. Average HHI was 919 with a minimum of 696 and a maximum of 1205 in 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. As demonstrated for the day-ahead market, 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 number of pivotal suppliers in the energy market is a more precise measure of structural market power than the HHI. The HHI is not a definitive measure of structural market power. 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 and local reliability issues. 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,

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 *2017 State of the Market Report for PJM*, Appendix A, "PJM Geography."

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.[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 are 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.

# Overview

## Market Structure

- **Supply.** Supply includes physical generation and imports and virtual transactions. The maximum of average offered real-time generation increased by 2,551 MW, or 1.5 percent, from 171,300 MW in the summer of 2016 to 173,851 MW in the summer of 2017. In 2017, 5,244.3 MW of new resources were added, 8,391.8 MW were retired.

  PJM average real-time cleared generation in 2017 decreased by 0.4 percent in 2016, from 91,304 MW to 90,944 MW.

  PJM average day-ahead cleared supply in 2017, including INCs and up to congestion transactions, decreased by 0.8 percent in 2016, from 131,634 MW to 130,601 MW.

- **Aggregate Pivotal Suppliers.** The PJM energy market at times requires generation from pivotal suppliers to meet the daily peak load, resulting in aggregate market power even when the HHI level indicates that the aggregate market is unconcentrated.

- **Generation Fuel Mix.** In 2017, coal units provided 31.8 percent, nuclear units 35.6 percent and natural gas units 26.8 percent of total generation. Compared to 2016, generation from coal units decreased 6.8 percent, generation from natural gas units increased 0.8 percent and generation from nuclear units increased 2.9 percent.

- **Fuel Diversity.** In 2017, the fuel diversity of energy generation, measured by the fuel diversity index for energy (FDIe), increased 0.8 percent over the FDI for 2016.

- **Marginal Resources.** In the PJM Real-Time Energy Market, in 2017, coal units were 32.3 percent of marginal resources and natural gas units were 53.3 percent of marginal resources. In 2016, coal units

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.

were 46.4 percent and natural gas units were 42.6 percent of the marginal resources.

In the PJM Day-Ahead Energy Market, in 2017, up to congestion transactions were 79.9 percent of marginal resources, INCs were 5.5 percent of marginal resources, DECs were 10.2 percent of marginal resources, and generation resources were 4.3 percent of marginal resources. In 2016, up to congestion transactions were 82.4 percent of marginal resources, INCs were 4.2 percent of marginal resources, DECs were 8.6 percent of marginal resources, and generation resources were 4.7 percent of marginal resources.

- **Demand.** Demand includes physical load and exports and virtual transactions. The PJM accounting peak load during 2017 was 145,636 MW in the HE 1700 on July 19, 2017, which was 6,541 MW, 4.3 percent, lower than the PJM peak load for 2016, which was 152,177 MW in the HE 1500 on August 11, 2016.

  PJM average real-time load in 2017 decreased by 2.2 percent from 2016, from 88,601 MW to 86,618 MW. PJM average day-ahead demand in 2017, including DECs and up to congestion transactions, decreased by 1.3 percent of 2016, from 127,390 MW to 125,792 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 2017, 14.4 percent of real-time load was supplied by bilateral contracts, 27.5 percent by spot market purchases and 58.9 percent by self-supply. Compared to 2016, reliance on bilateral contracts increased by 1.6 percentage points, reliance on spot market purchases increased by 3.5 percentage points and reliance on self-supply decreased by 4.4 percentage points.

- **Supply and Demand: Scarcity.** Five minute shortage pricing was triggered on one day in 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 2016 to 0 percent in 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 2016 to 0.3 percent in 2017.

  In 2017, 12 control zones experienced congestion resulting from one or more constraints binding for 100 or more hours. The analysis of the application of the TPS test to local markets demonstrates that it is working successfully to identify pivotal owners when the market structure is noncompetitive and to ensure that owners are not subject to offer capping when the market structure is competitive. There are, however, identified issues with the application of market power mitigation to resources whose owners fail the TPS test that can result in the exercise of local market power. These issues need to be addressed.

- **Offer Capping for Reliability.** PJM also offer caps units that are committed for reliability reasons, specifically for black start service and reactive service. In the Day-Ahead Energy Market, for units committed for reliability reasons, offer-capped unit hours increased from 0 percent in 2016 to 0.1 percent in 2017. In the Real-Time Energy Market, for units committed for reliability reasons, offer-capped unit hours remained at 0.1 percent in 2016 and 2017.

- **Markup Index.** The markup index is a summary measure of participant offer behavior for individual marginal units. In 2017, in the PJM Real-Time Energy Market, 91.5 percent of marginal units had offer prices less than $50 per MWh. The average dollar markup of units with offer prices less than $25 was zero when using unadjusted cost-based offers. The average dollar markup of units with offer prices between $25 and $50 was positive when using unadjusted cost-based 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-based offers, the highest markup for any marginal unit in 2017 was more than $700 per MWh while the highest markup in 2016 was more than $200 per MWh.

In 2017, in the PJM Day-Ahead Energy Market, 92.8 percent of marginal generating units had offer prices less than $50 per MWh. The average dollar markup of units with offer prices less than $25 was positive when using unadjusted cost-based offers. The average dollar markup of units with offer prices between $25 and $50 was positive when using unadjusted cost-based offers. Using the unadjusted cost-based offers, the highest markup for any marginal unit in 2017 was more than $60 per MWh, while the highest markup in 2016 was more than $160 per MWh.

- **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 2017, the average hourly increment offers submitted MW increased by 11.1 percent from 7,175 MW in 2016 to 7,968 MW in 2017, and cleared MW decreased by 2.4 percent from 4,675 MW in 2016 to 4,562 MW in 2017. In 2017, the average hourly decrement bids submitted MW increased by 14.5 percent from 6,879 MW in 2016 to 7,874 MW in 2017, and cleared MW decreased by 0.3 percent from 4,051 MW in 2016 to 4,035 MW in 2017. In 2017, the average hourly up to congestion submitted MW decreased by 3.3 percent from 142,075 MW in 2016 to 137,419 MW in 2017, and cleared MW increased by 1.6 percent from 34,387 MW in 2016 to 34,927 MW in 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 2017, 54.9 percent were offered as available for economic dispatch, 3.8 percent were offered as emergency dispatch, 20.1 percent were offered as self scheduled, and 21.2 percent were offered as self scheduled and dispatchable.

## Market Performance

- **Prices.** PJM LMPs are a direct measure of market performance. Price level is a good, general indicator of market performance, although the number of factors influencing the overall level of prices means it must be analyzed carefully. Among other things, overall average prices reflect 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 2017 compared to 2016. The load-weighted, average real-time LMP was 6.0 percent higher in 2017 than in 2016, $30.99 per MWh versus $29.23 per MWh.

  PJM day-ahead energy market prices increased in 2017 compared to 2016. The load-weighted, average day-ahead LMP was 3.9 percent higher in 2017 than in 2016, $30.85 per MWh versus $29.68 per MWh.

- **Components of LMP.** In the PJM Real-Time Energy Market, in 2017, 28.9 percent of the load-weighted LMP was the result of coal costs, 39.2 percent was the result of gas costs and 1.79 percent was the result of the cost of emission allowances.

In the PJM Day-Ahead Energy Market, in 2017, 21.1 percent of the load-weighted LMP was the result of coal costs, 23.7 percent was the result of DEC bid costs, 18.4 percent was the result of gas costs, 22.2 percent was the result of INC bid costs, and 3.1 percent was the result of up to congestion transaction costs.

- **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 2017, the adjusted markup component of LMP was $4.94 per MWh or 16.0 percent of the PJM load-weighted, average LMP. May had the highest adjusted peak markup component, $8.23 per MWh, or 21.72 percent of the real-time, peak hour load-weighted, average LMP. There were 50 hours in 2017 where the positive markup contribution to the PJM system wide, load-weighted, average LMP exceeded $48.33 per MWh.

  In the PJM Day-Ahead Energy Market, INCs, DECs and UTCs have zero markups. In 2017, the adjusted markup component of LMP resulting from generation resources was $2.04 per MWh or 6.6 percent of the PJM day-ahead load-weighted average LMP. September had the highest adjusted markup component, $2.98 per MWh or 9.4 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 -$0.53 per MWh in 2016 and -$0.06 per MWh in 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

- PJM implemented five minute shortage pricing beginning May 11, 2017. Five minute shortage pricing was triggered for one day, September 21, 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. The MMU recommends that the level of incremental costs includable in cost-based offers not exceed the short run marginal cost of the unit. (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 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-based offers based on short run marginal costs and the correct calculation of cost-based offers. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends removal of all use of 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-based offers, and 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 price-based non-PLS 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. (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. Stakeholder process.)

- The MMU recommends that Market Sellers not be allowed to designate any portion of an available Capacity Resource's ICAP equivalent of cleared UCAP capacity commitment as a Maximum Emergency offer at any time during the delivery year.[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: Adopted 2012.)
- 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 all buses with a net withdrawal be treated as load 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 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 2014.)
- The MMU recommends that PJM increase the interaction of outage and operational restrictions data submitted by Market Participants via eDART/eGADs and offer data submitted via Markets Gateway. (Priority: Low. New recommendation. Status: Not adopted.)

## Conclusion

The MMU analyzed key elements of PJM energy market structure, participant conduct and market performance in 2017, including aggregate supply and demand, concentration ratios, aggregate pivotal supplier results, local three pivotal supplier test results, offer capping, participation in demand response programs, loads and prices.

4 This recommendation was accepted by PJM and filed with FERC in 2014 as part of the capacity performance updates to the RPM. See Schedule 1, Section 1.10.1A(d), Revisions to the PJM Open Access Transmission Tariff and PJM Operating Agreement (Marked/Redline Format), EL15-29-000 (December 12, 2014). FERC rejected the proposed change in Order 151FERC¶61,208 at 476 (June 9, 2015).

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>.

PJM average real-time cleared generation decreased by 360 MW, 0.4 percent, and peak load decreased by 6,541 MW, 4.3 percent, in 2017 compared to 2016. 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. The market structure of the PJM aggregate energy market is partially competitive because aggregate market power does exist for a significant number of hours. The HHI is not a definitive measure of structural market power. The number of pivotal suppliers in the energy market is a more precise measure of structural market power than the HHI. It is possible to have pivotal suppliers in the aggregate market even when the HHI level is not in the highly concentrated range. The current market power mitigation rules for the PJM energy market rely on the assumption that the ownership structure of the aggregate market ensures competitive outcomes. This assumption requires that the total demand for energy can be met without the supply from any individual supplier or without the supply from a small group of suppliers. This assumption is not correct. There are pivotal suppliers in the aggregate energy market at times. High markups for some units demonstrate the potential to exercise market power during high demand conditions. The existing market power mitigation measures do not address aggregate market power. The MMU is developing an aggregate market power test and will propose market power mitigation rules to address aggregate market power.

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] 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. These issues can be resolved by simple rule changes.

The enforcement of market power mitigation rules is undermined if the definition of a competitive offer is not correct. A competitive offer is equal to short run marginal costs. 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 rule changes to incorporate a clear and accurate definition of short run marginal costs.

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 to serve load in each market interval. 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 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.

Prices in PJM are not too low. There is no evidence to support the need for a significant change to the calculation of LMP. The underlying problem that fast start pricing and PJM's convex hull pricing approach are attempting to address is actually scarcity pricing including the impact of operator actions on the definition of scarcity. Prices do not reflect market conditions when the market is tight. Rather than undercutting the basic LMP logic that is core to market efficiency, it would make more sense to directly address scarcity pricing, operator actions and the design of reserve markets.

The objective of efficient short run price signals is to minimize system production costs, not to minimize uplift. Repricing the market to reflect commitment costs would create a tradeoff between minimizing production costs and reduction of uplift. The tradeoff would exist because when commitment costs are included in prices, the price signal no longer equals the short run marginal

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

cost and therefore no longer provides the correct signal for efficient behavior for market participants making decisions on the margin, whether resources, load, interchange transactions, or virtual traders. This tradeoff would be created by PJM's fast start pricing proposal and in a much more extensive form by PJM's modified convex hull pricing proposal.

The fast start pricing and convex hull solutions would undercut LMP logic rather than directly addressing the underlying issues. The solution is not to accept that the inflexible CT should be paid or set price based on its commitment costs rather than its short run marginal costs. The question of why units make inflexible offers should be addressed directly. Are units inflexible because they are old and inefficient, because owners have not invested in increased flexibility or because they serve as a mechanism for the exercise of market power? The question of why this unit was built, whether it was built under cost of service regulation and whether it is efficient to retain the unit should be answered directly. The question of how to provide market incentives for investment in flexible units and for investment in increased flexibility of existing units should be addressed directly. The question of whether inflexible units should be paid uplift at all should be addressed directly. Marginal cost pricing without paying excess uplift to inflexible units would create incentives for market participants to provide flexible solutions including replacing inefficient units with flexible, efficient units.

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. However, the explicit balancing mechanism that included net revenues directly in unit offers in the prior capacity market design is not present in the Capacity Performance design. The nature of a direct and explicit scarcity pricing net revenue true up mechanism should be addressed if scarcity revenues are expected to increase. PJM implemented scarcity pricing rules in 2012. PJM implemented five minute scarcity pricing on May 11, 2017, and implemented two step operating reserve demand curves on July 12, 2017. 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 2017 or prior years. This is evidence of generally competitive behavior and competitive market outcomes, although the behavior of some participants during high demand periods is consistent with economic withholding. Markups were higher in 2017. Given the structure of the energy market which can permit the exercise of aggregate market power at times of high demand, the change in some participants' behavior is a source of concern in the energy market and provides a reason to use correctly defined short run marginal 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 2017.

# Market Structure

## Market Concentration

Analysis of supply curve segments of the PJM energy market in 2017 indicates low concentration in the base load segment and moderate concentration in the intermediate segment, 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 a highly concentrated market structure. It is possible to have an exercise of market power even when the HHI level does not indicate a highly concentrated market structure.

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 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 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 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 FERC standards, the PJM energy market during 2017 was unconcentrated (Table 3-2).

### Table 3-2 PJM hourly energy market HHI: 2016 and 2017[10]

| | Hourly Market HHI (2016) | Hourly Market HHI (2017) |
|---|---|---|
| Average | 1024 | 919 |
| Minimum | 786 | 696 |
| Maximum | 1356 | 1205 |
| Highest market share (One hour) | 28% | 27% |
| Average of the highest hourly market share | 20% | 19% |
| | | |
| # Hours | 8,784 | 8,760 |
| # Hours HHI > 1800 | 0 | 0 |
| % Hours HHI > 1800 | 0% | 0% |

Table 3-3 includes HHI values by supply curve segment, including base, intermediate and peaking plants for 2016 and 2017. The PJM energy market was unconcentrated overall with low concentration in the baseload, moderate concentration in the intermediate segment, and high concentration in the peaking segment.

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.

9 See *"Inquiry Concerning the Commission's Merger Policy under the Federal Power Act: Policy Statement*, 77 FERC ¶ 61,263 *mimeo* at 80 (1996).

10 This analysis includes all hours in 2016 and 2017, regardless of congestion.

### Table 3-3 PJM hourly energy market HHI (By supply segment): 2016 and 2017

| | 2016 | | | 2017 | | |
|---|---|---|---|---|---|---|
| | Minimum | Average | Maximum | Minimum | Average | Maximum |
| Base | 945 | 1106 | 1428 | 836 | 983 | 1273 |
| Intermediate | 578 | 1371 | 5029 | 718 | 1542 | 5124 |
| Peak | 684 | 5620 | 10000 | 671 | 5826 | 10000 |

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

### Figure 3-1 Fuel source distribution in unit segments: 2017[11]

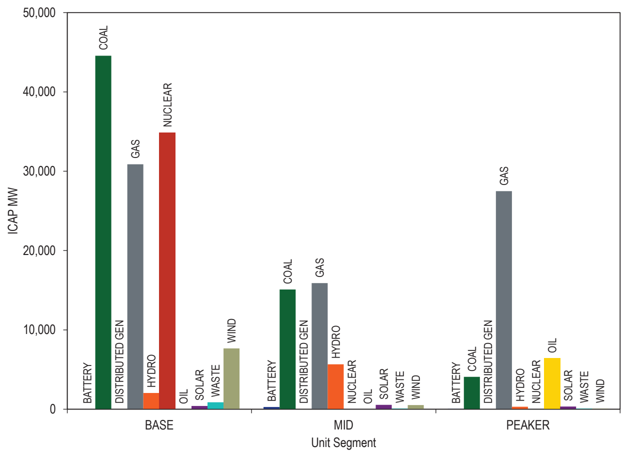
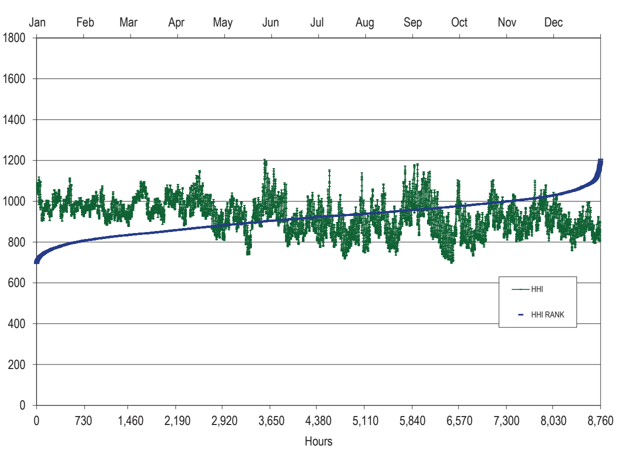



Figure 3-2 presents the hourly HHI values in chronological order and an HHI duration curve for 2017.

### Figure 3-2 PJM hourly energy market HHI: 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 Rev.," (July 26, 2012) <http://www.pjm.com/~/media/committees-groups/committees/mrc/20120726/20120726-item-04-nemstf-report-and-proposed-manual-revisions.ashx>.

## Aggregate Market Pivotal Supplier Results

Notwithstanding the HHI level, a supplier may have the ability to raise energy market prices. If reliably meeting the PJM system load requires energy from a single supplier, that supplier is pivotal and has monopoly power in the aggregate energy market. If a small number of suppliers are jointly required to meet load, those suppliers are jointly pivotal and have oligopoly power. The number of pivotal suppliers in the energy market is a more precise measure of structural market power than the HHI. The HHI is not a definitive measure of structural market power.

In the PJM Day-Ahead Energy Market, two suppliers were jointly pivotal on 15 percent of days in 2017. Three suppliers were jointly pivotal on 68 percent of days. The frequency of pivotal suppliers increased in the summer months and on high demand days in September.

## Day-Ahead Energy Market Aggregate Pivotal Suppliers

To assess the number of pivotal suppliers in the Day-Ahead Energy Market, the MMU determined, for each supplier, the MW available for economic commitment that were already running or were available to start between the close of the Day-Ahead Energy Market and the peak load hour of the operating day. The available supply is defined as MW offered at a price less than 150 percent of the applicable LMP because supply available at higher prices is not competing to meet the demand for energy.[12] Generating units, import transactions, economic demand response, and INCs, are included for each supplier. Demand is the total MW required by PJM to meet physical load, cleared load bids, export transactions, and DECs. A supplier is pivotal if PJM would require some portion of the supplier's available economic capacity in the peak hour of the operating day in order to meet demand. Suppliers are jointly pivotal if PJM would require some portion of the joint suppliers' available economic capacity in the peak hour of the operating day in order to meet demand.

Figure 3-3 shows the number of days in 2017 with one pivotal supplier, two jointly pivotal suppliers, and three jointly pivotal suppliers for the Day-Ahead Energy Market along with the number of suppliers meeting each

12 Each LMP is scaled by 150 percent to determine the relevant supply, resulting in a different price threshold for each LMP value. The analysis does not solve a redispatch of the PJM market.

criterion. No supplier was singly pivotal for any day in 2017. Two suppliers were jointly pivotal on 56 days. Three suppliers were jointly pivotal on 247 days, despite average HHIs at persistently unconcentrated levels.

Figure 3-3 Days with pivotal suppliers and numbers of pivotal suppliers in the PJM Day-Ahead Energy Market: 2017

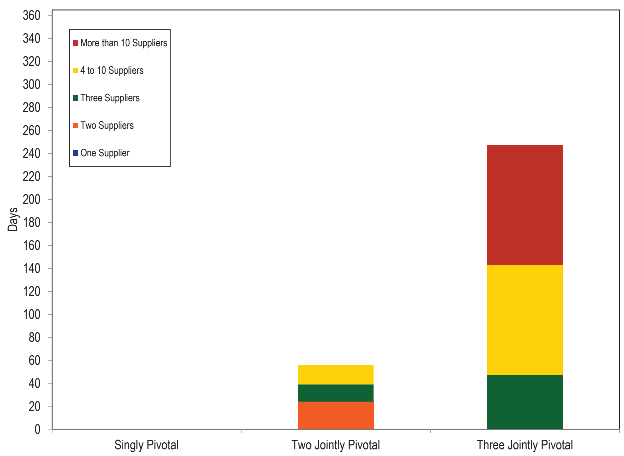



Table 3-4 provides the frequency with which each of the 10 largest suppliers was singly or jointly pivotal for the Day-Ahead Energy Market in 2017. The two largest suppliers were one of two pivotal suppliers on 55 and 54 days, 15 percent of days in 2017. All of the top 10 suppliers were one of three pivotal suppliers on at least 31 percent of days, and the largest two suppliers were one of three pivotal suppliers on 67 percent of days.

Table 3-4 Frequency of days as a pivotal supplier for the 10 largest suppliers: 2017

| Pivotal Supplier Rank | Days Singly Pivotal | Percent of Days | Days Jointly Pivotal with One Other Supplier | Percent of Days | Days Jointly Pivotal with Two Other Suppliers | Percent of Days |
|---|---|---|---|---|---|---|
| 1 | 0 | 0% | 55 | 15% | 247 | 68% |
| 2 | 0 | 0% | 54 | 15% | 243 | 67% |
| 3 | 0 | 0% | 32 | 9% | 232 | 64% |
| 4 | 0 | 0% | 17 | 5% | 191 | 52% |
| 5 | 0 | 0% | 10 | 3% | 181 | 50% |
| 6 | 0 | 0% | 5 | 1% | 139 | 38% |
| 7 | 0 | 0% | 2 | 1% | 142 | 39% |
| 8 | 0 | 0% | 0 | 0% | 128 | 35% |
| 9 | 0 | 0% | 2 | 1% | 125 | 34% |
| 10 | 0 | 0% | 1 | 0% | 112 | 31% |

The current market power mitigation rules for the PJM energy market rely on the assumption that the aggregate market includes sufficient competing sellers to ensure competitive market outcomes. With sufficient competition, any attempt to economically or physically withhold generation would not result in higher market prices, because another supplier would replace the generation at a similar price. This assumption requires that the total demand for energy can be met without the supply from any individual supplier or without the supply from a small group of suppliers. This assumption is not correct, as demonstrated by these results. There are pivotal suppliers in the aggregate energy market.

The existing market power mitigation measures do not address aggregate market power.[13] The MMU is developing an aggregate market power test for the day-ahead and real-time energy markets based on pivotal suppliers and will propose appropriate market power mitigation rules to address aggregate market power.

## Ownership of Marginal Resources

Table 3-5 shows the contribution to real-time, load-weighted LMP by individual marginal resource owners.[14] 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 2017, the offers of one company resulted in 13.4 percent of the real-time, load-weighted PJM system LMP and the offers of the top four companies resulted in 49.2 percent of the real-time, load-weighted, average PJM system LMP. During 2016, the offers of one company resulted in 23.6 percent of the real-time, load-weighted PJM system LMP and offers of the top four companies resulted in 61.3 percent of the real-time, load-weighted, average PJM system LMP. In 2017, the offers of one company resulted in 12.3 percent of the peak hour real-time, load weighted PJM system LMP. In 2016, the offers of one company resulted in 22.6 percent of the peak hour, real-time, load weighted PJM system LMP.

13 One supplier, Exelon, is partially mitigated for aggregate market power through its merger agreement. The agreement is not part of the PJM market rules. See Monitoring Analytics, LLC, Letter attaching Settlement Terms and Conditions, FERC Docket No. EC11-83-000 and Maryland PSC Case No. 9271 (October 11, 2011).

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

Table 3-5 Marginal unit contribution to PJM real-time, load-weighted LMP (By parent company): 2016 and 2017

| 2016 | | | | | | 2017 | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 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 | 23.6% | 23.6% | 1 | 22.6% | 22.6% | 1 | 13.4% | 13.4% | 1 | 12.3% | 12.3% |
| 2 | 14.2% | 37.8% | 2 | 14.8% | 37.4% | 2 | 12.6% | 26.0% | 2 | 11.7% | 24.1% |
| 3 | 13.9% | 51.6% | 3 | 12.2% | 49.6% | 3 | 12.5% | 38.5% | 3 | 10.6% | 34.7% |
| 4 | 9.7% | 61.3% | 4 | 8.7% | 58.2% | 4 | 10.7% | 49.2% | 4 | 10.4% | 45.1% |
| 5 | 7.3% | 68.6% | 5 | 7.9% | 66.1% | 5 | 9.2% | 58.4% | 5 | 9.4% | 54.5% |
| 6 | 5.4% | 74.0% | 6 | 4.6% | 70.7% | 6 | 4.7% | 63.0% | 6 | 5.8% | 60.3% |
| 7 | 2.4% | 76.5% | 7 | 3.1% | 73.8% | 7 | 3.7% | 66.7% | 7 | 5.0% | 65.3% |
| 8 | 2.2% | 78.7% | 8 | 2.6% | 76.4% | 8 | 3.5% | 70.3% | 8 | 3.7% | 69.0% |
| 9 | 1.8% | 80.5% | 9 | 2.3% | 78.7% | 9 | 3.2% | 73.5% | 9 | 3.5% | 72.6% |
| Other (70 companies) | 19.5% | 100.0% | Other (63 companies) | 21.3% | 100.0% | Other (76 companies) | 26.5% | 100.0% | Other (70 companies) | 27.4% | 100.0% |

Table 3-6 shows the contribution to day-ahead, load-weighted LMP by individual marginal resource owners.[15] The contribution of each marginal resource to price at each load bus is calculated hourly, and summed by the parent company that offers the marginal resource into the Day-Ahead Energy Market. The results show that in 2017, the offers of one company contributed 10.2 percent of the day-ahead, load-weighted, PJM system LMP and that the offers of the top four companies contributed 31.0 percent of the day-ahead, load-weighted, average, PJM system LMP. In 2016, the offers of one company contributed 13.4 percent of the day-ahead, load-weighted PJM system LMP and offers of the top four companies contributed 36.1 percent of the day-ahead, load-weighted, average PJM system LMP.

Table 3-6 Marginal resource contribution to PJM day-ahead, load-weighted LMP (By parent company)

| 2016 | | | | | | 2017 | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 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 | 13.4% | 13.4% | 1 | 10.9% | 10.9% | 1 | 10.2% | 10.2% | 1 | 12.6% | 12.6% |
| 2 | 8.4% | 21.9% | 2 | 10.8% | 10.8% | 2 | 8.2% | 18.4% | 2 | 6.7% | 19.3% |
| 3 | 7.4% | 29.3% | 3 | 9.3% | 9.3% | 3 | 6.5% | 24.9% | 3 | 5.2% | 24.5% |
| 4 | 6.8% | 36.1% | 4 | 7.0% | 7.0% | 4 | 6.1% | 31.0% | 4 | 5.0% | 29.5% |
| 5 | 6.5% | 42.5% | 5 | 6.3% | 6.3% | 5 | 5.6% | 36.5% | 5 | 4.7% | 34.2% |
| 6 | 4.7% | 47.2% | 6 | 5.3% | 5.3% | 6 | 5.5% | 42.1% | 6 | 4.5% | 38.7% |
| 7 | 4.3% | 51.5% | 7 | 5.0% | 5.0% | 7 | 5.0% | 47.0% | 7 | 4.4% | 43.1% |
| 8 | 3.6% | 55.1% | 8 | 3.3% | 3.3% | 8 | 3.6% | 50.7% | 8 | 4.1% | 47.3% |
| 9 | 3.0% | 58.2% | 9 | 3.3% | 3.3% | 9 | 3.6% | 54.3% | 9 | 4.1% | 51.4% |
| Other (166 companies) | 41.8% | 100.0% | Other (159 companies) | 38.7% | 38.7% | Other (166 companies) | 45.7% | 100.0% | Other (161 companies) | 48.6% | 100.0% |

## Type of Marginal Resources

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

Table 3-7 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 2017, coal units were 32.28 percent and natural gas units were 53.26 percent of marginal resources. In 2016, coal units were 46.39 percent and natural gas units were 42.57 percent of the total marginal resources. In 2017, 73.3 percent of the wind marginal units had negative offer prices, 20.4 percent had zero offer prices and 6.3 percent had positive offer prices. In 2016, 86.6

15 *Id.*

percent of the wind marginal units had negative offer prices, 11.2 percent had zero offer prices and 2.1 percent had positive offer prices.

The proportion of marginal nuclear units increased from 0.03 percent in 2015 to 1.06 percent in 2016 and to 1.23 percent in 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 3-7 Type of fuel used (By real-time marginal units): 2013 through 2017

| Type/Fuel | 2013 | 2014 | 2015 | 2016 | 2017 |
|---|---|---|---|---|---|
| Gas | 34.72% | 35.80% | 35.52% | 42.57% | 53.26% |
| Coal | 56.94% | 52.90% | 51.74% | 46.39% | 32.28% |
| Wind | 4.76% | 3.29% | 3.27% | 2.98% | 7.28% |
| Oil | 3.27% | 7.45% | 8.99% | 6.79% | 5.50% |
| Uranium | 0.02% | 0.04% | 0.03% | 1.06% | 1.23% |
| Other | 0.20% | 0.43% | 0.39% | 0.14% | 0.37% |
| Municipal Waste | 0.07% | 0.05% | 0.06% | 0.08% | 0.08% |
| Emergency DR | 0.02% | 0.04% | 0.00% | 0.00% | 0.00% |

Figure 3-4 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 3-4 Type of fuel used (By real-time marginal units): 2004 through 2017

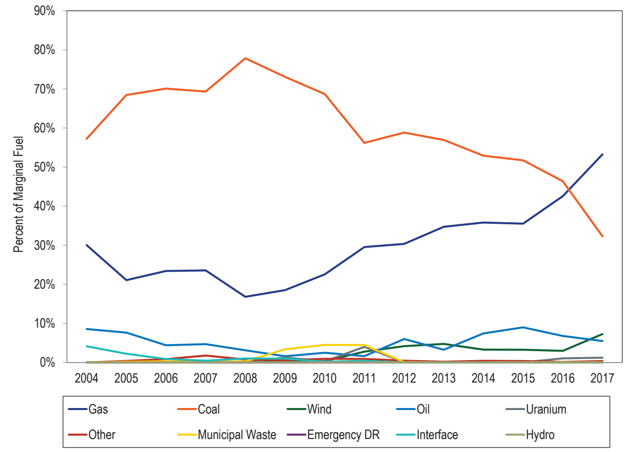



Table 3-8 shows the type and fuel type where relevant, of marginal resources in the Day-Ahead Energy Market. In 2017, up to congestion transactions were 79.9 percent of marginal resources. Up to congestion transactions were 82.4 percent of marginal resources in 2016.

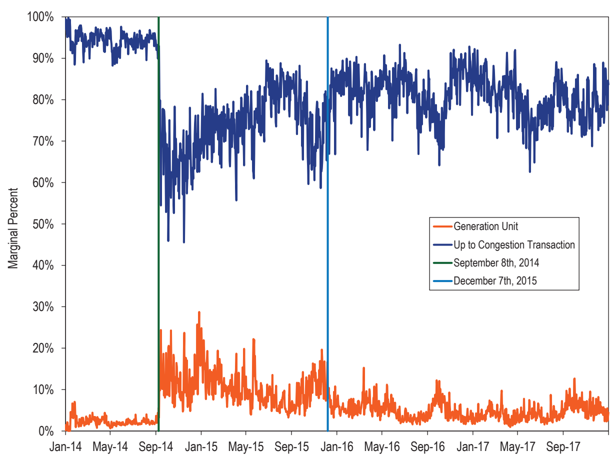
 

Table 3-8 Day-ahead marginal resources by type/fuel: 2011 through 2017

| Type/Fuel | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 |
|---|---|---|---|---|---|---|---|
| Up to Congestion Transaction | 73.40% | 88.40% | 96.44% | 91.05% | 76.14% | 82.38% | 79.88% |
| DEC | 12.38% | 4.30% | 1.27% | 3.28% | 8.87% | 8.65% | 10.21% |
| INC | 7.54% | 3.81% | 1.05% | 2.28% | 5.08% | 4.18% | 5.53% |
| Coal | 4.66% | 2.31% | 0.78% | 2.03% | 5.54% | 2.16% | 1.90% |
| Gas | 1.54% | 1.04% | 0.36% | 1.16% | 3.39% | 1.99% | 1.95% |
| Oil | 0.00% | 0.00% | 0.00% | 0.05% | 0.44% | 0.41% | 0.25% |
| Uranium | 0.00% | 0.00% | 0.00% | 0.00% | 0.11% | 0.11% | 0.08% |
| Wind | 0.07% | 0.03% | 0.04% | 0.05% | 0.12% | 0.06% | 0.15% |
| Dispatchable Transaction | 0.17% | 0.07% | 0.05% | 0.08% | 0.26% | 0.05% | 0.04% |
| Other | 0.00% | 0.00% | 0.00% | 0.00% | 0.02% | 0.01% | 0.00% |
| Price Sensitive Demand | 0.23% | 0.04% | 0.01% | 0.01% | 0.02% | 0.00% | 0.00% |
| Municipal Waste | 0.01% | 0.01% | 0.00% | 0.01% | 0.00% | 0.00% | 0.00% |
| Hydro | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.01% |
| Total | 100.00% | 100.00% | 100.00% | 100.00% | 100.00% | 100.00% | 100.00% |

Figure 3-5 shows, for the Day-Ahead Energy Market from 2014, through 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 and that of generation units increased beginning on September 8, 2014, as a result of FERC's UTC uplift refund notice which became effective on that date.[16] That trend has reversed as a result of the expiration of the fifteen month uplift refund period for UTC transactions.

Figure 3-5 Day-ahead marginal up to congestion transaction and generation units: 2014 through 2017




## Supply

Supply includes physical generation and imports and virtual transactions.

Figure 3-6 shows the average PJM aggregate real-time generation supply curves by incremental offer price for the entire range of offers, peak load and average load for the summer of 2016 and 2017. The maximum of average offered real-time generation increased by 2,551 MW, or 1.5 percent, from 171,300 MW in the summer of 2016 to 173,851 MW in the summer of 2017.

Figure 3-6 Average PJM aggregate real-time generation supply curves by offer price: summer, 2016 and 2017

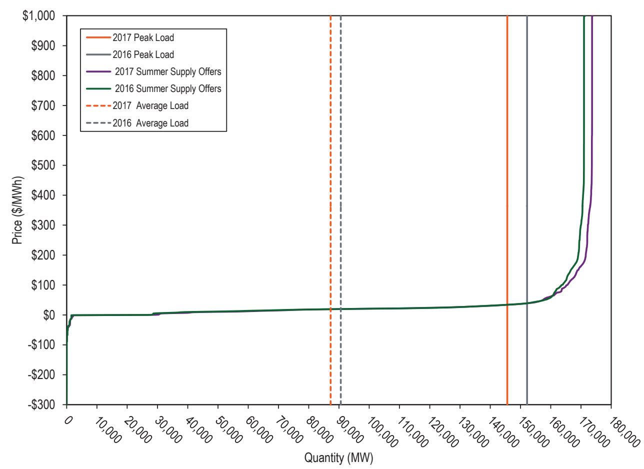
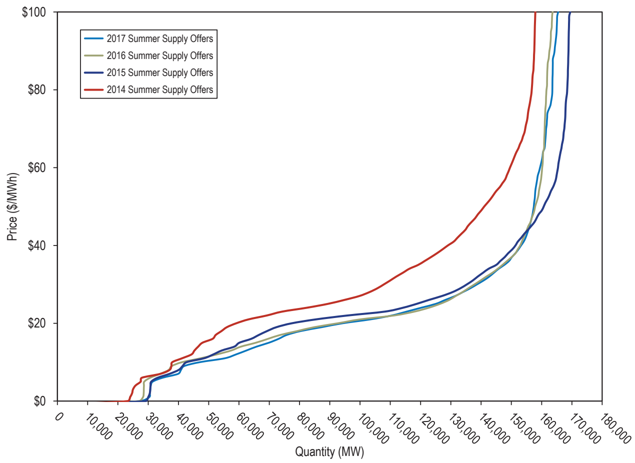



Figure 3-7 shows the average PJM aggregate real-time generation supply curves by offer price, for the typical dispatch range and for the summer of 2014 through 2017. Figure 3-7 shows that the supply curve is not flat in the typical dispatch range and that the supply curve has not become flatter over this period.

16 See 18 CFR § 385.213 (2014).

## Figure 3-7 Average PJM aggregate real-time generation supply curves by offer price: summer, 2014 through 2017




## Figure 3-8 Average PJM aggregate day-ahead generation supply curves by offer price: summer, 2016 and 2017

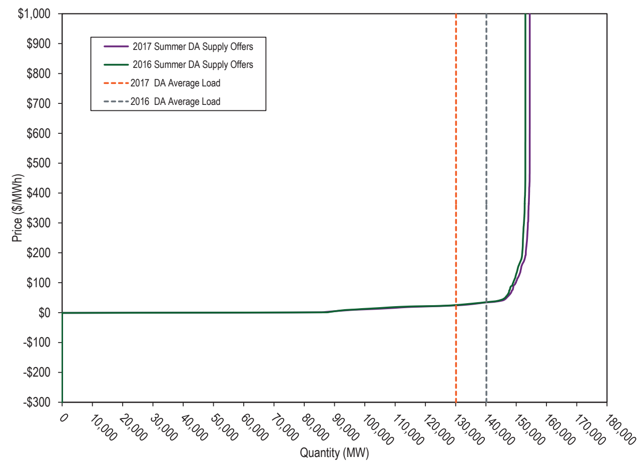



Table 3-9 shows the price elasticities by segment of the PJM aggregate real-time generation supply curve for the summer of 2014 through 2017.[17] The price elasticity of supply reflects the slope of the supply curve, with flatter segments of the curve having a higher elasticity.

The elasticities vary over time, but there is no trend. The PJM supply curve is not getting flatter.

## Table 3-9 Price elasticity of supply for PJM real-time generation: summer, 2014 through 2017

| | | Elasticity of Supply | | | |
|---|---|---|---|---|---|
| Load Level | GWh | 2014 | 2015 | 2016 | 2017 |
| Low | 60 - 80 | 1.977 | 0.864 | 1.072 | 0.723 |
| Moderate | 80 - 100 | 1.677 | 2.646 | 1.571 | 1.718 |
| High | 100 - 120 | 0.658 | 1.124 | 1.886 | 1.138 |
| Very High | 120 - 140 | 0.437 | 0.577 | 0.533 | 0.588 |
| Peak | 140 - 160 | 0.067 | 0.284 | 0.165 | 0.137 |

Figure 3-8 shows the average PJM aggregate day-ahead generation supply curves by offer price for the entire range of offer and average load for the summer of 2016 and 2017. The maximum of average offered day-ahead generation increased by 1,972 MW, or 1.3 percent, from 155,847 MW in the summer of 2016 to 157,819 MW in the summer of 2017.

## Energy Production by Fuel Source

Table 3-10 shows PJM generation by fuel source in GWh for 2016 and 2017. In 2017, generation from coal units decreased 6.8 percent and generation from natural gas units increased 0.8 percent compared to 2016. The largest fuel source increases were a 2.9 percent increase in nuclear generation and a 16.9 percent increase in wind generation compared to 2016.[18]

17 The elasticity of supply is a measure of the relationship between a change in the quantity supplied and the corresponding change in price. Elasticity of Supply = Percent change in quantity / Percent change in price

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

## Table 3-10 PJM generation (By fuel source (GWh)): 2016 and 2017[19 20 21]

| | 2016 | | 2017 | | Change in |
|---|---|---|---|---|---|
| | GWh | Percent | GWh | Percent | Output |
| Coal | 275,289.4 | 33.9% | 256,613.8 | 31.8% | (6.8%) |
| Bituminous | 241,050.2 | 29.7% | 220,789.4 | 27.3% | (8.4%) |
| Sub Bituminous | 28,949.8 | 3.6% | 28,016.0 | 3.5% | (3.2%) |
| Other Coal | 5,289.5 | 0.7% | 7,808.4 | 1.0% | 47.6% |
| Nuclear | 279,546.4 | 34.4% | 287,575.8 | 35.6% | 2.9% |
| Gas | 217,199.0 | 26.7% | 219,205.1 | 27.1% | 0.9% |
| Natural Gas | 215,021.4 | 26.5% | 216,758.6 | 26.8% | 0.8% |
| Landfill Gas | 2,177.6 | 0.3% | 2,433.1 | 0.3% | 11.7% |
| Other Gas | 0.0 | 0.0% | 13.4 | 0.0% | NA |
| Hydroelectric | 13,686.8 | 1.7% | 14,868.4 | 1.8% | 8.6% |
| Pumped Storage | 4,840.2 | 0.6% | 5,132.6 | 0.6% | 6.0% |
| Run of River | 7,332.8 | 0.9% | 8,119.8 | 1.0% | 10.7% |
| Other Hydro | 1,513.8 | 0.2% | 1,616.0 | 0.2% | 6.8% |
| Wind | 17,716.0 | 2.2% | 20,714.1 | 2.6% | 16.9% |
| Waste | 4,358.9 | 0.5% | 3,984.1 | 0.5% | (8.6%) |
| Solid Waste | 4,139.8 | 0.5% | 3,740.7 | 0.5% | (9.6%) |
| Miscellaneous | 219.2 | 0.0% | 243.4 | 0.0% | 11.1% |
| Oil | 2,163.2 | 0.3% | 2,301.7 | 0.3% | 6.4% |
| Heavy Oil | 270.7 | 0.0% | 174.4 | 0.0% | (35.6%) |
| Light Oil | 340.7 | 0.0% | 340.3 | 0.0% | (0.1%) |
| Diesel | 59.4 | 0.0% | 81.7 | 0.0% | 37.5% |
| Gasoline | 0.0 | 0.0% | 0.0 | 0.0% | NA |
| Kerosene | 74.8 | 0.0% | 15.2 | 0.0% | (79.6%) |
| Jet Oil | 0.0 | 0.0% | 3.1 | 0.0% | NA |
| Other Oil | 1,417.7 | 0.2% | 1,687.0 | 0.2% | 19.0% |
| Solar, Net Energy Metering | 1,019.4 | 0.1% | 1,468.7 | 0.2% | 44.1% |
| Energy Storage | 15.7 | 0.0% | 25.1 | 0.0% | 59.6% |
| Battery | 15.7 | 0.0% | 25.1 | 0.0% | 59.6% |
| Compressed Air | 0.0 | 0.0% | 0.0 | 0.0% | NA |
| Biofuel | 1,541.5 | 0.2% | 1,473.0 | 0.2% | (4.4%) |
| Geothermal | 0.0 | 0.0% | 0.0 | 0.0% | NA |
| Other Fuel Type | 0.0 | 0.0% | 0.0 | 0.0% | NA |
| Total | 812,536.3 | 100.0% | 808,229.7 | 100.0% | (0.5%) |

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

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

21 Other Gas includes: Propane, Butane, Hydrogen, Gasified Coal, and Refinery Gas.

### Table 3-11 Monthly PJM generation (By fuel source (GWh)): 2017

| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Coal | 25,115.1 | 19,246.2 | 21,910.6 | 17,843.2 | 19,836.7 | 22,512.3 | 26,748.3 | 23,892.6 | 18,878.6 | 17,523.8 | 18,238.5 | 24,868.0 | 256,613.8 |
| Bituminous | 21,145.9 | 16,596.5 | 18,996.6 | 15,674.8 | 17,627.2 | 19,757.0 | 22,750.8 | 20,480.3 | 16,178.0 | 14,477.3 | 15,922.3 | 21,182.8 | 220,789.4 |
| Sub Bituminous | 3,189.9 | 1,945.5 | 2,192.2 | 1,733.6 | 1,697.4 | 2,177.7 | 3,264.8 | 2,652.3 | 2,030.7 | 2,509.0 | 1,795.6 | 2,827.3 | 28,016.0 |
| Other Coal | 779.3 | 704.2 | 721.8 | 434.9 | 512.1 | 577.6 | 732.7 | 760.0 | 669.9 | 537.5 | 520.6 | 858.0 | 7,808.4 |
| Nuclear | 26,016.6 | 22,140.8 | 23,047.7 | 23,076.4 | 22,564.3 | 24,441.8 | 25,419.2 | 25,180.0 | 23,202.6 | 22,653.2 | 23,604.2 | 26,229.1 | 287,575.8 |
| Gas | 16,095.2 | 15,213.3 | 17,833.8 | 13,438.6 | 15,290.2 | 20,016.6 | 24,184.7 | 22,139.2 | 20,830.4 | 18,218.4 | 16,923.8 | 19,021.1 | 219,205.1 |
| Natural Gas | 15,884.0 | 15,017.6 | 17,625.2 | 13,234.8 | 15,096.3 | 19,822.6 | 23,975.8 | 21,923.2 | 20,627.3 | 18,017.7 | 16,717.6 | 18,816.5 | 216,758.6 |
| Landfill Gas | 211.2 | 195.7 | 208.6 | 201.3 | 193.9 | 192.7 | 208.3 | 212.5 | 197.6 | 200.7 | 206.1 | 204.6 | 2,433.1 |
| Other Gas | 0.0 | 0.0 | 0.0 | 2.6 | 0.0 | 1.4 | 0.5 | 3.4 | 5.5 | 0.0 | 0.0 | 0.0 | 13.4 |
| Hydroelectric | 1,266.9 | 1,083.6 | 1,215.3 | 1,432.4 | 1,620.7 | 1,552.8 | 1,536.4 | 1,305.7 | 915.3 | 819.0 | 1,134.2 | 986.1 | 14,868.4 |
| Pumped Storage | 337.1 | 253.0 | 308.4 | 320.8 | 431.6 | 542.8 | 656.1 | 637.7 | 501.6 | 396.5 | 347.4 | 399.5 | 5,132.6 |
| Run of River | 826.8 | 753.2 | 809.9 | 1,008.9 | 1,034.7 | 817.5 | 638.8 | 468.1 | 275.5 | 309.7 | 690.6 | 486.0 | 8,119.8 |
| Other Hydro | 103.0 | 77.4 | 97.0 | 102.6 | 154.4 | 192.5 | 241.5 | 199.9 | 138.2 | 112.9 | 96.2 | 100.6 | 1,616.0 |
| Wind | 2,017.5 | 2,178.6 | 2,299.9 | 2,072.0 | 1,825.5 | 1,457.9 | 811.9 | 693.5 | 911.5 | 1,917.8 | 2,198.1 | 2,329.9 | 20,714.1 |
| Waste | 392.4 | 304.0 | 325.6 | 288.2 | 323.9 | 322.3 | 342.2 | 339.8 | 328.3 | 327.8 | 324.1 | 365.6 | 3,984.1 |
| Solid Waste | 364.9 | 281.5 | 302.3 | 264.4 | 303.6 | 301.5 | 320.9 | 318.8 | 306.4 | 319.7 | 314.9 | 341.9 | 3,740.7 |
| Miscellaneous | 27.5 | 22.5 | 23.3 | 23.9 | 20.3 | 20.8 | 21.3 | 21.1 | 21.9 | 8.2 | 9.2 | 23.7 | 243.4 |
| Oil | 210.9 | 152.6 | 112.8 | 142.8 | 214.7 | 226.0 | 200.3 | 201.2 | 206.1 | 165.2 | 161.2 | 308.0 | 2,301.7 |
| Heavy Oil | 0.5 | 3.1 | 0.0 | 0.0 | 34.7 | 58.2 | 25.9 | 28.9 | 3.2 | 0.0 | 0.0 | 19.8 | 174.4 |
| Light Oil | 59.6 | 21.8 | 5.8 | 4.9 | 21.6 | 19.8 | 11.3 | 8.1 | 42.5 | 43.2 | 23.0 | 78.8 | 340.3 |
| Diesel | 6.0 | 0.1 | 1.1 | 1.2 | 5.6 | 2.6 | 1.9 | 2.3 | 4.0 | 1.9 | 6.3 | 48.8 | 81.7 |
| Gasoline | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Kerosene | 0.8 | 0.0 | 0.1 | 0.0 | 0.0 | 0.0 | 0.2 | 0.1 | 0.0 | 0.0 | 0.0 | 14.0 | 15.2 |
| Jet Oil | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 3.1 | 3.1 |
| Other Oil | 144.0 | 127.6 | 105.9 | 136.6 | 152.9 | 145.3 | 161.0 | 161.8 | 156.4 | 120.1 | 132.0 | 143.4 | 1,687.0 |
| Solar, Net Energy Metering | 52.9 | 93.1 | 121.0 | 134.8 | 141.2 | 161.2 | 160.1 | 150.9 | 141.5 | 121.7 | 107.2 | 83.0 | 1,468.7 |
| Energy Storage | 2.6 | 3.2 | 3.4 | 2.6 | 2.3 | 1.8 | 1.7 | 1.5 | 1.4 | 1.6 | 1.5 | 1.5 | 25.1 |
| Battery | 2.6 | 3.2 | 3.4 | 2.6 | 2.3 | 1.8 | 1.7 | 1.5 | 1.4 | 1.6 | 1.5 | 1.5 | 25.1 |
| Compressed Air | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Biofuel | 145.5 | 135.8 | 153.0 | 117.9 | 89.4 | 146.5 | 153.5 | 160.7 | 59.1 | 62.7 | 105.5 | 143.4 | 1,473.0 |
| Geothermal | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Other Fuel Type | 0.0 | 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 | 71,315.5 | 60,551.1 | 67,023.0 | 58,549.0 | 61,908.9 | 70,839.1 | 79,558.4 | 74,065.2 | 65,474.7 | 61,811.1 | 62,798.2 | 74,335.5 | 808,229.7 |

## Generator Offers

Generator offers are categorized as dispatchable (Table 3-12) or self scheduled (Table 3-13).[22] 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 3-12 and Table 3-13 do not include units that did not indicate their offer status or 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 3-12 shows the proportion of MW offered by dispatchable units, by unit type and by offer price range, in 2017. For example, 79.8 percent of CC offers were dispatchable and in the $0 to $200 per MWh offer price range. The total column is the proportion of all MW offers by unit type that were dispatchable. For example, 86.4 percent of all CC MW offers were dispatchable, including the 6.0 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, 50.1 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 2017, 54.9 percent were offered as available for economic dispatch, excluding emergency MW (58.7 percent less 3.8 percent).

22 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 of owners and the small number of units.

### Table 3-12 Distribution of MW for dispatchable unit offer prices: 2017

| | Dispatchable (Range) | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Unit Type | ($200) - $0 | $0 - $200 | $200 - $400 | $400 - $600 | $600 - $800 | $800 - $1,000 | Emergency | Total |
| CC | 0.2% | 79.8% | 0.3% | 0.1% | 0.0% | 0.0% | 6.0% | 86.4% |
| CT | 0.0% | 83.0% | 6.0% | 1.4% | 0.0% | 0.1% | 8.6% | 99.1% |
| Diesel | 0.2% | 39.2% | 18.9% | 2.1% | 0.3% | 0.0% | 15.6% | 76.2% |
| Fuel Cell | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| Nuclear | 0.0% | 6.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 6.0% |
| Pumped Storage | 66.5% | 1.2% | 0.0% | 0.0% | 0.0% | 0.0% | 2.4% | 70.1% |
| Run of River | 0.2% | 0.1% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.2% |
| Solar | 54.5% | 3.4% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 57.9% |
| Steam | 0.1% | 49.1% | 0.3% | 0.1% | 0.0% | 0.4% | 2.5% | 52.6% |
| Transaction | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| Wind | 57.3% | 7.6% | 0.0% | 0.0% | 0.0% | 0.0% | 0.5% | 65.3% |
| All Dispatchable Offers | 3.0% | 50.1% | 1.3% | 0.3% | 0.0% | 0.2% | 3.8% | 58.7% |

### Table 3-13 Distribution of MW for self scheduled and dispatchable unit offer prices: 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 | 1.3% | 0.3% | 0.2% | 10.6% | 0.0% | 0.0% | 0.0% | 0.0% | 1.2% | 13.6% |
| CT | 0.2% | 0.0% | 0.0% | 0.6% | 0.0% | 0.0% | 0.0% | 0.0% | 0.1% | 0.9% |
| Diesel | 19.6% | 1.1% | 2.7% | 0.2% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 23.8% |
| Fuel Cell | 100.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 100.0% |
| Nuclear | 79.2% | 1.1% | 9.4% | 4.2% | 0.0% | 0.0% | 0.0% | 0.0% | 0.1% | 94.0% |
| Pumped Storage | 15.0% | 9.6% | 2.5% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 2.8% | 29.9% |
| Run of River | 61.9% | 16.3% | 0.5% | 18.7% | 0.0% | 0.0% | 0.0% | 0.0% | 2.3% | 99.8% |
| Solar | 27.7% | 9.8% | 4.5% | 0.1% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 42.1% |
| Steam | 3.9% | 1.2% | 0.2% | 40.1% | 0.0% | 0.0% | 0.0% | 0.0% | 2.0% | 47.4% |
| Transaction | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| Wind | 3.0% | 2.3% | 24.0% | 2.0% | 0.0% | 0.0% | 0.0% | 0.0% | 3.3% | 34.7% |
| All Self-Scheduled Offers | 18.9% | 1.2% | 2.5% | 17.6% | 0.0% | 0.0% | 0.0% | 0.0% | 1.1% | 41.3% |

Table 3-13 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 2017. For example, 10.6 percent of CC offers were self scheduled and dispatchable and in the $0 to $200 offer price range. The total column is the proportion of all MW offers by unit type that were self scheduled to generate fixed output or are self scheduled and dispatchable. For example, 13.6 percent of all CC MW offers were either self scheduled to generate at fixed output or self scheduled to generate at economic minimum and dispatchable up to economic maximum, including the 1.2 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 18.9 percent of all offers and self scheduled and dispatchable units accounted for 21.2 percent of all offers. The total column in the all self scheduled offers row is the proportion of all MW offers that were either self scheduled to generate at fixed output or self scheduled to generate at economic minimum and dispatchable up to economic maximum, including emergency MW. Among all the generator offers in 2017, 20.1 percent were offered as self scheduled and 21.2 percent were offered as self scheduled and dispatchable.

## Fuel Diversity

Figure 3-9 shows the fuel diversity index ($FDI_e$) for PJM energy generation.[23] 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

23 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.

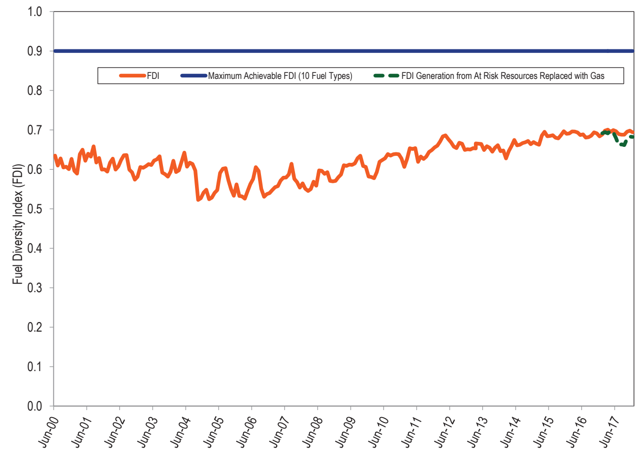
equal share of total generation. For a generation fleet composed of 10 fuel types, the maximum achievable index is 0.9. The fuel type categories used in the calculation of the $FDI_e$ are the 10 primary fuel sources in Table 3-10 with nonzero generation values. The $FDI_e$ exhibited seasonality in prior years with most of the peaks occurring in the spring and summer months, and the valleys occurring in the fall and winter months. As fuel diversity has increased, the seasonality in the $FDI_e$ has decreased and the $FDI_e$ has exhibited less volatility. A significant drop in the $FDI_e$ occurred in the 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.[24] The increasing trend that began in 2008 corresponds to a period of decreasing coal generation, increasing gas generation and increasing wind generation. Coal generation as a share of total generation dropped 23.2 percentage points from 2008 to 2017 and gas generation increased 19.8 percentage points. Wind generation was 2.6 percent of total generation in 2017 and 0.5 percent of total generation in 2008, an increase of 2.1 percentage points. The average $FDI_e$ increased 0.8 percent from 2016 to 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 MMU's net revenue adequacy analysis.[25] There were 118 units with installed capacity totaling 30.8 GW identified as the high estimate of units at risk. The 118 at risk resources generated 123.1 GWh in 2017, with 119.6 GWh from coal, nuclear and oil fired generators. The dashed line in Figure 3-9 shows the $FDI_e$ calculated assuming that the 119.6 GWh of generation from coal, nuclear and oil fired generators, identified as being at risk resources, were replaced by gas generation. The $FDI_e$ under these assumptions would have decreased in ten of the 12 months with an average monthly decrease of 1.8 percent over the actual $FDI_e$.

24 See the *2017 State of the Market Report for PJM*, Volume 2, 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.

25 See the *2017 State of the Market Report for PJM*, Volume 2, Section 7: Net Revenue, Units at Risk.

Figure 3-9 Fuel diversity index for PJM monthly generation: June 1, 2000 through December 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 in the summer of 2017 increased by 2,551 MW, or 1.5 percent, from the summer of 2016, from 171,300 MW to 173,851 MW.[26]

In 2017, 5,244.3 MW of new resources were added and 8,391.8 MW were retired.

PJM average real-time cleared generation in 2017 decreased by 0.4 percent from 2016, from 91,304 MW to 90,944 MW.[27]

PJM average real-time cleared supply including imports in 2017 decreased by 0.9 percent from 2016, from 93,326 MW to 92,481 MW.

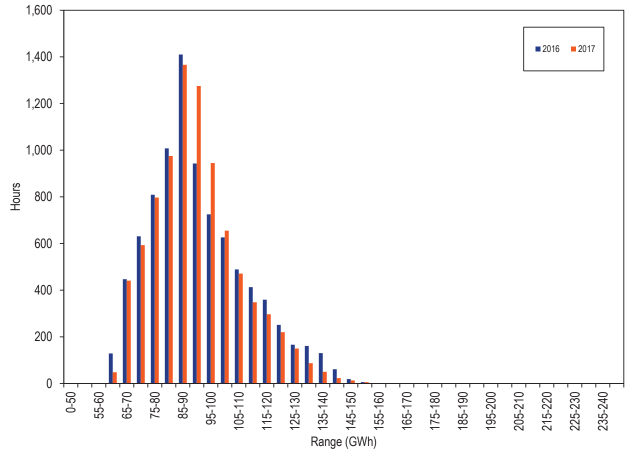
In the PJM Real-Time Energy Market, there are three types of supply offers:

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

### PJM Real-Time Supply Duration

Figure 3-10 shows the hourly distribution of PJM real-time generation plus imports for 2016 and 2017.

Figure 3-10 Distribution of PJM real-time generation plus imports: 2016 and 2017[28]




### PJM Real-Time, Average Supply

Table 3-14 presents summary real-time supply statistics for each year for the 18-year period from 2000 through 2017.[29]

26 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.

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

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

29 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.

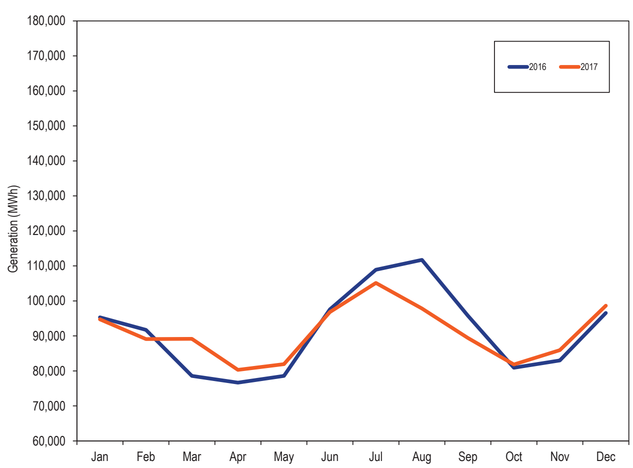
Table 3-14 PJM real-time average hourly generation and real-time average hourly generation plus average hourly imports: 2000 through 2017

| | PJM Real-Time Supply (MWh) | | | | Year-to-Year Change | | | |
|---|---|---|---|---|---|---|---|---|
| | Generation | | Generation Plus Imports | | Generation | | Generation Plus Imports | |
| | Generation | Standard Deviation | Supply | Standard Deviation | Generation | Standard Deviation | Supply | Standard Deviation |
| 2001 | 29,553 | 4,937 | 32,552 | 5,285 | NA | NA | NA | NA |
| 2002 | 34,928 | 7,535 | 38,535 | 7,751 | 18.2% | 52.6% | 18.4% | 46.7% |
| 2003 | 36,628 | 6,165 | 40,205 | 6,162 | 4.9% | (18.2%) | 4.3% | (20.5%) |
| 2004 | 51,068 | 13,790 | 55,781 | 14,652 | 39.4% | 123.7% | 38.7% | 137.8% |
| 2005 | 81,127 | 15,452 | 86,353 | 15,981 | 58.9% | 12.0% | 54.8% | 9.1% |
| 2006 | 82,780 | 13,709 | 86,978 | 14,402 | 2.0% | (11.3%) | 0.7% | (9.9%) |
| 2007 | 85,860 | 14,018 | 90,351 | 14,763 | 3.7% | 2.3% | 3.9% | 2.5% |
| 2008 | 83,476 | 13,787 | 88,899 | 14,256 | (2.8%) | (1.7%) | (1.6%) | (3.4%) |
| 2009 | 78,026 | 13,647 | 83,058 | 14,140 | (6.5%) | (1.0%) | (6.6%) | (0.8%) |
| 2010 | 82,585 | 15,556 | 87,386 | 16,227 | 5.8% | 14.0% | 5.2% | 14.8% |
| 2011 | 85,775 | 15,932 | 90,511 | 16,759 | 3.9% | 2.4% | 3.6% | 3.3% |
| 2012 | 88,708 | 15,701 | 94,083 | 16,505 | 3.4% | (1.4%) | 3.9% | (1.5%) |
| 2013 | 89,769 | 15,012 | 94,833 | 15,878 | 1.2% | (4.4%) | 0.8% | (3.8%) |
| 2014 | 90,894 | 15,151 | 96,295 | 16,199 | 1.3% | 0.9% | 1.5% | 2.0% |
| 2015 | 88,628 | 16,118 | 94,330 | 17,313 | (2.5%) | 6.4% | (2.0%) | 6.9% |
| 2016 | 91,304 | 17,731 | 95,054 | 17,980 | 3.0% | 10.0% | 0.8% | 3.9% |
| 2017 | 90,945 | 15,194 | 92,721 | 15,493 | (0.4%) | (14.3%) | (2.5%) | (13.8%) |
| 2017 | 90,944 | 15,194 | 92,481 | 15,491 | (0.4%) | (14.3%) | (0.9%) | (11.8%) |

## PJM Real-Time, Monthly Average Generation

Figure 3-11 compares the real-time, monthly average hourly generation in 2016 and 2017.

Figure 3-11 PJM real-time monthly average hourly generation: 2016 through 2017




## Day-Ahead Supply

PJM average day-ahead cleared supply in 2017, including INCs and up to congestion transactions, decreased by 0.8 percent from 2016, from 131,634 MW to 130,601 MW.

PJM average day-ahead cleared supply in 2017, including INCs, up to congestion transactions, and imports, decreased by 1.0 percent from 2016, from 132,263 MW to 130,912 MW.

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

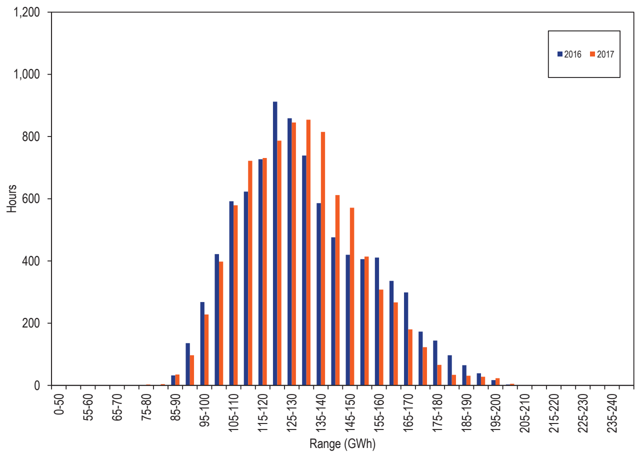
- **Self Scheduled Generation Offer.** Offer to supply a fixed block of MWh, as a price taker, from a unit that may also have a dispatchable component above the minimum.
- **Dispatchable Generation Offer.** Offer to supply a schedule of MWh and corresponding offer prices from a unit.
- **Increment Offer (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 3-12 shows the hourly distribution of PJM day-ahead supply, including increment offers, up to congestion transactions, and imports for 2016 and 2017.

### Figure 3-12 Distribution of PJM day-ahead supply plus imports: 2016 and 2017[30]




## PJM Day-Ahead, Average Supply

Table 3-15 presents summary day-ahead supply statistics for the 18-year period from 2000 through 2017.[31]

### Table 3-15 PJM day-ahead average hourly supply and day-ahead average hourly supply plus average hourly imports: 2000 through 2017

| | PJM Day-Ahead Supply (MWh) | | | | Year-to-Year Change | | | |
|---|---|---|---|---|---|---|---|---|
| | Supply | | Supply Plus Imports | | Supply | | Supply Plus Imports | |
| | Supply | Standard Deviation | Supply | Standard Deviation | Supply | Standard Deviation | Supply | Standard Deviation |
| 2001 | 26,762 | 4,595 | 27,497 | 4,664 | NA | NA | NA | NA |
| 2002 | 31,434 | 10,007 | 31,982 | 10,015 | 17.5% | 117.8% | 16.3% | 114.7% |
| 2003 | 40,642 | 8,292 | 41,183 | 8,287 | 29.3% | (17.1%) | 28.8% | (17.3%) |
| 2004 | 62,755 | 17,141 | 63,654 | 17,362 | 54.4% | 106.7% | 54.6% | 109.5% |
| 2005 | 94,438 | 17,204 | 96,449 | 17,462 | 50.5% | 0.4% | 51.5% | 0.6% |
| 2006 | 100,056 | 16,543 | 102,164 | 16,559 | 5.9% | (3.8%) | 5.9% | (5.2%) |
| 2007 | 108,707 | 16,549 | 111,023 | 16,729 | 8.6% | 0.0% | 8.7% | 1.0% |
| 2008 | 105,485 | 15,994 | 107,885 | 16,136 | (3.0%) | (3.4%) | (2.8%) | (3.5%) |
| 2009 | 97,388 | 16,364 | 100,022 | 16,397 | (7.7%) | 2.3% | (7.3%) | 1.6% |
| 2010 | 107,307 | 21,655 | 110,026 | 21,837 | 10.2% | 32.3% | 10.0% | 33.2% |
| 2011 | 117,130 | 20,977 | 119,501 | 21,259 | 9.2% | (3.1%) | 8.6% | (2.6%) |
| 2012 | 134,479 | 17,905 | 136,903 | 18,080 | 14.8% | (14.6%) | 14.6% | (15.0%) |
| 2013 | 148,323 | 18,783 | 150,595 | 18,978 | 10.3% | 4.9% | 10.0% | 5.0% |
| 2014 | 146,672 | 33,145 | 148,906 | 33,346 | (1.1%) | 76.5% | (1.1%) | 75.7% |
| 2015 | 114,890 | 19,165 | 117,147 | 19,406 | (21.7%) | (42.2%) | (21.3%) | (41.8%) |
| 2016 | 131,618 | 22,329 | 133,246 | 22,368 | 14.6% | 16.5% | 13.7% | 15.3% |
| 2017 | 130,603 | 20,035 | 131,142 | 20,153 | (0.8%) | (10.3%) | (1.6%) | (9.9%) |
| 2017 | 130,601 | 20,035 | 130,912 | 20,049 | (0.8%) | (10.3%) | (1.0%) | (10.2%) |

30 Each range on the horizontal axis excludes the start value and includes the end value.
31 Since the Day-Ahead Energy Market did not start until June 1, 2000, the day-ahead data for 2000 only includes data for the last six months of that year.

## PJM Day-Ahead, Monthly Average Supply

Figure 3-13 compares the day-ahead, monthly average hourly supply, including increment offers and up to congestion transactions for 2016 and 2017.

### Figure 3-13 PJM day-ahead monthly average hourly supply: 2016 through 2017

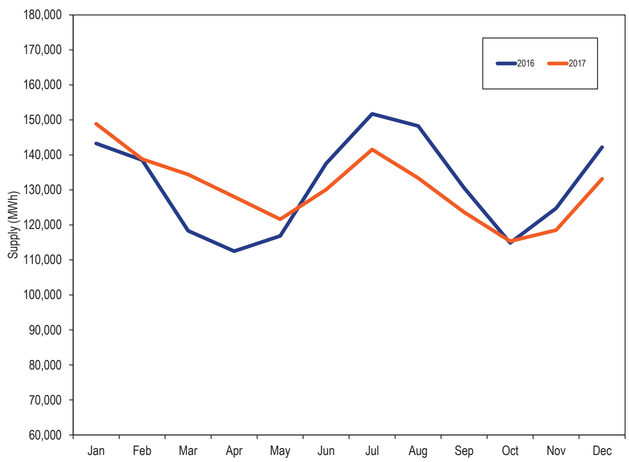



Table 3-16 presents summary statistics for 2016 and 2017, for day-ahead and real-time supply. All data are cleared MW. The last two columns of Table 3-16 are the day-ahead supply minus the real-time supply. The first of these columns is the total day-ahead supply less the total real-time supply and the second of these columns is the total physical day-ahead generation less the total physical real-time generation. In 2017, up to congestion transactions were 26.7 percent of the total day-ahead supply compared to 26.0 percent in 2016.

Figure 3-14 shows the average hourly cleared volumes of day-ahead supply and real-time supply for 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.

## Real-Time and Day-Ahead Supply

### Table 3-16 Day-ahead and real-time supply (MW): 2016 and 2017

| | | Day-Ahead | | | | | Real-Time | | Day-Ahead Less Real-Time | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | Generation | INC Offers | Up to Congestion | Imports | Total Supply | Generation | Total Supply | Total Supply | Total Generation |
| Average | 2016 | 92,039 | 5,207 | 34,385 | 629 | 132,263 | 91,304 | 93,326 | 38,937 | 735 |
| | 2017 | 91,112 | 4,562 | 34,927 | 311 | 130,912 | 90,944 | 92,481 | 38,430 | 168 |
| Median | 2016 | 88,770 | 5,084 | 33,949 | 0 | 128,943 | 87,831 | 89,803 | 39,140 | 939 |
| | 2017 | 89,647 | 4,396 | 33,823 | 281 | 129,718 | 89,088 | 90,543 | 39,175 | 559 |
| Standard Deviation | 2016 | 18,234 | 1,025 | 7,114 | 779 | 22,316 | 17,731 | 17,560 | 4,756 | 503 |
| | 2017 | 15,883 | 1,472 | 8,226 | 194 | 20,049 | 15,194 | 15,491 | 4,558 | 689 |
| Peak Average | 2016 | 101,669 | 5,393 | 36,382 | 665 | 144,119 | 99,875 | 102,116 | 42,003 | 1,794 |
| | 2017 | 100,078 | 4,968 | 36,995 | 275 | 142,315 | 99,239 | 100,919 | 41,397 | 838 |
| Peak Median | 2016 | 98,175 | 5,291 | 35,993 | 53 | 140,821 | 95,658 | 98,481 | 42,340 | 2,517 |
| | 2017 | 96,430 | 4,786 | 35,940 | 250 | 140,085 | 95,650 | 97,439 | 42,646 | 780 |
| Peak Standard Deviation | 2016 | 16,527 | 1,002 | 6,892 | 846 | 20,106 | 16,872 | 16,313 | 3,793 | (345) |
| | 2017 | 13,448 | 1,435 | 8,205 | 188 | 16,983 | 13,398 | 13,649 | 3,334 | 50 |
| Off-Peak Average | 2016 | 83,312 | 5,039 | 32,575 | 596 | 121,518 | 83,537 | 85,359 | 36,160 | (225) |
| | 2017 | 83,003 | 4,194 | 33,058 | 343 | 120,599 | 83,442 | 84,851 | 35,748 | (439) |
| Off-Peak Median | 2016 | 81,052 | 4,904 | 31,868 | 0 | 118,401 | 80,881 | 82,604 | 35,797 | 171 |
| | 2017 | 80,866 | 3,947 | 32,028 | 325 | 117,901 | 81,269 | 82,543 | 35,358 | (403) |
| Off-Peak Standard Deviation | 2016 | 15,036 | 1,017 | 6,821 | 710 | 18,444 | 14,645 | 14,600 | 3,843 | 391 |
| | 2017 | 13,359 | 1,408 | 7,786 | 193 | 16,754 | 12,602 | 12,881 | 3,873 | 757 |

## Figure 3-14 Day-ahead and real-time supply (Average hourly volumes): 2017

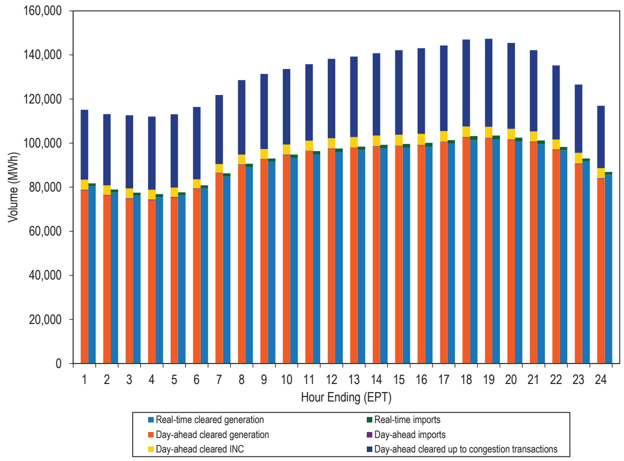



Figure 3-15 shows the difference between the day-ahead and real-time average daily supply for 2016 and 2017.

## Figure 3-15 Difference between day-ahead and real-time supply (Average daily volumes): 2016 and 2017

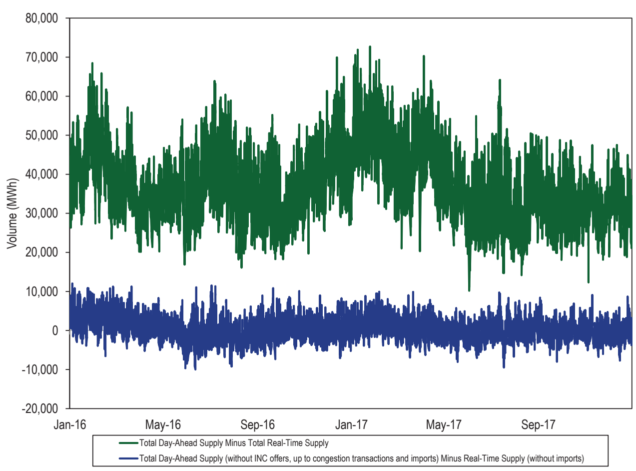
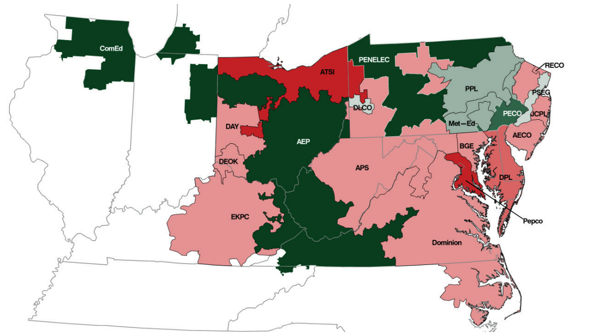



Figure 3-16 shows the difference between the PJM real-time generation and real-time load by zone in 2017. Figure 3-16 is color coded using a scale on which red shades represent zones that have less generation than load and green shades represent zones that have more generation than load, with darker 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 3-17 shows the difference between the PJM real-time generation and real-time load by zone in 2016 and 2017.

## Figure 3-16 Map of PJM real-time generation, less real-time load, by zone: 2017[32]




| Zone | Net Gen Minus Load (GWh) | Zone | Net Gen Minus Load (GWh) | Zone | Net Gen Minus Load (GWh) | Zone | Net Gen Minus Load (GWh) |
|---|---|---|---|---|---|---|---|
| AECO | (3,315) | ComEd | 33,880 | DPL | (10,516) | PENELEC | 26,656 |
| AEP | 27,058 | DAY | (5,293) | EKPC | (4,659) | Pepco | (20,673) |
| APS | (205) | DEOK | (6,184) | JCPL | (3,874) | PPL | 9,402 |
| ATSI | (25,114) | DLCO | 3,284 | Met-Ed | 6,870 | PSEG | 1,203 |
| BGE | (10,322) | Dominion | (3,056) | PECO | 24,187 | RECO | (1,433) |

## Table 3-17 PJM real-time generation less real-time load by zone (GWh): 2016 and 2017

| Zonal Generation and Load (GWh) | | | | | | |
|---|---|---|---|---|---|---|
| | 2016 | | | 2017 | | |
| Zone | Generation | Load | Net | Generation | Load | Net |
| AECO | 6,712.8 | 10,140.1 | (3,427.3) | 6,408.9 | 9,724.0 | (3,315.1) |
| AEP | 141,703.3 | 126,717.0 | 14,986.3 | 150,914.4 | 123,856.3 | 27,058.1 |
| APS | 47,489.1 | 48,063.0 | (573.9) | 47,076.4 | 47,281.8 | (205.3) |
| ATSI | 42,776.0 | 67,220.3 | (24,444.3) | 40,233.7 | 65,348.0 | (25,114.4) |
| BGE | 22,065.3 | 31,428.3 | (9,363.0) | 19,957.3 | 30,279.0 | (10,321.7) |
| ComEd | 129,371.6 | 98,002.4 | 31,369.2 | 128,205.5 | 94,325.9 | 33,879.5 |
| DAY | 15,380.9 | 17,288.8 | (1,907.9) | 11,555.2 | 16,848.4 | (5,293.2) |
| DEOK | 16,659.5 | 27,275.5 | (10,616.0) | 20,082.9 | 26,267.3 | (6,184.3) |
| DLCO | 17,258.8 | 13,897.4 | 3,361.3 | 16,684.1 | 13,399.6 | 3,284.5 |
| Dominion | 96,504.9 | 96,240.9 | 264.1 | 92,302.0 | 95,358.0 | (3,056.0) |
| DPL | 8,398.6 | 18,204.8 | (9,806.2) | 7,262.6 | 17,778.6 | (10,516.0) |
| EKPC | 9,799.9 | 12,564.8 | (2,764.9) | 7,558.9 | 12,218.3 | (4,659.5) |
| JCPL | 18,119.0 | 22,831.3 | (4,712.3) | 18,217.2 | 22,090.8 | (3,873.6) |
| Met-Ed | 22,197.7 | 15,260.5 | 6,937.2 | 21,915.9 | 15,046.3 | 6,869.7 |
| PECO | 64,614.9 | 40,109.1 | 24,505.8 | 63,483.9 | 39,296.8 | 24,187.1 |
| PENELEC | 37,177.8 | 16,870.8 | 20,307.0 | 43,413.5 | 16,757.9 | 26,655.6 |
| Pepco | 10,135.6 | 30,339.2 | (20,203.6) | 8,532.6 | 29,205.5 | (20,672.9) |
| PPL | 50,035.8 | 40,368.0 | 9,667.8 | 48,872.5 | 39,470.6 | 9,401.9 |
| PSEG | 45,616.5 | 43,816.1 | 1,800.4 | 43,991.4 | 42,788.0 | 1,203.3 |
| RECO | 0.0 | 1,481.2 | (1,481.2) | 0.0 | 1,432.6 | (1,432.6) |

32 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>.

## 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.[33]

The PJM system real-time peak load in 2017 was 145,635.9 MW in the HE 1800 on July 19, 2017, which was 6,541 MW, or 4.3 percent, lower than the peak load in 2016, which was 152,176.9 MW in the HE 1600 on August 11, 2016.

Table 3-18 shows the peak loads of 1999 through 2017.

Table 3-18 Actual PJM footprint peak loads: 1999 to 2017[34]

| | Date | Hour Ending (EPT) | PJM Load (MW) | Annual Change (MW) | Annual Change (%) |
|---|---|---|---|---|---|
| 1999 | Fri, July 30 | 17 | 120,227 | NA | NA |
| 2000 | Wed, August 09 | 17 | 114,036 | (6,191) | (5.1%) |
| 2001 | Wed, August 08 | 17 | 128,535 | 14,499 | 12.7% |
| 2002 | Thu, August 01 | 17 | 130,159 | 1,625 | 1.3% |
| 2003 | Thu, August 21 | 17 | 126,259 | (3,900) | (3.0%) |
| 2004 | Wed, June 09 | 17 | 120,218 | (6,041) | (4.8%) |
| 2005 | Tue, July 26 | 16 | 133,761 | 13,543 | 11.3% |
| 2006 | Wed, August 02 | 17 | 144,644 | 10,883 | 8.1% |
| 2007 | Wed, August 08 | 16 | 139,428 | (5,216) | (3.6%) |
| 2008 | Mon, June 09 | 17 | 130,100 | (9,328) | (6.7%) |
| 2009 | Mon, August 10 | 17 | 126,798 | (3,302) | (2.5%) |
| 2010 | Tue, July 06 | 17 | 136,460 | 9,662 | 7.6% |
| 2011 | Thu, July 21 | 17 | 158,016 | 21,556 | 15.8% |
| 2012 | Tue, July 17 | 17 | 154,344 | (3,672) | (2.3%) |
| 2013 | Thu, July 18 | 17 | 157,508 | 3,165 | 2.1% |
| 2014 | Tue, June 17 | 17 | 141,673 | (15,835) | (10.1%) |
| 2015 | Tue, July 28 | 17 | 143,697 | 2,023 | 1.4% |
| 2016 | Thu, August 11 | 16 | 152,177 | 8,480 | 5.9% |
| 2017 | Wed, July 19 | 18 | 145,636 | (6,541) | (4.3%) |

Figure 3-17 shows the peak loads for 1999 through 2017.

Figure 3-17 PJM footprint calendar year peak loads: 1999 to 2017

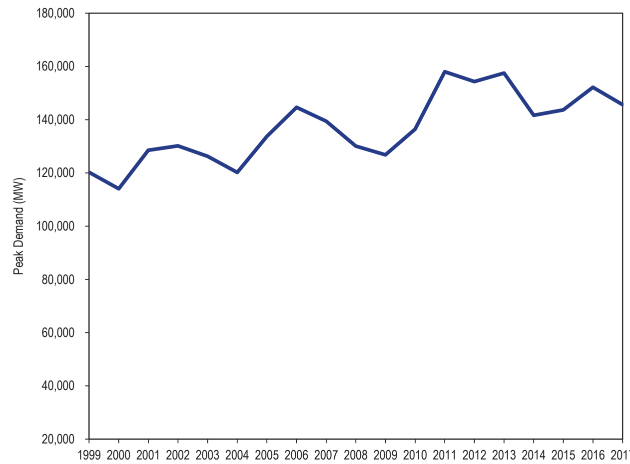
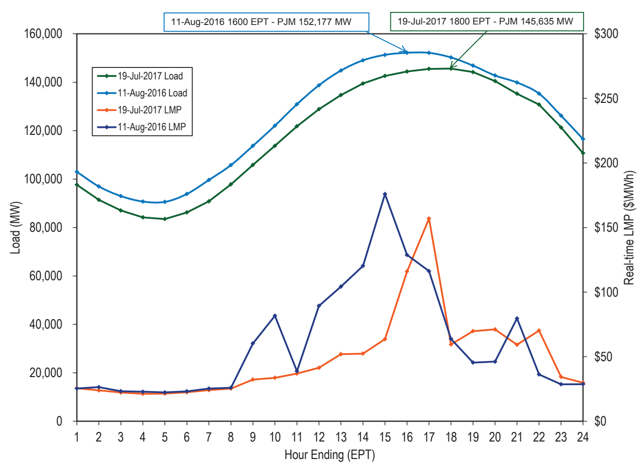



Figure 3-18 compares the peak load days of 2016 and 2017. The average real-time LMP for the July 19, 2017 peak load hour was $59.49 and for the August 11, 2016 peak load hour was $128.83.

Figure 3-18 PJM peak-load comparison: Thursday, August 11, 2016 and Wednesday, July 19, 2017




33 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>.

34 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>.

## Real-Time Demand

PJM average real-time load in 2017 decreased by 2.2 percent from 2016, from 88,601 MW to 86,618 MW.[35]

PJM average real-time demand including exports in 2017 decreased by 3.0 percent from 2016, from 93,551 MW to 90,755 MW.

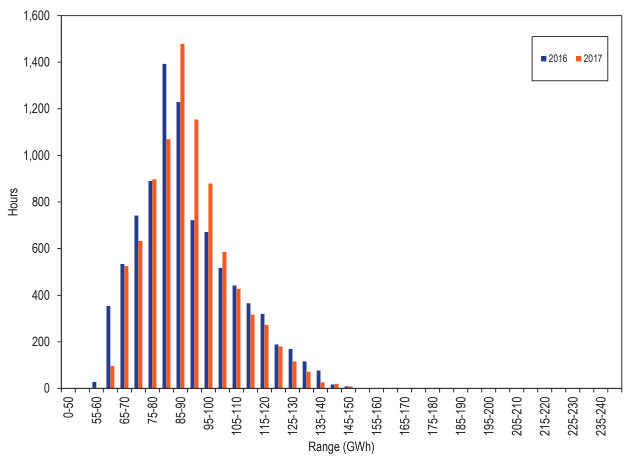
In the PJM Real-Time Energy Market, there are two types of demand:

- **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's checkout process.

### PJM Real-Time Demand Duration

Figure 3-19 shows the hourly distribution of PJM real-time load plus exports for 2016 and 2017.[36]

#### Figure 3-19 Distribution of PJM real-time accounting load plus exports: 2016 and 2017[37]




### PJM Real-Time, Average Load

Table 3-19 presents summary real-time demand statistics for 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.[38]

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

36 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>.

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

38 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.

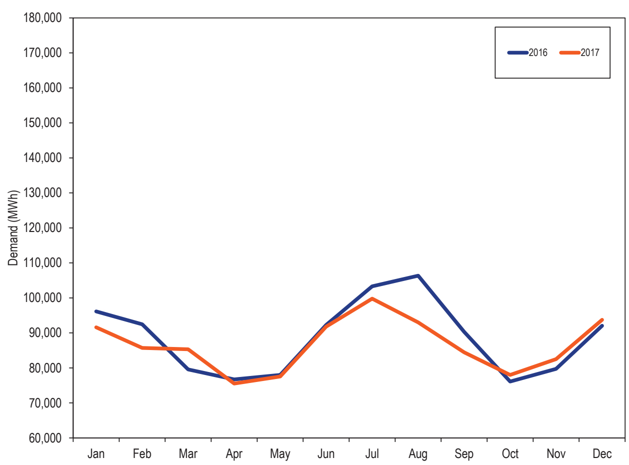
### Table 3-19 PJM real-time average hourly load and real-time average hourly load plus average hourly exports: 1998 through 2017[39]

| | PJM Real-Time Demand (MWh) | | | | Year-to-Year Change | | | |
|---|---|---|---|---|---|---|---|---|
| | Load | | Load Plus Exports | | Load | | Load Plus Exports | |
| | Load | Standard Deviation | Demand | Standard Deviation | Load | Standard Deviation | Demand | Standard Deviation |
| 1998 | 28,578 | 5,511 | 28,578 | 5,511 | NA | NA | NA | NA |
| 1999 | 29,641 | 5,955 | 29,641 | 5,955 | 3.7% | 8.1% | 3.7% | 8.1% |
| 2000 | 30,113 | 5,529 | 31,341 | 5,728 | 1.6% | (7.2%) | 5.7% | (3.8%) |
| 2001 | 30,297 | 5,873 | 32,165 | 5,564 | 0.6% | 6.2% | 2.6% | (2.9%) |
| 2002 | 35,776 | 7,976 | 37,676 | 8,145 | 18.1% | 35.8% | 17.1% | 46.4% |
| 2003 | 37,395 | 6,834 | 39,380 | 6,716 | 4.5% | (14.3%) | 4.5% | (17.5%) |
| 2004 | 49,963 | 13,004 | 54,953 | 14,947 | 33.6% | 90.3% | 39.5% | 122.6% |
| 2005 | 78,150 | 16,296 | 85,301 | 16,546 | 56.4% | 25.3% | 55.2% | 10.7% |
| 2006 | 79,471 | 14,534 | 85,696 | 15,133 | 1.7% | (10.8%) | 0.5% | (8.5%) |
| 2007 | 81,681 | 14,618 | 87,897 | 15,199 | 2.8% | 0.6% | 2.6% | 0.4% |
| 2008 | 79,515 | 13,758 | 86,306 | 14,322 | (2.7%) | (5.9%) | (1.8%) | (5.8%) |
| 2009 | 76,034 | 13,260 | 81,227 | 13,792 | (4.4%) | (3.6%) | (5.9%) | (3.7%) |
| 2010 | 79,611 | 15,504 | 85,518 | 15,904 | 4.7% | 16.9% | 5.3% | 15.3% |
| 2011 | 82,541 | 16,156 | 88,466 | 16,313 | 3.7% | 4.2% | 3.4% | 2.6% |
| 2012 | 87,011 | 16,212 | 92,135 | 16,052 | 5.4% | 0.3% | 4.1% | (1.6%) |
| 2013 | 88,332 | 15,489 | 92,879 | 15,418 | 1.5% | (4.5%) | 0.8% | (3.9%) |
| 2014 | 89,099 | 15,763 | 94,471 | 15,677 | 0.9% | 1.8% | 1.7% | 1.7% |
| 2015 | 88,594 | 16,663 | 92,665 | 16,784 | (0.6%) | 5.7% | (1.9%) | 7.1% |
| 2016 | 88,601 | 17,229 | 93,551 | 17,498 | 0.0% | 3.4% | 1.0% | 4.3% |
| 2017 | 86,618 | 15,170 | 90,755 | 15,082 | (2.2%) | (11.9%) | (3.0%) | (13.8%) |

## PJM Real-Time, Monthly Average Load

Figure 3-20 compares the real-time, monthly average hourly loads for 2016 and 2017.

### Figure 3-20 PJM real-time monthly average hourly load: 2016 and 2017

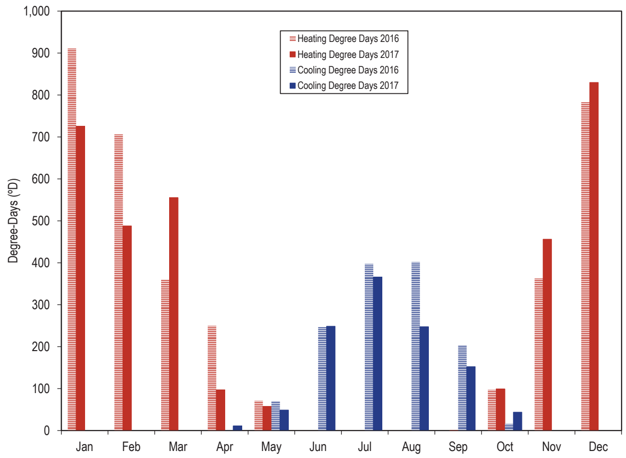



39 Export data are not available before June 1, 2000. The export data for 2000 are for the last six months of 2000.

PJM real-time load is significantly affected by temperature. Figure 3-21 and Table 3-20 compare the PJM monthly heating and cooling degree days in 2016 and 2017.[40] Heating degree days decreased 6.5 percent from 2016 to 2017.

### Figure 3-21 PJM heating and cooling degree days: 2016 and 2017




### Table 3-20 PJM heating and cooling degree days: 2016 and 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 | 97 | 11 | (61.0%) | 1375.9% |
| May | 71 | 71 | 58 | 49 | (18.9%) | (30.6%) |
| Jun | 0 | 247 | 0 | 249 | 0.0% | 0.6% |
| Jul | 0 | 397 | 0 | 366 | 0.0% | (8.0%) |
| Aug | 0 | 402 | 0 | 248 | 0.0% | (38.3%) |
| Sep | 0 | 203 | 1 | 152 | 0.0% | (24.8%) |
| Oct | 98 | 17 | 99 | 44 | 1.6% | 164.0% |
| Nov | 363 | 0 | 456 | 0 | 25.8% | 0.0% |
| Dec | 782 | 0 | 830 | 0 | 6.0% | 0.0% |
| Total | 3,541 | 1,337 | 3,309 | 1,118 | (6.5%) | (16.3%) |

40 A heating degree day is defined as the number of degrees that a day's average temperature is below 65 degrees F (the temperature below which buildings need to be heated). A cooling degree day is the number of degrees that a day's average temperature is above 65 degrees F (the temperature when people will start to use air conditioning to cool buildings). PJM uses 60 degrees F for a heating degree day as stated in Manual 19.
Heating and cooling degree days are calculated by weighting the temperature at each weather station in the individual transmission zones using weights provided by PJM in Manual 19. Then the temperature is weighted by the real-time zonal accounting load for each transmission zone. After calculating an average hourly temperature across PJM, the heating and cooling degree formulas are used to calculate the daily heating and cooling degree days, which are summed for monthly reporting. The weather stations that provided the basis for the analysis are ABE, ACY, AVP, BWI, CAK, CLE, CMH, CRW, CVG, DAY, DCA, ERI, EWR, FWA, IAD, ILG, IPT, LEX, ORD, ORF, PHL, PIT, RIC, ROA, TOL and WAL.

## Day-Ahead Demand

PJM average day-ahead demand in 2017, including DECs and up to congestion transactions, decreased by 1.3 percent from 2016, from 127,390 MW to 125,792 MW.

PJM average day-ahead demand in 2017, including DECs, up to congestion transactions, and exports, increased by 0.1 percent from 2016, from 128,441 MW to 128,526 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.[41]

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

- **Fixed-Demand Bid.** Bid to purchase a defined MWh level of energy, regardless of LMP.
- **Price-Sensitive Bid.** Bid to purchase a defined MWh level of energy only up to a specified LMP, above which the load bid is zero.
- **Decrement Bid (DEC).** Financial bid to purchase a defined MWh level of energy up to a specified LMP, above which the bid is zero. A DEC can be submitted by any market participant.
- **Up to Congestion Transaction (UTC).** A conditional transaction that permits a market participant to specify a maximum price spread between the transaction source and sink. An up to congestion transaction is evaluated as a matched pair of an injection and a withdrawal analogous to a matched pair of an INC offer and a DEC bid.

41 148 FERC ¶ 61,144 (2014).

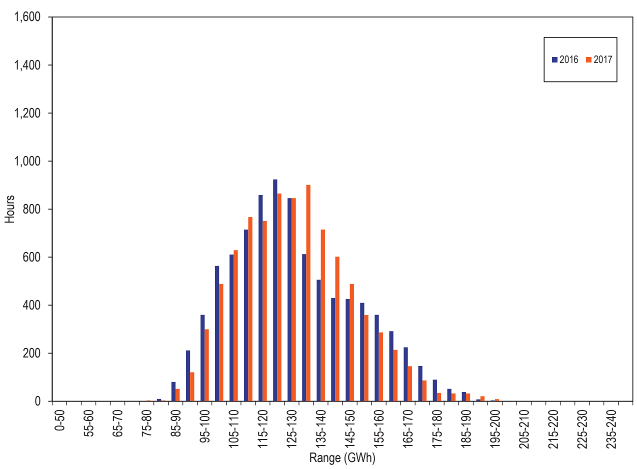
- **Export.** An external energy transaction scheduled from PJM to another balancing authority. An export must have a valid willing to pay congestion (WPC) OASIS reservation when offered. An export energy transaction that clears the Day-Ahead Energy Market is financially binding. There is no link between 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 3-22 shows the hourly distribution of PJM day-ahead demand, including decrement bids, up to congestion transactions, and exports for 2016 and 2017.

### Figure 3-22 Distribution of PJM day-ahead demand plus exports: 2016 and 2017[42]




## PJM Day-Ahead, Average Demand

Table 3-21 presents summary day-ahead demand statistics of each year from 2000 to 2017.[43]

### Table 3-21 PJM day-ahead average demand and day-ahead average hourly demand plus average hourly exports: 2000 through 2017

| | PJM Day-Ahead Demand (MWh) | | | | Year-to-Year Change | | | |
|---|---|---|---|---|---|---|---|---|
| | Demand | | Demand Plus Exports | | Demand | | Demand Plus Exports | |
| | Demand | Standard Deviation | Demand | Standard Deviation | Demand | Standard Deviation | Demand | Standard Deviation |
| 2001 | 33,370 | 6,562 | 33,757 | 6,431 | NA | NA | NA | NA |
| 2002 | 42,305 | 10,161 | 42,413 | 10,208 | 26.8% | 54.8% | 25.6% | 58.7% |
| 2003 | 44,674 | 7,841 | 44,807 | 7,811 | 5.6% | (22.8%) | 5.6% | (23.5%) |
| 2004 | 62,101 | 16,654 | 63,455 | 17,730 | 39.0% | 112.4% | 41.6% | 127.0% |
| 2005 | 93,534 | 17,643 | 96,447 | 17,952 | 50.6% | 5.9% | 52.0% | 1.3% |
| 2006 | 98,527 | 16,723 | 101,592 | 17,197 | 5.3% | (5.2%) | 5.3% | (4.2%) |
| 2007 | 105,503 | 16,686 | 108,932 | 17,030 | 7.1% | (0.2%) | 7.2% | (1.0%) |
| 2008 | 101,903 | 15,871 | 105,368 | 16,119 | (3.4%) | (4.9%) | (3.3%) | (5.3%) |
| 2009 | 94,941 | 15,869 | 98,094 | 15,999 | (6.8%) | (0.0%) | (6.9%) | (0.7%) |
| 2010 | 103,937 | 21,358 | 108,069 | 21,640 | 9.5% | 34.6% | 10.2% | 35.3% |
| 2011 | 113,866 | 20,708 | 117,681 | 20,929 | 9.6% | (3.0%) | 8.9% | (3.3%) |
| 2012 | 131,612 | 17,421 | 134,947 | 17,527 | 15.6% | (15.9%) | 14.7% | (16.3%) |
| 2013 | 144,858 | 18,489 | 148,132 | 18,570 | 10.1% | 6.1% | 9.8% | 6.0% |
| 2014 | 142,251 | 32,664 | 146,120 | 32,671 | (1.8%) | 76.7% | (1.4%) | 75.9% |
| 2015 | 111,644 | 18,716 | 114,827 | 18,872 | (21.5%) | (42.7%) | (21.4%) | (42.2%) |
| 2016 | 127,374 | 21,513 | 130,808 | 21,803 | 14.1% | 14.9% | 13.9% | 15.5% |
| 2017 | 125,794 | 19,402 | 128,757 | 19,625 | (1.2%) | (9.8%) | (1.6%) | (10.0%) |
| 2017 | 125,792 | 19,402 | 128,526 | 19,522 | (1.3%) | (9.9%) | 0.1% | (9.4%) |

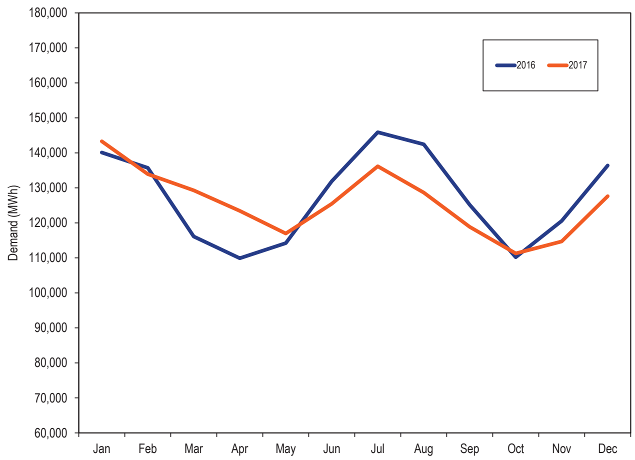
42 Each range on the horizontal axis excludes the start value and includes the end value.
43 Since the Day-Ahead Energy Market did not start until June 1, 2000, the day-ahead data for 2000 only includes data for the last six months of that year.

## PJM Day-Ahead, Monthly Average Demand

Figure 3-23 compares the day-ahead, monthly average hourly demand, including decrement bids and up to congestion transactions in 2016 and 2017

### Figure 3-23 PJM day-ahead monthly average hourly demand: 2016 and 2017




## Real-Time and Day-Ahead Demand

Table 3-22 presents summary statistics for 2016 and 2017 day-ahead and real-time demand. All data are cleared MW. The last two columns of Table 3-22 are the day-ahead demand minus the real-time demand. The first such column is the total day-ahead demand less the total real-time demand and the second such column is the total physical day-ahead load (fixed demand plus price-sensitive demand) less the physical real-time load.

### Table 3-22 Cleared day-ahead and real-time demand (MWh): 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 | 85,182 | 3,016 | 4,805 | 34,385 | 1,051 | 128,441 | 88,601 | 90,075 | 38,367 | 50,234 |
| | 2017 | 83,959 | 2,871 | 4,035 | 34,927 | 2,735 | 128,526 | 86,618 | 90,755 | 37,772 | 48,846 |
| Median | 2016 | 82,409 | 2,997 | 4,578 | 33,949 | 0 | 125,353 | 85,273 | 86,620 | 38,732 | 46,541 |
| | 2017 | 82,645 | 2,847 | 4,006 | 33,823 | 2,617 | 127,363 | 84,875 | 88,890 | 38,472 | 46,403 |
| Standard Deviation | 2016 | 16,089 | 439 | 1,404 | 7,114 | 1,222 | 21,540 | 17,229 | 17,179 | 4,361 | 12,868 |
| | 2017 | 14,567 | 437 | 1,401 | 8,226 | 907 | 19,522 | 15,170 | 15,082 | 4,440 | 10,730 |
| Peak Average | 2016 | 94,198 | 3,273 | 5,077 | 36,382 | 1,065 | 140,004 | 97,454 | 98,889 | 41,115 | 56,339 |
| | 2017 | 92,526 | 3,148 | 4,253 | 36,995 | 2,749 | 139,670 | 94,969 | 98,995 | 40,675 | 54,294 |
| Peak Median | 2016 | 91,257 | 3,250 | 4,904 | 35,993 | 555 | 136,691 | 93,849 | 95,492 | 41,199 | 52,650 |
| | 2017 | 89,714 | 3,094 | 4,323 | 35,940 | 2,624 | 137,483 | 91,681 | 95,607 | 41,875 | 49,806 |
| Peak Standard Deviation | 2016 | 14,305 | 374 | 1,379 | 6,892 | 1,206 | 19,253 | 15,812 | 15,746 | 3,508 | 12,304 |
| | 2017 | 12,238 | 389 | 1,374 | 8,205 | 948 | 16,541 | 13,224 | 13,281 | 3,260 | 9,963 |
| Off-Peak Average | 2016 | 77,011 | 2,783 | 4,559 | 32,575 | 1,039 | 117,962 | 80,577 | 82,087 | 35,876 | 44,702 |
| | 2017 | 76,210 | 2,620 | 3,839 | 33,058 | 2,722 | 118,449 | 79,067 | 83,302 | 35,147 | 43,920 |
| Off-Peak Median | 2016 | 74,748 | 2,738 | 4,324 | 31,868 | 0 | 114,954 | 77,842 | 79,348 | 35,607 | 42,235 |
| | 2017 | 74,315 | 2,571 | 3,706 | 32,028 | 2,610 | 115,825 | 76,979 | 81,153 | 34,671 | 42,308 |
| Off-Peak Standard Deviation | 2016 | 12,945 | 356 | 1,381 | 6,821 | 1,236 | 17,820 | 14,278 | 14,272 | 3,548 | 10,730 |
| | 2017 | 11,928 | 308 | 1,397 | 7,786 | 867 | 16,264 | 12,651 | 12,520 | 3,744 | 8,907 |

Figure 3-24 shows the average hourly cleared volumes of day-ahead demand and real-time demand for 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 3-24 Day-ahead and real-time demand (Average hourly volumes): 2017**

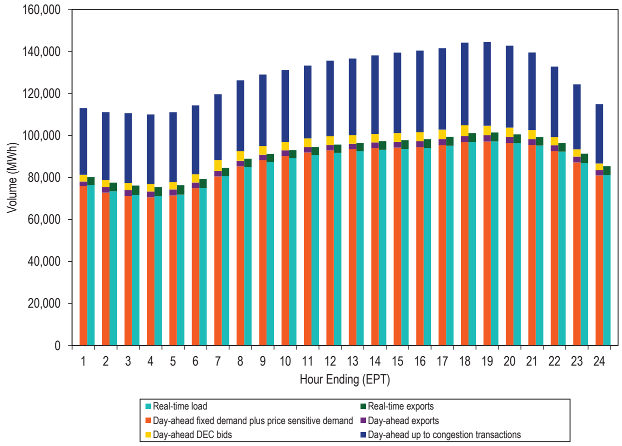
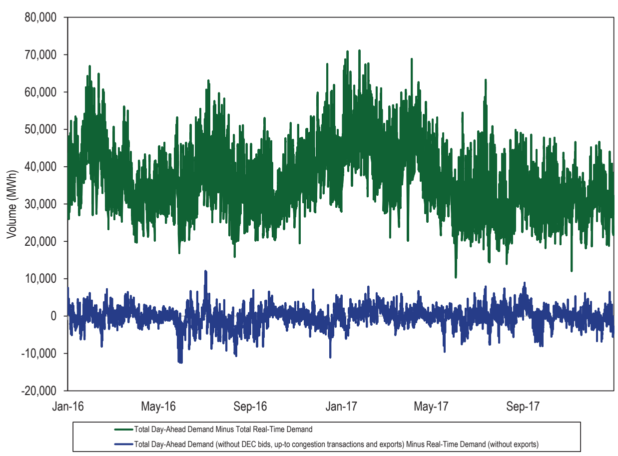



Figure 3-25 shows the difference between the day-ahead and real-time average daily demand from 2016 through 2017.

**Figure 3-25 Difference between day-ahead and real-time demand (Average daily volumes): 2016 and 2017**




# 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 3-23 shows the monthly average share of real-time load served by self-supply, bilateral contracts and spot purchase in 2016 and 2017 based on parent company. In 2017, 14.4 percent of real-time load was supplied by bilateral contracts, 27.5 percent by spot market purchase and 58.9 percent by self-supply. Compared with 2016, reliance on bilateral contracts increased by 1.6 percentage points, reliance on spot supply increased by 3.5 percentage points and reliance on self-supply decreased by 4.4 percentage points.

**Table 3-23 Monthly average percent of real-time self-supply load, bilateral-supply load and spot-supply load based on parent companies: 2016 and 2017[44]**

| | 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% | 15.6% | 23.1% | 61.3% | 4.4% | (2.8%) | (1.7%) |
| Feb | 11.5% | 25.5% | 63.0% | 16.8% | 22.9% | 60.3% | 5.3% | (2.6%) | (2.7%) |
| Mar | 11.7% | 26.4% | 61.9% | 14.0% | 25.3% | 60.7% | 2.3% | (1.1%) | (1.2%) |
| Apr | 12.7% | 24.0% | 63.4% | 13.0% | 26.9% | 60.1% | 0.3% | 3.0% | (3.2%) |
| May | 12.6% | 24.5% | 62.9% | 13.3% | 25.1% | 62.3% | 0.6% | 0.6% | (0.6%) |
| Jun | 12.5% | 24.2% | 63.2% | 13.3% | 28.0% | 59.9% | 0.7% | 3.8% | (3.3%) |
| Jul | 12.8% | 23.3% | 63.9% | 15.0% | 26.9% | 59.5% | 2.1% | 3.6% | (4.4%) |
| Aug | 12.7% | 23.6% | 63.7% | 15.5% | 26.3% | 59.6% | 2.7% | 2.7% | (4.1%) |
| Sep | 12.4% | 22.7% | 64.9% | 14.0% | 30.0% | 57.2% | 1.6% | 7.3% | (7.7%) |
| Oct | 14.6% | 21.4% | 64.0% | 13.4% | 30.3% | 57.3% | (1.2%) | 8.9% | (6.7%) |
| Nov | 14.3% | 23.2% | 62.4% | 13.5% | 31.1% | 56.4% | (0.9%) | 7.9% | (6.0%) |
| Dec | 15.6% | 22.3% | 62.1% | 15.4% | 33.4% | 52.3% | (0.2%) | 11.0% | (9.8%) |
| Annual | 12.9% | 23.9% | 63.2% | 14.4% | 27.5% | 58.9% | 1.6% | 3.5% | (4.4%) |

## 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.

**Table 3-24 Monthly average share of day-ahead self-supply demand, bilateral supply demand, and spot-supply demand based on parent companies: 2017**

| | 2016 | | | 2017 | | | Difference in Percentage Points | | |
|---|---|---|---|---|---|---|---|---|---|
| | Bilateral Contract | Spot | Self-Supply | Bilateral Contract | Spot | Self-Supply | Bilateral Contract | Spot | Self-Supply |
| Jan | 8.1% | 25.4% | 66.6% | 10.6% | 20.7% | 68.7% | 2.5% | (4.7%) | 2.1% |
| Feb | 8.3% | 25.0% | 66.7% | 10.8% | 20.7% | 68.5% | 2.5% | (4.3%) | 1.8% |
| Mar | 7.8% | 26.6% | 65.6% | 8.9% | 21.9% | 69.2% | 1.2% | (4.7%) | 3.6% |
| Apr | 9.7% | 23.9% | 66.4% | 8.1% | 21.9% | 70.0% | (1.6%) | (2.0%) | 3.7% |
| May | 9.4% | 23.9% | 66.6% | 7.6% | 22.3% | 70.2% | (1.8%) | (1.7%) | 3.5% |
| Jun | 8.1% | 21.7% | 70.1% | 8.4% | 23.6% | 68.0% | 0.2% | 1.9% | (2.1%) |
| Jul | 8.5% | 22.2% | 69.3% | 9.2% | 23.1% | 67.7% | 0.7% | 1.0% | (1.7%) |
| Aug | 8.3% | 22.1% | 69.5% | 9.5% | 22.9% | 67.6% | 1.2% | 0.8% | (1.9%) |
| Sep | 7.7% | 22.0% | 70.3% | 8.9% | 22.9% | 68.3% | 1.2% | 0.8% | (2.0%) |
| Oct | 9.3% | 20.9% | 69.8% | 8.5% | 23.5% | 67.9% | (0.8%) | 2.6% | (1.8%) |
| Nov | 9.2% | 22.1% | 68.7% | 8.5% | 23.5% | 67.9% | (0.7%) | 1.5% | (0.8%) |
| Dec | 10.1% | 21.2% | 68.7% | 9.9% | 22.6% | 67.5% | (0.2%) | 1.4% | (1.1%) |
| Annual | 8.7% | 23.1% | 68.3% | 9.1% | 22.5% | 68.4% | 0.4% | (0.6%) | 0.2% |

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 3-24 shows the monthly average share of day-ahead demand served by self-supply, bilateral contracts and spot purchases in 2016 and 2017, based on parent companies. In 2017, 9.1 percent of day-ahead demand was supplied by bilateral contracts, 22.5 percent by spot market purchases and 68.4 percent by self-supply. Compared with 2016, reliance on bilateral contracts increased by 0.4 percentage points, reliance on spot supply decreased by 0.6 percentage points, and reliance on self-supply increased by 0.2 percentage points.

# 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.

44 Table 3-23 and Table 3-24 were calculated as of January 17, 2018. The values may change slightly as billing values are updated by PJM.

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. In the Day-Ahead Energy Market, PJM commits a unit on the schedule that results in the lower overall system production cost. This is consistent with the Day-Ahead Energy Market objective of clearing resources (including physical and virtual resources) to meet the total demand (including physical and virtual demand) at the lowest bid production cost for the system over the 24 hour period. In the Real-Time Energy Market, PJM uses a dispatch cost formula to compare price-based offers and cost-based offers to select the cheaper offer.[45] Dispatch cost is calculated as:

$$\{(\text{Incremental Energy Offer@EcoMin} \times \text{EcoMin MW}) + \text{No Load Cost}\} \times \text{Min Run Time} + \text{Start Cost}$$

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 3-26 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.

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

## Figure 3-26 Offers with varying markups at different MW output levels

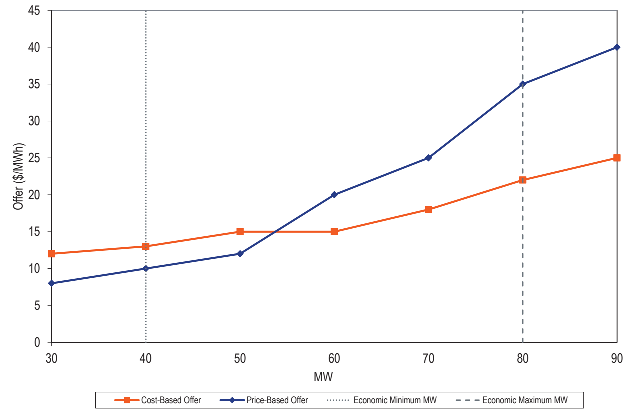



Table 3-25 shows the number and percent of unit schedule hours, by month, when units offered with crossing curves in the PJM Day-Ahead and Real-Time Energy Markets resulted in a lower dispatch cost for the price-based offer than the cost-based offer, in 2017. The analysis only includes price-based units because the determination of the cheaper of price-based and cost-based offers is only required if a unit elects to offer both cost-based and price-based offers. Units in PJM are only required to submit cost-based offers, and they may elect to offer price-based offers, but are not required to do so.

### Table 3-25 Units offered with crossing curves in the Day-Ahead and Real-Time Energy Markets: 2017

| | Day-Ahead | | | Real-Time | | |
|---|---|---|---|---|---|---|
| 2017 | Number of Schedule Hours with Crossing Curves | Total Number of Cost Schedule Hours Offered by Price Based Units | Percent of Schedule Hours with Crossing Curves | Number of Schedule Hours with Crossing Curves | Total Number of Cost Schedule Hours Offered by Price Based Units | Percent of Schedule Hours with Crossing Curves |
| Jan | 21,600 | 803,424 | 2.7% | 19,381 | 803,424 | 2.4% |
| Feb | 20,435 | 729,264 | 2.8% | 19,318 | 729,264 | 2.6% |
| Mar | 22,429 | 806,810 | 2.8% | 20,547 | 806,810 | 2.5% |
| Apr | 18,940 | 792,480 | 2.4% | 17,970 | 792,480 | 2.3% |
| May | 18,797 | 822,552 | 2.3% | 18,168 | 822,552 | 2.2% |
| Jun | 19,523 | 810,240 | 2.4% | 18,606 | 810,240 | 2.3% |
| Jul | 25,533 | 833,568 | 3.1% | 23,352 | 833,568 | 2.8% |
| Aug | 18,211 | 838,248 | 2.2% | 17,798 | 838,248 | 2.1% |
| Sep | 21,017 | 810,048 | 2.6% | 20,343 | 810,048 | 2.5% |
| Oct | 17,000 | 830,400 | 2.0% | 16,409 | 830,400 | 2.0% |
| Nov | 10,337 | 805,123 | 1.3% | 29,357 | 687,562 | 4.3% |
| Dec | 11,888 | 832,008 | 1.4% | 35,043 | 770,464 | 4.5% |

Offering a different economic minimum MW level, different minimum run times, or different start up and notification times in 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) in 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. Table 3-26 shows the number and percent of unit schedule hours when units offered lower minimum run times in price-based offers than in cost-based offers while having a positive markup that resulted in the dispatch cost being lower for the price-based offer.

### Table 3-26 Units offered with lower minimum run time on price compared to cost but with positive markup in the Day-Ahead and Real-Time Energy Markets: 2017

| | Day-Ahead | | | Real-Time | | |
|---|---|---|---|---|---|---|
| 2017 | Number of Schedule Hours with Lower Min Run Time in Price Compared to Cost | Total Number of Cost Schedule Hours Offered by Price Based Units | Percent of Schedule Hours with Lower Min Run Time in Price Compared to Cost | Number of Schedule Hours with Lower Min Run Time in Price Compared to Cost | Total Number of Cost Schedule Hours Offered by Price Based Units | Percent of Schedule Hours with Lower Min Run Time in Price Compared to Cost |
| Jan | 12,346 | 803,424 | 1.5% | 11,996 | 803,424 | 1.5% |
| Feb | 10,356 | 729,264 | 1.4% | 10,374 | 729,264 | 1.4% |
| Mar | 6,831 | 806,810 | 0.8% | 6,759 | 806,810 | 0.8% |
| Apr | 5,757 | 792,480 | 0.7% | 5,462 | 792,480 | 0.7% |
| May | 5,904 | 822,552 | 0.7% | 5,720 | 822,552 | 0.7% |
| Jun | 8,750 | 810,240 | 1.1% | 8,669 | 810,240 | 1.1% |
| Jul | 7,162 | 833,568 | 0.9% | 7,072 | 833,568 | 0.8% |
| Aug | 7,128 | 838,248 | 0.9% | 7,128 | 838,248 | 0.9% |
| Sep | 6,480 | 810,048 | 0.8% | 6,119 | 810,048 | 0.8% |
| Oct | 7,248 | 830,400 | 0.9% | 7,248 | 830,400 | 0.9% |
| Nov | 4,342 | 805,123 | 0.5% | 5,304 | 687,562 | 0.8% |
| Dec | 4,720 | 832,008 | 0.6% | 7,366 | 770,464 | 1.0% |

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 with the price-based offer with a lower economic minimum level compared to cost-based offer. Figure 3-27 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 3-27 Offers with a positive markup but different economic minimum MW

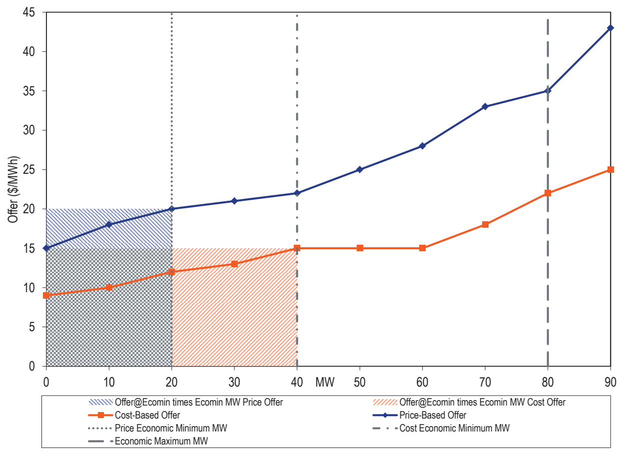



Table 3-27 shows the number and percent of unit schedule hours when units offered lower economic minimum MW in price-based offers than in cost-based offers while having a positive markup that resulted in the dispatch cost being lower for the price-based offer.

## Table 3-27 Units offered with lower economic minimum MW on price compared to cost but with positive markup in the Day-Ahead and Real-Time Energy Markets: 2017

| | Day-Ahead | | | Real-Time | | |
|---|---|---|---|---|---|---|
| 2017 | Number of Schedule Hours with Lower Economic Minimum MW in Price Compared to Cost | Total Number of Cost Schedule Hours Offered by Price Based Units | Percent of Schedule Hours with Lower Economic Minimum MW in Price Compared to Cost | Number of Schedule Hours with Lower Economic Minimum MW in Price Compared to Cost | Total Number of Cost Schedule Hours Offered by Price Based Units | Percent of Schedule Hours with Lower Economic Minimum MW in Price Compared to Cost |
| Jan | 72 | 803,424 | 0.01% | 48 | 803,424 | 0.01% |
| Feb | 0 | 729,264 | 0.00% | 0 | 729,264 | 0.00% |
| Mar | 168 | 806,810 | 0.02% | 136 | 806,810 | 0.02% |
| Apr | 24 | 792,480 | 0.00% | 0 | 792,480 | 0.00% |
| May | 216 | 822,552 | 0.03% | 216 | 822,552 | 0.03% |
| Jun | 168 | 810,240 | 0.02% | 168 | 810,240 | 0.02% |
| Jul | 168 | 833,568 | 0.02% | 152 | 833,568 | 0.02% |
| Aug | 0 | 838,248 | 0.00% | 0 | 838,248 | 0.00% |
| Sep | 0 | 810,048 | 0.00% | 0 | 810,048 | 0.00% |
| Oct | 0 | 830,400 | 0.00% | 0 | 830,400 | 0.00% |
| Nov | 0 | 805,123 | 0.00% | 45 | 687,562 | 0.01% |
| Dec | 0 | 832,008 | 0.00% | 0 | 770,464 | 0.00% |

## Table 3-28 Units with lower dispatch cost on price based offer compared to cost based offer, having positive markup in the Day-Ahead and Real-Time Energy Markets: 2017

| | Day-Ahead | | | Real-Time | | |
|---|---|---|---|---|---|---|
| 2017 | Number of Schedule Hours with Potential Evasion | Total Number of Cost Schedule Hours Offered by Price Based Units | Percent of Schedule Hours with Potential Evasion | Number of Schedule Hours with Potential Evasion | Total Number of Cost Schedule Hours Offered by Price Based Units | Percent of Schedule Hours with Potential Evasion |
| Jan | 30,582 | 803,424 | 3.8% | 28,882 | 803,424 | 3.6% |
| Feb | 28,426 | 729,264 | 3.9% | 27,861 | 729,264 | 3.8% |
| Mar | 27,298 | 806,810 | 3.4% | 25,838 | 806,810 | 3.2% |
| Apr | 23,050 | 792,480 | 2.9% | 22,124 | 792,480 | 2.8% |
| May | 22,757 | 822,552 | 2.8% | 22,236 | 822,552 | 2.7% |
| Jun | 26,414 | 810,240 | 3.3% | 25,525 | 810,240 | 3.2% |
| Jul | 31,365 | 833,568 | 3.8% | 29,291 | 833,568 | 3.5% |
| Aug | 23,891 | 838,248 | 2.9% | 23,599 | 838,248 | 2.8% |
| Sep | 25,769 | 810,048 | 3.2% | 25,203 | 810,048 | 3.1% |
| Oct | 23,623 | 830,400 | 2.8% | 23,172 | 830,400 | 2.8% |
| Nov | 13,949 | 805,123 | 1.7% | 34,138 | 687,562 | 5.0% |
| Dec | 15,864 | 832,008 | 1.9% | 41,803 | 770,464 | 5.4% |

Table 3-28 shows the number and percent of unit schedule hours that have exhibited one of the three behaviors (crossing curves, lower minimum run time on price based offer, lower economic minimum on price based offer) that resulted in the dispatch cost being lower for the price-based offer while having a positive markup. The data in Table 3-28 is a combination of the data for each individual behavior that is shown in Table 3-25, Table 3-26, and Table 3-27, adjusted for units that engaged in more than one such behavior simultaneously.

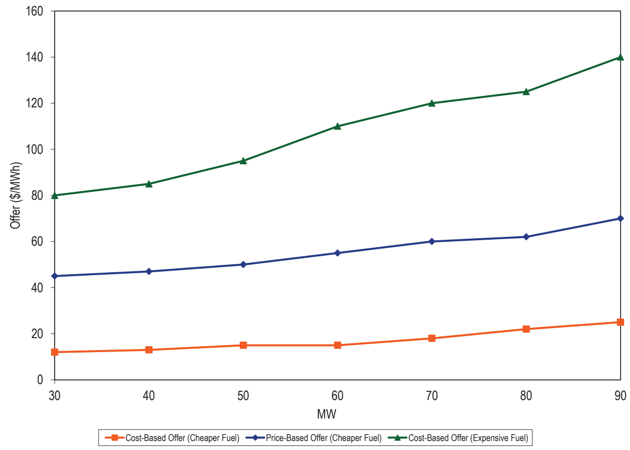
The MMU analyzed the data for units that exhibited any of the three behaviors (crossing curves, lower minimum run time on price-based offer, lower economic minimum on price-based offer) that also failed the TPS test in the Real-Time Energy Market, and were marginal in those intervals. Table 3-29 shows the total number of schedule hours when the units with behavior that resulted in evasion of market power mitigation rules failed the TPS test and were marginal in the Real-Time Energy Market.

### Table 3-29 Units with potential evasion that failed the TPS test and were marginal in the Real-Time Energy Market: 2017

| | Real-Time | | | | |
|---|---|---|---|---|---|
| 2017 | Schedule Hours with Potential Evasion When Units were Marginal | Number of Schedule Hours with Potential Evasion | Total Number of Cost Schedule Hours Offered by Price Based Units | Marginal Units with Evasion as a Percent of Total Schedule Hours | Marginal Units with Evasion as a Percent of Schedule Hours with Potential Evasion |
| Jan | 312 | 28,882 | 803,424 | 0.04% | 1.08% |
| Feb | 367 | 27,861 | 729,264 | 0.05% | 1.32% |
| Mar | 401 | 25,838 | 806,810 | 0.05% | 1.55% |
| Apr | 217 | 22,124 | 792,480 | 0.03% | 0.98% |
| May | 245 | 22,236 | 822,552 | 0.03% | 1.10% |
| Jun | 165 | 25,525 | 810,240 | 0.02% | 0.65% |
| Jul | 349 | 29,291 | 833,568 | 0.04% | 1.19% |
| Aug | 257 | 23,599 | 838,248 | 0.03% | 1.09% |
| Sep | 612 | 25,203 | 810,048 | 0.08% | 2.43% |
| Oct | 485 | 23,172 | 830,400 | 0.06% | 2.09% |
| Nov | 452 | 34,138 | 687,562 | 0.07% | 1.32% |
| Dec | 107 | 41,803 | 770,464 | 0.01% | 0.26% |

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 3-28 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 3-28 Dual fuel unit offers




These issues can be solved by simple rule changes.[46] 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.

46 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.

Levels of offer capping have historically been low in PJM, as shown in Table 3-30. The offer capping percentages shown in Table 3-30 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 3-30 Offer capping statistics – energy only: 2013 through 2017

| | Real Time | | Day Ahead | |
|---|---|---|---|---|
| Year | Unit Hours Capped | MW Capped | Unit Hours Capped | MW Capped |
| 2013 | 0.4% | 0.2% | 0.1% | 0.0% |
| 2014 | 0.5% | 0.2% | 0.2% | 0.1% |
| 2015 | 0.4% | 0.2% | 0.2% | 0.1% |
| 2016 | 0.4% | 0.2% | 0.1% | 0.0% |
| 2017 | 0.3% | 0.2% | 0.0% | 0.0% |

Table 3-31 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 because higher LMPs 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 in the closed loops, 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 3-30.

### Table 3-31 Offer capping statistics for energy and reliability: 2013 through 2017

| | Real Time | | Day Ahead | |
|---|---|---|---|---|
| Year | Unit Hours Capped | MW Capped | Unit Hours Capped | MW Capped |
| 2013 | 2.9% | 2.4% | 3.2% | 2.1% |
| 2014 | 0.8% | 0.5% | 0.6% | 0.4% |
| 2015 | 0.7% | 0.8% | 0.6% | 0.7% |
| 2016 | 0.4% | 0.3% | 0.1% | 0.1% |
| 2017 | 0.4% | 0.4% | 0.1% | 0.2% |

Table 3-32 shows the offer capping percentages for units committed to provide black start service and reactive support. The data in Table 3-32 is the difference between the offer cap percentages shown in Table 3-31 and Table 3-30.

### Table 3-32 Offer capping statistics for reliability: 2013 through 2017

| | Real Time | | Day Ahead | |
|---|---|---|---|---|
| Year | Unit Hours Capped | MW Capped | Unit Hours Capped | MW Capped |
| 2013 | 2.5% | 2.2% | 3.1% | 2.1% |
| 2014 | 0.3% | 0.3% | 0.4% | 0.3% |
| 2015 | 0.4% | 0.6% | 0.4% | 0.6% |
| 2016 | 0.1% | 0.1% | 0.0% | 0.0% |
| 2017 | 0.1% | 0.2% | 0.1% | 0.2% |

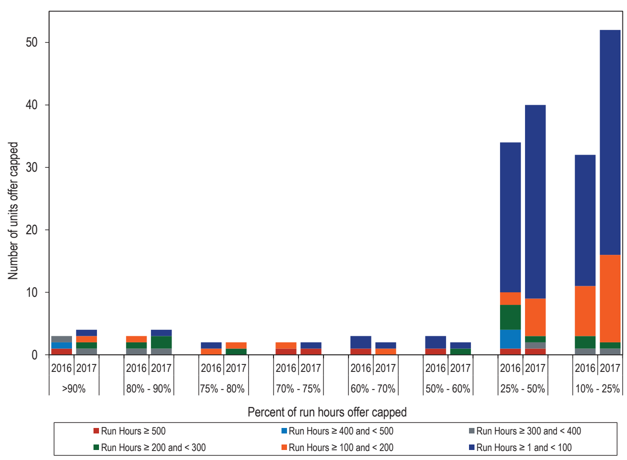
Table 3-33 presents data on the frequency with which units were offer capped in 2016 and 2017 for failing the TPS test to provide energy for constraint relief in the Real-Time Energy Market. Table 3-33 shows that two units were offer capped for 90 percent or more of their run hours in 2017 compared to five in 2016.

Table 3-33 Real-time offer capped unit statistics: 2016 and 2017

| Run Hours Offer-Capped, Percent Greater Than Or Equal To: | Year | Offer-Capped Hours: Hours ≥ 500 | Hours ≥ 400 and < 500 | Hours ≥ 300 and < 400 | Hours ≥ 200 and < 300 | Hours ≥ 100 and < 200 | Hours ≥ 1 and < 100 |
|---|---|---|---|---|---|---|---|
| 90% | 2016 | 1 | 1 | 1 | 0 | 0 | 0 |
| | 2017 | 0 | 0 | 1 | 1 | 1 | 1 |
| 80% and < 90% | 2016 | 0 | 0 | 1 | 1 | 1 | 0 |
| | 2017 | 0 | 0 | 1 | 2 | 0 | 1 |
| 75% and < 80% | 2016 | 0 | 0 | 0 | 0 | 1 | 1 |
| | 2017 | 0 | 0 | 0 | 1 | 1 | 0 |
| 70% and < 75% | 2016 | 1 | 0 | 0 | 0 | 1 | 0 |
| | 2017 | 1 | 0 | 0 | 0 | 0 | 1 |
| 60% and < 70% | 2016 | 1 | 0 | 0 | 0 | 0 | 2 |
| | 2017 | 0 | 0 | 0 | 0 | 1 | 1 |
| 50% and < 60% | 2016 | 1 | 0 | 0 | 0 | 0 | 2 |
| | 2017 | 0 | 0 | 0 | 1 | 0 | 1 |
| 25% and < 50% | 2016 | 1 | 3 | 0 | 4 | 2 | 24 |
| | 2017 | 1 | 0 | 1 | 1 | 6 | 31 |
| 10% and < 25% | 2016 | 0 | 0 | 1 | 2 | 8 | 21 |
| | 2017 | 0 | 0 | 1 | 1 | 14 | 36 |

Figure 3-29 shows the frequency with which units were offer capped in 2016 and 2017 for failing the TPS test to provide energy for constraint relief in the Real-Time Energy Market.

Figure 3-29 Real-time offer capped unit statistics: 2016 and 2017




## TPS Test Statistics

In 2017, the AEP, APS, ATSI, BGE, ComEd, Dominion, DPL, Met-Ed, PECO, PENELEC, PPL and PSEG control zones experienced congestion resulting from one or more constraints binding for 100 or more hours or resulting from an interface constraint (Table 3-34). The AECO, DAY, DEOK, DLCO, EKPC, JCPL, Pepco, and RECO control zones did not have constraints binding for 100 or more hours in 2017. Table 3-34 shows that BGE, ComEd, PPL and PSEG were the control zones that experienced congestion resulting from one or more constraints binding for 100 or more hours or resulting from an interface constraint that was binding for one or more hours in every year from 2009 through 2017. The constrained hours in the BGE Zone decreased from 11,434 hours in 2016 to 2,178 hours in 2017 due to the completion of RTEP upgrades in the zone. The constrained hours in the ComEd Zone decreased from 7,336 hours in 2016 to 2,257 hours in 2017 due to the completion of equipment outages.

Table 3-34 Numbers of hours when control zones experienced congestion resulting from one or more constraints binding for 100 or more hours or from an interface constraint: 2009 through 2017

| | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 |
|---|---|---|---|---|---|---|---|---|---|
| AECO | 149 | 172 | 234 | 0 | 208 | 0 | 394 | 439 | 0 |
| AEP | 1,045 | 1,636 | 2,510 | 0 | 2,611 | 2,710 | 1,274 | 796 | 469 |
| APS | 509 | 1,714 | 0 | 206 | 0 | 170 | 167 | 0 | 265 |
| ATSI | 157 | 0 | 0 | 208 | 270 | 489 | 242 | 141 | 1,113 |
| BGE | 152 | 470 | 1,041 | 2,970 | 1,760 | 6,255 | 9,601 | 11,434 | 2,178 |
| ComEd | 1,212 | 2,080 | 1,134 | 4,554 | 5,143 | 4,119 | 5,878 | 7,336 | 2,257 |
| DEOK | 0 | 0 | 0 | 109 | 0 | 0 | 112 | 0 | 0 |
| DLCO | 156 | 475 | 206 | 209 | 0 | 223 | 617 | 0 | 0 |
| Dominion | 468 | 905 | 1,179 | 1,020 | 664 | 0 | 1,172 | 459 | 436 |
| DPL | 0 | 122 | 0 | 1,542 | 639 | 3,071 | 2,066 | 2,719 | 673 |
| Met-Ed | 0 | 180 | 162 | 0 | 0 | 0 | 222 | 0 | 116 |
| PECO | 247 | 0 | 788 | 386 | 732 | 1,953 | 895 | 692 | 1,013 |
| PENELEC | 103 | 284 | 0 | 0 | 176 | 4,281 | 1,683 | 451 | 3,074 |
| Pepco | 149 | 1 | 0 | 143 | 245 | 41 | 0 | 0 | 0 |
| PPL | 176 | 118 | 40 | 350 | 452 | 148 | 266 | 936 | 2,044 |
| PSEG | 303 | 549 | 1,107 | 913 | 3,021 | 4,688 | 2,665 | 810 | 239 |

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 2017.[47] The three pivotal supplier (TPS) test is applied every time the system solution indicates that out of merit resources are needed to relieve a transmission constraint. Until November 1, 2017, only uncommitted resources, started to relieve the transmission constraint, were subject to offer capping. Beginning November 1, 2017, under certain circumstances, online resources that are committed beyond their original commitment (day-ahead or real-time) can be offer capped if the owner

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

fails the TPS test, and the latest available cost-based offer is determined to be cheaper than the price-based offer.[48] Units running in real time as part of their original commitment on the price-based offer on economics, that can provide incremental relief to a constraint, cannot be switched to their cost based offer. The results of the TPS test are shown for tests that could have resulted in offer capping and tests that resulted in offer capping.

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

Table 3-35 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 3-35 Three pivotal supplier test details for interface constraints: 2017

| Constraint | Period | Average Constraint Relief (MW) | Average Effective Supply (MW) | Average Number Owners | Average Number Owners Passing | Average Number Owners Failing |
|---|---|---|---|---|---|---|
| 5004 - 5005 | Peak | 263 | 256 | 12 | 0 | 12 |
| | Off Peak | 487 | 477 | 14 | 0 | 13 |
| AEP - DOM | Peak | 58 | 102 | 10 | 5 | 5 |
| | Off Peak | 231 | 176 | 8 | 0 | 8 |
| AP South | Peak | 448 | 656 | 15 | 2 | 13 |
| | Off Peak | 426 | 645 | 11 | 0 | 10 |
| Bedington - Black Oak | Peak | 118 | 191 | 12 | 4 | 7 |
| | Off Peak | 115 | 96 | 8 | 1 | 7 |
| East | Peak | 0 | 0 | NA | NA | NA |
| | Off Peak | 546 | 505 | 11 | 2 | 10 |
| Seneca | Peak | 125 | 132 | 1 | 0 | 1 |
| | Off Peak | 139 | 151 | 1 | 0 | 1 |

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. Offline units that are committed to provide relief for a transmission constraint, whose owners fail the TPS test, are committed on the cheaper of their cost or price-based offers. Beginning November 1, 2017, with the introduction of hourly offers and intraday offer updates, certain online units whose commitment is extended beyond the day-ahead or real-time commitment, whose owners fail the TPS test, are also switched to the cost-based offer if it is cheaper than the price-based offer. Table 3-36 provides, for the identified interface constraints, information on total tests applied, the subset of three pivotal supplier tests that could have resulted in offer capping and the portion of those tests that did result in offer capping. 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.

48 See PJM, OATT Attachment K Appendix § 6.4.1 (Offer Price Caps - Applicability) (January 3, 2018).

Table 3-36 Summary of three pivotal supplier tests applied for interface constraints: 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 |
|---|---|---|---|---|---|---|---|
| 5004 - 5005 | Peak | 106 | 105 | 99% | 14 | 13% | 13% |
| | Off Peak | 391 | 390 | 100% | 16 | 4% | 4% |
| AEP - DOM | Peak | 12 | 12 | 100% | 2 | 17% | 17% |
| | Off Peak | 175 | 133 | 76% | 16 | 9% | 12% |
| AP South | Peak | 201 | 123 | 61% | 10 | 5% | 8% |
| | Off Peak | 390 | 184 | 47% | 9 | 2% | 5% |
| Bedington - Black Oak | Peak | 50 | 36 | 72% | 2 | 4% | 6% |
| | Off Peak | 170 | 116 | 68% | 7 | 4% | 6% |
| East | Peak | 0 | 0 | NA | 0 | NA | NA |
| | Off Peak | 102 | 94 | 92% | 0 | 0% | 0% |
| Seneca | Peak | 366 | 2 | 1% | 0 | 0% | 0% |
| | Off Peak | 582 | 0 | 0% | 0 | 0% | NA |

# 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.[49] 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 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 2017, 2016, 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 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.

49 See PJM, OATT Attachment K Appendix § 6.6 (Minimum Generator Operating Parameters—Parameter-Limited Schedules) (June 1, 2017) at 2367 - 2376.

Key parameters like startup and notification time were not included in the PLS matrix in 2017 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 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.

## 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.[50] The Commission directed that capacity performance resources with parameters based on nonphysical constraints should receive uplift payments.[51] 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.[52]

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

50 151 FERC ¶ 61,208 at P 437 (June 9th Order).
51 *Id* at P 439.
52 *Id* at P 440.

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 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 reference resource used for the Cost of New Entry (CONE) calculation 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. When a seller responds competitively to a market price, markup is zero. When a seller exercises market power in its pricing, markup is positive. The degree of markup increases with the degree of market power. The markup index for each marginal unit is calculated as (Price – Cost)/Price.[53] 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 Index

Table 3-37 shows the average markup index of marginal units in the Real-Time Energy Market, by offer price category using unadjusted cost-based offers. Table 3-38 shows the average markup index of marginal units in the Real-Time Energy Market, by offer price category using adjusted cost-based offers. The unadjusted markup is the difference between the price-based offer and the cost-based offer including the 10 percent adder in the cost-based offer. The adjusted markup is the difference between the price-based offer and the cost-based offer excluding the 10 percent adder from the cost-based 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.[54] The markup is negative if the cost-based offer of the marginal unit exceeds its price-based offer at its operating point.

All generating units are allowed to add an additional 10 percent to their cost-based offer. The 10 percent adder was included 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. The owners of coal units, facing competition, typically exclude the additional 10 percent from their actual offers. The owners of many gas fired and oil fired units have also begun to exclude the 10 percent adder. The unadjusted markup is calculated as the difference between the price-based offer and the cost-based offer including the additional 10 percent in the cost-based offer for coal, gas and oil fired units. The adjusted markup is calculated as the difference between the price-based offer and the cost-based offer excluding the additional 10 percent from the cost-based offers of coal, gas and oil fired units. Even the adjusted markup overestimates the negative markup because units facing increased competitive pressure have excluded both the 10 percent and the components of operating and maintenance cost that are not short run marginal cost. While the 10 percent adder is permitted under the definition of cost-based offers in the PJM Market Rules and some have interpreted the rules to permit maintenance costs that are not short run marginal costs, neither are part of a competitive offer because they are not actually short run marginal costs, and actual market behavior reflects that fact.[55]

In 2017, 91.5 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 zero when using unadjusted cost-based offers. The average dollar markups of units with offer prices between $25 and $50 was positive ($1.57 per MWh) when using unadjusted cost-based offers. Negative markup means the unit is offering to run at a price less than its cost-based offer, revealing a short run marginal cost that is less than the maximum allowable cost-based offer under the PJM Market Rules.

Some marginal units did have substantial markups. Among the units that were marginal in 2017, less than 0.1 percent had offer prices above $400 per MWh. Among the units that were marginal in 2016, less than 0.1 percent had offer prices greater than $400 per MWh. Using the unadjusted cost-based offers, the highest markup for any marginal unit in 2017 was more than $700 while the highest markup in 2016 was more than $250.

53 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.

54 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.

55 See PJM. "Manual 15: Cost Development Guidelines," Rev. 29 (May 15, 2017).

## Table 3-37 Average, real-time marginal unit markup index (By offer price category unadjusted): 2016 and 2017

| | 2016 | | | 2017 | | |
|---|---|---|---|---|---|---|
| Offer Price Category | Average Markup Index | Average Dollar Markup | Frequency | Average Markup Index | Average Dollar Markup | Frequency |
| < $25 | 0.03 | ($0.65) | 63.6% | 0.14 | ($0.00) | 63.4% |
| $25 to $50 | (0.01) | ($1.13) | 26.7% | 0.06 | $1.57 | 28.1% |
| $50 to $75 | 0.17 | $9.57 | 1.6% | 0.37 | $20.20 | 1.9% |
| $75 to $100 | 0.28 | $24.14 | 0.5% | 0.29 | $23.91 | 0.7% |
| $100 to $125 | 0.05 | $5.24 | 1.8% | 0.23 | $25.00 | 0.3% |
| $125 to $150 | 0.01 | $1.63 | 4.2% | 0.19 | $24.53 | 0.4% |
| >= $150 | 0.05 | $10.32 | 1.5% | 0.01 | $2.94 | 5.2% |

## Table 3-38 Average, real-time marginal unit markup index (By offer price category adjusted): 2016 and 2017

| | 2016 | | | 2017 | | |
|---|---|---|---|---|---|---|
| Offer Price Category | Average Markup Index | Average Dollar Markup | Frequency | Average Markup Index | Average Dollar Markup | Frequency |
| < $25 | 0.11 | $1.02 | 63.6% | 0.22 | $1.56 | 63.4% |
| $25 to $50 | 0.08 | $1.84 | 26.7% | 0.14 | $4.23 | 28.1% |
| $50 to $75 | 0.25 | $13.89 | 1.6% | 0.42 | $23.48 | 1.9% |
| $75 to $100 | 0.35 | $29.92 | 0.5% | 0.36 | $29.68 | 0.7% |
| $100 to $125 | 0.14 | $14.77 | 1.8% | 0.30 | $32.83 | 0.3% |
| $125 to $150 | 0.11 | $14.03 | 4.2% | 0.26 | $34.61 | 0.4% |
| >= $150 | 0.14 | $25.31 | 1.5% | 0.11 | $20.52 | 5.2% |

Table 3-39 shows the percentage of marginal units that had markups, calculated using unadjusted cost-based offers, below, above and equal to zero for coal, gas and oil fuel types.[56] Table 3-40 shows the percentage of marginal units that had markups, calculated using adjusted cost-based offers, below, above and equal to zero for coal, gas and oil fuel types. In 2017, using unadjusted cost-based offers for coal units, 45.45 percent of coal units had negative markups. In 2017, using adjusted cost-based offers for coal units, 23.84 percent of coal units had negative markups.

## Table 3-39 Percent of marginal units with markup below, above and equal to zero (By fuel type unadjusted): 2016 and 2017

| | 2016 | | | 2017 | | |
|---|---|---|---|---|---|---|
| Type/Fuel | Negative | Zero | Positive | Negative | Zero | Positive |
| Coal | 58.25% | 22.45% | 19.30% | 45.45% | 22.22% | 32.32% |
| Gas | 22.46% | 16.52% | 61.02% | 36.06% | 13.01% | 50.93% |
| Oil | 11.80% | 84.58% | 3.61% | 25.13% | 73.87% | 1.01% |

## Table 3-40 Percent of marginal units with markup below, above and equal to zero (By fuel type adjusted): 2016 and 2017

| | 2016 | | | 2017 | | |
|---|---|---|---|---|---|---|
| Type/Fuel | Negative | Zero | Positive | Negative | Zero | Positive |
| Coal | 38.40% | 3.92% | 57.68% | 23.84% | 5.17% | 70.98% |
| Gas | 4.75% | 3.03% | 92.22% | 10.05% | 5.53% | 84.42% |
| Oil | 0.02% | 0.00% | 99.98% | 0.40% | 0.00% | 99.60% |

Figure 3-30 shows the frequency distribution of hourly markups for all gas units offered in 2016 and 2017 using unadjusted cost-based offers. The highest markup within the economic operating range of the unit's offer curve was used for creating the frequency distributions.[57] Of the gas units offered in the PJM market in 2017, nearly 28 percent of gas unit-hours had a maximum markup that was negative. More than six percent of gas fired unit-hours had a maximum markup above $100 per MWh.

## Figure 3-30 Frequency distribution of highest markup of gas units offered using unadjusted cost offers: 2016 and 2017

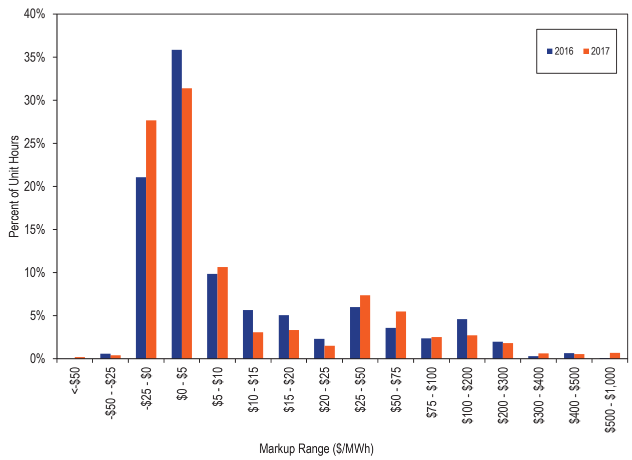



Figure 3-31 shows the frequency distribution of hourly markups for all coal units offered in 2016 and 2017 using unadjusted cost-based offers. Of the coal units offered in the PJM market in 2017, nearly 41 percent of coal unit-hours had a maximum markup that was negative.

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

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

Figure 3-31 Frequency distribution of highest markup of coal units offered using unadjusted cost offers: 2016 and 2017

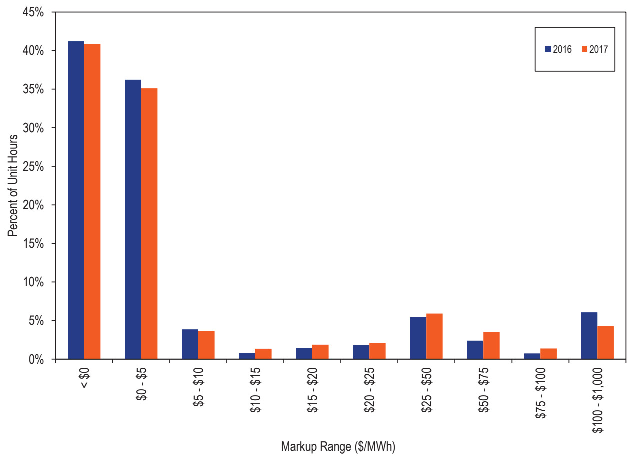
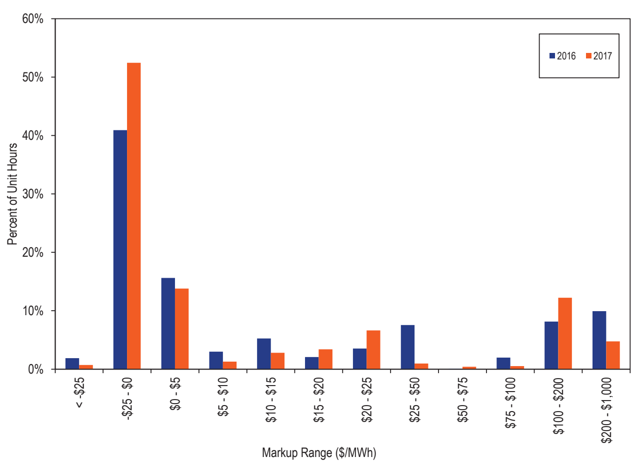



Figure 3-32 shows the frequency distribution of hourly markups for all offered oil units in 2016 and 2017 using unadjusted cost-based offers. Of the oil units offered in the PJM market in 2017, nearly 53 percent of oil unit-hours had a maximum markup that was negative.

Figure 3-32 Frequency distribution of highest markup of oil units offered using unadjusted cost offers: 2016 and 2017

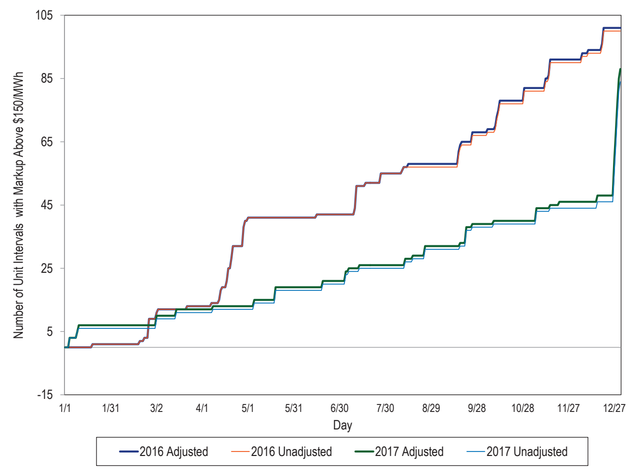



The markup frequency distributions show that a significant proportion of units make price-based offers less than the cost-based offers permitted under the PJM market rules. This behavior means that competitive price-based offers reveal actual unit marginal costs and that PJM market rules permit the inclusion 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 3-33 shows the number of marginal unit intervals in 2017 and 2016 with markup above $150 per MWh. The number of intervals with markups above $150 per MWh increased during the last week of December 2017, when the PJM region experienced low temperatures.

Figure 3-33 Cumulative number of unit intervals with markups above $150 per MWh: 2016 and 2017




## Day-Ahead Markup Index

Table 3-41 shows the average markup index of marginal generating units in the Day-Ahead Energy Market, by offer price category using unadjusted cost-based offers. The majority of marginal units are virtual transactions, which do not have markup. In 2017, 92.8 percent of marginal generating units had offer prices less than $50 per MWh. The average dollar markups of units with offer prices less than $25 was positive ($0.26 per MWh) when using unadjusted cost-based offers. The average dollar markups of units with offer prices between $25 and $50 was positive ($2.87 per MWh) when using unadjusted cost-based offers.

Some marginal units did have substantial markups. Among the units that were marginal in 2017, none had offer prices above $400 per MWh. Among the units that were marginal in 2016, none had offer prices greater than $400 per MWh. Using the unadjusted cost-based offers, the highest markup for any marginal unit in 2017 was more than \$60 per MWh while the highest markup in 2016 was more than \$160 per MWh.

### Table 3-41 Average day-ahead marginal unit markup index (By offer price category, unadjusted): 2016 and 2017

| | 2016 | | | 2017 | | |
|---|---|---|---|---|---|---|
| Offer Price Category | Average Markup Index | Average Dollar Markup | Frequency | Average Markup Index | Average Dollar Markup | Frequency |
| < \$25 | 0.20 | \$0.25 | 62.1% | 0.14 | \$0.26 | 60.1% |
| \$25 to \$50 | 0.04 | \$0.53 | 27.6% | 0.10 | \$2.87 | 32.7% |
| \$50 to \$75 | 0.10 | \$5.66 | 1.5% | 0.32 | \$17.41 | 1.0% |
| \$75 to \$100 | 0.04 | \$2.50 | 0.1% | 0.04 | \$0.15 | 0.4% |
| \$100 to \$125 | (0.01) | (\$0.72) | 0.3% | 0.05 | \$4.48 | 0.1% |
| \$125 to \$150 | 0.00 | \$0.00 | 7.4% | (0.05) | (\$8.80) | 0.1% |
| >= \$150 | 0.01 | \$2.62 | 1.0% | (0.00) | (\$0.79) | 5.6% |

Table 3-42 shows the average markup index of marginal generating units in the Day-Ahead Energy Market, by offer price category using adjusted cost-based offers. In 2017, 0.4 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 decreased from 0.28 in 2016, to 0.22 in 2017 in the offer price category less than \$25.

### Table 3-42 Average day-ahead marginal unit markup index (By offer price category, adjusted): 2016 and 2017

| | 2016 | | | 2017 | | |
|---|---|---|---|---|---|---|
| Offer Price Category | Average Markup Index | Average Dollar Markup | Frequency | Average Markup Index | Average Dollar Markup | Frequency |
| < \$25 | 0.28 | \$1.93 | 62.1% | 0.22 | \$1.93 | 60.1% |
| \$25 to \$50 | 0.12 | \$3.35 | 27.6% | 0.17 | \$5.35 | 32.7% |
| \$50 to \$75 | 0.18 | \$10.21 | 1.5% | 0.37 | \$20.81 | 1.0% |
| \$75 to \$100 | 0.12 | \$9.90 | 0.1% | 0.12 | \$8.18 | 0.4% |
| \$100 to \$125 | 0.08 | \$9.76 | 0.3% | 0.13 | \$13.79 | 0.1% |
| \$125 to \$150 | 0.09 | \$12.47 | 7.4% | 0.04 | \$4.28 | 0.1% |
| >= \$150 | 0.10 | \$19.37 | 1.0% | 0.09 | \$16.43 | 5.6% |

## 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 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 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. Cost of inputs consumed or converted to produce energy, and the costs associated with byproducts that result from consuming or converting materials to produce energy, net of any revenues from the sale of those byproducts. The categories of short run marginal costs are:
  - Fuel costs: Includes commodity costs, delivery costs (such as variable transportation costs), fuel supplier fees and taxes;
  - Emission allowance costs: Includes costs of emission allowances and any variable regulatory fees;
  - Operating costs: Includes water purchases, water or waste water treatment control reagents, emission control reagents, equipment lubricants, electricity byproducts disposal;
  - Energy market opportunity costs;[58]
- 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

On February 3, 2017, FERC accepted PJM's compliance filing regarding hourly offers and Fuel Cost Policies

58 See PJM Operating Agreement Schedule 2 (a)

(FCP) and required an additional compliance filing.[59] PJM made two additional compliance filings.[60] FERC has not made a determination on the two most recent filings related to FCPs and cost-based offers.

PJM's filings set standards for its FCP approval and reserve to itself final authority for approving fuel cost policies as compliant.[61]

Fuel cost policies document the process by which Market Sellers calculate the fuel cost component of their cost-based offers. Short run marginal fuel costs include commodity costs, transportation costs, fees, and taxes for the purchase of fuel.

## Fuel Cost Policy Review

In 2017, PJM and the MMU performed two FCP reviews. The first one, with a deadline of May 15, 2017, was ordered by FERC as part of PJM's compliance filing. The second one, with a deadline of November 1, 2017, was incorporated in the tariff approved by FERC regarding hourly offers and fuel cost policies. The latter review included the review of new fuel cost policies to address the implementation of hourly offers and intraday offer updates.

Table 3-43 shows the summary of the May 15, 2017, FCP review. In this review, 1,206 units (89 percent) of all units had an FCP passed by the MMU and 149 units (11 percent) had an FCP failed by the MMU. All units had an FCP approved by PJM. The units with failed policies were owned by nine companies out of 132 companies in PJM at that time.

### Table 3-43 May 15, 2017, FCP review results

| | MMU Status | | | |
|---|---|---|---|---|
| PJM Status | Pass | Submitted | Fail | Total |
| Approved | 1,206 | 0 | 149 | 1,355 |
| Rejected | 0 | 0 | 0 | 0 |
| Under Review | 0 | 0 | 0 | 0 |
| Submitted | 0 | 0 | 0 | 0 |
| Total | 1,206 | 0 | 149 | 1,355 |

Table 3-44 shows the summary of the November 1, 2017, FCP review. In this review, 1,000 units (73 percent) had an FCP passed by the MMU, 342 units (25 percent) had an FCP submitted and 29 units (2 percent) had an FCP failed by the MMU. All units had an FCP approved by PJM. Due to the large number of submittals a few days before the November 1 deadline, the MMU could not effectively evaluate all fuel cost policies by November 1.

### Table 3-44 November 1, 2017, FCP review results

| | MMU Status | | | |
|---|---|---|---|---|
| PJM Status | Pass | Submitted | Fail | Total |
| Approved | 1,000 | 342 | 29 | 1,371 |
| Rejected | 0 | 0 | 0 | 0 |
| Under Review | 0 | 0 | 0 | 0 |
| Submitted | 0 | 0 | 0 | 0 |
| Total | 1,000 | 342 | 29 | 1,371 |

Of the 342 units with a submitted FCP, 212 had an FCP failed by the MMU by December 31, 2017. The remainder had an FCP passed by the MMU. Of the 29 units that had an FCP failed by the MMU, 18 resubmitted new FCPs that the MMU later passed. The result was 1,148 units (84 percent) had an FCP passed by the MMU and 223 units (16 percent) had an FCP failed by the MMU at the end of 2017.

The MMU performed a detailed review of every FCP. PJM approved the FCPs that the MMU passed. PJM reviewed and approved every FCP failed by the MMU.

The standards for the MMU's market power evaluation are that FCPs be algorithmic, verifiable and systematic, accurately reflecting the short run marginal cost of producing energy. In its filings with FERC, PJM agreed with the MMU that FCPs should be verifiable and systematic:[62]

- Verifiable: Must provide a fuel price that can be calculated by the MMU after the fact with the same data available to the Market Seller at the time the decision was made and documentation for that data from a public or a private source.
- Systematic: Document a standardized method or methods for calculating fuel costs including objective triggers for each method.[63]

PJM and FERC did not agree that Fuel Cost Policies should be algorithmic:[64]

59 *PJM Interconnection, L.L.C.*, 158 FERC ¶ 61,133 (2017) ("February 3rd Order").
60 Compliance Filing of PJM Interconnection, L.L.C., Docket No. ER16-372-003 (March 6, 2017). Amended Compliance Filing of PJM Interconnection, L.L.C., Docket No. ER16-372-003 (July 31, 2017).
61 Prior to this order, only the MMU reviewed Fuel Cost Policies, and only the MMU had standards for Fuel Cost Policies. PJM deemed Fuel Cost Policies approved upon MMU approval. PJM did not track Fuel Cost Policy approvals or consider any appeals to the MMU's determinations.
62 Answer of PJM Interconnection, L.L.C. to Protests and Comments, Docket No. ER16-372-002 (October 7, 2016) ("October 7th Filing") at P 11.
63 Protest of the Independent Market Monitor for PJM, Docket No. ER16-372-002 (September 16, 2016) ("September 16th Filing") at P8.
64 Answer of PJM Interconnection, L.L.C. to Protests and Comments, Docket No. ER16-372-002 (October 7, 2016) ("October 7th Filing") at P12. PJM Interconnection, L.L.C., 158 FERC ¶ 61,133 (2017) ("February 3rd Order") P57.

- Algorithmic: Must use a set of defined, logical steps. These steps may be as simple as a single number from a contract, a simple average of broker quotes, a simple average of bilateral offers, or the weighted average index price posted on the Intercontinental Exchange trading platform ('ICE').[65]

FCPs are not verifiable and systematic if they are not algorithmic. The natural gas FCPs failed by the MMU and approved by PJM are not verifiable and systematic.

Not all FCPs approved by PJM met the standard of the PJM tariff. The tariff standards that some Fuel Cost Policies did not meet are:[66]

1. Accuracy: Reflect applicable costs accurately;
2. Procurement Practices: Provide information sufficient for the verification of the Market Seller's fuel procurement practices;
3. Fuel Contracts: Reflect the Market Seller's applicable commodity and/or transportation contracts (to the extent it holds such contracts);
4. Adders: Provide a detailed explanation of the basis for and reasonableness of any applicable adders included in determining fuel costs in accordance with PJM Manual 15.

The MMU failed FCPs not related to natural gas submitted by some Market Sellers because they do not accurately describe the short run marginal cost of fuel. Some policies include contractual terms (in $ per MWh or in $ per MMBtu) that do not reflect the actual cost of fuel. The MMU determined that the terms used in these policies do not reflect the cost of fuel based on the information provided by the Market Sellers and information gathered by the MMU for similar resources.

The MMU failed the remaining FCPs because they do not accurately reflect the cost of natural gas. The main issues identified by the MMU in the natural gas policies were:

- Unverifiable cost estimates. Some of these policies include options under which the estimate of the natural gas commodity cost would be calculated by the Market Seller without specifying a verifiable, quantitative method. For example, some FCPs specify that the source of the natural gas cost would be communications with traders within the Market Seller's organization. A fuel cost from discretionary and undocumented decision making within the Market Seller's organization is not verifiable. Verifiability requires that fuel cost estimates be transparently derived from market information and that PJM or the MMU could reproduce the same fuel cost estimates after the fact by applying the methods documented in the FCP to the same inputs. Verifiable is a key requirement of a FCP. If it is not verifiable, a FCP is meaningless and has no value. Unverifiable fuel costs permit the exercise of market power.
- Use of available market information that results in inaccurate expected costs. Some Market Sellers include the use of offers to sell natural gas on ICE as the sole basis for the cost of natural gas. An offer to sell is often not an accurate indication of the expected fuel cost. The price of uncleared offers on the exchange often exceed the value of cleared transactions. Use of sell offers alone is equivalent to using the supply curve alone to determine the market price of a good without considering the demand curve. It is clearly incorrect.
- Use of unsupported natural gas hubs (indices). Some FCPs include hubs not related to the location of the unit, without an explanation or an analysis of the basis between the location of the unit and the proposed hub. Other FCPs do not include all the applicable hubs accessible to the units (e.g. units with access to multiple interstate pipelines). The use of a trading hub that is not applicable to the unit, or the failure to use a hub that is accessible to the unit, results in an inaccurate estimate of the cost of natural gas.
- Use of unsupported adders. Some policies include unsupported adders to the cost of natural gas that result in the overstatement of natural gas costs. The only legitimate role for adding additional cost to an indexed commodity cost of natural gas is to incorporate an empirically established difference between that posted price and the actual price of natural gas paid for supplying the unit. The MMU compared all proposed adders to the final published index to evaluate their accuracy. Market Sellers with policies that passed the MMU's evaluation either

65 Protest of the Independent Market Monitor for PJM, Docket No. ER16-372-002 (September 16, 2016) ("September 16th Filing") at P8.

66 See PJM Operating Agreement filed on March 6, 2017. Schedule 2 Section 2.3 (a).

include no adders or include adders supported by empirical evidence.

- Unclear implementation of hourly offers and intraday offer updates. Some policies incorporated new sections for hourly offers and intraday offer updates that overlapped and in some cases contradicted the previous daily fuel cost calculation. Some policies had such sections but failed to explain how the fuel cost was going to be updated.

The FCPs that failed the MMU's evaluation also fail to meet the standards defined in the PJM tariff. PJM should not have approved inaccurate Fuel Cost Policies.

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

The MMU recommends that the tariff be changed to allow units to have Fuel Cost Policies that do not include fuel procurement practices, including fuel contracts. Fuel procurement practices, including fuel contracts, may be used as the basis for Fuel Cost Policies but should not be required. In a large number of approved Fuel Cost Policies, the actual fuel procurement process plays no role in calculating the Market Seller's accurate estimate of the daily replacement value of their fuel.

## Hourly Offers and Intraday Offer Updates

On November 1, 2017, PJM implemented hourly offers and intraday offer updates. Hourly offers means the ability to offer hourly differentiated offers (up to one offer per hour instead of one offer per day). Intraday offer updates means the ability to make changes to an offer after the rebid period. All participants are eligible to make hourly offers. Participants must opt in on a monthly basis to make intraday offer updates. Table 3-45 shows the average number of units that opted in to intraday offer updates and as a reference the average number of units that make positive offers. In December 2017, on average, 268 natural gas fired units had opted in for intraday offer updates out of an average of 444 natural gas fired units.

### Table 3-45 Average number of units opted in for intraday offers by month: 2017

| | 2017 | | | | | |
|---|---|---|---|---|---|---|
| | Number of units opt in | | | Number of units with positive offers | | |
| | Natural Gas | Other Fuels | Total | Natural Gas | Other Fuels | Total |
| Jan | 0 | 0 | 0 | 444 | 420 | 864 |
| Feb | 0 | 0 | 0 | 445 | 419 | 864 |
| Mar | 0 | 0 | 0 | 448 | 418 | 866 |
| Apr | 0 | 0 | 0 | 448 | 420 | 868 |
| May | 0 | 0 | 0 | 450 | 417 | 867 |
| Jun | 0 | 0 | 0 | 452 | 418 | 869 |
| Jul | 0 | 0 | 0 | 449 | 410 | 859 |
| Aug | 0 | 0 | 0 | 449 | 402 | 851 |
| Sep | 0 | 0 | 0 | 449 | 401 | 850 |
| Oct | 0 | 0 | 0 | 451 | 399 | 850 |
| Nov | 246 | 31 | 277 | 442 | 397 | 839 |
| Dec | 268 | 31 | 299 | 444 | 395 | 839 |

Table 3-46 shows the average number of units that made hourly differentiated offers in the day-ahead market or rebid period. In December 2017 an average of 173 units made hourly differentiated offers.

### Table 3-46 Average number of units with hourly differentiated offers by month: 2017

| | 2017 | | |
|---|---|---|---|
| | Natural Gas | Other Fuels | Total |
| Jan | 0 | 0 | 0 |
| Feb | 0 | 0 | 0 |
| Mar | 0 | 0 | 0 |
| Apr | 0 | 0 | 0 |
| May | 0 | 0 | 0 |
| Jun | 0 | 0 | 0 |
| Jul | 0 | 0 | 0 |
| Aug | 0 | 0 | 0 |
| Sep | 0 | 0 | 0 |
| Oct | 0 | 0 | 0 |
| Nov | 176 | 5 | 181 |
| Dec | 165 | 9 | 173 |

Table 3-47 shows the average number of units that made rebid offer updates and intraday offer updates. In December 2017, an average of 103 units made intraday offer updates. Prior to November 2017, real-time offer updates refers to offer updates made during the rebid period.

#### Table 3-47 Average number of units making rebid or intraday offer updates by month: 2017

| | 2017 | | |
|---|---|---|---|
| | Average number of units that made real-time offer updates | | |
| | Natural Gas | Other Fuels | Total |
| Jan | 30 | 4 | 35 |
| Feb | 33 | 5 | 38 |
| Mar | 29 | 5 | 33 |
| Apr | 28 | 5 | 33 |
| May | 32 | 5 | 36 |
| Jun | 28 | 5 | 33 |
| Jul | 22 | 4 | 26 |
| Aug | 31 | 2 | 33 |
| Sep | 31 | 1 | 33 |
| Oct | 31 | 1 | 33 |
| Nov | 100 | 5 | 105 |
| Dec | 99 | 4 | 103 |

## Cost-Based Offer Penalties

In addition to implementing the Fuel Cost Policy approval process, the February 3, 2017, FERC Order, created a process for penalizing generators identified by PJM or the MMU with cost-based offers that do not comply with Schedule 2 of the PJM Operating Agreement and PJM Manual 15.[67] In 2017, 57 penalty cases were identified, 48 resulted in assessed cost-based offer penalties, nine remain pending PJM's determination. The 48 cases were from units owned by 13 different companies. The total penalties totaled $281,442, charged to units that totaled 7,629 available MW. The average penalty was $1.54 per available MW. [68] The 48 cases had incorrect cost-based offers for 2,800 unit days. PJM only assessed penalties for the last day of the violation resulting in 48 unit days penalized.[69] The MMU identified nine additional cases of cost-based offer penalties in 2017 that have not been assessed and remain under evaluation by PJM. These cases total 662 unit days.

The incorrect cost-based offers resulted from incorrect application of Fuel Cost Policies, lack of approved Fuel Cost Policies, miscalculation of no load costs, inclusion of prohibited maintenance costs, use of incorrect incremental heat rates, use of incorrect start cost, and use of incorrect emission costs.

67 *PJM Interconnection, L.L.C.*, 158 FERC ¶ 61,133 (2017) ("February 3rd Order").

68 Cost-based offer penalties are assessed by hour. Therefore, a $1 per available MW penalty results in a total of $24 for a 1 MW unit if the violation is for the entire day.

69 PJM proposed the limitation of the penalty to a single day in an amended compliance filing, which has not been approved by FERC. *See* Amended Compliance Filing of PJM Interconnection, L.L.C., Docket No. ER16-372-003, July 31, 2017.

## 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 PJM Manual 15 be replaced with a straightforward description of the components of cost-based offers based on short run marginal costs and the correct calculation of cost-based offers.

### VOM Costs

PJM Manual 15 and the PJM Operating Agreement Schedule 2 include rules related to VOM costs. These rules are unclear. PJM Manual 15 provides for the inclusion of Variable Operating and Maintenance (VOM) costs in energy market cost-based offers. PJM Manual 15 is unclear regarding the inclusion of variable operating costs. PJM Manual 15 includes provisions for incremental maintenance costs mainly based on FERC's accounting system. A competitive offer, at short run marginal costs, includes only operating costs. Effective market power mitigation requires excluding maintenance costs from cost-based offers.

As part of its March 6, 2017, offer flexibility compliance filing, PJM proposed a review process for VOM costs.[70] In 2017, PJM began requesting from Market Sellers information regarding the calculation of VOM costs and approving such costs without input from the MMU.

PJM Manual 15 allows for the calculation of VOM costs in $ per MMBtu, $ per equivalent operating hour (EOH) and $ per start. PJM Manual 15 allows for the use of VOM costs in $ per MWh in the peaking segments of combustion turbines and combined cycles. The MMU converted all VOM costs in $ per EOH and in $ per MMBtu into $ per MWh.

Table 3-48 shows the range of PJM approved VOM costs for combustion turbines and engines. Table 3-48 shows the number of units and economic maximum (MW) by ranges defined as multiples of the MMU benchmark of $0.25 per MWh. Table 3-48 shows that all PJM approved VOM costs exceeded the MMU benchmark, and that 77 units had VOM costs greater than 100 times the MMU benchmark. The average PJM approved VOM cost for combustion turbines and engines was $48.42 per MWh.

70 *See* PJM Compliance Filing, Docket ER16-372, March 6, 2017. FERC has not yet approved the compliance filing language.

The average is skewed by high outliers but the outliers cannot be posted based on PJM confidentiality rules.

### Table 3-48 PJM approved VOM Costs for combustion turbines and diesels[71]

| VOM Cost Range | Number of units | Economic Max (MW) |
|---|---|---|
| Between $0.01 and $0.25 per MWh | Confidential | Confidential |
| Between $0.25 and $2.50 per MWh | 96 | 9,788 |
| Between $2.50 and $25.00 per MWh | 160 | 10,075 |
| More than $25.00 per MWh | 77 | 2,540 |

Table 3-49 shows the range of PJM approved VOM costs for combined cycles. Table 3-49 shows the number of units and economic maximum (MW) by ranges defined as multiples of the MMU benchmark of $1.00 per MWh. Table 3-49 shows that 34 units had approved VOM costs within the MMU benchmark, and that 14 units had VOM costs greater than four times the MMU benchmark. The average PJM approved VOM cost for combined cycles was $3.59 per MWh. The average is skewed by high outliers but the outliers cannot be posted based on PJM confidentiality rules.

### Table 3-49 PJM approved VOM Costs for combined cycles

| VOM Cost Range | Number of units | Economic Max (MW) |
|---|---|---|
| Between $0.01 and $1 per MWh | 34 | 15,424 |
| Between $1 and $2 per MWh | 28 | 13,932 |
| Between $2 and $4 per MWh | 9 | 2,629 |
| More than $4 per MWh | 14 | 2,614 |

Table 3-50 shows the range of PJM approved VOM costs for coal units. Table 3-50 shows the number of units and economic maximum (MW) by ranges defined as multiples of the MMU benchmark of $4.00 per MWh. Table 3-50 shows that 72 units had approved VOM costs within the MMU benchmark, and that 52 units had VOM costs greater than the MMU benchmark and lower than four times the MMU benchmark. The average PJM approved VOM cost for coal units was $4.35 per MWh. The average is skewed by high outliers but the outliers cannot be posted based on PJM confidentiality rules.

### Table 3-50 PJM approved VOM Costs for coal units

| VOM Cost Range | Number of units | Economic Max (MW) |
|---|---|---|
| Between $0.01 and $4 per MWh | 72 | 29,080 |
| Between $4 and $16 per MWh | 52 | 16,157 |
| Between $16 and $40 per MWh | 0 | 0 |
| More than $40 per MWh | 0 | 0 |

High VOM levels allow generators to economically withhold energy and to exercise market power even when offers are set to cost to mitigate market power. The MMU recommendation to limit cost-based offers to short run marginal costs would prevent such withholding. When units are not committed due to high VOM costs and instead a unit with higher short run marginal costs is committed, the market outcome is inefficient. When units that fail the TPS test are committed on their price-based offer when their short run marginal cost is lower, the market outcome is inefficient.

## FERC System of Accounts

PJM Manual 15 relies 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 PJM Manual 15.

## 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 incremental offer 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. Table 3-48 includes the impact of the cyclic starting factors but it does not include the impact of the cyclic peaking factor. PJM Manual 15 allows for a peaking cyclic factor of three, which means that a unit with a $300 per hour (EOH) VOM cost can add $180 per MWh to a 5 MW peak segment.[72]

The MMU recommends the removal of all cyclic starting and peaking factors from PJM Manual 15.

71 Data for units with an approved VOM cost greater than $0 per MWh and lower than or equal to the MMU benchmark cannot be posted due to PJM's data posting rules per PJM Manual 33.

72 The peak adder is equal to $300 times three divided by 5 MW.

## 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 not short run marginal costs.

The MMU recommends the removal of all labor costs from the PJM Manual 15.

## 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. Exceptions to this definition should be granted when the amount of fuel used from synchronization to when the unit becomes dispatchable is greater than the no load heat plus the output during this period times the incremental heat rate.

## 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 PJM Manual 15.

## 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 affect 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.[73] The goal, in 2005, was to ensure that units that were offer capped for most

73 110 FERC ¶ 61,053 (2005).

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. Units have the opportunity to recover ACR in the capacity market.

For those reasons, the MMU recommended the elimination of FMU and AU adders.[74] FMU and AU adders no longer serve the purpose for which they were created and interfere with the efficient operation of PJM markets.

The FMU and AU adders were effectively eliminated on November 1, 2014.[75]

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.[76]

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.[77] 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 3-34 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.[78] 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.

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

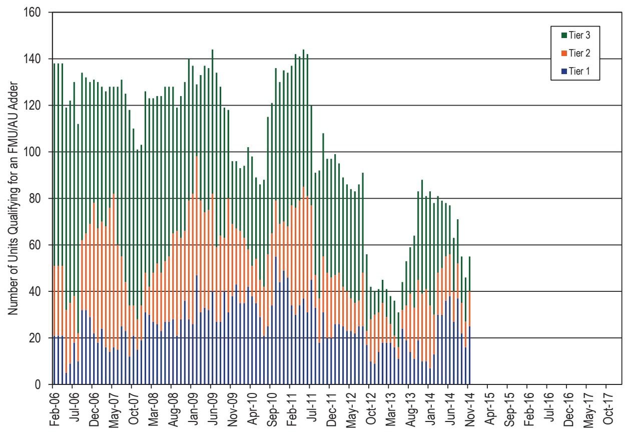
75 The MMU and PJM proposed a compromise on the elimination of FMU adders that maintains the ability of generating units to qualify for FMU adders when units have net revenues less than unit going forward costs or ACR. PJM submitted the joint MMU/PJM proposal to the Commission pursuant to section 206 of the Federal Power Act. On October 31, 2014, the Commission conditionally approved the filing and the new rule became effective November 1, 2014.

76 OA, Schedule 1 § 6.4.2.

77 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.

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

Figure 3-34 Frequently mitigated units and associated units (By month): February 1, 2006 through December 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 market clearing 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.[79] 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 3-35 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 3-35 PJM day-ahead aggregate supply curves: 2017 example day

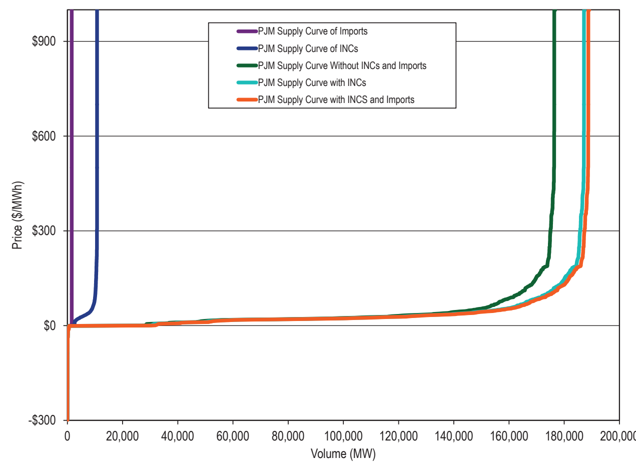



Table 3-51 shows the hourly average number of cleared and submitted increment offers and decrement bids by month in 2016 and 2017. The hourly average submitted increment MW increased by 11.1 percent and cleared increment MW decreased by 2.4 percent, from 7,175 MW and 4,675 MW in 2016 to 7,968 MW and 4,562 MW in 2017. The hourly average submitted decrement MW increased by 14.5 percent and cleared decrement MW decreased by 0.3 percent, from 6,879 MW and 4,051 MW in 2016 to 7,874 MW and 4,035 MW in 2017.

79 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 3-51 Average hourly number of cleared and submitted INCs and DECs by month: 2016 and 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 | Apr | 5,115 | 8,860 | 280 | 1,401 | 5,139 | 8,986 | 178 | 776 |
| 2017 | May | 5,643 | 9,724 | 278 | 1,286 | 5,030 | 9,188 | 164 | 768 |
| 2017 | Jun | 3,961 | 7,705 | 193 | 1,153 | 4,314 | 8,257 | 173 | 831 |
| 2017 | Jul | 3,921 | 7,087 | 233 | 1,014 | 3,807 | 7,828 | 167 | 779 |
| 2017 | Aug | 3,418 | 5,951 | 279 | 1,022 | 3,209 | 5,845 | 169 | 593 |
| 2017 | Sep | 3,537 | 6,201 | 190 | 919 | 3,502 | 6,076 | 139 | 603 |
| 2017 | Oct | 3,927 | 6,498 | 309 | 1,128 | 3,111 | 6,008 | 168 | 586 |
| 2017 | Nov | 3,558 | 6,454 | 290 | 1,240 | 2,632 | 5,970 | 179 | 683 |
| 2017 | Dec | 3,404 | 6,029 | 234 | 1,102 | 3,138 | 7,400 | 177 | 793 |
| 2017 | Annual | 4,562 | 7,968 | 256 | 1,220 | 4,035 | 7,874 | 164 | 753 |

Table 3-52 shows the average hourly number of up to congestion transactions and the average hourly MW in 2016 and 2017. In 2017, the average hourly up to congestion submitted MW decreased by 3.3 percent and cleared MW increased 1.6 percent, compared to 2016.

## Table 3-52 Average hourly cleared and submitted up to congestion bids by month: 2016 and 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 | Apr | 42,274 | 152,868 | 2,247 | 6,022 |
| 2017 | May | 34,477 | 116,688 | 1,962 | 4,957 |
| 2017 | Jun | 29,996 | 112,071 | 1,801 | 4,839 |
| 2017 | Jul | 32,287 | 118,609 | 1,875 | 5,108 |
| 2017 | Aug | 31,511 | 122,677 | 1,931 | 5,062 |
| 2017 | Sep | 30,485 | 120,956 | 1,740 | 4,423 |
| 2017 | Oct | 29,718 | 117,486 | 1,938 | 4,745 |
| 2017 | Nov | 29,606 | 110,325 | 1,851 | 4,679 |
| 2017 | Dec | 31,741 | 113,992 | 1,776 | 4,749 |
| 2017 | Annual | 34,927 | 137,419 | 2,137 | 5,770 |

Table 3-53 shows the average hourly number of import and export transactions and the average hourly MW in 2016 and 2017. In 2017, the average hourly submitted and cleared import transaction MW decreased by 66.4 and 66.9 percent, and the average hourly submitted and cleared export transaction MW decreased by 13.4 and 13.8 percent, compared to 2016. The large difference in net interchange volumes from 2016 to 2017 was primarily a result of the requirement for external capacity resources to be pseudo tied into PJM.[80]

## Table 3-53 Hourly average day-ahead number of cleared and submitted import and export transactions by month: 2016 and 2017

| | | Imports | | | | Exports | | | |
|---|---|---|---|---|---|---|---|---|---|
| Year | Month | 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 | 2,708 | 20 | 22 | 3,044 | 3,063 | 16 | 16 |
| 2016 | Feb | 2,396 | 2,480 | 20 | 22 | 2,634 | 2,653 | 13 | 13 |
| 2016 | Mar | 2,097 | 2,152 | 17 | 18 | 2,324 | 2,332 | 11 | 11 |
| 2016 | Apr | 2,150 | 2,110 | 16 | 16 | 2,620 | 2,499 | 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 | 1,361 | 6 | 7 | 4,327 | 4,353 | 21 | 21 |
| 2016 | Aug | 1,384 | 1,424 | 6 | 7 | 4,331 | 4,352 | 20 | 20 |
| 2016 | Sep | 939 | 956 | 5 | 5 | 3,997 | 4,004 | 21 | 21 |
| 2016 | Oct | 1,104 | 1,140 | 6 | 7 | 3,800 | 3,813 | 22 | 22 |
| 2016 | Nov | 1,012 | 1,030 | 6 | 7 | 2,883 | 2,895 | 17 | 17 |
| 2016 | Dec | 1,302 | 1,354 | 8 | 9 | 4,284 | 4,323 | 22 | 22 |
| 2016 | Annual | 1,627 | 1,666 | 11 | 12 | 3,439 | 3,445 | 18 | 18 |
| 2017 | Jan | 1,465 | 1,505 | 8 | 9 | 3,826 | 3,855 | 20 | 20 |
| 2017 | Feb | 1,379 | 1,418 | 7 | 8 | 3,540 | 3,558 | 19 | 19 |
| 2017 | Mar | 1,131 | 1,157 | 7 | 7 | 3,791 | 3,813 | 18 | 18 |
| 2017 | Apr | 614 | 621 | 5 | 5 | 3,050 | 3,070 | 16 | 16 |
| 2017 | May | 188 | 201 | 4 | 4 | 2,805 | 2,817 | 18 | 18 |
| 2017 | Jun | 248 | 255 | 3 | 4 | 2,705 | 2,730 | 16 | 16 |
| 2017 | Jul | 240 | 247 | 3 | 3 | 3,092 | 3,113 | 16 | 16 |
| 2017 | Aug | 158 | 168 | 2 | 3 | 2,399 | 2,410 | 12 | 13 |
| 2017 | Sep | 233 | 237 | 3 | 4 | 2,884 | 2,903 | 14 | 15 |
| 2017 | Oct | 211 | 218 | 3 | 3 | 2,293 | 2,301 | 12 | 12 |
| 2017 | Nov | 337 | 362 | 3 | 4 | 1,998 | 2,010 | 10 | 10 |
| 2017 | Dec | 324 | 386 | 3 | 5 | 3,192 | 3,245 | 15 | 15 |
| 2017 | Annual | 539 | 560 | 4 | 5 | 2,965 | 2,984 | 15 | 16 |

Table 3-54 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 from January 1, 2016, through December 31, 2017.

## Table 3-54 Type of day-ahead marginal units: 2016 and 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% | 2.8% | 0.0% | 83.4% | 8.9% | 4.9% |
| May | 6.2% | 0.1% | 83.8% | 6.5% | 3.4% | 0.0% | 3.5% | 0.0% | 77.4% | 11.8% | 7.2% |
| Jun | 3.5% | 0.0% | 84.2% | 8.5% | 3.7% | 0.0% | 4.3% | 0.0% | 73.5% | 15.4% | 6.7% |
| Jul | 3.0% | 0.0% | 83.1% | 10.1% | 3.7% | 0.0% | 2.9% | 0.0% | 77.1% | 13.6% | 6.4% |
| Aug | 3.1% | 0.0% | 78.4% | 13.1% | 5.3% | 0.0% | 3.8% | 0.0% | 81.8% | 9.0% | 5.4% |
| Sep | 6.1% | 0.0% | 76.3% | 11.4% | 6.2% | 0.0% | 6.6% | 0.0% | 77.8% | 9.8% | 5.8% |
| Oct | 6.1% | 0.1% | 77.0% | 10.9% | 5.9% | 0.0% | 6.3% | 0.0% | 77.7% | 10.3% | 5.7% |
| Nov | 4.0% | 0.0% | 86.5% | 6.3% | 3.1% | 0.0% | 5.1% | 0.1% | 78.7% | 10.6% | 5.6% |
| Dec | 3.1% | 0.0% | 86.6% | 6.9% | 3.3% | 0.0% | 4.9% | 0.1% | 78.9% | 10.8% | 5.3% |
| Annual | 4.7% | 0.0% | 82.4% | 8.6% | 4.2% | 0.0% | 4.3% | 0.0% | 79.9% | 10.2% | 5.5% |

80 2017 State of the Market Report for PJM, Volume 2, Section 9: Interchange Transactions, Figure 9-1.

Figure 3-36 shows the monthly volume of bid and cleared INC, DEC and up to congestion bids by month from January 1, 2005, through December 31, 2017.

### Figure 3-36 Monthly bid and cleared INCs, DECs and UTCs (MW): 2005 through 2017

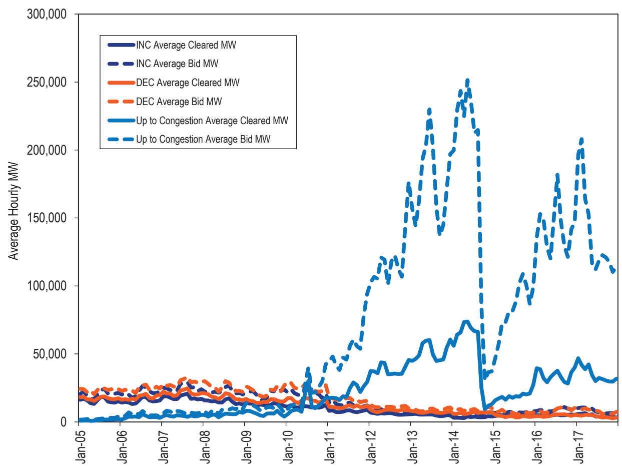
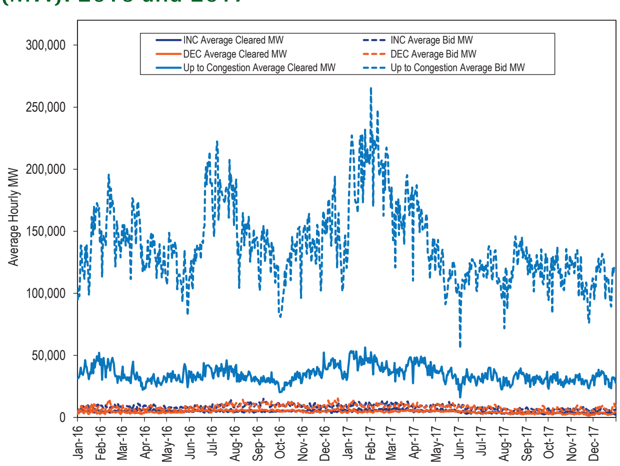



Figure 3-37 shows the daily volume of bid and cleared INC, DEC and up to congestion bids from January 1, 2016 through December 31, 2017.

### Figure 3-37 Daily bid and cleared INCs, DECs, and UTCs (MW): 2016 and 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 3-55 shows, in 2016 and 2017, the total increment offers and decrement bids and cleared MW by type of parent organization.

### Table 3-55 PJM INC and DEC bids and cleared MWh by type of parent organization (MWh): 2016 and 2017

| | 2016 | | | | 2017 | | | |
|---|---|---|---|---|---|---|---|---|
| Category | Total Virtual Bid MWh | Percent | Total Virtual Cleared MWh | Percent | Total Virtual Bid MWh | Percent | Total Virtual Cleared MWh | Percent |
| Financial | 85,003,436 | 54.8% | 31,248,242 | 35.5% | 84,330,236 | 60.8% | 33,711,497 | 44.8% |
| Physical | 70,131,528 | 45.2% | 56,700,299 | 64.5% | 54,433,944 | 39.2% | 41,594,291 | 55.2% |
| Total | 155,134,964 | 100.0% | 87,948,540 | 100.0% | 138,764,180 | 100.0% | 75,305,788 | 100.0% |

Table 3-56 shows, in 2016 and 2017, the total up to congestion bids and cleared MWh by whether the parent organization was financial or physical.

### Table 3-56 PJM up to congestion transactions by type of parent organization (MWh): 2016 and 2017

| | 2016 | | | | 2017 | | | |
|---|---|---|---|---|---|---|---|---|
| Category | Total Up to Congestion Bid MWh | Percent | Total Up to Congestion Cleared MWh | Percent | Total Up to Congestion Bid MWh | Percent | Total Up to Congestion Cleared MWh | Percent |
| Financial | 1,198,418,888 | 96.0% | 282,808,931 | 93.6% | 1,180,634,460 | 98.1% | 293,713,948 | 96.0% |
| Physical | 49,564,960 | 4.0% | 19,231,146 | 6.4% | 23,152,092 | 1.9% | 12,250,315 | 4.0% |
| Total | 1,247,983,848 | 100.0% | 302,040,077 | 100.0% | 1,203,786,552 | 100.0% | 305,964,263 | 100.0% |

Table 3-57 shows, in 2016 and 2017, the total import and export transactions by whether the parent organization was financial or physical.

### Table 3-57 PJM import and export transactions by type of parent organization (MW): 2016 and 2017

| | | 2016 | | 2017 | |
|---|---|---|---|---|---|
| | Category | Total Import and Export MW | Percent | Total Import and Export MW | Percent |
| Day-Ahead | Financial | 18,842,285 | 42.4% | 11,402,508 | 37.2% |
| | Physical | 25,620,598 | 57.6% | 19,275,555 | 62.8% |
| | Total | 44,462,883 | 100.0% | 30,678,064 | 100.0% |
| Real-Time | Financial | 26,873,422 | 35.8% | 19,528,399 | 36.1% |
| | Physical | 48,147,933 | 64.2% | 34,550,062 | 63.9% |
| | Total | 75,021,355 | 100.0% | 54,078,461 | 100.0% |

Table 3-58 shows increment offers and decrement bids by top 10 locations in 2016 and 2017.

### Table 3-58 PJM virtual offers and bids by top 10 locations (MW): 2016 and 2017

| 2016 | | | | | 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 | 23,814,905 | 22,211,825 | 46,026,730 | WESTERN HUB | HUB | 19,470,362 | 13,886,396 | 33,356,758 |
| MISO | INTERFACE | 394,038 | 4,965,920 | 5,359,958 | MISO | INTERFACE | 298,749 | 5,702,665 | 6,001,414 |
| SOUTHIMP | INTERFACE | 3,883,473 | 0 | 3,883,473 | AEP-DAYTON HUB | HUB | 2,281,775 | 670,706 | 2,952,481 |
| N ILLINOIS HUB | HUB | 1,157,102 | 2,568,493 | 3,725,595 | NYIS | INTERFACE | 1,567,702 | 1,353,652 | 2,921,355 |
| NYIS | INTERFACE | 1,644,784 | 1,492,322 | 3,137,107 | N ILLINOIS HUB | HUB | 595,931 | 1,917,519 | 2,513,450 |
| BGE | ZONE | 589,850 | 2,524,058 | 3,113,908 | SOUTHIMP | INTERFACE | 2,156,933 | 0 | 2,156,933 |
| AEP-DAYTON HUB | HUB | 1,795,772 | 1,095,818 | 2,891,590 | DCKCRKCE345 KV UN1 DYN | GEN | 1,331,426 | 773,672 | 2,105,098 |
| PEPCO | ZONE | 573,729 | 899,139 | 1,472,868 | BGE | ZONE | 417,037 | 1,384,137 | 1,801,174 |
| PECO | ZONE | 995,878 | 314,897 | 1,310,775 | FOWLER 34.5 KV FWLR1AWF | GEN | 378,544 | 1,399,471 | 1,778,015 |
| IMO | INTERFACE | 1,087,467 | 66,638 | 1,154,105 | PEPCO | ZONE | 480,538 | 672,508 | 1,153,047 |
| Top ten total | | 35,936,998 | 36,139,112 | 72,076,110 | | | 28,978,996 | 27,760,726 | 56,739,722 |
| PJM total | | 79,431,310 | 75,703,653 | 155,134,964 | | | 69,794,286 | 68,969,894 | 138,764,181 |
| Top ten total as percent of PJM total | | 45.2% | 47.7% | 46.5% | | | 41.5% | 40.3% | 40.9% |

Table 3-59 shows up to congestion transactions by import bids for the top 10 locations and associated profits at each path in 2016 and 2017.[81]

### Table 3-59 PJM cleared up to congestion import bids by top 10 source and sink pairs (MW): 2016 and 2017

| 2016 | | | | | | | |
|---|---|---|---|---|---|---|---|
| Imports | | | | | | | |
| Source | Source Type | Sink | Sink Type | MW | Source Profit | Sink Profit | UTC Profit |
| MISO | INTERFACE | COOK | EHVAGG | 924,623 | $324,666 | ($116,950) | $207,716 |
| HUDSONTP | INTERFACE | LEONIA 230 T-2 | AGGREGATE | 621,050 | $823,501 | ($790,051) | $33,450 |
| SOUTHWEST | INTERFACE | DUMONT | EHVAGG | 496,135 | $183,774 | ($96,395) | $87,378 |
| NEPTUNE | INTERFACE | SOUTHRIV 230 | AGGREGATE | 493,953 | $374,916 | ($111,860) | $263,056 |
| SOUTHWEST | INTERFACE | COOK | EHVAGG | 446,275 | $341,360 | ($62,815) | $278,544 |
| SOUTHIMP | INTERFACE | NAGELAEP | EHVAGG | 424,592 | $580,390 | ($661,851) | ($81,460) |
| MISO | INTERFACE | 112 WILTON | EHVAGG | 414,903 | $534,468 | ($438,828) | $95,640 |
| OVEC | INTERFACE | DEOK | ZONE | 376,077 | $226,257 | ($177,879) | $48,378 |
| OVEC | INTERFACE | BUCKEYE - AEP | AGGREGATE | 352,277 | $344,727 | ($308,143) | $36,584 |
| OVEC | INTERFACE | ATSI | ZONE | 333,697 | $83,965 | $139,439 | $223,405 |
| Top ten total | | | | 4,883,581 | $3,818,025 | ($2,625,333) | $1,192,692 |
| PJM total | | | | 27,794,147 | $19,515,404 | ($13,793,283) | $5,722,122 |
| Top ten total as percent of PJM total | | | | 17.6% | 19.6% | 19.0% | 20.8% |
| 2017 | | | | | | | |
| Imports | | | | | | | |
| Source | Source Type | Sink | Sink Type | MW | Source Profit | Sink Profit | UTC Profit |
| MISO | INTERFACE | COOK | EHVAGG | 862,597 | $530,817 | ($362,091) | $168,726 |
| HUDSONTP | INTERFACE | LEONIA 230 T-2 | AGGREGATE | 716,396 | ($1,077,843) | $1,106,825 | $28,981 |
| NYIS | INTERFACE | PSEG | ZONE | 440,185 | $620,936 | ($674,473) | ($53,537) |
| SOUTHEAST | INTERFACE | WEST INT HUB | HUB | 431,218 | $288,985 | ($234,984) | $54,002 |
| OVEC | INTERFACE | DEOK | ZONE | 414,137 | $453,386 | ($338,163) | $115,223 |
| SOUTHEAST | INTERFACE | VP KERR DAM 1-7 | AGGREGATE | 400,948 | $790,018 | ($552,390) | $237,628 |
| OVEC | INTERFACE | ATSI | ZONE | 361,693 | $125,111 | $89,257 | $214,368 |
| SOUTHWEST | INTERFACE | COOK | EHVAGG | 328,062 | $579,239 | ($284,341) | $294,898 |
| MISO | INTERFACE | AELC | AGGREGATE | 289,641 | $51,714 | ($34,635) | $17,079 |
| NORTHWEST | INTERFACE | COMED | ZONE | 273,133 | $61,611 | $103,176 | $164,787 |
| Top ten total | | | | 4,518,009 | $2,423,975 | ($1,181,820) | $1,242,155 |
| PJM total | | | | 22,394,654 | $14,515,393 | ($11,183,972) | $3,331,421 |
| Top ten total as percent of PJM total | | | | 20.2% | 16.7% | 10.6% | 37.3% |

81 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 3-60 shows up to congestion transactions by export bids for the top 10 locations and associated profits at each path in 2016 and 2017.

### Table 3-60 PJM cleared up to congestion export bids by top 10 source and sink pairs (MW): 2016 and 2017

| 2016 | | | | | | | |
|---|---|---|---|---|---|---|---|
| Exports | | | | | | | |
| Source | Source Type | Sink | Sink Type | MW | Source Profit | Sink Profit | UTC Profit |
| COMED | ZONE | NIPSCO | INTERFACE | 1,427,296 | $1,150,528 | $271,313 | $1,421,841 |
| 21 KINCA ATR24304 | AGGREGATE | SOUTHWEST | INTERFACE | 984,202 | $1,074,369 | ($776,386) | $297,984 |
| SULLIVAN-AEP | EHVAGG | OVEC | INTERFACE | 865,527 | $964,583 | ($657,405) | $307,179 |
| 21 KINCA ATR24304 | AGGREGATE | NIPSCO | INTERFACE | 766,929 | $745,474 | $47,324 | $792,799 |
| POWERTON 5 | AGGREGATE | NORTHWEST | INTERFACE | 550,217 | $736,607 | ($596,755) | $139,852 |
| ROCKPORT | EHVAGG | SOUTHWEST | INTERFACE | 521,854 | $21,884 | $45,506 | $67,390 |
| STMARYSGEN | AGGREGATE | NIPSCO | INTERFACE | 452,574 | $333,034 | ($241,863) | $91,170 |
| EAST BEND 2 | AGGREGATE | SOUTHWEST | INTERFACE | 398,268 | $393,612 | ($305,651) | $87,962 |
| GRAND RIDGE WF | AGGREGATE | NIPSCO | INTERFACE | 361,733 | $168,945 | $39,281 | $208,226 |
| 21 KINCA ATR24404 | AGGREGATE | SOUTHWEST | INTERFACE | 361,040 | ($62,242) | $222,140 | $159,898 |
| Top ten total | | | | 6,689,640 | $5,526,794 | ($1,952,495) | $3,574,298 |
| PJM total | | | | 21,121,645 | $13,506,455 | ($5,059,150) | $8,447,305 |
| Top ten total as percent of PJM total | | | | 31.7% | 40.9% | 38.6% | 42.3% |
| 2017 | | | | | | | |
| Exports | | | | | | | |
| Source | Source Type | Sink | Sink Type | MW | Source Profit | Sink Profit | UTC Profit |
| JEFFERSON | EHVAGG | SOUTHWEST | INTERFACE | 958,719 | $1,105,168 | ($832,337) | $272,832 |
| COMED | ZONE | NIPSCO | INTERFACE | 902,140 | $213,294 | $753,759 | $967,053 |
| 21 KINCA ATR24304 | AGGREGATE | SOUTHWEST | INTERFACE | 885,040 | $420,564 | ($337,615) | $82,949 |
| SULLIVAN-AEP | EHVAGG | SOUTHWEST | INTERFACE | 596,031 | $201,669 | ($114,584) | $87,085 |
| POWERTON 5 | AGGREGATE | NORTHWEST | INTERFACE | 467,263 | ($130,278) | $93,241 | ($37,037) |
| JEFFERSON | EHVAGG | NIPSCO | INTERFACE | 440,544 | $511,047 | ($307,845) | $203,202 |
| ROCKPORT | EHVAGG | SOUTHWEST | INTERFACE | 409,795 | $205,091 | ($191,932) | $13,159 |
| 21 KINCA ATR24304 | AGGREGATE | NIPSCO | INTERFACE | 368,921 | $102,909 | ($48,839) | $54,070 |
| STMARYSGEN | AGGREGATE | NIPSCO | INTERFACE | 364,289 | $391,159 | ($414,341) | ($23,182) |
| NAGELAEP | EHVAGG | SOUTHWEST | INTERFACE | 315,139 | $185,106 | ($95,591) | $89,515 |
| Top ten total | | | | 5,707,881 | $3,205,729 | ($1,496,083) | $1,709,646 |
| PJM total | | | | 20,710,413 | $6,965,558 | $321,519 | $7,287,077 |
| Top ten total as percent of PJM total | | | | 27.6% | 46.0% | (465.3%) | 23.5% |

Table 3-61 shows up to congestion transactions by wheel bids and associated profits at each path for the top 10 locations in 2016 and 2017.

### Table 3-61 PJM cleared up to congestion wheel bids by top 10 source and sink pairs (MW): 2016 and 2017

| 2016 | | | | | | | |
|---|---|---|---|---|---|---|---|
| Wheels | | | | | | | |
| Source | Source Type | Sink | Sink Type | MW | Source Profit | Sink Profit | UTC Profit |
| NORTHWEST | INTERFACE | MISO | INTERFACE | 483,587 | $205,487 | ($138,661) | $66,826 |
| MISO | INTERFACE | NIPSCO | INTERFACE | 456,491 | $407,571 | ($101,219) | $306,352 |
| SOUTHWEST | INTERFACE | SOUTHEXP | INTERFACE | 355,456 | $712,745 | ($580,097) | $132,648 |
| MISO | INTERFACE | NORTHWEST | INTERFACE | 249,915 | $248,663 | ($15,678) | $232,985 |
| NYIS | INTERFACE | IMO | INTERFACE | 235,084 | $17,499 | $41,318 | $58,817 |
| IMO | INTERFACE | NYIS | INTERFACE | 125,377 | $92,270 | ($146,944) | ($54,673) |
| SOUTHWEST | INTERFACE | NIPSCO | INTERFACE | 89,731 | $111,695 | ($63,301) | $48,394 |
| IMO | INTERFACE | MISO | INTERFACE | 76,985 | $33,213 | ($103,413) | ($70,200) |
| MISO | INTERFACE | SOUTHEXP | INTERFACE | 40,226 | $104,721 | ($76,174) | $28,547 |
| NEPTUNE | INTERFACE | NYIS | INTERFACE | 33,963 | $41,687 | ($35,445) | $6,242 |
| Top ten total | | | | 2,146,815 | $1,975,552 | ($1,219,614) | $755,937 |
| PJM total | | | | 2,492,100 | $2,189,382 | ($1,291,897) | $897,485 |
| Top ten total as percent of PJM total | | | | 86.1% | 90.2% | 94.4% | 84.2% |
| 2017 | | | | | | | |
| Wheels | | | | | | | |
| Source | Source Type | Sink | Sink Type | MW | Source Profit | Sink Profit | UTC Profit |
| MISO | INTERFACE | NIPSCO | INTERFACE | 312,671 | $373,405 | ($178,579) | $194,827 |
| MISO | INTERFACE | NORTHWEST | INTERFACE | 290,558 | $254,925 | ($157,891) | $97,035 |
| SOUTHWEST | INTERFACE | SOUTHEXP | INTERFACE | 249,976 | $572,074 | ($618,373) | ($46,298) |
| NORTHWEST | INTERFACE | MISO | INTERFACE | 245,473 | $207,111 | ($48,206) | $158,905 |
| SOUTHWEST | INTERFACE | NIPSCO | INTERFACE | 78,378 | $96,395 | ($31,898) | $64,497 |
| NORTHWEST | INTERFACE | NIPSCO | INTERFACE | 66,895 | $11,965 | $88,301 | $100,266 |
| OVEC | INTERFACE | SOUTHWEST | INTERFACE | 42,037 | $44,820 | ($47,195) | ($2,375) |
| OVEC | INTERFACE | MISO | INTERFACE | 37,097 | $6,134 | $1,438 | $7,572 |
| SOUTHEAST | INTERFACE | SOUTHEXP | INTERFACE | 34,279 | $11,127 | $5,177 | $16,304 |
| SOUTHEAST | INTERFACE | NORTHWEST | INTERFACE | 22,300 | $28,198 | $54,892 | $83,090 |
| Top ten total | | | | 1,379,663 | $1,606,156 | ($932,332) | $673,823 |
| PJM total | | | | 1,652,065 | $1,637,231 | ($973,154) | $664,077 |
| Top ten total as percent of PJM total | | | | 83.5% | 98.1% | 95.8% | 101.5% |

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 5.6 percent of the PJM total internal up to congestion transactions MW in 2017.

Table 3-62 shows up to congestion transactions by internal bids for the top 10 locations and associated profits at each path in 2016 and 2017. The total UTC profit by top 10 locations increased by $0.5 million, from $2.4 million in 2016 to $2.9 million in 2017. The total internal cleared MW increased by 10.5 million MW, or 4.2 percent, from 250.6 million MW in 2016 to 261.2 million MW in 2017.

## Table 3-62 PJM cleared up to congestion internal bids by top 10 source and sink pairs (MW): 2016 and 2017

| 2016 | | | | | | | |
|---|---|---|---|---|---|---|---|
| Internal | | | | | | | |
| Source | Source Type | Sink | Sink Type | MW | Source Profit | Sink Profit | UTC Profit |
| 21 KINCA ATR24304 | AGGREGATE | MICHFE | AGGREGATE | 1,723,607 | $152,078 | $417,191 | $569,268 |
| 21 KINCA ATR24404 | AGGREGATE | MICHFE | AGGREGATE | 1,376,889 | ($261,431) | $444,443 | $183,012 |
| BERGEN 2CC | AGGREGATE | LEONIA 230 T-1 | AGGREGATE | 1,238,324 | $1,483,047 | ($1,494,384) | ($11,337) |
| WHIPPANY BK 7 | AGGREGATE | TRAYNOR | AGGREGATE | 1,134,144 | $806,939 | ($745,745) | $61,194 |
| BYRON 1 | AGGREGATE | ROCKFORD | AGGREGATE | 1,092,314 | $712,354 | $187,518 | $899,873 |
| AEP-DAYTON HUB | HUB | N ILLINOIS HUB | HUB | 970,055 | $249,345 | ($453,393) | ($204,048) |
| BLACKOAK | EHVAGG | BEDINGTON | EHVAGG | 927,715 | $702,188 | ($1,303,092) | ($600,904) |
| BRISTERS | EHVAGG | OX | EHVAGG | 900,322 | $1,344,558 | ($1,275,869) | $68,689 |
| WAUKEGAN TR412 | AGGREGATE | COMED | ZONE | 871,975 | $435,670 | ($175,527) | $260,142 |
| CLOVERDALE | EHVAGG | CLOVERD2 138 KV T4 | AGGREGATE | 870,195 | $627,455 | $534,600 | $1,162,055 |
| Top ten total | | | | 11,105,541 | $6,252,202 | ($3,864,258) | $2,387,944 |
| PJM total | | | | 250,632,186 | $166,288,527 | ($133,865,762) | $32,422,765 |
| Top ten total as percent of PJM total | | | | 4.4% | 3.8% | 2.9% | 7.4% |
| 2017 | | | | | | | |
| Internal | | | | | | | |
| Source | Source Type | Sink | Sink Type | MW | Source Profit | Sink Profit | UTC Profit |
| DUMONT | EHVAGG | COOK | EHVAGG | 2,543,775 | $1,574,512 | ($1,246,431) | $328,081 |
| STUART 3 | AGGREGATE | MICHFE | AGGREGATE | 1,669,383 | $658,096 | ($62,625) | $595,471 |
| DAY | ZONE | BUCKEYE - DPL | AGGREGATE | 1,598,133 | $726,065 | ($528,828) | $197,237 |
| AEP-DAYTON HUB | HUB | N ILLINOIS HUB | HUB | 1,525,047 | $474,692 | ($16,762) | $457,930 |
| BAKER | EHVAGG | AMP-OHIO | AGGREGATE | 1,342,005 | $648,116 | ($254,350) | $393,767 |
| FE GEN | AGGREGATE | ATSI | ZONE | 1,327,118 | ($51,472) | $239,827 | $188,355 |
| JEFFERSON | EHVAGG | OHIO HUB | HUB | 1,302,743 | $1,079,684 | ($695,857) | $383,827 |
| WINNETKA | AGGREGATE | CHICAGO HUB | HUB | 1,110,026 | $279,842 | ($154,257) | $125,585 |
| WAUKEGAN TR412 | AGGREGATE | KENDALL 1-2 | AGGREGATE | 1,093,269 | $206,011 | ($47,976) | $158,036 |
| ELWOOD 5 | AGGREGATE | KENDALL 1-2 | AGGREGATE | 1,021,633 | $212,292 | ($116,383) | $95,909 |
| Top ten total | | | | 14,533,132 | $5,807,839 | ($2,883,640) | $2,924,199 |
| PJM total | | | | 261,207,130 | $83,701,553 | ($40,113,288) | $43,588,265 |
| Top ten total as percent of PJM total | | | | 5.6% | 6.9% | 7.2% | 6.7% |

Table 3-63 shows the number of source-sink pairs that were offered and cleared monthly for January 1, 2016 through December 31, 2017.

## Table 3-63 Number of PJM offered and cleared source and sink pairs: 2016 and 2017

| | | Daily Number of Source-Sink Pairs | | | |
|---|---|---|---|---|---|
| Year | Month | Average Offered | Max Offered | Average Cleared | Max Cleared |
| 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 | Apr | 8,168 | 8,805 | 6,494 | 7,172 |
| 2017 | May | 7,936 | 9,117 | 6,477 | 7,294 |
| 2017 | Jun | 9,776 | 13,012 | 5,822 | 6,228 |
| 2017 | Jul | 12,726 | 13,334 | 5,960 | 6,481 |
| 2017 | Aug | 12,966 | 15,729 | 6,578 | 7,201 |
| 2017 | Sep | 7,758 | 9,229 | 6,030 | 7,162 |
| 2017 | Oct | 8,540 | 9,432 | 6,507 | 7,189 |
| 2017 | Nov | 8,027 | 9,665 | 6,273 | 7,444 |
| 2017 | Dec | 7,782 | 8,872 | 5,892 | 6,771 |
| 2017 | Annual | 9,392 | 10,928 | 6,385 | 7,212 |

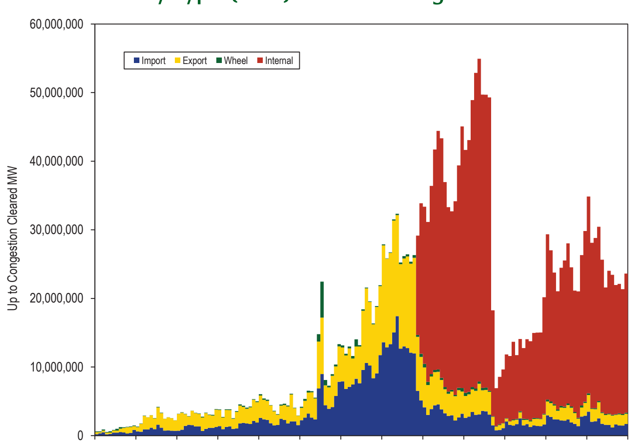
Table 3-64 and Figure 3-38 show total cleared up to congestion transactions by type in 2016 and 2017. Total up to congestion transactions in 2017 increased by 1.3 percent from 302.0 million MW in 2016 to 306.0 million MW in 2017. Internal up to congestion transactions in 2017 were 85.4 percent of all up to congestion transactions compared to 83.0 percent in 2016.

### Table 3-64 PJM cleared up to congestion transactions by type (MW): 2016 and 2017

| | 2016 | | | | |
|---|---|---|---|---|---|
| | Cleared Up to Congestion Bids | | | | |
| | Import | Export | Wheel | Internal | Total |
| Top ten total (MW) | 4,883,581 | 6,689,640 | 2,146,815 | 11,105,541 | 24,825,577 |
| PJM total (MW) | 27,794,147 | 21,121,645 | 2,492,100 | 250,632,186 | 302,040,078 |
| Top ten total as percent of PJM total | 17.6% | 31.7% | 86.1% | 4.4% | 8.2% |
| PJM total as percent of all up to congestion transactions | 9.2% | 7.0% | 0.8% | 83.0% | 100.0% |
| | 2017 | | | | |
| | Cleared Up to Congestion Bids | | | | |
| | Import | Export | Wheel | Internal | Total |
| Top ten total (MW) | 4,518,009 | 5,707,881 | 1,379,663 | 14,533,132 | 26,138,685 |
| PJM total (MW) | 22,394,654 | 20,710,413 | 1,652,065 | 261,207,130 | 305,964,262 |
| Top ten total as percent of PJM total | 20.2% | 27.6% | 83.5% | 5.6% | 8.5% |
| PJM total as percent of all up to congestion transactions | 7.3% | 6.8% | 0.5% | 85.4% | 100.0% |

Figure 3-38 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 15 month refund period for the proceeding related to uplift charges for UTC transactions.[82]

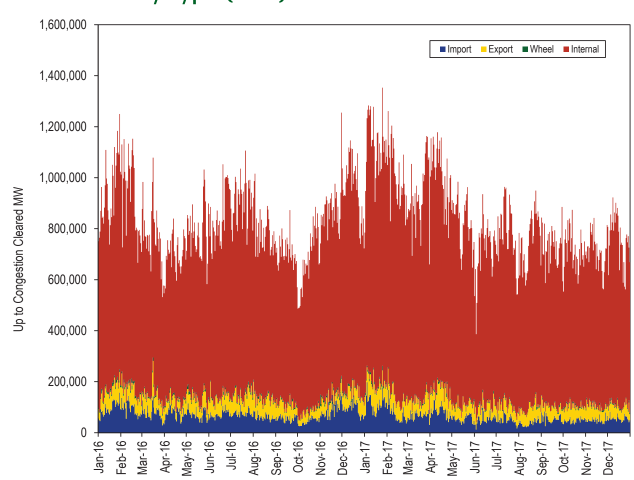
### Figure 3-38 PJM monthly cleared up to congestion transactions by type (MW): 2005 through 2017




82 *Id.*

Figure 3-39 shows the daily cleared up to congestion MW by transaction type from January 1, 2016 through December 31, 2017.

### Figure 3-39 PJM daily cleared up to congestion transaction by type (MW): 2016 and 2017



# Market Performance

PJM locational marginal prices (LMPs) are a direct measure of market performance. The market performs optimally when the market structure provides incentives for market participants to behave competitively. With price formation in a competitive market, prices equal the value of the marginal unit of output and reflect the most efficient and least cost allocation of resources to meet demand.

## Markup

The markup index is a measure of the competitiveness of participant behavior for individual 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 have different impacts on total system price. Markup can also affect prices when units with high markups are not marginal by altering the economic dispatch order of supply.

The MMU calculates an explicit measure of the impact of marginal unit markups on LMP using the mathematical relationships among LMPs in the market solution.[83] The markup impact calculation sums, over all marginal units, the product of the dollar markup of the unit and the marginal impact of the unit's offer on the system load-weighted LMP. The markup impact includes the impact of the identified markup behavior of all marginal units. Positive and negative markup impacts may offset one another. The markup analysis is a direct measure of market performance. It does not take into account whether or not marginal units have either locational or aggregate structural market power.

The markup calculation is not based on a counterfactual 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. 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.

## 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 3-65 shows the impact (markup component of LMP) of the markup behavior by fuel type and unit type on the real-time load-weighted average system LMP, using unadjusted and adjusted offers. The adjusted markup component of LMP increased from $2.68 per MWh in 2016 to $4.94 per MWh in 2017. The adjusted markup contribution of coal units in 2017 was $1.38 per MWh. The adjusted markup component of gas fired units in 2017 was $3.35 per MWh, an increase of $0.92 per MWh from 2016. The markup component of wind units was $0.07 per MWh. If a price-based offer is negative, but less negative than a cost-based offer, the markup is positive. In 2017, among the wind units that were marginal, 6.3 percent had positive offer prices.

83 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. 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.

Table 3-65 Markup component of the overall PJM real-time, load-weighted, average LMP by primary fuel type and unit type: 2016 and 2017[84]

| | | 2016 | | 2017 | |
|---|---|---|---|---|---|
| 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 | ($1.23) | $0.31 | $0.35 | $1.38 |
| Gas | CC | $1.18 | $1.69 | $1.80 | $2.86 |
| Gas | CT | $0.16 | $0.37 | $0.22 | $0.40 |
| Gas | Diesel | $0.00 | $0.00 | ($0.00) | $0.01 |
| Gas | Steam | $0.26 | $0.38 | $0.02 | $0.09 |
| Municipal Waste | Diesel | $0.01 | $0.01 | $0.00 | $0.00 |
| Municipal Waste | Steam | ($0.00) | ($0.00) | $0.00 | $0.00 |
| Oil | CC | $0.00 | $0.00 | ($0.00) | ($0.00) |
| Oil | CT | $0.01 | $0.03 | $0.01 | $0.04 |
| Oil | Diesel | $0.00 | $0.00 | $0.00 | $0.00 |
| Oil | Steam | $0.00 | $0.00 | ($0.01) | $0.00 |
| Other | Steam | ($0.13) | ($0.13) | $0.09 | $0.09 |
| Uranium | | $0.00 | $0.00 | $0.00 | $0.00 |
| Wind | | $0.02 | $0.02 | $0.07 | $0.07 |
| Total | | $0.27 | $2.68 | $2.55 | $4.94 |

## Markup Component of Real-Time Price

Table 3-66 shows the markup component, calculated using unadjusted offers, of average prices and of average monthly on peak and off peak prices. Table 3-67 shows the markup component, calculated using adjusted offers, of average prices and of average monthly on peak and off peak prices. In 2017, when using unadjusted cost offers, $2.55 per MWh of the PJM real-time load-weighted average LMP was attributable to markup. Using adjusted cost offers, $4.94 per MWh of the PJM real-time load-weighted, average LMP was attributable to markup. In 2017, the peak markup component was highest in May, $5.51 per MWh using unadjusted cost-based offers and $8.23 per MWh using adjusted cost-based offers. This corresponds to 14.54 percent and 21.72 percent of the real-time peak load-weighted average LMP in May.

Table 3-66 Monthly markup components of real-time load-weighted LMP (Unadjusted): 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) | $1.47 | $0.53 | $2.36 |
| Mar | ($1.24) | ($1.22) | ($1.25) | $1.10 | $1.70 | $0.55 |
| Apr | $0.32 | ($0.82) | $1.41 | $1.87 | $0.93 | $2.86 |
| May | ($1.68) | ($1.13) | ($2.24) | $2.91 | ($0.01) | $5.51 |
| Jun | $0.86 | $0.60 | $1.07 | $3.08 | $0.93 | $4.88 |
| Jul | ($0.06) | ($1.02) | $0.89 | $3.62 | $2.16 | $5.12 |
| Aug | $1.18 | $0.10 | $2.06 | $2.87 | $1.51 | $3.94 |
| Sep | $2.23 | $1.25 | $3.12 | $3.42 | $1.46 | $5.35 |
| Oct | $1.51 | ($0.05) | $3.05 | $2.52 | $1.33 | $3.62 |
| Nov | $1.37 | $0.28 | $2.45 | $0.72 | $0.68 | $0.77 |
| Dec | $1.07 | ($0.10) | $2.29 | $4.68 | $5.03 | $4.26 |
| Total | $0.27 | ($0.41) | $0.92 | $2.55 | $1.49 | $3.58 |

84 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 3-67 Monthly markup components of real-time load-weighted LMP (Adjusted): 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 | $3.66 | $2.60 | $4.67 |
| Mar | $0.63 | $0.49 | $0.76 | $3.56 | $3.82 | $3.33 |
| Apr | $2.61 | $1.32 | $3.85 | $4.01 | $2.95 | $5.12 |
| May | $0.35 | $0.65 | $0.06 | $5.33 | $2.07 | $8.23 |
| Jun | $3.10 | $2.54 | $3.58 | $5.29 | $2.85 | $7.33 |
| Jul | $2.64 | $1.19 | $4.08 | $6.08 | $4.29 | $7.92 |
| Aug | $4.02 | $2.39 | $5.35 | $5.06 | $3.43 | $6.35 |
| Sep | $4.58 | $3.25 | $5.79 | $5.57 | $3.37 | $7.73 |
| Oct | $3.81 | $2.05 | $5.54 | $4.77 | $3.34 | $6.08 |
| Nov | $3.54 | $2.29 | $4.78 | $3.16 | $2.88 | $3.43 |
| Dec | $3.78 | $2.44 | $5.17 | $7.64 | $7.84 | $7.40 |
| Total | $2.68 | $1.71 | $3.61 | $4.94 | $3.66 | $6.18 |

## Hourly Markup Component of Real-Time Prices

Figure 3-40 shows the markup contribution to the hourly load-weighted LMP using unadjusted cost offers in 2017 and 2016. Figure 3-41 shows the markup contribution to the hourly load-weighted LMP using adjusted cost-based offers in 2017 and 2016. The hourly markup component of real-time prices was higher during the last week of December 2017, when the PJM region experienced particularly low temperatures.

Figure 3-40 Markup contribution to real-time hourly load-weighted LMP (Unadjusted): 2016 and 2017

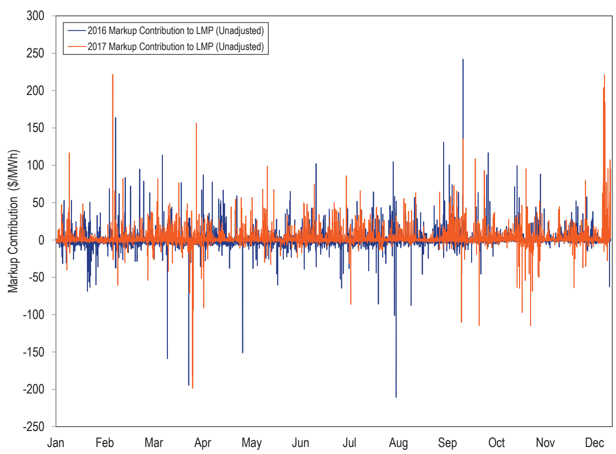
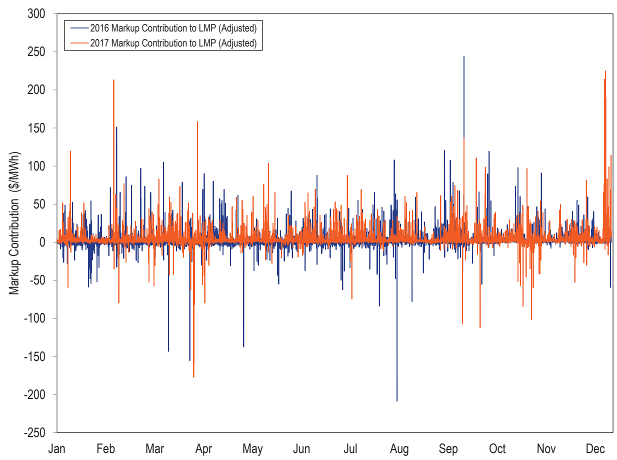



Figure 3-41 Markup contribution to real-time hourly load-weighted LMP (Adjusted): 2016 and 2017




## 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 2016 and 2017 in Table 3-68 and for adjusted offers in Table 3-69. The smallest zonal all hours average markup component using unadjusted offers in 2017 was in the EKPC Zone, $2.08 per MWh, while the highest was in the BGE Control Zone, $3.46 per MWh. The smallest zonal on peak average markup component using unadjusted offers in 2017 was in the PECO Control Zone, $2.90 per MWh, while the highest was in the BGE Control Zone, $4.73 per MWh.

## Table 3-68 Average real-time zonal markup component (Unadjusted): 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 |
| AECO | $1.21 | $0.69 | $1.72 | $2.38 | $1.67 | $3.09 |
| AEP | ($0.06) | ($0.75) | $0.62 | $2.25 | $1.27 | $3.20 |
| APS | $0.06 | ($0.67) | $0.78 | $2.56 | $1.47 | $3.65 |
| ATSI | $0.12 | ($0.67) | $0.86 | $2.36 | $1.23 | $3.43 |
| BGE | ($0.81) | ($1.94) | $0.28 | $3.46 | $2.16 | $4.73 |
| ComEd | $0.17 | ($0.58) | $0.85 | $2.17 | $1.08 | $3.19 |
| DAY | ($0.10) | ($0.71) | $0.45 | $2.33 | $1.30 | $3.30 |
| DEOK | $0.00 | ($0.69) | $0.66 | $2.39 | $1.29 | $3.46 |
| DLCO | $0.26 | ($0.56) | $1.04 | $2.32 | $1.16 | $3.44 |
| DPL | $1.50 | $0.87 | $2.12 | $2.76 | $2.02 | $3.48 |
| Dominion | ($0.17) | ($0.86) | $0.50 | $3.18 | $1.88 | $4.47 |
| EKPC | ($0.04) | ($0.47) | $0.39 | $2.08 | $1.27 | $2.92 |
| JCPL | $1.28 | $0.81 | $1.71 | $2.77 | $1.77 | $3.70 |
| Met-Ed | $0.98 | $0.65 | $1.28 | $2.37 | $1.44 | $3.26 |
| PECO | $1.38 | $0.75 | $1.98 | $2.26 | $1.58 | $2.90 |
| PENELEC | $0.42 | ($0.22) | $1.02 | $2.60 | $1.49 | $3.65 |
| PPL | $1.13 | $0.64 | $1.59 | $2.37 | $1.46 | $3.23 |
| PSEG | $1.21 | $0.73 | $1.65 | $2.82 | $1.69 | $3.88 |
| Pepco | ($0.51) | ($1.30) | $0.24 | $3.13 | $1.90 | $4.30 |
| RECO | $1.25 | $0.62 | $1.80 | $3.07 | $2.03 | $3.97 |

## Table 3-69 Average real-time zonal markup component (Adjusted): 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 |
| AECO | $3.34 | $2.52 | $4.13 | $4.74 | $3.80 | $5.67 |
| AEP | $2.37 | $1.42 | $3.29 | $4.59 | $3.43 | $5.73 |
| APS | $2.55 | $1.54 | $3.53 | $4.98 | $3.68 | $6.26 |
| ATSI | $2.58 | $1.49 | $3.60 | $4.82 | $3.43 | $6.15 |
| BGE | $2.34 | $0.90 | $3.73 | $6.05 | $4.45 | $7.60 |
| ComEd | $2.49 | $1.43 | $3.47 | $4.37 | $3.06 | $5.60 |
| DAY | $2.34 | $1.48 | $3.14 | $4.75 | $3.50 | $5.92 |
| DEOK | $2.37 | $1.43 | $3.26 | $4.68 | $3.40 | $5.92 |
| DLCO | $2.68 | $1.55 | $3.76 | $4.72 | $3.33 | $6.06 |
| DPL | $3.75 | $2.81 | $4.67 | $5.36 | $4.49 | $6.22 |
| Dominion | $2.55 | $1.58 | $3.51 | $5.67 | $4.17 | $7.16 |
| EKPC | $2.34 | $1.68 | $3.00 | $4.39 | $3.40 | $5.40 |
| JCPL | $3.37 | $2.60 | $4.07 | $5.15 | $3.92 | $6.30 |
| Met-Ed | $3.04 | $2.40 | $3.64 | $4.80 | $3.54 | $5.99 |
| PECO | $3.41 | $2.49 | $4.27 | $4.60 | $3.72 | $5.43 |
| PENELEC | $2.70 | $1.77 | $3.58 | $5.03 | $3.63 | $6.35 |
| PPL | $3.15 | $2.39 | $3.87 | $4.74 | $3.61 | $5.81 |
| PSEG | $3.31 | $2.50 | $4.06 | $5.20 | $3.82 | $6.50 |
| Pepco | $2.34 | $1.25 | $3.36 | $5.65 | $4.16 | $7.06 |
| RECO | $3.41 | $2.43 | $4.26 | $5.48 | $4.16 | $6.63 |

### Markup by Real Time Price Levels

Table 3-70 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 3-70 Average real-time markup component (By price category, unadjusted): 2016 and 2017

| | 2016 | | 2017 | |
|---|---|---|---|---|
| LMP Category | Average Markup Component | Frequency | Average Markup Component | Frequency |
| < $25 | ($0.43) | 70.0% | ($0.07) | 47.9% |
| $25 to $50 | ($0.24) | 25.7% | $1.19 | 45.9% |
| $50 to $75 | $0.46 | 2.8% | $0.76 | 4.2% |
| $75 to $100 | $0.27 | 1.0% | $0.31 | 1.2% |
| $100 to $125 | $0.11 | 0.3% | $0.14 | 0.4% |
| $125 to $150 | $0.03 | 0.1% | $0.05 | 0.2% |
| >= $150 | $0.07 | 0.1% | $0.20 | 0.2% |

#### Table 3-71 Average real-time markup component (By price category, adjusted): 2016 and 2017

| | 2016 | | 2017 | |
|---|---|---|---|---|
| LMP Category | Average Markup Component | Frequency | Average Markup Component | Frequency |
| < $25 | $0.94 | 70.0% | $0.76 | 47.9% |
| $25 to $50 | $0.63 | 25.7% | $2.48 | 45.9% |
| $50 to $75 | $0.58 | 2.7% | $0.94 | 4.2% |
| $75 to $100 | $0.34 | 1.0% | $0.38 | 1.2% |
| $100 to $125 | $0.13 | 0.3% | $0.17 | 0.4% |
| $125 to $150 | $0.04 | 0.1% | $0.07 | 0.2% |
| >= $150 | $0.08 | 0.1% | $0.20 | 0.2% |

## Day-Ahead Markup

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

The markup component of the PJM day-ahead, load-weighted average LMP by primary fuel and unit type is shown in Table 3-72. INC, DEC and up to congestion transactions have zero markups. INCs were 5.5 percent of marginal resources and DECs were 10.2 percent of marginal resources in 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. However, the share of marginal up to congestion transactions increased from 76.1 percent in 2015 to 82.4 percent in 2016 due to the expiration of the fifteen months resettlement period for the proceeding related to uplift charges for UTC transactions. The share of marginal up to congestion transactions decreased from 82.4 percent in 2016 to 79.9 percent in 2017. The adjusted markup of coal, gas and oil units is calculated as the difference between the price-based offer, and the cost-based offer excluding the 10 percent adder. Table 3-72 shows the markup component of LMP for marginal generating resources. Generating resources were only 4.3 percent of marginal resources in 2017. Using adjusted cost-based offers, the markup component of LMP for marginal generating resources increased for coal fired steam units from -$0.15 to $0.95 and increased for gas fired CT units from $0.05 to $0.08. The markup component of LMP for coal fired steam units increased from -$1.12 in 2016 to $0.22 in 2017 using unadjusted cost-based offers. The markup component of LMP for gas fired steam units increased from $0.34 in 2016 to $0.45 in 2017 using unadjusted cost-based offers.

#### Table 3-72 Markup component of the annual PJM day-ahead, load-weighted, average LMP by primary fuel type and unit type: 2016 and 2017

| | | 2016 | | 2017 | |
|---|---|---|---|---|---|
| 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 | ($1.12) | ($0.15) | $0.22 | $0.95 |
| Gas | CT | $0.03 | $0.05 | $0.04 | $0.08 |
| Gas | Diesel | $0.00 | $0.00 | $0.00 | $0.00 |
| Gas | Steam | $0.34 | $0.65 | $0.45 | $1.00 |
| 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 | ($0.01) | ($0.01) |
| Other | Steam | ($0.12) | ($0.12) | $0.01 | $0.01 |
| Wind | Wind | $0.02 | $0.02 | $0.01 | $0.01 |
| Total | | ($0.85) | $0.46 | $0.72 | $2.04 |

### 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 3-73 shows the markup component of average prices and of average monthly on-peak and off-peak prices using unadjusted cost-based offers. In 2017, when using unadjusted cost-based offers, $0.72 per MWh of the PJM day-ahead load-weighted average LMP was attributable to markup. In 2017, the peak markup component was highest in September, $2.72 per MWh using unadjusted cost-based offers.

Table 3-73 Monthly markup components of day-ahead (Unadjusted), load-weighted LMP: 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) | $0.82 | $1.64 | $0.03 |
| May | ($0.71) | ($0.16) | ($1.26) | $0.45 | $1.07 | ($0.25) |
| Jun | $0.19 | $0.74 | ($0.48) | $0.90 | $1.35 | $0.35 |
| Jul | ($3.73) | ($6.42) | ($1.05) | $0.60 | $1.12 | $0.09 |
| Aug | ($0.05) | $0.08 | ($0.22) | $1.13 | $1.94 | $0.09 |
| Sep | ($0.99) | ($0.57) | ($1.47) | $1.65 | $2.72 | $0.57 |
| Oct | $0.65 | $1.75 | ($0.45) | $1.71 | $2.69 | $0.64 |
| Nov | $0.08 | $0.52 | ($0.37) | ($0.08) | ($0.23) | $0.08 |
| Dec | $0.30 | $0.89 | ($0.27) | $0.90 | $1.60 | $0.29 |
| Annual | ($0.85) | ($0.66) | ($1.04) | $0.72 | $1.29 | $0.12 |

Table 3-74 shows the markup component of average prices and of average monthly on peak and off peak prices using adjusted cost-based offers. In 2017, when using adjusted cost-based offers, $2.04 per MWh of the PJM day-ahead load-weighted average LMP was attributable to markup. In 2017, the peak markup component was highest in September, $3.99 per MWh using adjusted cost-based offers.

Table 3-74 Monthly markup components of day-ahead (Adjusted), load-weighted LMP: 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 | ($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) | $1.94 | $2.50 | $1.41 |
| May | $0.60 | $1.10 | $0.09 | $1.62 | $2.05 | $1.14 |
| Jun | $1.58 | $2.16 | $0.89 | $2.40 | $2.96 | $1.71 |
| Jul | ($2.90) | ($6.38) | $0.58 | $1.73 | $1.96 | $1.50 |
| Aug | $1.10 | $0.97 | $1.27 | $2.40 | $3.09 | $1.52 |
| Sep | $0.17 | $0.17 | $0.16 | $2.98 | $3.99 | $1.96 |
| Oct | $1.69 | $2.46 | $0.91 | $2.88 | $3.76 | $1.92 |
| Nov | $1.25 | $1.51 | $0.99 | $1.33 | $1.13 | $1.53 |
| Dec | $1.82 | $2.14 | $1.50 | $2.52 | $3.10 | $2.03 |
| Annual | $0.46 | $0.43 | $0.49 | $2.04 | $2.50 | $1.56 |

## Markup Component of Day-Ahead Zonal Prices

The markup component of annual average day-ahead price using unadjusted cost-based offers is shown for each zone in Table 3-75. The markup component of annual average day-ahead price using adjusted cost-based offers is shown for each zone in Table 3-76. Using unadjusted cost-based offers, the markup component of the average day-ahead price increased in all zones except PECO from 2016 to 2017. The smallest zonal all hours average markup component using adjusted cost-based offers for 2017 was in the ComEd Zone, $1.75 per MWh, while the highest was in the AECO Control Zone, $2.39 per MWh. The smallest zonal on peak average markup using adjusted cost-based offers was in the ComEd Control Zone, $2.08 per MWh, while the highest was in the AECO Control Zone, $2.92 per MWh.

## Table 3-75 Day-ahead, average, zonal markup component (Unadjusted): 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 |
| AECO | ($0.20) | ($0.21) | ($0.20) | $1.06 | $1.70 | $0.38 |
| AEP | ($1.33) | ($1.45) | ($1.20) | $0.72 | $1.34 | $0.09 |
| APS | ($1.28) | ($1.55) | ($1.00) | $0.64 | $1.22 | $0.05 |
| ATSI | ($1.32) | ($1.24) | ($1.40) | $0.72 | $1.28 | $0.12 |
| BGE | ($2.05) | ($2.43) | ($1.64) | $0.58 | $1.15 | ($0.01) |
| ComEd | ($0.29) | $0.44 | ($1.09) | $0.49 | $0.93 | $0.02 |
| DAY | ($0.89) | ($0.67) | ($1.14) | $0.78 | $1.41 | $0.10 |
| DEOK | ($0.67) | ($0.21) | ($1.17) | $0.82 | $1.51 | $0.10 |
| DLCO | $0.14 | $1.57 | ($1.40) | $0.72 | $1.27 | $0.13 |
| Dominion | ($0.82) | ($0.35) | ($1.31) | $0.67 | $1.33 | ($0.00) |
| DPL | ($2.00) | ($3.73) | ($0.18) | $0.85 | $1.36 | $0.33 |
| EKPC | ($0.10) | $0.91 | ($1.13) | $0.69 | $1.25 | $0.15 |
| JCPL | ($0.76) | ($1.03) | ($0.44) | $0.95 | $1.48 | $0.36 |
| Met-Ed | ($0.83) | ($1.15) | ($0.47) | $0.99 | $1.69 | $0.23 |
| PECO | $1.18 | $2.76 | ($0.49) | $0.92 | $1.47 | $0.33 |
| PENELEC | ($1.05) | ($1.01) | ($1.09) | $0.68 | $1.24 | $0.11 |
| Pepco | ($1.56) | ($1.71) | ($1.41) | $0.63 | $1.25 | ($0.02) |
| PPL | ($0.69) | ($0.86) | ($0.51) | $0.87 | $1.45 | $0.26 |
| PSEG | ($0.45) | ($0.37) | ($0.54) | $0.94 | $1.51 | $0.32 |
| RECO | ($1.14) | ($1.64) | ($0.56) | $1.02 | $1.61 | $0.37 |

## Table 3-76 Day-ahead, average, zonal markup component (Adjusted): 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 |
| AECO | $0.99 | $0.84 | $1.14 | $2.39 | $2.92 | $1.84 |
| AEP | ($0.05) | ($0.44) | $0.34 | $2.06 | $2.56 | $1.54 |
| APS | $0.08 | ($0.56) | $0.75 | $1.98 | $2.43 | $1.51 |
| ATSI | ($0.09) | ($0.25) | $0.08 | $2.07 | $2.52 | $1.58 |
| BGE | ($0.70) | ($1.44) | $0.09 | $1.96 | $2.41 | $1.49 |
| ComEd | $1.08 | $1.68 | $0.43 | $1.75 | $2.08 | $1.40 |
| DAY | $0.44 | $0.44 | $0.44 | $2.14 | $2.67 | $1.58 |
| DEOK | $0.67 | $0.93 | $0.39 | $2.13 | $2.69 | $1.53 |
| DLCO | $1.53 | $2.90 | $0.04 | $2.02 | $2.46 | $1.56 |
| Dominion | $0.57 | $0.84 | $0.30 | $2.03 | $2.56 | $1.48 |
| DPL | ($0.86) | ($2.93) | $1.31 | $2.22 | $2.58 | $1.84 |
| EKPC | $1.34 | $2.21 | $0.46 | $2.01 | $2.43 | $1.58 |
| JCPL | $0.42 | ($0.06) | $0.96 | $2.26 | $2.67 | $1.82 |
| Met-Ed | $0.41 | ($0.15) | $1.02 | $2.31 | $2.90 | $1.66 |
| PECO | $2.63 | $4.25 | $0.92 | $2.24 | $2.67 | $1.80 |
| PENELEC | $0.18 | ($0.01) | $0.38 | $1.97 | $2.41 | $1.51 |
| Pepco | ($0.23) | ($0.72) | $0.29 | $2.00 | $2.51 | $1.47 |
| PPL | $0.55 | $0.20 | $0.93 | $2.19 | $2.63 | $1.72 |
| PSEG | $0.76 | $0.66 | $0.87 | $2.23 | $2.66 | $1.76 |
| RECO | ($0.05) | ($0.79) | $0.80 | $2.30 | $2.75 | $1.80 |

## Markup by Day-Ahead Price Levels

Table 3-77 and Table 3-78 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 3-77 Average, day-ahead markup (By LMP category, unadjusted): 2016 and 2017

| | 2016 | | 2017 | |
|---|---|---|---|---|
| LMP Category | Average Markup Component | Frequency | Average Markup Component | Frequency |
| < $25 | ($1.63) | 49.1% | ($0.36) | 43.4% |
| $25 to $50 | $0.12 | 47.5% | $1.09 | 52.7% |
| $50 to $75 | ($8.05) | 2.9% | $5.70 | 2.9% |
| $75 to $100 | $2.52 | 0.4% | $6.04 | 0.7% |
| $100 to $125 | ($10.09) | 0.1% | $3.75 | 0.2% |
| $125 to $150 | $0.00 | 0.0% | $14.40 | 0.0% |
| >= $150 | $0.00 | 0.0% | $24.36 | 0.1% |

### Table 3-78 Average, day-ahead markup (By LMP category, adjusted): 2016 and 2017

| | 2016 | | 2017 | |
|---|---|---|---|---|
| LMP Category | Average Markup Component | Frequency | Average Markup Component | Frequency |
| < $25 | $0.08 | 49.1% | $1.32 | 43.4% |
| $25 to $50 | $1.70 | 47.5% | $2.60 | 52.7% |
| $50 to $75 | ($8.29) | 2.9% | $7.37 | 2.9% |
| $75 to $100 | $0.17 | 0.4% | $8.09 | 0.7% |
| $100 to $125 | ($1.17) | 0.1% | $6.56 | 0.2% |
| $125 to $150 | $0.00 | 0.0% | $16.33 | 0.0% |
| >= $150 | $0.00 | 0.0% | $29.44 | 0.1% |

# Prices

The behavior 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 6.0 percent and 3.9 percent higher in 2017 than in 2016.

PJM real-time energy market prices increased in 2017 compared to 2016. The average LMP was 6.7 percent higher in 2017 than in 2016, $29.42 per MWh versus $27.57 per MWh. The load-weighted average LMP was 6.0 percent higher in 2017 than in 2016, $30.99 per MWh versus $29.23 per MWh.

The fuel-cost adjusted, load-weighted, average LMP in 2017 was 18.1 percent lower than the load-weighted, average LMP for 2016. If fuel and emission costs in 2017 had been the same as in 2016, holding everything else constant, the load-weighted LMP would have been lower, $25.39 per MWh instead of the observed $30.99 per MWh.

PJM day-ahead energy market prices increased in 2017 compared 2016. The day-ahead average LMP was 4.9 percent higher in 2017 than in 2016, $29.48 per MWh versus $28.10 per MWh. The day-ahead load-weighted average LMP was 3.9 percent higher in 2017 than in 2016, $30.85 per MWh versus $29.68 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.[85] 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.[86]

## Real-Time LMP

Real-time average LMP is the hourly average LMP for the PJM Real-Time Energy Market.[87]

85 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) at 19–27.

86 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. See 153 FERC ¶ 61,289 (2015).

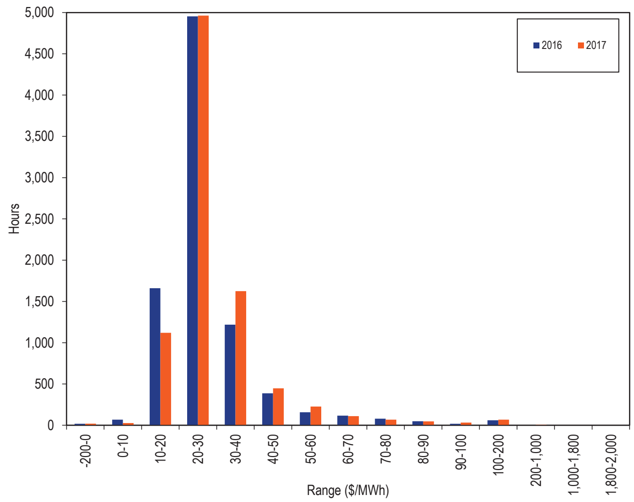
87 See the 2010 State of the Market Report for PJM: *Technical Reference for PJM Markets*, at "Calculating Locational Marginal Price," p 16-18 for detailed definition of Real-Time LMP. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

## Real-Time Average LMP

### PJM Real-Time Average LMP Duration

Figure 3-42 shows the hourly distribution of PJM real-time average LMP for 2016 and 2017.

#### Figure 3-42 Average LMP for the PJM Real-Time Energy Market: 2016 and 2017




### PJM Real-Time, Average LMP

Table 3-79 shows the PJM real-time, average LMP for each year from 1998 through 2017.[88]

#### Table 3-79 PJM real-time, average LMP (Dollars per MWh): 1998 through 2017

| | Real-Time LMP | | | Year-to-Year Change | | |
|---|---|---|---|---|---|---|
| | Average | Median | Standard Deviation | Average | Median | Standard Deviation |
| 1998 | $21.72 | $16.60 | $31.45 | NA | NA | NA |
| 1999 | $28.32 | $17.88 | $72.42 | 30.4% | 7.7% | 130.3% |
| 2000 | $28.14 | $19.11 | $25.69 | (0.6%) | 6.9% | (64.5%) |
| 2001 | $32.38 | $22.98 | $45.03 | 15.1% | 20.3% | 75.3% |
| 2002 | $28.30 | $21.08 | $22.41 | (12.6%) | (8.3%) | (50.2%) |
| 2003 | $38.28 | $30.79 | $24.71 | 35.2% | 46.1% | 10.3% |
| 2004 | $42.40 | $38.30 | $21.12 | 10.8% | 24.4% | (14.5%) |
| 2005 | $58.08 | $47.18 | $35.91 | 37.0% | 23.2% | 70.0% |
| 2006 | $49.27 | $41.45 | $32.71 | (15.2%) | (12.1%) | (8.9%) |
| 2007 | $57.58 | $49.92 | $34.60 | 16.9% | 20.4% | 5.8% |
| 2008 | $66.40 | $55.53 | $38.62 | 15.3% | 11.2% | 11.6% |
| 2009 | $37.08 | $32.71 | $17.12 | (44.1%) | (41.1%) | (55.7%) |
| 2010 | $44.83 | $36.88 | $26.20 | 20.9% | 12.7% | 53.1% |
| 2011 | $42.84 | $35.38 | $29.03 | (4.4%) | (4.1%) | 10.8% |
| 2012 | $33.11 | $29.53 | $20.67 | (22.7%) | (16.5%) | (28.8%) |
| 2013 | $36.55 | $32.25 | $20.57 | 10.4% | 9.2% | (0.5%) |
| 2014 | $48.22 | $34.46 | $65.08 | 31.9% | 6.8% | 216.4% |
| 2015 | $33.39 | $26.61 | $27.80 | (30.7%) | (22.8%) | (57.3%) |
| 2016 | $27.57 | $24.10 | $14.76 | (17.4%) | (9.4%) | (46.9%) |
| 2017 | $29.42 | $25.44 | $17.40 | 6.7% | 5.6% | 17.9% |

## 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 3-80 shows the PJM real-time, load-weighted, average LMP in 1998 through 2017.

#### Table 3-80 PJM real-time, load-weighted, average LMP (Dollars per MWh): 1998 through 2017

| | Real-Time, Load-Weighted, Average LMP | | | Year-to-Year Change | | |
|---|---|---|---|---|---|---|
| | Average | Median | Standard Deviation | Average | Median | Standard Deviation |
| 1998 | $24.16 | $17.60 | $39.29 | NA | NA | NA |
| 1999 | $34.07 | $19.02 | $91.49 | 41.0% | 8.1% | 132.8% |
| 2000 | $30.72 | $20.51 | $28.38 | (9.8%) | 7.9% | (69.0%) |
| 2001 | $36.65 | $25.08 | $57.26 | 19.3% | 22.3% | 101.8% |
| 2002 | $31.60 | $23.40 | $26.75 | (13.8%) | (6.7%) | (53.3%) |
| 2003 | $41.23 | $34.96 | $25.40 | 30.5% | 49.4% | (5.0%) |
| 2004 | $44.34 | $40.16 | $21.25 | 7.5% | 14.9% | (16.3%) |
| 2005 | $63.46 | $52.93 | $38.10 | 43.1% | 31.8% | 79.3% |
| 2006 | $53.35 | $44.40 | $37.81 | (15.9%) | (16.1%) | (0.7%) |
| 2007 | $61.66 | $54.66 | $36.94 | 15.6% | 23.1% | (2.3%) |
| 2008 | $71.13 | $59.54 | $40.97 | 15.4% | 8.9% | 10.9% |
| 2009 | $39.05 | $34.23 | $18.21 | (45.1%) | (42.5%) | (55.6%) |
| 2010 | $48.35 | $39.13 | $28.90 | 23.8% | 14.3% | 58.7% |
| 2011 | $45.94 | $36.54 | $33.47 | (5.0%) | (6.6%) | 15.8% |
| 2012 | $35.23 | $30.43 | $23.66 | (23.3%) | (16.7%) | (29.3%) |
| 2013 | $38.66 | $33.25 | $23.78 | 9.7% | 9.3% | 0.5% |
| 2014 | $53.14 | $36.20 | $76.20 | 37.4% | 8.9% | 220.4% |
| 2015 | $36.16 | $27.66 | $31.06 | (31.9%) | (23.6%) | (59.2%) |
| 2016 | $29.23 | $25.01 | $16.12 | (19.2%) | (9.6%) | (48.1%) |
| 2017 | $30.99 | $26.35 | $19.32 | 6.0% | 5.4% | 19.9% |

Table 3-81 shows zonal real-time, and real-time, load-weighted, average LMP in 2016 and 2017.

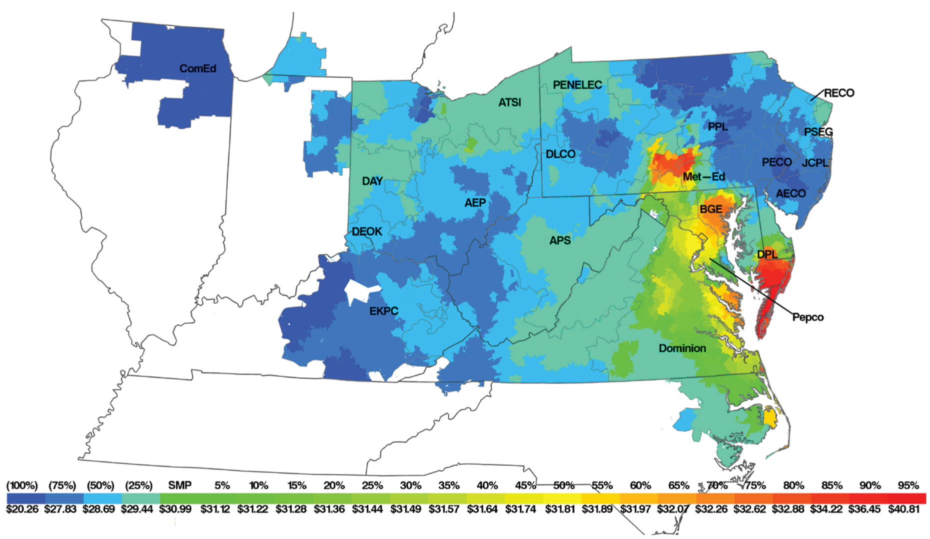
88 The system average LMP is the average of the hourly LMP without any weighting. The only exception is that market-clearing prices (MCPs) are included for January to April 1998. MCP was the single market-clearing price calculated by PJM prior to implementation of LMP.

### Table 3-81 Zonal real-time and real-time, load-weighted, average LMP (Dollars per MWh): 2016 and 2017

| | Real-Time Average LMP | | | Real-Time, Load-Weighted, Average LMP | | |
|---|---|---|---|---|---|---|
| Zone | 2016 | 2017 | Percent Change | 2016 | 2017 | Percent Change |
| AECO | $24.42 | $27.82 | 13.9% | $27.41 | $28.38 | 3.5% |
| AEP | $27.82 | $29.01 | 4.3% | $29.06 | $30.15 | 3.7% |
| APS | $28.25 | $29.81 | 5.5% | $29.79 | $30.56 | 2.6% |
| ATSI | $28.19 | $29.90 | 6.1% | $29.91 | $31.19 | 4.3% |
| BGE | $36.07 | $32.52 | (9.8%) | $39.31 | $33.73 | (14.2%) |
| ComEd | $26.05 | $26.83 | 3.0% | $27.61 | $28.64 | 3.7% |
| Day | $27.90 | $29.67 | 6.3% | $29.31 | $31.14 | 6.2% |
| DEOK | $27.12 | $29.02 | 7.0% | $28.67 | $30.68 | 7.0% |
| DLCO | $27.51 | $29.24 | 6.3% | $29.39 | $30.58 | 4.1% |
| Dominion | $30.27 | $31.44 | 3.9% | $32.22 | $32.19 | (0.1%) |
| DPL | $26.65 | $30.66 | 15.0% | $30.57 | $30.36 | (0.7%) |
| EKPC | $26.79 | $27.89 | 4.1% | $27.98 | $29.25 | 4.5% |
| JCPL | $23.86 | $28.40 | 19.0% | $26.63 | $29.72 | 11.6% |
| Met-Ed | $24.13 | $29.05 | 20.4% | $26.08 | $30.32 | 16.2% |
| PECO | $23.52 | $27.90 | 18.6% | $25.76 | $28.42 | 10.3% |
| PENELEC | $26.28 | $29.21 | 11.2% | $27.62 | $29.28 | 6.0% |
| Pepco | $32.16 | $31.70 | (1.4%) | $34.30 | $32.63 | (4.9%) |
| PPL | $23.77 | $28.01 | 17.9% | $25.37 | $28.85 | 13.7% |
| PSEG | $24.25 | $29.05 | 19.8% | $26.28 | $29.38 | 11.8% |
| RECO | $24.54 | $29.13 | 18.7% | $27.07 | $30.02 | 10.9% |
| PJM | $27.57 | $29.42 | 6.7% | $29.32 | $30.36 | 3.5% |

Figure 3-43 is a contour map of the real-time, load-weighted, average LMP in 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.

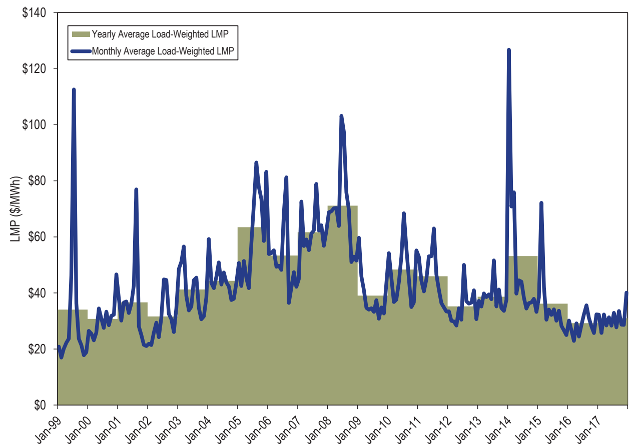
### Figure 3-43 PJM real-time, load-weighted, average LMP: 2017




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

Figure 3-44 shows the PJM real-time monthly and annual load-weighted LMP in 1999 through 2017. PJM real-time monthly load-weighted average LMP in June 2016 was $22.90, which is the lowest real-time monthly load-weighted average LMP since February 2002 at $21.39.

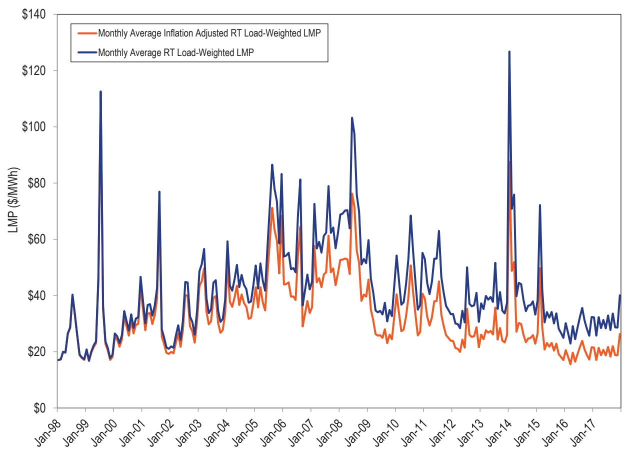
### Figure 3-44 PJM real-time, monthly and annual, load-weighted, average LMP: 1999 through 2017



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

Figure 3-45 shows the PJM real-time monthly load-weighted average LMP and inflation adjusted monthly load-weighted average LMP for 1998, through 2017.[89] Table 3-82 shows the PJM real-time yearly load-weighted average LMP and inflation adjusted yearly load-weighted average LMP for every year starting from 1998 through 2017.

### Figure 3-45 PJM real-time, monthly, load-weighted, average LMP and real-time, monthly inflation adjusted load-weighted, average LMP: 1998 through 2017




### Table 3-82 PJM real-time, yearly, load-weighted, average LMP and real-time, yearly inflation adjusted load-weighted, average LMP: 1998 through 2017

| | Load-Weighted, Average LMP | Inflation Adjusted Load-Weighted, Average LMP |
|---|---|---|
| 1998 | $24.16 | $23.94 |
| 1999 | $34.07 | $33.04 |
| 2000 | $30.72 | $28.80 |
| 2001 | $36.65 | $33.45 |
| 2002 | $31.60 | $28.35 |
| 2003 | $41.23 | $36.24 |
| 2004 | $44.34 | $37.91 |
| 2005 | $63.46 | $52.37 |
| 2006 | $53.35 | $42.73 |
| 2007 | $61.66 | $48.06 |
| 2008 | $71.13 | $53.27 |
| 2009 | $39.05 | $29.46 |
| 2010 | $48.35 | $35.83 |
| 2011 | $45.94 | $33.01 |
| 2012 | $35.23 | $24.80 |
| 2013 | $38.66 | $26.82 |
| 2014 | $53.14 | $36.37 |
| 2015 | $36.16 | $24.69 |
| 2016 | $29.23 | $19.68 |
| 2017 | $30.99 | $20.43 |

## 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 2017 compared to 2016. The price of Northern Appalachian coal was 17.4 percent higher; the price of Central Appalachian coal was 25.3 percent higher; the price of Powder River Basin coal was 12.7 percent higher; the price of eastern natural gas was 35.1 percent higher; and the price of western natural gas was 23.7 percent higher. Figure 3-46 shows monthly average spot fuel prices.[90]

### Figure 3-46 Spot average fuel price comparison with fuel delivery charges: 2012 through 2017 ($/MMBtu)

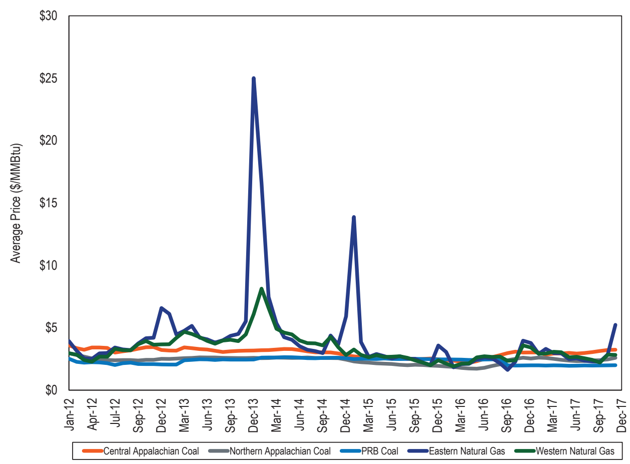



Table 3-83 compares the 2017 PJM real-time fuel-cost adjusted, load-weighted, average LMP to 2017 load-weighted, average LMP.[91] The real-time fuel-cost adjusted, load-weighted, average LMP for 2017 was 18.1 percent lower than the real-time load-weighted, average LMP for 2017. The real-time, fuel-cost adjusted, load-

89 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> (Accessed January 26, 2018)

90 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.

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

weighted, average LMP for 2017 was 13.1 percent lower than the real-time load-weighted LMP for 2016. If fuel and emissions costs in 2017 had been the same as in 2016, holding everything else constant, the real-time load-weighted LMP in 2017 would have been lower, $25.39 per MWh, than the observed $30.99 per MWh.

#### Table 3-83 PJM real-time annual, fuel-cost adjusted, load-weighted average LMP (Dollars per MWh): 2016 and 2017

| | 2017 Load-Weighted LMP | 2017 Fuel-Cost Adjusted, Load-Weighted LMP | Change |
|---|---|---|---|
| Average | $30.99 | $25.39 | (18.1%) |
| | 2016 Load-Weighted LMP | 2017 Fuel-Cost Adjusted, Load-Weighted LMP | Change |
| Average | $29.23 | $25.39 | (13.1%) |
| | 2016 Load-Weighted LMP | 2017 Load-Weighted LMP | Change |
| Average | $29.23 | $30.99 | 6.0% |

Table 3-84 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 2017. Table 3-84 shows that higher natural gas prices and coal prices explain most of the fuel-cost related increase in the real-time annual load-weighted average LMP in 2017.

#### Table 3-84 Change in PJM real-time annual, fuel-cost adjusted, load-weighted average LMP (Dollars per MWh) by fuel type: 2016 and 2017

| Fuel Type | Share of Change in Fuel Cost Adjusted, Load Weighted LMP | Percent |
|---|---|---|
| Coal | $2.15 | 38.5% |
| Gas | $3.27 | 58.3% |
| Municipal Waste | $0.02 | 0.3% |
| Oil | $0.16 | 2.8% |
| Other | $0.00 | 0.0% |
| Uranium | ($0.00) | -0.0% |
| Wind | ($0.00) | -0.0% |
| Total | $5.60 | 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.[92] 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, January 7 of 2014 and September 21 of 2017.[93] During the shortage conditions, the LMPs of marginal generators reflect the cost of not meeting the reserve requirements, the scarcity adder, which is defined by the operating reserve demand curve.

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

Table 3-87 shows the frequency and average shadow price of transmission constraints in PJM. In 2017, there were 162,534 transmission constraints in the real-time market with a non-zero shadow price. For nearly eight

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

93 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. PJM triggered shortage pricing on September 21, 2017 due to a sudden decrease in imports from neighboring regions.

percent of these transmission constraints, the line limit was violated, meaning that the flow exceeded the facility limit.[94] In 2017, the average shadow price of transmission constraints when the line limit was violated was nearly six 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 2017, for all the violated transmission constraints for which the penalty factor was greater than or equal to $2,000 per MWh, 58 percent of the constraints' shadow prices were within 10 percent of the penalty factor.

### Table 3-85 Components of PJM real-time (Unadjusted), load-weighted, average LMP: 2016 and 2017

| | 2016 | | 2017 | | Change |
|---|---|---|---|---|---|
| Element | Contribution to LMP | Percent | Contribution to LMP | Percent | Percent |
| Gas | $7.76 | 26.5% | $12.15 | 39.2% | 12.7% |
| Coal | $13.44 | 46.0% | $8.97 | 28.9% | (17.0%) |
| Markup | $0.27 | 0.9% | $2.55 | 8.2% | 7.3% |
| Ten Percent Adder | $2.43 | 8.3% | $2.39 | 7.7% | (0.6%) |
| VOM | $2.04 | 7.0% | $1.70 | 5.5% | (1.5%) |
| NA | $1.48 | 5.1% | $0.81 | 2.6% | (2.5%) |
| LPA Rounding Difference | $0.15 | 0.5% | $0.78 | 2.5% | 2.0% |
| Oil | $0.24 | 0.8% | $0.44 | 1.4% | 0.6% |
| $NO_x$ Cost | $0.42 | 1.4% | $0.41 | 1.3% | (0.1%) |
| Increase Generation Adder | $0.41 | 1.4% | $0.39 | 1.2% | (0.2%) |
| Ancillary Service Redispatch Cost | $0.32 | 1.1% | $0.25 | 0.8% | (0.3%) |
| $CO_2$ Cost | $0.09 | 0.3% | $0.09 | 0.3% | (0.0%) |
| $SO_2$ Cost | $0.07 | 0.3% | $0.06 | 0.2% | (0.1%) |
| Other | $0.15 | 0.5% | $0.06 | 0.2% | (0.3%) |
| Scarcity Adder | $0.00 | 0.0% | $0.05 | 0.2% | 0.2% |
| Municipal Waste | $0.04 | 0.1% | $0.05 | 0.2% | 0.0% |
| Opportunity Cost Adder | $0.00 | 0.0% | $0.04 | 0.1% | 0.1% |
| 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%) |
| Constraint Violation Adder | $0.00 | 0.0% | $0.00 | 0.0% | 0.0% |
| LPA-SCED Differential | ($0.01) | (0.0%) | ($0.01) | (0.0%) | 0.0% |
| Decrease Generation Adder | ($0.03) | (0.1%) | ($0.07) | (0.2%) | (0.1%) |
| Wind | ($0.05) | (0.2%) | ($0.11) | (0.4%) | (0.2%) |
| Total | $29.23 | 100.0% | $30.99 | 100.0% | 0.0% |

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 3-85, including markup using unadjusted cost-based offers.[95] Table 3-85 shows that in 2017, 28.9 percent of the load-weighted LMP was the result of coal costs, 39.2 percent was the result of gas costs and 1.79 percent was the result of the cost of emission allowances. Using adjusted cost-based offers, markup was 16.0 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 2017, nearly 21.19 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 2017 and 2016.

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 3-85 and Table 3-92), markup is simply the difference between the price offer and the cost-based offer (unadjusted markup). In the second approach (Table 3-86 and Table 3-93), the 10 percent markup is removed from the cost-based offers of coal gas and oil units (adjusted markup).

94 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.

95 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>.

The components of LMP are shown in Table 3-86, including markup using adjusted cost-based offers.

### Table 3-86 Components of PJM real-time (Adjusted), load-weighted, average LMP: 2016 and 2017

| | 2016 | | 2017 | | Change |
|---|---|---|---|---|---|
| Element | Contribution to LMP | Percent | Contribution to LMP | Percent | Percent |
| Gas | $7.76 | 26.5% | $12.16 | 39.2% | 12.7% |
| Coal | $13.44 | 46.0% | $8.97 | 28.9% | (17.0%) |
| Markup | $2.68 | 9.2% | $4.94 | 16.0% | 6.8% |
| VOM | $2.04 | 7.0% | $1.70 | 5.5% | (1.5%) |
| NA | $1.48 | 5.1% | $0.81 | 2.6% | (2.5%) |
| LPA Rounding Difference | $0.15 | 0.5% | $0.80 | 2.6% | 2.1% |
| Oil | $0.24 | 0.8% | $0.44 | 1.4% | 0.6% |
| $NO_x$ Cost | $0.42 | 1.4% | $0.41 | 1.3% | (0.1%) |
| Increase Generation Adder | $0.41 | 1.4% | $0.39 | 1.2% | (0.2%) |
| Ancillary Service Redispatch Cost | $0.32 | 1.1% | $0.25 | 0.8% | (0.3%) |
| $CO_2$ Cost | $0.09 | 0.3% | $0.09 | 0.3% | (0.0%) |
| $SO_2$ Cost | $0.07 | 0.3% | $0.06 | 0.2% | (0.1%) |
| Other | $0.15 | 0.5% | $0.06 | 0.2% | (0.3%) |
| Scarcity Adder | $0.00 | 0.0% | $0.05 | 0.2% | 0.2% |
| Municipal Waste | $0.04 | 0.1% | $0.05 | 0.2% | 0.0% |
| Opportunity Cost Adder | $0.00 | 0.0% | $0.02 | 0.1% | 0.1% |
| Market-to-Market Adder | $0.01 | 0.0% | $0.00 | 0.0% | (0.0%) |
| Ten Percent Adder | $0.02 | 0.1% | $0.00 | 0.0% | (0.1%) |
| Uranium | $0.00 | 0.0% | $0.00 | 0.0% | (0.0%) |
| Constraint Violation Adder | $0.00 | 0.0% | $0.00 | 0.0% | 0.0% |
| LPA-SCED Differential | ($0.01) | (0.0%) | ($0.01) | (0.0%) | 0.0% |
| Decrease Generation Adder | ($0.03) | (0.1%) | ($0.07) | (0.2%) | (0.1%) |
| Wind | ($0.05) | (0.2%) | ($0.11) | (0.4%) | (0.2%) |
| Total | $29.23 | 100.0% | $30.99 | 100.0% | 0.0% |

### Table 3-87 Frequency and average shadow price of transmission constraints in PJM: 2016 and 2017

| | Frequency | | Average Shadow Price | |
|---|---|---|---|---|
| Description | 2016 | 2017 | 2016 | 2017 |
| PJM Internal Violated Transmission Constraints | 19,536 | 12,405 | $643.04 | $722.58 |
| PJM Internal Binding Transmission Constraints | 130,855 | 102,571 | $120.13 | $123.23 |
| Market to Market Transmission Constraints | 54,848 | 47,558 | $264.34 | $331.62 |
| All Transmission Constraints | 205,239 | 162,534 | $208.44 | $229.95 |

## Day-Ahead LMP

Day-ahead average LMP is the hourly average LMP for the PJM Day-Ahead Energy Market.[96]

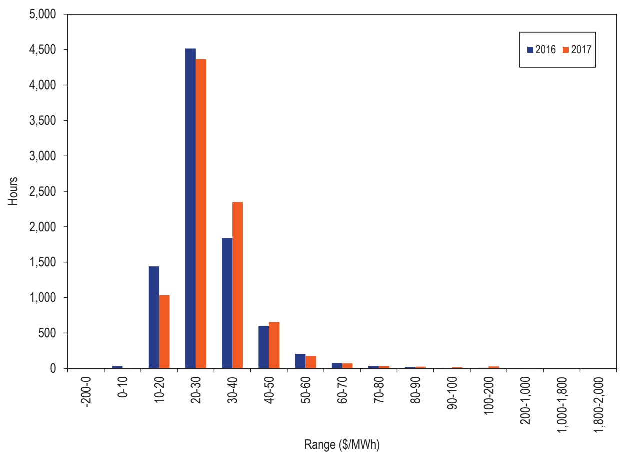
## Day-Ahead Average LMP

### PJM Day-Ahead Average LMP Duration

Figure 3-47 shows the hourly distribution of PJM day-ahead average LMP in 2016 and 2017.

96 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 3-47 Average LMP for the PJM Day-Ahead Energy Market: 2016 and 2017




## PJM Day-Ahead, Average LMP

Table 3-88 shows the PJM day-ahead, average LMP in 18-year period 2000 through 2017.

#### Table 3-88 PJM day-ahead, average LMP (Dollars per MWh): 2000 through 2017

| | Day-Ahead LMP | | | Year-to-Year Change | | |
|---|---|---|---|---|---|---|
| | Average | Median | Standard Deviation | Average | Median | Standard Deviation |
| 2000 | $31.97 | $24.42 | $21.33 | NA | NA | NA |
| 2001 | $32.75 | $27.05 | $30.42 | 2.4% | 10.8% | 42.6% |
| 2002 | $28.46 | $23.28 | $17.68 | (13.1%) | (14.0%) | (41.9%) |
| 2003 | $38.73 | $35.22 | $20.84 | 36.1% | 51.3% | 17.8% |
| 2004 | $41.43 | $40.36 | $16.60 | 7.0% | 14.6% | (20.4%) |
| 2005 | $57.89 | $50.08 | $30.04 | 39.7% | 24.1% | 81.0% |
| 2006 | $48.10 | $44.21 | $23.42 | (16.9%) | (11.7%) | (22.0%) |
| 2007 | $54.67 | $52.34 | $23.99 | 13.7% | 18.4% | 2.4% |
| 2008 | $66.12 | $58.93 | $30.87 | 20.9% | 12.6% | 28.7% |
| 2009 | $37.00 | $35.16 | $13.39 | (44.0%) | (40.3%) | (56.6%) |
| 2010 | $44.57 | $39.97 | $18.83 | 20.5% | 13.7% | 40.6% |
| 2011 | $42.52 | $38.13 | $20.48 | (4.6%) | (4.6%) | 8.8% |
| 2012 | $32.79 | $30.89 | $13.27 | (22.9%) | (19.0%) | (35.2%) |
| 2013 | $37.15 | $34.63 | $15.46 | 13.3% | 12.1% | 16.5% |
| 2014 | $49.15 | $38.10 | $51.88 | 32.3% | 10.0% | 235.6% |
| 2015 | $34.12 | $29.09 | $22.59 | (30.6%) | (23.7%) | (56.5%) |
| 2016 | $28.10 | $25.76 | $10.68 | (17.7%) | (11.4%) | (52.7%) |
| 2017 | $29.48 | $26.94 | $11.69 | 4.9% | 4.6% | 9.5% |

## Day-Ahead, Load-Weighted, Average LMP

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

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

Table 3-89 shows the PJM day-ahead, load-weighted, average LMP in the 18-year period 2000 through 2017.

#### Table 3-89 PJM day-ahead, load-weighted, average LMP (Dollars per MWh): 2000 through 2017

| | Day-Ahead, Load-Weighted, Average LMP | | | Year-to-Year Change | | |
|---|---|---|---|---|---|---|
| | Average | Median | Standard Deviation | Average | Median | Standard Deviation |
| 2000 | $35.12 | $28.50 | $22.26 | NA | NA | NA |
| 2001 | $36.01 | $29.02 | $37.48 | 2.5% | 1.8% | 68.3% |
| 2002 | $31.80 | $26.00 | $20.68 | (11.7%) | (10.4%) | (44.8%) |
| 2003 | $41.43 | $38.29 | $21.32 | 30.3% | 47.3% | 3.1% |
| 2004 | $42.87 | $41.96 | $16.32 | 3.5% | 9.6% | (23.4%) |
| 2005 | $62.50 | $54.74 | $31.72 | 45.8% | 30.4% | 94.3% |
| 2006 | $51.33 | $46.72 | $26.45 | (17.9%) | (14.6%) | (16.6%) |
| 2007 | $57.88 | $55.91 | $25.02 | 12.8% | 19.7% | (5.4%) |
| 2008 | $70.25 | $62.91 | $33.14 | 21.4% | 12.5% | 32.4% |
| 2009 | $38.82 | $36.67 | $14.03 | (44.7%) | (41.7%) | (57.7%) |
| 2010 | $47.65 | $42.06 | $20.59 | 22.7% | 14.7% | 46.8% |
| 2011 | $45.19 | $39.66 | $24.05 | (5.2%) | (5.7%) | 16.8% |
| 2012 | $34.55 | $31.84 | $15.48 | (23.5%) | (19.7%) | (35.6%) |
| 2013 | $38.93 | $35.77 | $18.05 | 12.7% | 12.3% | 16.6% |
| 2014 | $53.62 | $39.84 | $59.62 | 37.8% | 11.4% | 230.4% |
| 2015 | $36.73 | $30.60 | $25.46 | (31.5%) | (23.2%) | (57.3%) |
| 2016 | $29.68 | $27.00 | $11.64 | (19.2%) | (11.8%) | (54.3%) |
| 2017 | $30.85 | $28.21 | $12.64 | 3.9% | 4.5% | 8.6% |

Table 3-90 shows zonal day-ahead, and day-ahead, load-weighted, average LMP in 2016 and 2017.

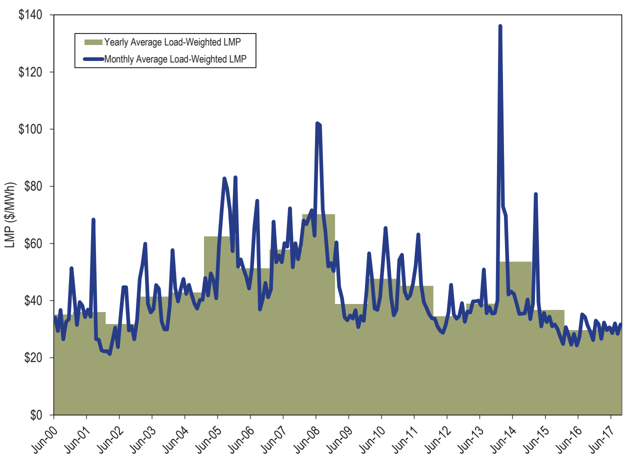
#### Table 3-90 Zonal day-ahead and day-ahead, load-weighted, average LMP (Dollars per MWh): 2016 and 2017

| | Day-Ahead Average LMP | | | Day-Ahead, Load-Weighted, Average LMP | | |
|---|---|---|---|---|---|---|
| Zone | 2016 | 2017 | Percent Change | 2016 | 2017 | Percent Change |
| AECO | $24.91 | $27.63 | 10.9% | $27.48 | $29.14 | 6.0% |
| AEP | $28.19 | $29.42 | 4.4% | $29.46 | $30.56 | 3.7% |
| APS | $28.79 | $29.91 | 3.9% | $30.18 | $31.17 | 3.3% |
| ATSI | $28.35 | $30.06 | 6.0% | $29.77 | $31.23 | 4.9% |
| BGE | $36.77 | $32.76 | (10.9%) | $39.59 | $34.78 | (12.2%) |
| ComEd | $26.49 | $26.94 | 1.7% | $28.00 | $28.24 | 0.9% |
| Day | $28.33 | $30.08 | 6.2% | $29.67 | $31.37 | 5.7% |
| DEOK | $27.78 | $29.56 | 6.4% | $29.30 | $31.00 | 5.8% |
| DLCO | $27.62 | $29.50 | 6.8% | $29.12 | $30.76 | 5.7% |
| Dominion | $31.08 | $31.69 | 2.0% | $33.02 | $33.59 | 1.8% |
| DPL | $27.93 | $29.93 | 7.2% | $31.00 | $32.18 | 3.8% |
| EKPC | $27.17 | $28.53 | 5.0% | $28.62 | $29.95 | 4.7% |
| JCPL | $24.30 | $28.20 | 16.0% | $26.52 | $29.92 | 12.8% |
| Met-Ed | $24.68 | $28.83 | 16.8% | $26.22 | $30.44 | 16.1% |
| PECO | $24.01 | $27.62 | 15.0% | $25.90 | $28.97 | 11.8% |
| PENELEC | $26.77 | $28.86 | 7.8% | $27.86 | $29.98 | 7.6% |
| Pepco | $33.08 | $32.04 | (3.1%) | $34.95 | $33.71 | (3.5%) |
| PPL | $24.24 | $27.82 | 14.8% | $25.68 | $29.30 | 14.1% |
| PSEG | $24.87 | $28.88 | 16.2% | $26.83 | $30.47 | 13.6% |
| RECO | $25.00 | $28.97 | 15.9% | $27.28 | $30.66 | 12.4% |
| PJM | $28.10 | $29.48 | 4.9% | $29.68 | $30.85 | 3.9% |

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

Figure 3-48 shows the PJM day-ahead, monthly and annual, load-weighted LMP from June 1, 2000 through December 31, 2017.[97] 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.

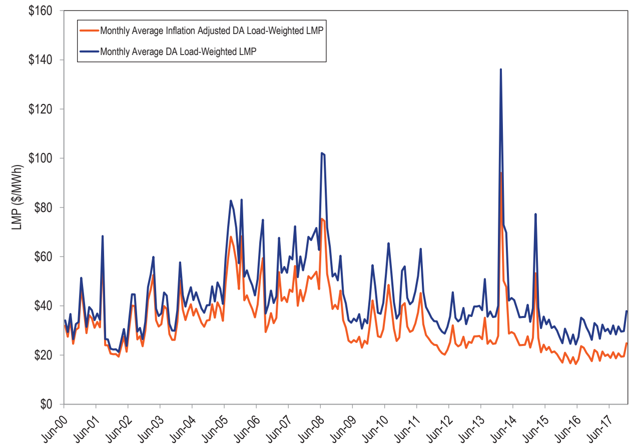
### Figure 3-48 Day-ahead, monthly and annual, load-weighted, average LMP: June 1, 2000 through December 31, 2017




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

Figure 3-49 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 2017.[98] 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 3-91 shows the PJM day-ahead yearly load- weighted average LMP and inflation adjusted yearly load-weighted average LMP for every year from 2000 through 2017.

### Figure 3-49 PJM day-ahead, monthly, load-weighted, average LMP and day-ahead, monthly inflation adjusted load-weighted, average LMP: June 1, 2000 through December 31, 2017




### Table 3-91 PJM day-ahead, yearly, load-weighted, average LMP and day-ahead, yearly inflation adjusted load-weighted, average LMP: 2000 through 2017

| | Load-Weighted, Average LMP | Inflation Adjusted Load-Weighted, Average LMP |
|---|---|---|
| 2000 | $35.13 | $32.74 |
| 2001 | $36.01 | $32.87 |
| 2002 | $31.80 | $28.53 |
| 2003 | $41.43 | $36.42 |
| 2004 | $42.87 | $36.65 |
| 2005 | $62.50 | $51.58 |
| 2006 | $51.33 | $41.12 |
| 2007 | $57.88 | $45.11 |
| 2008 | $70.25 | $52.61 |
| 2009 | $38.82 | $29.29 |
| 2010 | $47.65 | $35.32 |
| 2011 | $45.19 | $32.48 |
| 2012 | $34.55 | $24.33 |
| 2013 | $38.93 | $27.00 |
| 2014 | $53.62 | $36.71 |
| 2015 | $36.73 | $25.08 |
| 2016 | $29.68 | $19.98 |
| 2017 | $30.85 | $20.34 |

## 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, 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

97 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 seven months of that year.

98 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> (Accessed January 26, 2018).

and the components of unit offers, it is possible to decompose PJM system LMP using the components of unit offers and sensitivity factors.

Cost-based 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.[99] 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.

Table 3-92 shows the components of the PJM day-ahead, annual, load-weighted average LMP. In 2017, 21.1 percent of the load-weighted LMP was the result of coal costs, 18.4 percent of the load-weighted LMP was the result of gas costs, 3.1 percent was the result of the up to congestion transaction costs, 23.7 percent was the result of DEC bid costs and 22.2 percent was the result of INC bid costs.

### Table 3-92 Components of PJM day-ahead, (unadjusted), load-weighted, average LMP (Dollars per MWh): 2016 and 2017

| | 2016 | | 2017 | | |
|---|---|---|---|---|---|
| Element | Contribution to LMP | Percent | Contribution to LMP | Percent | Change Percent |
| DEC | $7.93 | 26.7% | $7.31 | 23.7% | (3.0%) |
| INC | $5.43 | 18.3% | $6.86 | 22.2% | 3.9% |
| Coal | $8.58 | 28.9% | $6.51 | 21.1% | (7.8%) |
| Gas | $3.14 | 10.6% | $5.69 | 18.4% | 7.9% |
| Ten Percent Cost Adder | $1.33 | 4.5% | $1.35 | 4.4% | (0.1%) |
| Up to Congestion Transaction | $1.09 | 3.7% | $0.94 | 3.1% | (0.6%) |
| VOM | $1.08 | 3.6% | $0.91 | 3.0% | (0.7%) |
| Markup | ($0.85) | (2.9%) | $0.72 | 2.3% | 5.2% |
| $NO_x$ | $0.23 | 0.8% | $0.26 | 0.9% | 0.1% |
| Dispatchable Transaction | $1.61 | 5.4% | $0.10 | 0.3% | (5.1%) |
| DASR LOC Adder | ($0.15) | (0.5%) | $0.06 | 0.2% | 0.7% |
| Oil | $0.03 | 0.1% | $0.05 | 0.2% | 0.1% |
| $CO_2$ | $0.06 | 0.2% | $0.05 | 0.2% | (0.0%) |
| $SO_2$ | $0.05 | 0.2% | $0.03 | 0.1% | (0.1%) |
| DASR Offer Adder | ($0.02) | (0.1%) | $0.01 | 0.0% | 0.1% |
| Other | $0.12 | 0.4% | $0.01 | 0.0% | (0.4%) |
| Constrained Off | $0.00 | 0.0% | $0.00 | 0.0% | (0.0%) |
| Uranium | $0.00 | 0.0% | $0.00 | 0.0% | (0.0%) |
| Wind | ($0.01) | (0.0%) | ($0.00) | (0.0%) | 0.0% |
| Price Sensitive Demand | $0.03 | 0.1% | $0.00 | 0.0% | (0.1%) |
| NA | $0.01 | 0.0% | $0.00 | 0.0% | (0.0%) |
| Total | $29.68 | 100.0% | $30.85 | 100.0% | 0.0% |

Table 3-93 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.

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

Table 3-93 Components of PJM day-ahead, (adjusted), load-weighted, average LMP (Dollars per MWh): 2016 and 2017

| | 2016 | | 2017 | | |
|---|---|---|---|---|---|
| Element | Contribution to LMP | Percent | Contribution to LMP | Percent | Change Percent |
| DEC | $7.93 | 26.7% | $7.31 | 23.7% | (3.0%) |
| INC | $5.43 | 18.3% | $6.86 | 22.2% | 3.9% |
| Coal | $8.58 | 28.9% | $6.51 | 21.1% | (7.8%) |
| Gas | $3.14 | 10.6% | $5.69 | 18.4% | 7.9% |
| Markup | $0.46 | 1.6% | $2.04 | 6.6% | 5.1% |
| Up to Congestion Transaction | $1.09 | 3.7% | $0.94 | 3.1% | (0.6%) |
| VOM | $1.08 | 3.6% | $0.91 | 3.0% | (0.7%) |
| $NO_x$ | $0.23 | 0.8% | $0.26 | 0.9% | 0.1% |
| Dispatchable Transaction | $1.61 | 5.4% | $0.10 | 0.3% | (5.1%) |
| DASR LOC Adder | ($0.15) | (0.5%) | $0.06 | 0.2% | 0.7% |
| Oil | $0.03 | 0.1% | $0.05 | 0.2% | 0.1% |
| $CO_2$ | $0.06 | 0.2% | $0.05 | 0.2% | (0.0%) |
| Ten Percent Cost Adder | $0.02 | 0.1% | $0.03 | 0.1% | 0.0% |
| $SO_2$ | $0.05 | 0.2% | $0.03 | 0.1% | (0.1%) |
| DASR Offer Adder | ($0.02) | (0.1%) | $0.01 | 0.0% | 0.1% |
| Other | $0.12 | 0.4% | $0.01 | 0.0% | (0.4%) |
| Constrained Off | $0.00 | 0.0% | $0.00 | 0.0% | (0.0%) |
| Uranium | $0.00 | 0.0% | $0.00 | 0.0% | (0.0%) |
| Wind | ($0.01) | (0.0%) | ($0.00) | (0.0%) | 0.0% |
| Price Sensitive Demand | $0.03 | 0.1% | $0.00 | 0.0% | (0.1%) |
| NA | $0.01 | 0.0% | $0.00 | 0.0% | (0.0%) |
| Total | $29.68 | 100.0% | $30.85 | 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 3-94 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 2016 and 2017. In 2017, 53.6 percent of all cleared UTC transactions were net profitable. Of cleared UTC transactions, 63.2 percent were profitable on the source side and 37.7 were profitable on the sink side but only 5.2 percent were profitable on both the source and sink side.

## Table 3-94 Cleared UTC profitability by source and sink point: 2016 and 2017[100]

| | Cleared UTCs | Profitable UTCs | UTC Profitable at Source Bus | UTC Profitable at Sink Bus | Profitable UTC | Profitable Source | Profitable Sink |
|---|---|---|---|---|---|---|---|
| 2016 | 22,382,027 | 10,807,587 | 14,409,047 | 7,844,293 | 48.3% | 64.4% | 35.0% |
| 2017 | 18,721,775 | 10,043,534 | 11,837,040 | 7,050,584 | 53.6% | 63.2% | 37.7% |

Figure 3-50 shows total UTC daily gross profits and losses and net profits and losses in 2017.

## Figure 3-50 UTC daily gross profits and losses and net profits: 2017[101]

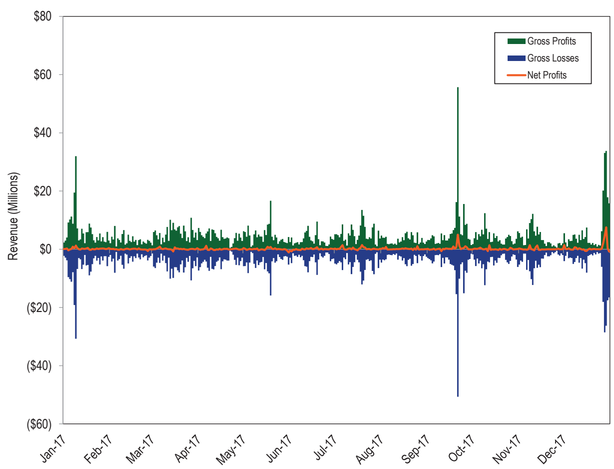



Figure 3-51 shows the cumulative UTC daily profits for the years 2013 through 2017. UTC profits during this period were primarily a result of significant unanticipated price differences between day ahead and real time LMPs. The large increases in cumulative daily UTC profits were due to PJM events that resulted in high 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. The 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 increased during late September and December 2017 as a result of profits from the significant day-ahead and real-time price difference that resulted from the shortage event on September 21, 2017 and cold weather in late December.

## Figure 3-51 Cumulative daily UTC profits: 2013 through 2017

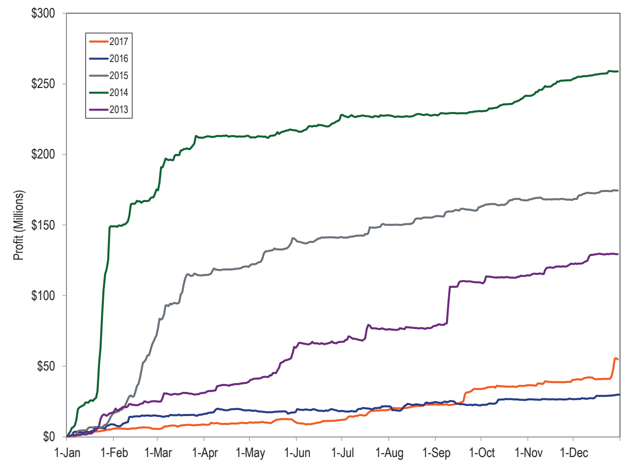



Table 3-95 shows UTC profits by month for January 1, 2013 through December 31, 2017. May 2016, September 2016 and February 2017 were the only months in the past five years where the total monthly profits were negative.

100 Calculations exclude PJM administrative charges.
101 Calculations exclude PJM administrative charges.

### Table 3-95 UTC profits by month: 2013 through 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) | $3,083,167 | $944,939 | $1,245,988 | $868,400 | $7,053,390 | $4,002,063 | $10,960,012 | $2,360,817 | $2,716,950 | $15,936,217 | $54,870,839 |

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 3-53).

Table 3-96 shows that the difference between the average real-time price and the average day-ahead price was -$0.53 per MWh in 2016, and -$0.06 per MWh in 2017. The difference between average peak real-time price and the average peak day-ahead price was -$0.73 per MWh in 2016 and -$0.35 per MWh in 2017.

### Table 3-96 Day-ahead and real-time average LMP (Dollars per MWh): 2016 and 2017[102]

| | 2016 | | | | 2017 | | | |
|---|---|---|---|---|---|---|---|---|
| | Day-Ahead | Real-Time | Difference | Percent of Real Time | Day-Ahead | Real-Time | Difference | Percent of Real Time |
| Average | $28.10 | $27.57 | ($0.53) | (1.9%) | $29.48 | $29.42 | ($0.06) | (0.2%) |
| Median | $25.76 | $24.10 | ($1.66) | (6.9%) | $26.94 | $25.44 | ($1.50) | (5.9%) |
| Standard deviation | $10.68 | $14.76 | $4.08 | 27.7% | $11.69 | $17.40 | $5.71 | 32.8% |
| Peak average | $33.43 | $32.71 | ($0.73) | (2.2%) | $34.42 | $34.07 | ($0.35) | (1.0%) |
| Peak median | $30.36 | $27.33 | ($3.03) | (11.1%) | $31.97 | $29.34 | ($2.63) | (9.0%) |
| Peak standard deviation | $11.16 | $17.05 | $5.89 | 34.5% | $12.50 | $20.17 | $7.67 | 38.0% |
| Off peak average | $23.47 | $23.12 | ($0.35) | (1.5%) | $25.20 | $25.39 | $0.20 | 0.8% |
| Off peak median | $22.15 | $21.60 | ($0.55) | (2.5%) | $22.98 | $22.57 | ($0.41) | (1.8%) |
| Off peak standard deviation | $7.66 | $10.57 | $2.91 | 27.5% | $8.95 | $13.33 | $4.38 | 32.8% |

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

Table 3-97 shows the difference between the real-time and the day-ahead energy market prices for 2001 through 2017.

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

### Table 3-97 Day-ahead and real-time average LMP (Dollars per MWh): 2001 through 2017

| | Day-Ahead | Real-Time | Difference | Percent of Real Time |
|---|---|---|---|---|
| 2001 | $32.75 | $32.38 | ($0.37) | (1.1%) |
| 2002 | $28.46 | $28.30 | ($0.16) | (0.6%) |
| 2003 | $38.73 | $38.28 | ($0.45) | (1.2%) |
| 2004 | $41.43 | $42.40 | $0.97 | 2.3% |
| 2005 | $57.89 | $58.08 | $0.18 | 0.3% |
| 2006 | $48.10 | $49.27 | $1.17 | 2.4% |
| 2007 | $54.67 | $57.58 | $2.90 | 5.3% |
| 2008 | $66.12 | $66.40 | $0.28 | 0.4% |
| 2009 | $37.00 | $37.08 | $0.08 | 0.2% |
| 2010 | $44.57 | $44.83 | $0.26 | 0.6% |
| 2011 | $42.52 | $42.84 | $0.32 | 0.7% |
| 2012 | $32.79 | $33.11 | $0.32 | 1.0% |
| 2013 | $37.15 | $36.55 | ($0.60) | (1.6%) |
| 2014 | $49.15 | $48.22 | ($0.93) | (1.9%) |
| 2015 | $34.12 | $33.39 | ($0.73) | (2.1%) |
| 2016 | $28.10 | $27.57 | ($0.53) | (1.9%) |
| 2017 | $29.48 | $29.42 | ($0.06) | (0.2%) |

Table 3-98 provides frequency distributions of the differences between PJM real-time hourly LMP and PJM day-ahead hourly LMP for 2016 through 2017.

### Table 3-98 Frequency distribution by hours of PJM real-time LMP minus day-ahead LMP (Dollars per MWh): 2016 through 2017

| | 2016 | | 2017 | |
|---|---|---|---|---|
| LMP | Frequency | Cumulative Percent | Frequency | Cumulative Percent |
| < ($1,000) | 0 | 0.00% | 0 | 0.00% |
| ($1,000) to ($750) | 0 | 0.00% | 0 | 0.00% |
| ($750) to ($500) | 0 | 0.00% | 0 | 0.00% |
| ($500) to ($450) | 0 | 0.00% | 0 | 0.00% |
| ($450) to ($400) | 0 | 0.00% | 0 | 0.00% |
| ($400) to ($350) | 0 | 0.00% | 0 | 0.00% |
| ($350) to ($300) | 0 | 0.00% | 0 | 0.00% |
| ($300) to ($250) | 0 | 0.00% | 0 | 0.00% |
| ($250) to ($200) | 0 | 0.00% | 0 | 0.00% |
| ($200) to ($150) | 0 | 0.00% | 0 | 0.00% |
| ($150) to ($100) | 0 | 0.00% | 2 | 0.02% |
| ($100) to ($50) | 13 | 0.15% | 9 | 0.13% |
| ($50) to $0 | 5,780 | 65.95% | 5,460 | 62.45% |
| $0 to $50 | 2,919 | 99.18% | 3,231 | 99.34% |
| $50 to $100 | 58 | 99.84% | 45 | 99.85% |
| $100 to $150 | 13 | 99.99% | 8 | 99.94% |
| $150 to $200 | 1 | 100.00% | 3 | 99.98% |
| $200 to $250 | 0 | 100.00% | 0 | 99.98% |
| $250 to $300 | 0 | 100.00% | 0 | 99.98% |
| $300 to $350 | 0 | 100.00% | 0 | 99.98% |
| $350 to $400 | 0 | 100.00% | 0 | 99.98% |
| $400 to $450 | 0 | 100.00% | 1 | 99.99% |
| $450 to $500 | 0 | 100.00% | 0 | 99.99% |
| $500 to $750 | 0 | 100.00% | 1 | 100.00% |
| $750 to $1,000 | 0 | 100.00% | 0 | 100.00% |
| $1,000 to $1,250 | 0 | 100.00% | 0 | 100.00% |
| >= $1,250 | 0 | 100.00% | 0 | 100.00% |

Figure 3-52 shows the hourly differences between day-ahead and real-time hourly LMP in 2017. The large spike in September is due to the shortage event on September 21, 2017.

### Figure 3-52 Real-time hourly LMP minus day-ahead hourly LMP: 2017

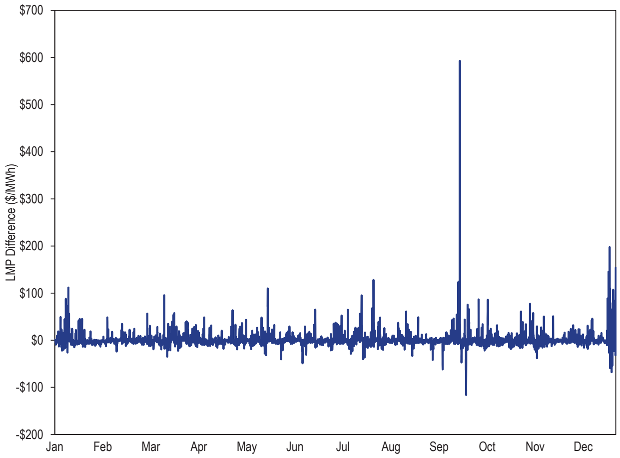



Figure 3-53 shows the monthly average of the differences between the day-ahead and real-time PJM average LMPs from January 1, 2013, through December 31, 2017.

### Figure 3-53 Monthly average of real-time minus day-ahead LMP: 2013 through 2017

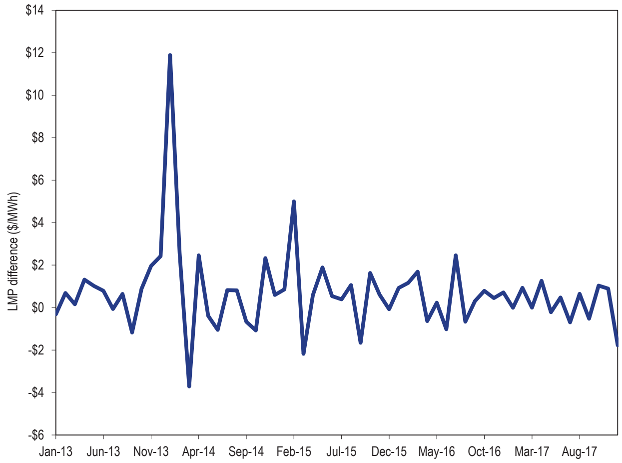



Figure 3-54 shows the monthly average of the absolute value of the differences between the day-ahead and real-time hourly, nodal LMPs from January 1, 2013, through December 31, 2017.

**Figure 3-54 Monthly average of the absolute value of real-time minus day-ahead LMP by pnode: 2013 through 2017**

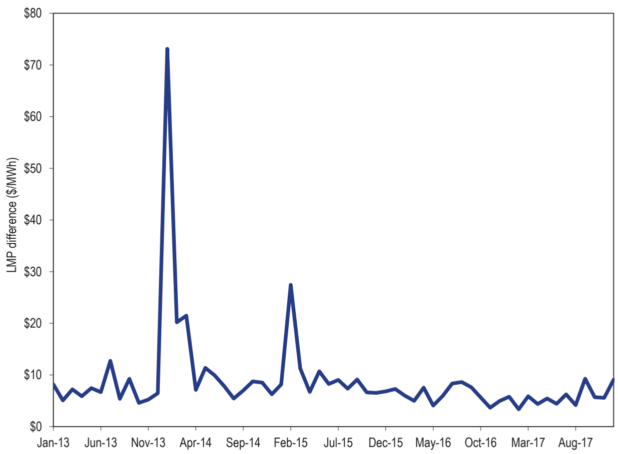
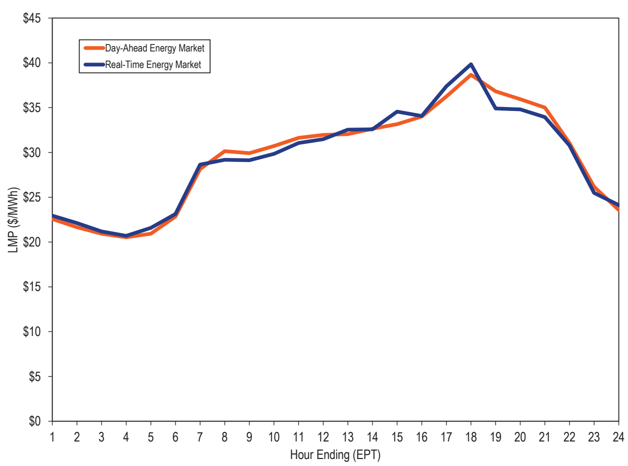



Figure 3-55 shows day-ahead and real-time LMP on an average hourly basis for 2017. Hour ending 19 had the largest difference between the DA and RT LMP, at $1.91 per MWh, and hour ending 16 had the smallest difference at $0.05 per MWh. The average for 2017 was $0.06 per MWh higher in the DA LMP than RT LMP.

**Figure 3-55 PJM system hourly average LMP: 2017**



# Scarcity

PJM's energy market experienced shortage pricing on one day (September 21) in 2017. Table 3-99 shows a summary of the number of days emergency alerts, warnings and actions were declared in PJM in 2016 and 2017.

### Table 3-99 Summary of emergency events declared: 2016 and 2017

| | Number of days events declared | |
|---|---|---|
| Event Type | 2016 | 2017 |
| Cold Weather Alert | 8 | 4 |
| Hot Weather Alert | 22 | 17 |
| 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 | 1 |
| Energy export recalls from PJM capacity resources | 0 | 0 |

Figure 3-56 shows the number of days that weather and capacity emergency alerts were issued in PJM from 2013 through 2017. Figure 3-57 shows the number of days emergency warnings were issued and actions were taken in PJM from 2013 through 2017.

### Figure 3-56 PJM declared emergency alerts: 2013 through 2017

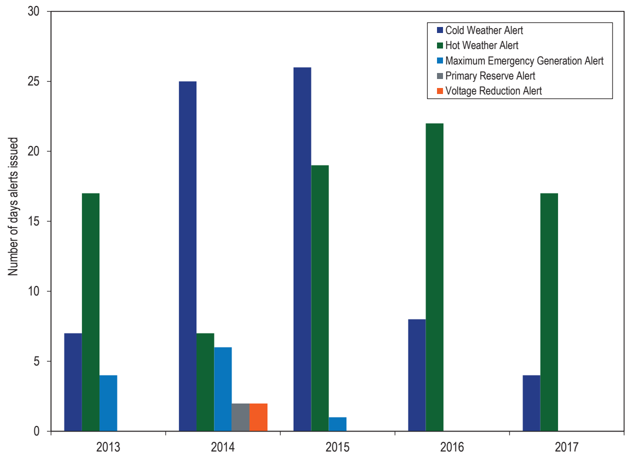
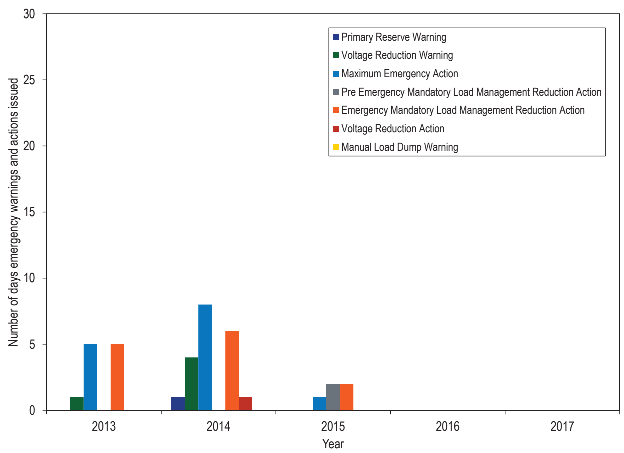


Figure 3-57 PJM declared emergency warnings and actions: 2013 through 2017




## Emergency Procedures

PJM declares alerts at least a day prior to the operating day to warn members of possible emergency actions that could be taken during the operating day. In real time, on the operating day, PJM issues warnings notifying members of system conditions that could result in emergency actions during the operating day.

PJM declared cold weather alerts on four days in 2017 compared to eight days in 2016.[103] 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 or fall below 10 degrees Fahrenheit.

PJM declared hot weather alerts on 17 days in 2017 compared to 22 days in 2016.[104] The purpose of a hot weather alert is to prepare personnel and facilities for expected extreme hot and humid weather conditions, generally when temperatures are forecast to exceed 90 degrees Fahrenheit with high humidity.

PJM did not declare any maximum emergency generation alerts in 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.[105] 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 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.[106] 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 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.[107] 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 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.[108]

PJM did not declare any voltage reduction warnings or reductions of noncritical plant load in 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 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

103 See PJM. "Manual 13: Emergency Operations," Rev. 65 (Jan. 1, 2018), Section 3.3 Cold Weather Alert, p. 56.
104 See PJM. "Manual 13: Emergency Operations," Rev. 65 (Jan. 1, 2018), Section 3.4 Hot Weather Alert, p. 60.
105 See PJM. "Manual 13: Emergency Operations," Rev. 65 (Jan. 1, 2018), Section 2.3.1 Advance Notice Emergency Procedures: Alerts, p. 23.
106 *Id* at 24.
107 *Id* at 25.
108 *Id* at 33.

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.[109]

PJM did not declare any maximum emergency generation actions in 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.[110] 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 2017 and 2016.

PJM did not declare any voltage reduction actions in 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 reserve market clearing prices and locational marginal prices until the voltage reduction action has been terminated.

PJM declared sixteen synchronized reserve events in both 2017 and 2016.[111] Synchronized reserve events may occur at any time of the year due to sudden loss of generation or transmission facilities, or sudden loss of imports, and do not necessarily coincide with capacity emergency conditions such as maximum generation emergency events or emergency load management events.

109 See PJM. "Manual 13: Emergency Operations," Rev. 65 (Jan. 1, 2018), Section 2.3 Capacity Shortages, pp. 30 – 32.

110 *Id* at 34.

111 See *2017 State of the Market Report for PJM*, Section 10: Ancillary Service Markets for details on the spinning events.

Table 3-100 provides a description of PJM declared emergency procedures.

## Table 3-100 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. |

Table 3-101 shows the dates when emergency alerts and warnings were declared and when emergency actions were implemented in 2017.

### Table 3-101 PJM declared emergency alerts, warnings and actions: 2017

| Date | Cold Weather Alert | Hot Weather Alert | Maximum Emergency Generation Alert | Primary Reserve Alert | Voltage Reduction Alert | Primary Reserve Warning | Voltage Reduction Warning and Reduction of Non-Critical Plant Load | Maximum Emergency Generation Action | Pre-Emergency Mandatory Load Management Reduction | Emergency Mandatory Load Management Reduction | Voltage Reduction | Manual Load Dump Warning |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 5/17/2017 | | PJM RTO | | | | | | | | | | |
| 5/18/2017 | | PJM RTO | | | | | | | | | | |
| 6/11/2017 | | PJM RTO | | | | | | | | | | |
| 6/12/2017 | | PJM RTO | | | | | | | | | | |
| 6/13/2017 | | PJM RTO | | | | | | | | | | |
| 6/30/2017 | | Mid Atlantic | | | | | | | | | | |
| 7/11/2017 | | Mid Atlantic and Dominion | | | | | | | | | | |
| 7/12/2017 | | PJM RTO | | | | | | | | | | |
| 7/13/2017 | | Mid Atlantic and Dominion | | | | | | | | | | |
| 7/14/2017 | | Dominion | | | | | | | | | | |
| 7/19/2017 | | Dominion and EKPC | | | | | | | | | | |
| 7/20/2017 | | PJM RTO | | | | | | | | | | |
| 7/21/2017 | | PJM RTO | | | | | | | | | | |
| 7/22/2017 | | Mid Atlantic and Dominion | | | | | | | | | | |
| 8/22/2017 | | Mid Atlantic and Dominion | | | | | | | | | | |
| 9/25/2017 | | PJM RTO | | | | | | | | | | |
| 9/26/2017 | | PJM RTO | | | | | | | | | | |
| 12/26/2017 | ComEd | | | | | | | | | | | |
| 12/27/2017 | AEP, ATSI, ComEd, DAY, DEOK | | | | | | | | | | | |
| 12/30/2017 | ComEd, DAY, DEOK | | | | | | | | | | | |
| 12/31/2017 | Western | | | | | | | | | | | |

## 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. PJM refers to scarcity pricing as shortage pricing. The terms are used interchangeably here.

On October 1, 2012, PJM introduced a new administrative scarcity pricing regime. Under these 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.[112] 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 reserve penalty factors are incorporated in the calculation of the market clearing prices for the reserve that is short. The market clearing prices for reserves during reserve shortages in real time were determined based on vertical demand curves for synchronized and primary reserves, defined for the Mid-Atlantic Region and for the entire RTO, called the Operating Reserve Demand Curves (ORDC). The penalty factors for the reserve products in

112 See OA Schedule 1 § 2.2(d).

the ORDC started at $250 per MWh for the 2012/2013 delivery year and gradually increased to $850 per MWh for the 2015/2016 delivery year.

In 2015, PJM revised the rules to add a conditional second step to the operating reserve demand curves, that is only in effect during hot weather alerts, cold weather alerts and other emergency conditions, to allow PJM to procure additional reserves at a lower clearing price of $300 per MWh.[113] When there are no emergency conditions in place, the ORDC remains a single-step curve.

On May 11, 2017, PJM made revisions to the triggers for shortage pricing and implemented five minute shortage pricing in response to Order No. 825. These revisions did not change the operating reserve demand curves.

On July 12, 2017, PJM implemented updates to the Operating Reserve Demand Curves that determine the value of the penalty factors that are incorporated in the calculation of the synchronized and primary reserve market clearing prices and the locational marginal price for energy. PJM added an extended reserve requirement to the operating reserve demand curves. The extended synchronized reserve requirement is defined as the synchronized reserve requirement plus 190 MW. The extended primary reserve requirement is defined as the primary reserve requirement plus 190 MW. PJM retains the ability to add a conditional extended reserve requirement during hot weather alerts, cold weather alerts or other emergencies that would increase the extended reserve requirement beyond 190 MW.

In 2017, shortage pricing was triggered on one day in PJM.

## Final Rule on Shortage Pricing and Settlement Intervals (Order No. 825)

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").[114] 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.[115]

The Commission 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.[116] As of May 11, 2017, the rule requires PJM to trigger shortage pricing for any five minute interval for which the Real-Time SCED (Security Constrained Economic Dispatch) indicates a shortage of synchronized reserves or primary reserves. Prior to May 11, 2017, 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 was considered a transient shortage, a shortage event was not declared, and shortage pricing was not implemented. Both Real-Time SCED and Intermediate-Term SCED had to consistently identify that a shortage of a particular reserve product existed 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 indicated a shortage of RTO wide primary reserve for an interval but the Intermediate-Term SCED forecasts that the reserve shortage did not extend beyond its first look ahead interval (15 minutes ahead of the Real-Time SCED interval), it was considered a transient shortage, and shortage pricing was not implemented. If Real-Time SCED indicated a shortage of RTO wide primary reserve for an interval and the Intermediate-Term SCED forecasts that the reserve shortage extended for at least two look ahead intervals (30 minutes ahead of the Real-Time SCED interval), shortage pricing was 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

113 151 FERC ¶ 61,017 (2015).
114 152 FERC ¶ 61,218 (2015).
115 *Id* at P 5.
116 *Id* at P 162.

that condition, even if the data does not show a shortage of reserves.[117]

## 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.[118] 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.

On February 1, 2017, the MMU filed comments generally supporting the January 11th Compliance Filing but seeking a number of refinements.[119] The MMU recommended that: (i) the PJM rules require that dispatchable resources have five minute meters so that there can be accurate five minute settlements; (ii) the rules clarify the settlement interval applicable to withdrawals by generators; (iii) the exemption of DR from the five minute settlements requirement be removed; (iv) the rules consistently provide for division by 12; (v) that the rules include a precise mathematical formulation of deviation charges with clear definitions of withdrawals and injections, units of measurement, and time periods; and (vi) that the rules require PJM to document biasing practices that affect market outcomes, as used in SCED (Security Constrained Economic Dispatch) and ASO (Ancillary Services Optimizer) and to report its application of biasing.[120]

On May 11, 2017, PJM implemented five minute shortage pricing. From May 11 through December 31, there were 21 intervals when five minute shortage pricing was triggered, all on the same day, September 21.

117 *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).

118 *See PJM Interconnection LLC*, Order No. 825 Compliance Filing, Docket No. ER17-775 (January 11, 2017) ("January 11th Compliance Filing").

119 Comments of the Independent Market Monitor for PJM, Docket No. ER17-775.

120 *Id.*

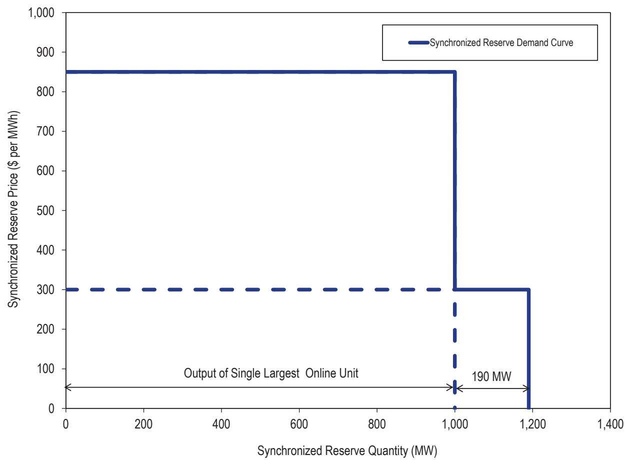
## PJM Tariff Revisions to Operating Reserve Demand Curves

On May 12, 2017, PJM submitted tariff revisions to reflect changes to the Operating Reserve Demand Curves (ORDC) used in the Real-Time Energy Market to price shortage of primary reserves and synchronized reserves.[121] The updates to the ORDC went into effect on July 12, 2017.

PJM revised the synchronized reserve requirement in a reserve zone or a subzone from the economic maximum of the largest unit on the system to 100 percent of the actual output of the single largest online unit in that reserve zone or subzone. PJM revised the primary reserve requirement in a reserve zone or a subzone from 150 percent of the economic maximum of the largest unit on the system to 150 percent of the actual output of the single largest online unit in that reserve zone or subzone. The first step of the demand curves for primary and synchronized reserves are set at the primary and synchronized reserve requirement. Since the primary and synchronized reserve requirements are based on the actual output of the largest resource, the MW value of the first step changes in real time based on the real-time dispatch solution. The first step continues to be priced at $850 per MWh. PJM also added a permanent second step to the primary and synchronized reserve demand curves, set at the extended primary and synchronized reserve requirements. The extended primary and synchronized reserve requirements are defined as the primary and synchronized reserve requirements, plus 190 MW. This 190 MW second step is priced at $300 per MWh. Figure 3-58 shows an example of the updated synchronized reserve demand curve when the output of the single largest unit in the region equals 1,000 MW.

121 See PJM Filing, FERC Docket No. ER17-1590-000 (May 12, 2017).

**Figure 3-58 Updated synchronized reserve demand curve showing the permanent second step**




## Shortage Pricing on September 21, 2017

The shortage pricing and spinning events that occurred in PJM on September 21 were primarily a result of actions taken outside the PJM control area that resulted in curtailments to imports. These events illustrate the performance of resources that clear as reserves within PJM. These events raise questions about the use of primary reserves for purposes other than a disturbance on the system and about whether interchange volatility should be studied as a source of disturbance and whether reserves should be procured to handle it.

PJM did not declare Hot Weather Alerts in any part of its service territory on September 21, 2017. MISO declared Conservative Operations at 11:06 EPT and declared a Maximum Generation Alert effective 1200 EPT through 2000 EPT.[122] Transmission Loading Relief (TLR) actions declared by the Tennessee Valley Authority on September 21, resulted in unanticipated reductions in the net interchange into PJM. PJM declared a spinning event to control for low Area Control Error (ACE) at 1415 EPT.

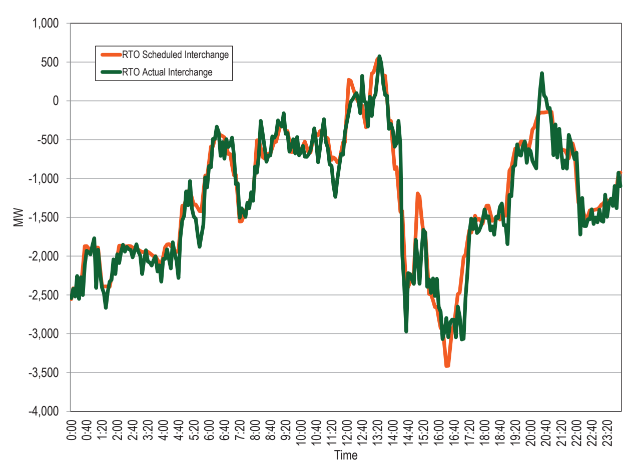
There were a number of factors that affected the PJM area response in the periods when shortage pricing was triggered on September 21, 2017, including interchange transactions, available and scheduled generation capacity in real time, operator inputs to SCED, and the performance of regulation resources.

## Interchange on September 21, 2017

There were significant changes in the net scheduled and actual interchange leading up to, and during the scarcity pricing event on September 21, 2017. The primary reason for these large changes was the curtailment of transactions scheduled into and out of PJM resulting from TLRs. As Figure 3-59 shows, between 1100 and 1130, PJM had a change in net interchange of approximately 1,000 MW. This change was the result of the curtailment of 1,014 MW of net import transactions as a result of the TLR level 3B called by TVA for relief on the Volunteer-Philipps Bend 500 for the loss of Conasauga-Mosteller 500 constraint (Flowgate 1024). The same TLR resulted in additional curtailments effective at the top of each hour from 1300 through 1900. In addition, Ontario called a TLR level 3A for relief on the Ontario-ITC constraint (Flowgate 9159), which resulted in additional net import curtailments starting at 1400.

At 1400, the NYISO NYIS/PJM interface price was $490.98 and the PJM PJM/NYIS interface price was $143.38, resulting in approximately 800 additional MW of exports from PJM to NYISO, in hours 1400 and 1500. At 1400, the MISO MISO/PJM interface price was $310.39, and the PJM PJM/MISO interface price was $180.52, resulting in approximately 800 additional MW of exports from PJM to MISO, in hours 1400 and 1500. The net interchange into PJM dropped by about 3,500 MW between 1325 EPT and 1440 EPT.

**Figure 3-59 Net RTO scheduled and actual interchange: September 21, 2017**




122 *See* MISO. "September 22 Maximum Generation Event Overview; Appendix," September 28, 2017 <https://cdn.misoenergy.org/20171012%20MSC%20Item%2007%20September%2022%20Overview75133.pdf>

## Reserve Levels on September 21, 2017

During the 21 five minute intervals with reserve shortages on September 21, 2017, reserves were greater than the Synchronized Reserve Requirement and the Primary Reserve Requirement, and as a result the $850/MWh penalty factors for violating these requirements were not incorporated in LMPs.

During two 5 minute intervals beginning 1415 EPT and 1420 EPT, synchronized reserves in the RTO Region were lower than the synchronized reserve requirement by 16.1 MW. As a result, the penalty price of $300 per MWh was incorporated in the price of synchronized reserves for both intervals. Table 3-102 shows the RTO synchronized reserve MW and the extended synchronized reserve requirement during the period from 1415 to 1425 EPT.

### Table 3-102 RTO synchronized reserve MW and extended synchronized reserve requirement during synchronized reserve shortage

| Interval | RTO Extended Synchronized Reserve Requirement (MW) | RTO Total Synchronized Reserves (MW) | RTO Synchronized Reserve Shortage (MW) |
|---|---|---|---|
| 21-Sep-17 14:15 | 1,576.5 | 1,560.4 | 16.1 |
| 21-Sep-17 14:20 | 1,576.5 | 1,560.4 | 16.1 |

After 1425 EPT, the synchronized reserves in RTO were replenished. During the seven 5 minute intervals beginning 1425 EPT through 1500 EPT, and the twelve 5 minute intervals beginning 1555 EPT through 1655 EPT, the primary reserves in the RTO Region were lower than the extended primary reserve requirement. Table 3-103 shows the RTO primary reserve MW and the extended primary reserve requirement during the period from 1425 EPT through 1500 EPT and from 1555 EPT through 1655 EPT.

### Table 3-103 RTO primary reserve MW and extended primary reserve requirement during primary reserve shortage

| Interval | RTO Extended Primary Reserve Requirement (MW) | RTO Total Primary Reserves (MW) | RTO Primary Reserve Shortage (MW) |
|---|---|---|---|
| 21-Sep-17 14:25 | 2,260 | 2,241 | 19 |
| 21-Sep-17 14:30 | 2,260 | 2,241 | 19 |
| 21-Sep-17 14:35 | 2,260 | 2,241 | 19 |
| 21-Sep-17 14:40 | 2,270 | 2,138 | 132 |
| 21-Sep-17 14:45 | 2,270 | 2,138 | 132 |
| 21-Sep-17 14:50 | 2,279 | 2,211 | 68 |
| 21-Sep-17 14:55 | 2,279 | 2,211 | 68 |
| 21-Sep-17 15:55 | 2,360 | 2,245 | 115 |
| 21-Sep-17 16:00 | 2,370 | 2,245 | 126 |
| 21-Sep-17 16:05 | 2,375 | 2,230 | 145 |
| 21-Sep-17 16:10 | 2,384 | 2,228 | 156 |
| 21-Sep-17 16:15 | 2,384 | 2,228 | 156 |
| 21-Sep-17 16:20 | 2,392 | 2,232 | 161 |
| 21-Sep-17 16:25 | 2,385 | 2,224 | 161 |
| 21-Sep-17 16:30 | 2,385 | 2,224 | 161 |
| 21-Sep-17 16:35 | 2,380 | 2,227 | 153 |
| 21-Sep-17 16:40 | 2,380 | 2,227 | 153 |
| 21-Sep-17 16:45 | 2,380 | 2,227 | 153 |
| 21-Sep-17 16:50 | 2,388 | 2,277 | 111 |

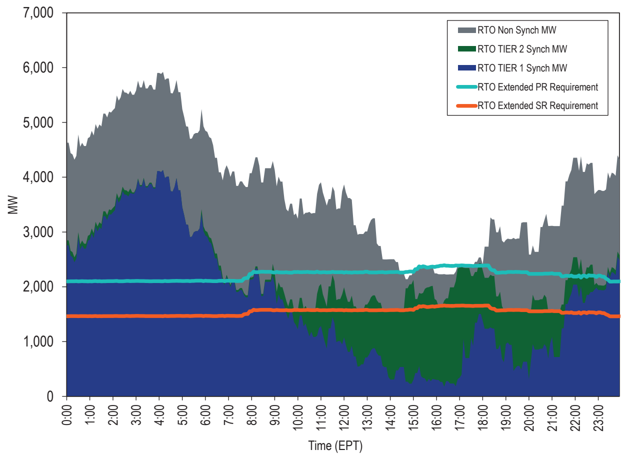
During the four 5 minute intervals beginning 1440 EPT through 1500 EPT, primary reserves in the MAD Region were lower than the MAD extended primary reserve requirement. (Table 3-104) From 1440 EPT to 1500 EPT, the market clearing price for synchronized and primary reserves for units located in the MAD Reserve Zone included the $300 per MWh penalty factor from the second step of the MAD primary reserve demand curve.

### Table 3-104 MAD primary reserve MW and extended primary reserve requirement during primary reserve shortage

| Interval | MAD Extended Primary Reserve Requirement (MW) | MAD Total Primary Reserves (MW) | MAD Primary Reserve Shortage (MW) |
|---|---|---|---|
| 21-Sep-17 14:40 | 2,236 | 2,125 | 112 |
| 21-Sep-17 14:45 | 2,236 | 2,125 | 112 |
| 21-Sep-17 14:50 | 2,233 | 2,197 | 36 |
| 21-Sep-17 14:55 | 2,233 | 2,197 | 36 |

Figure 3-60 shows the five minute MW quantities of RTO area tier 1 and tier 2 synchronized reserves, nonsynchronized reserves, the extended synchronized reserve requirement and the extended primary reserve requirement on September 21, 2017.

**Figure 3-60 Five minute dispatched reserves: September 21, 2017**




The purpose of primary reserve is to remediate a load/generation imbalance caused by a disturbance. A disturbance is defined as an instantaneous loss of generation greater than or equal to 80 percent of the most severe single contingency (900 MW in the eastern interconnection).[123] There was no disturbance on September 21, 2017. ACE declined approximately 1,400 MW between 1400 EPT and 1415 EPT. PJM dispatchers called a spinning event to solve the decrease in ACE.

Total primary reserve MW began to decline before the actual shortages of synchronized reserves and primary reserves emerged in hours 15 through 17 (Figure 3-60). The mix of available primary reserve elements (Tier 1, Tier 2, and NSR) changed as reserves were converted to energy.

Tier 1 synchronized reserve began to be converted to energy at hour 0400 EPT. ASO and real-time SCED scheduled more Tier 2 synchronized reserve to compensate. The extended synchronized reserve requirement was met until 1415 EPT.

At the same time, PJM called on CTs. Each CT, with a start time less than 10 minutes, that started reduced nonsynchronized reserves with the result that primary reserves were less than the extended primary reserve requirement beginning 1425 EPT. Increases in tier 1 and tier 2 synchronized reserves beginning 1700 EPT offset the reduction in nonsynchronized reserves.

## Reserve Performance and Compensation on September 21, 2017

During the spinning event that was in effect between 1415 and 1431 EPT on September 21, 2017, 71 percent of tier 1 responded and 83 percent of tier 2 responded.

Tier 1 synchronized reserve receives credits under two circumstances. Tier 1 is compensated when it responds to a spinning event. Tier 1 is also compensated at the tier 2 price whenever the NSRMCP goes above $0. The NSRMCP rose above $0 in hours 15, 16, and 17. Costs, prices, and response MW are shown in Table 3-105.

123 NERC BAL-002-2 - Background Document, July 2015, p. 10. This standard is being updated by BAL-002-3 effective January 1, 2018.

Table 3-105 Costs, Prices, and MW of tier 1 synchronized reserve hours: September 21, 2017

| Year | Month | Day | Hour | Tier 1 MW | Tier 1 Credits | Tier 1 Cost Per MW | Average Synchronized Energy Premium Price | Average SRMCP |
|---|---|---|---|---|---|---|---|---|
| 2017 | Sep | 21 | 14 | 453.2 | $190,539 | $420.43 | $420.36 | N/A |
| 2017 | Sep | 21 | 15 | 815.6 | $117,902 | $144.56 | N/A | $144.57 |
| 2017 | Sep | 21 | 16 | 914.2 | $308,038 | $336.95 | N/A | $336.95 |
| 2017 | Sep | 21 | 17 | 1,316.7 | $48,798 | $37.06 | N/A | $37.06 |

## CT Scheduling and Real Time Performance on September 21, 2017

PJM dispatched 5,236 MW from CTs between 1400 and 1700. Of these CTs, 54 percent performed as offered, 27 percent responded more slowly than the offered ramp rate and 18 percent did not reach their full offered output.

Table 3-106 shows the CT capacity that came online between hours 1400 and 1600 EPT following PJM dispatchers' instruction to start. Among the CTs that were instructed to start between 1330 and 1430 EPT, 54 percent of the capacity started within the next half hour. Among the CTs that were instructed to start between 1400 and 1430, 64 percent of capacity started within the next half hour.

Table 3-106 CT response to PJM's start instruction: September 21, 2017

| | | Interval Started | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | 14:00 - 14:30 | 14:30 - 15:00 | 15:00 - 15:30 | 15:30 - 16:00 | 16:00 - 16:30 | 16:30 - 17:00 | 17:00 - 17:30 | 18:00 - 18:30 |
| Interval Called | 13:30 - 14:00 | 54% | 39% | 3% | | | 4% | | |
| | 14:00 - 14:30 | 2% | 62% | 27% | 5% | | 4% | | |
| | 14:30 - 15:00 | | 13% | 49% | 28% | 6% | 4% | | |
| | 15:00 - 15:30 | | | | 26% | 13% | 13% | | 49% |
| | 15:30 - 16:00 | | | | | | | 100% | |
| | Total | 7% | 31% | 27% | 16% | 4% | 5% | 2% | 8% |

## Regulation signal and response on September 21, 2017

Figure 3-61 shows ACE on September 21, 2017, between 1200 and 1800.

Figure 3-61 ACE between 1200 and 1800: September 21, 2017

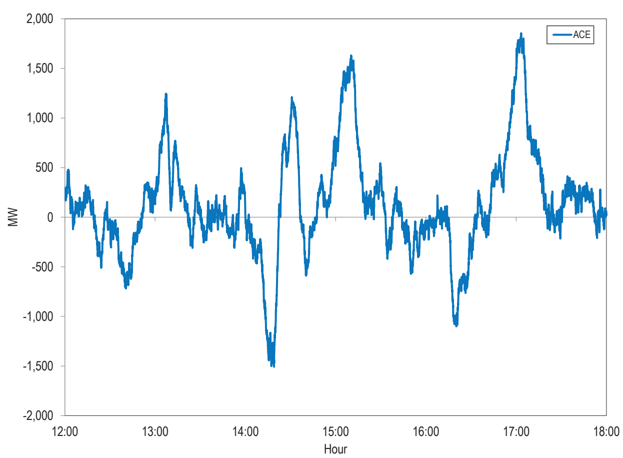



Figure 3-62 and Figure 3-63 show the RegA and RegD signals during the scarcity event. The RegA and RegD signals are the percent of the maximum regulation MW requested of units following the signals. For example, a RegA or RegD signal of 0.5 means that a unit providing 10 MW of regulation capability (± 10 MW from its regulation set point) should be producing 5 MW above its regulation set point. The periods of maximum or minimum regulation signals, when either full regulation output or no regulation output from the operating units is being requested, are called signal pegging. As a result of fluctuations in ACE during the scarcity event, there was an increase in both the total amount and average duration of pegging events between the hours of 1400 and 1700 on September 21, 2017.

Figure 3-62 RegA signal between 1200 and 1800: September 21, 2017

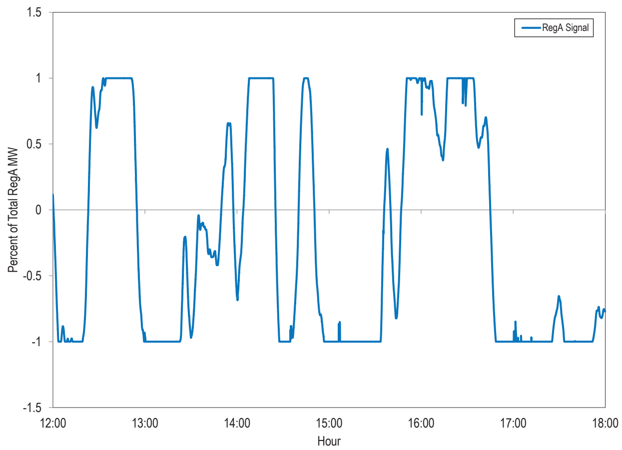



Figure 3-63 RegD signal between 1200 and 1800: September 21, 2017

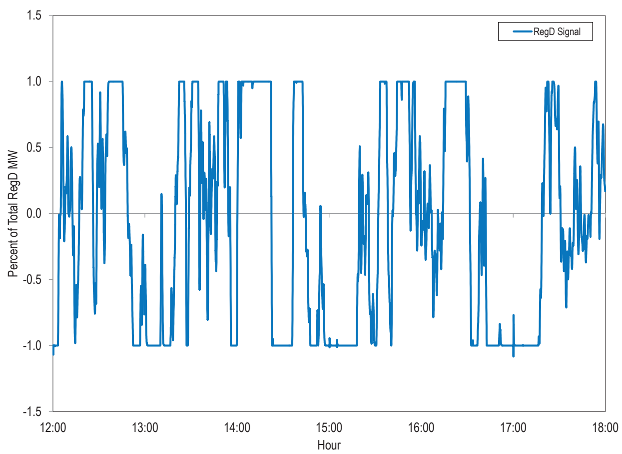



Figure 3-64 Amount of time the RegA and RegD signal were pegged during each hour: September 21, 2017

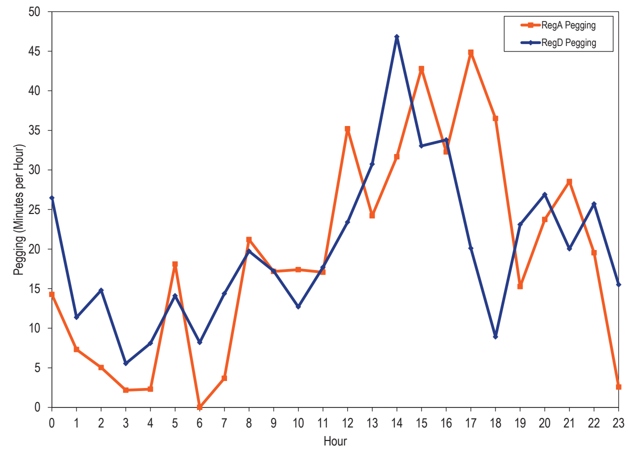



Figure 3-65 Average duration of RegA and RegD pegging events in each hour: September 21, 2017

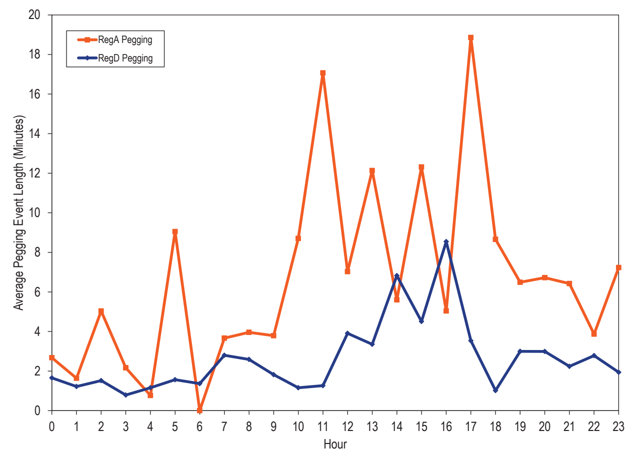



Figure 3-64 and Figure 3-65 show the amount of time in minutes per hour that the RegA and RegD signals were pegged, and the average length of the pegging events within an hour for each signal. The duration of a pegging event is defined as any period of time in which the RegD signal is within five percent of its full maximum or minimum, and is not interrupted for more than 10 consecutive seconds. These figures illustrate, that between 1300 and 1700 on September 21, 2017, there was an increase in both the total pegging per hour, and the average length of a pegging event.

## Operator load forecast bias on September 21, 2017

PJM dispatchers are allowed to increase or decrease (bias) the load forecast from SCED for the next ten minutes in the real-time SCED software in order to correct for short term load forecast error.[124] Between 1400 and 1700, PJM's dispatchers lowered the forecast on average by 475 MW. For a few intervals, the load forecast was lowered by 1,300 MW. This reduced load forecast, in combination with curtailments in imports, could have resulted in SCED not dispatching enough units to meet load, and could have resulted in an overestimate of reserves during the peak hours on September 21, 2017.

124 Prior to July 17, 2017, the load forecast in the SCED software was for 15 minutes.

## Accuracy of Reserve Measurement

The definition of a shortage of synchronized and primary reserves is based on the measured and estimated levels of load, generation, interchange, demand response, and reserves from the real-time SCED software. The definition of such shortage also includes discretionary operator inputs to the ASO (Ancillary Service Optimizer) or SCED software. For shortage pricing to be accurate, there must 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 accurately measure reserves. Without accurate measurement of reserves on a minute by minute basis, system operators cannot know with certainty that there is a shortage condition and a reliable trigger for five minute shortage pricing does not exist. The benefits of five minute shortage pricing are based on the assumption that a shortage can be precisely and transparently defined.[125]

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.[126] PJM did not propose any enhancements to reserve measurement in the January 11th compliance filing.

In the period between May 11, 2017, and December 31, 2017, there were instances when the real time reserve data on the PJM website showed a shortage of synchronized reserves but there was not shortage pricing. The real-time reserves on the PJM website were operational reserves as measured by Energy Management System (EMS), and not the reserves dispatched and priced by SCED.[127] RT SCED estimated reserves based on generation dispatch with a 15 minute look ahead until July 16, 2017. On July 17, PJM reduced the RT SCED look-ahead from 15 minutes to 10 minutes, but the reserve levels used to define shortage pricing continue to be look-ahead estimates and not real time operational reserves. As a result, PJM's scarcity pricing does not reflect actual current scarcity conditions, but reflects the expected response of generation and forecast load 10 minutes in the future.[128]

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.

### Historical Performance During Spinning Events

All resources that respond to spinning events are paid for their response. Table 3-107 shows the performance of tier 1 and tier 2 synchronized reserves during spinning events declared in 2015, 2016, and 2017 that lasted at least 10 minutes. In 2015, tier 1 response MW 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. As a result, the 2015 estimates for tier 1 response were greater than 100 percent.

Beginning in 2016, PJM reported the response to spinning events only from the units that were part of its tier 1 estimate. In 2016, the tier 1 response rate was never greater than 85 percent, with an average response rate of 75 percent. In 2017, the tier 1 response rate was never greater than 75 percent, with an average response rate of 60 percent.

PJM's current approach to estimating tier 1 reserves is not an accurate basis for defining shortage.

125 See Comments of the Independent Market Monitor for PJM, Docket No. RM15-24-000 (December 1, 2015) at 9.

126 155 FERC ¶ 61,276 at P 177 (June 16, 2016).

127 PJM has since added the real-time SCED dispatched reserve quantities, in addition to the operational reserve quantities to its website.

128 Prior to July 17, 2017, PJM's scarcity pricing reflected the expected response of generation and load fifteen minutes in the future.

Table 3-107 Performance of synchronized reserves during spinning events: 2015 through 2017

| 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% |
| Apr 08, 2017 11 | 10 | 1,222.6 | 827.2 | 879.3 | 828.7 | 67.7% | 94.2% |
| May 08, 2017 04 | 10 | 1,325.6 | 976.3 | 335.1 | 298.5 | 73.6% | 89.1% |
| Jun 08, 2017 03 | 10 | 974.4 | 726.7 | 575.7 | 522.4 | 74.6% | 90.7% |
| Sep 04, 2017 20 | 15 | 476.3 | 68.1 | 601.0 | 563.8 | 14.3% | 93.8% |
| Sep 21, 2017 14 | 16 | 305.8 | 217.4 | 1,253.9 | 1,037.3 | 71.1% | 82.7% |

### Tier 1 Synchronized Reserve Estimate Bias

Tier 1 synchronized reserves are calculated based on unit capabilities but are also subject to tier 1 estimate bias by PJM. PJM manually modifies (increasing or decreasing) the tier 1 synchronized reserve estimate of the market solution, forcing more or less tier 2 synchronized reserve and nonsynchronized reserve to clear to meet reserve requirements. Tier 1 biasing reflects the operators' view of the available tier 1 MW. Table 10-14 shows the average monthly biasing of tier 1 estimates in the Ancillary Service Optimizer (ASO) in 2015 and 2016.

There are no rules in the PJM tariff or manuals regarding the use of tier 1 MW biasing. With five minute shortage pricing and the associated market impacts, there is a clear need for explicit rules governing operator discretion to calculated reserves. The MMU has recommended since 2012 that PJM explicitly define the rules for using tier 1 biasing.

### Generator Data used for Reserve Estimates

A potential source of error in calculating tier 1 MW is the use of the economic dispatch point to calculate the available ramp limited MW in 10 minutes rather than the actual output from the generator for any five minute interval. PJM addressed this issue partially in 2015 by adjusting a resource's available 10 minute ramp with Degree of Generator Performance metric (DGP).

## PJM Cold Weather Operations 2017

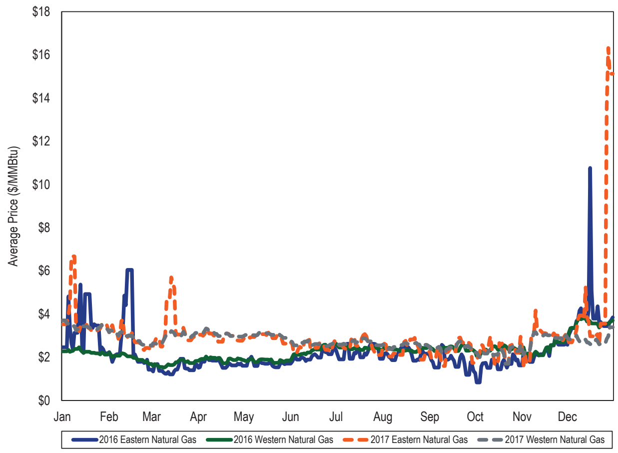
### Natural Gas Supply and Prices

As of December 31, 2017, gas fired generation was 36.8 percent (67,726.4 MW) of the total installed PJM capacity (183,881.6 MW).[129] Figure 3-66 shows the average daily price of delivered natural gas for eastern and western parts of PJM service territory in 2017 and 2016.[130]

129 *2017 State of the Market Report for PJM*, Volume 2, Section 5: Capacity Market, at Installed Capacity.

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

Figure 3-66 Average daily delivered price for natural gas: 2016 through 2017 ($/MMBtu)




During 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 and to facilitate the interoperability of the pipelines in an explicit network.

# 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. Part of that uplift is the result of the nonconvexity of power production costs. 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 short run 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 $7.5 million, or 5.5 percent, in 2017 compared to 2016, from $136.7 million to $129.1 million.
- **Energy Uplift Charges Categories.** The decrease of $7.5 million in 2017 is comprised of a $32.6 million decrease in day-ahead operating reserve charges, a $7.2 million increase in balancing operating reserve charges and a $17.9 million increase in reactive services charges.
- **Average Effective Operating Reserve Rates in the Eastern Region.** Day-ahead load paid $0.030 per MWh, real-time load paid $0.037 per MWh, a DEC paid $0.386 per MWh and an INC and any load, generation or interchange transaction deviation paid $0.355 per MWh.
- **Average Effective Operating Reserve Rates in the Western Region.** Day-ahead load paid $0.030 per MWh, real-time load paid $0.028 per MWh, a DEC paid $0.357 per MWh and an INC and any load, generation or interchange transaction deviation paid $0.327 per MWh.
- **Reactive Services Rates.** The ComEd, PENELEC, and DPL control zones had the three highest local voltage support rates: $0.139, $0.099 and $0.073 per MWh.

### Characteristics of Credits

- **Types of units.** Coal units received 78.7 percent of all day-ahead generator credits. Combustion turbines received 76.3 percent of all balancing generator credits. Combustion turbines and diesels received 70.3 percent of the lost opportunity cost credits.
- **Concentration of Energy Uplift Credits.** The top 10 units receiving energy uplift credits received 33.1 percent of all credits. The top 10 organizations received 77.9 percent of all credits. Concentration

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 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.

indexes for energy uplift categories classify them as highly concentrated. Day-ahead operating reserves HHI was 7486, balancing operating reserves HHI was 3334 and lost opportunity cost HHI was 5538.

- **Economic and Noneconomic Generation.** In 2017, 85.1 percent of the day-ahead generation eligible for operating reserve credits was economic and 73.1 percent of the real-time generation eligible for operating reserve credits was economic.
- **Day-Ahead Unit Commitment for Reliability.** In 2017, 1.2 percent of the total day-ahead generation MWh was scheduled as must run by PJM, of which 54.9 percent received energy uplift payments.

## Geography of Charges and Credits

- In 2017, 89.2 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 6.4 percent by interchange transactions at interfaces.
- Generators in the Eastern Region received 50.7 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.
- Generators in the Western Region received 47.4 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.
- External generators received 1.9 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. Pending before FERC.)
- 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. Pending before FERC.)
- 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 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 must 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 consistent with pricing at short run marginal cost 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.[4] 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.

It is not appropriate to accept that inflexible units should be paid or set price based on short run marginal costs plus no load. The question of why units make inflexible offers should be addressed directly. Are units inflexible because they are old and inefficient, because owners have not invested in increased flexibility or because they serve as a mechanism for the exercise of market power. The question of why this unit was built, whether it was built under cost of service regulation and whether it is efficient to retain the unit should be answered directly. The question of how to provide market incentives for investment in flexible units and for investment in increased flexibility of existing units should be addressed directly. The question of whether inflexible units should be paid uplift at all should be addressed directly. Marginal cost pricing without paying uplift to inflexible units would create incentives for market participants to provide flexible solutions including replacing inefficient units with flexible, efficient units.

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. The same is true of fast start pricing and of convex hull pricing.

Accurate short run price signals, equal to the short run marginal cost of generating power, provide market incentives for cost minimizing production to all economically dispatched resources and provide market incentives to load based on the marginal cost of additional consumption. The objective of efficient short run price signals is to minimize system production costs, not to minimize uplift. Repricing the market to reflect commitment costs would create a tradeoff between minimizing production costs and reduction of uplift. The tradeoff would exist because when commitment costs are included in prices, the price signal no longer equals the short run marginal cost and therefore no longer provides the correct signal for efficient behavior for market participants making decisions on the margin, whether resources, load, interchange transactions, or virtual traders. This tradeoff would be created in more

4 On October 17, 2017, PJM filed with FERC to begin charging uplift to UTC transactions and eliminating the netting of deviations with internal bilateral transactions. See FERC Docket No. ER18-86-000.

limited form by PJM's fast start pricing proposal and in extensive form by PJM's modified convex hull pricing proposal.

# 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<br>Day-Ahead Operating Reserve Generator | → | Day-Ahead Operating Reserve | Day-Ahead Load<br>Day-Ahead Export Transactions<br>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<br>Day-Ahead Export Transactions<br>Decrement Bids | in RTO Region |
| Unallocated Negative Load Congestion Charges<br>Unallocated Positive Generation Congestion Credits | | → | Unallocated Congestion | Day-Ahead Load<br>Day-Ahead Export Transactions<br>Decrement Bids | in RTO Region |
| | | Balancing | | | |
| Generation Resources | Balancing Operating Reserve Generator | → | Balancing Operating Reserve for Reliability | Real-Time Load plus Real-Time Export Transactions | in RTO, Eastern or Western Region |
| | | | Balancing Operating Reserve for Deviations | Deviations | in RTO, Eastern or Western Region |
| | | | Balancing Local Constraint | Applicable Requesting Party | |
| Canceled Resources | Balancing Operating Reserve Startup Cancellation | → | Balancing Operating Reserve for Deviations | Deviations | in RTO Region |
| Lost Opportunity Cost (LOC) | Balancing Operating Reserve LOC | | | | |
| Real-Time Import Transactions | Balancing Operating Reserve Transaction | | | | |
| Economic Load Response Resources | Balancing Operating Reserves for Load Response | → | Balancing Operating Reserve for Load Response | Deviations | in RTO Region |

Table 4-2 Reactive services, synchronous condensing and black start services credits and charges

| Credits Received For: | Credits Category: | | Charges Category: | Charges Paid By: |
|---|---|---|---|---|
| | | Reactive | | |
| Resources Providing Reactive Service | Day-Ahead Operating Reserve | → | Reactive Services Charge | Zonal Real-Time Load |
| | Reactive Services Generator | | | |
| | Reactive Services LOC | | | |
| | Reactive Services Condensing | | Reactive Services Local Constraint | Applicable Requesting Party |
| | Reactive Services Synchronous Condensing LOC | | | |
| | | Synchronous Condensing | | |
| Resources Providing Synchronous Condensing | Synchronous Condensing | → | Synchronous Condensing | Real-Time Load |
| | Synchronous Condensing LOC | | | Real-Time Export Transactions |
| | | Black Start | | |
| Resources Providing Black Start Service | Day-Ahead Operating Reserve | → | Black Start Service Charge | Zone/Non-zone Peak Transmission Use and Point to Point Transmission Reservations |
| | Balancing Operating Reserve | | | |
| | Black Start Testing | | | |

# Energy Uplift Results

## Energy Uplift Charges

Total energy uplift charges decreased by $7.5 million or 5.5 percent in 2017 compared to 2016. Table 4-3 shows total energy uplift charges for 2001 through 2017.[5]

Table 4-3 Total energy uplift charges: 2001 through 2017

| | Total Energy Uplift Charges (Millions) | Change (Millions) | Percent Change | Energy Uplift as a Percent of Total PJM Billing |
|---|---|---|---|---|
| 2001 | $284.0 | $67.0 | 30.9% | 8.5% |
| 2002 | $273.7 | ($10.3) | (3.6%) | 5.8% |
| 2003 | $376.5 | $102.8 | 37.6% | 5.4% |
| 2004 | $537.6 | $161.1 | 42.8% | 6.1% |
| 2005 | $712.6 | $175.0 | 32.6% | 3.1% |
| 2006 | $365.6 | ($347.0) | (48.7%) | 1.7% |
| 2007 | $503.3 | $137.7 | 37.7% | 1.6% |
| 2008 | $474.3 | ($29.0) | (5.8%) | 1.4% |
| 2009 | $322.7 | ($151.6) | (32.0%) | 1.2% |
| 2010 | $623.2 | $300.5 | 93.1% | 1.8% |
| 2011 | $603.4 | ($19.8) | (3.2%) | 1.7% |
| 2012 | $649.8 | $46.4 | 7.7% | 2.2% |
| 2013 | $843.0 | $193.2 | 29.7% | 2.5% |
| 2014 | $961.2 | $118.2 | 14.0% | 1.9% |
| 2015 | $312.0 | ($649.2) | (67.5%) | 0.7% |
| 2016 | $136.7 | ($824.5) | (85.8%) | 0.3% |
| 2017 | $129.1 | ($7.5) | (5.5%) | 0.3% |

Table 4-4 compares energy uplift charges by category for 2016 and 2017. The decrease of $7.5 million in 2017 is comprised of a decrease of $32.6 million in day-ahead operating reserve charges, an increase of $7.2 million in balancing operating reserve charges and an increase of $17.9 million in reactive service charges.

Table 4-4 Energy uplift charges by category: 2016 and 2017

| Category | 2016 Charges (Millions) | 2017 Charges (Millions) | Change (Millions) | Percent Change |
|---|---|---|---|---|
| Day-Ahead Operating Reserves | $57.3 | $24.7 | ($32.6) | (56.9%) |
| Balancing Operating Reserves | $76.6 | $83.8 | $7.2 | 9.4% |
| Reactive Services | $2.5 | $20.4 | $17.9 | 719.1% |
| Synchronous Condensing | $0.0 | $0.0 | ($0.0) | (100.0%) |
| Black Start Services | $0.3 | $0.3 | ($0.0) | (7.8%) |
| Total | $136.7 | $129.1 | ($7.5) | (5.5%) |

Table 4-5 compares monthly energy uplift charges by category for 2016 and 2017.

5 Table 4-3 includes all categories of charges as defined in Table 4-1 and Table 4-2 and includes all PJM Settlements billing adjustments. Billing data can be modified by PJM Settlements at any time to reflect changes in the evaluation of energy uplift. The billing data reflected in this report were current on January 9, 2018.

### Table 4-5 Monthly energy uplift charges: 2016 and 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 | $7.5 | $1.25 | $0.0 | $0.0 | $11.4 |
| 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 | $5.4 | $1.4 | $0.0 | $0.0 | $7.4 |
| Apr | $3.0 | $4.8 | $0.2 | $0.0 | $0.0 | $8.0 | $0.5 | $3.3 | $1.3 | $0.0 | $0.0 | $5.0 |
| May | $2.8 | $3.3 | $0.1 | $0.0 | $0.0 | $6.3 | $0.9 | $7.4 | $1.3 | $0.0 | $0.0 | $9.7 |
| Jun | $4.6 | $5.3 | $0.1 | $0.0 | $0.1 | $10.1 | $1.8 | $6.8 | $0.9 | $0.0 | $0.0 | $9.5 |
| Jul | $3.6 | $10.9 | $0.1 | $0.0 | $0.0 | $14.6 | $2.5 | $7.9 | $0.9 | $0.0 | $0.0 | $11.4 |
| Aug | $2.4 | $11.5 | $0.0 | $0.0 | $0.0 | $13.9 | $2.9 | $5.4 | $1.5 | $0.0 | $0.0 | $9.8 |
| Sep | $2.9 | $6.9 | $0.1 | $0.0 | $0.0 | $9.9 | $3.0 | $10.3 | $2.3 | $0.0 | $0.0 | $15.6 |
| Oct | $3.6 | $8.7 | $0.3 | $0.0 | $0.0 | $12.6 | $1.6 | $7.9 | $2.2 | $0.0 | $0.0 | $11.8 |
| Nov | $5.7 | $2.8 | $1.0 | $0.0 | $0.1 | $9.5 | $2.1 | $7.8 | $1.9 | $0.0 | $0.0 | $11.8 |
| Dec | $7.3 | $4.5 | $0.4 | $0.0 | $0.0 | $12.2 | $4.0 | $12.8 | $2.3 | $0.0 | $0.0 | $19.1 |
| Total | $57.3 | $76.6 | $2.5 | $0.0 | $0.3 | $136.7 | $24.7 | $83.8 | $20.4 | $0.0 | $0.3 | $129.1 |
| Share | 42.0% | 56.0% | 1.8% | 0.0% | 0.2% | 100.0% | 19.1% | 64.9% | 15.8% | 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.[6] Day-ahead operating reserve charges decreased by $32.6 million or 56.9 percent in 2017 compared to 2016. Day-ahead operating reserve charges have decreased in 2017 due to transmission upgrades in the BGE and Pepco control zones that were completed in the first quarter of 2017. These upgrades have reduced the need to commit noneconomic coal fired generation in the BGE and Pepco control zones to meet local load. These upgrades have increased the transfer capability from other control zones into BGE and Pepco.

### Table 4-6 Day-ahead operating reserve charges: 2016 and 2017

| Type | 2016 Charges (Millions) | 2017 Charges (Millions) | Change (Millions) | 2016 Share | 2017 Share |
|---|---|---|---|---|---|
| Day-Ahead Operating Reserve Charges | $57.3 | $24.7 | ($32.6) | 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 | $57.3 | $24.7 | ($32.6) | 100.0% | 100.0% |

Table 4-7 shows the composition of the balancing operating reserve charges. Balancing operating reserve charges consist of balancing operating reserve reliability charges (credits to generators), balancing operating reserve deviation charges (credits to generators and import transactions), balancing operating reserve charges for economic load response and balancing local constraint charges. Balancing operating reserve charges increased by $7.2 million in 2017 compared to 2016.

### Table 4-7 Balancing operating reserve charges: 2016 and 2017

| Type | 2016 Charges (Millions) | 2017 Charges (Millions) | Change (Millions) | 2016 Share | 2017 Share |
|---|---|---|---|---|---|
| Balancing Operating Reserve Reliability Charges | $22.5 | $27.1 | $4.6 | 29.3% | 32.3% |
| Balancing Operating Reserve Deviation Charges | $53.6 | $55.0 | $1.4 | 70.0% | 65.6% |
| Balancing Operating Reserve Charges for Load Response | $0.1 | $0.4 | $0.3 | 0.1% | 0.5% |
| Balancing Local Constraint Charges | $0.4 | $1.4 | $0.9 | 0.6% | 1.6% |
| Total | $76.6 | $83.8 | $7.2 | 100.0% | 100.0% |

6 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 4-8 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 2017, 73.3 percent of balancing operating reserve deviation charges were for make whole credits paid to generators and import transactions, an increase of 8.6 percentage points compared to 2016. The increase in the share of make whole credits was the result of an increase in make whole credits, and a decrease in energy lost opportunity cost credits, which decreased by $4.2 million or 22.3 percent.

### Table 4-8 Balancing operating reserve deviation charges: 2016 and 2017

| Charge Attributable To | 2016 Charges (Millions) | 2017 Charges (Millions) | Change (Millions) | 2016 Share | 2017 Share |
|---|---|---|---|---|---|
| Make Whole Payments to Generators and Imports | $34.7 | $40.3 | $5.6 | 64.8% | 73.3% |
| Energy Lost Opportunity Cost | $18.8 | $14.6 | ($4.2) | 35.1% | 26.6% |
| Canceled Resources | $0.1 | $0.0 | ($0.1) | 0.2% | 0.0% |
| Total | $53.6 | $55.0 | $1.4 | 100.0% | 100.0% |

Table 4-9 shows reactive services, synchronous condensing and black start services charges. Reactive services charges increased by $17.9 million in 2017 compared to 2016. Reactive services charges increased in 2017 due to high voltage issues caused by light loads in the ComEd and DPL control zones, and low voltage issues caused by transmission outages in the BGE, Pepco and PENELEC control zones.

### Table 4-9 Additional energy uplift charges: 2016 and 2017

| Type | 2016 Charges (Millions) | 2017 Charges (Millions) | Change (Millions) | 2016 Share | 2017 Share |
|---|---|---|---|---|---|
| Reactive Services Charges | $2.5 | $20.4 | $17.9 | 89.9% | 98.8% |
| Synchronous Condensing Charges | $0.0 | $0.0 | ($0.0) | 0.0% | 0.0% |
| Black Start Services Charges | $0.3 | $0.3 | ($0.0) | 10.1% | 1.2% |
| Total | $2.8 | $20.6 | $17.9 | 100.0% | 100.0% |

Table 4-10 and Table 4-11 show the amount and percent shares of regional balancing charges in 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 2017, regional balancing operating reserve charges increased by $5.5 million compared to 2016. Balancing operating reserve reliability charges increased by $4.1 million or 17.6 percent, and balancing operating reserve deviation charges increased by $1.5 million or 2.8 percent.

### Table 4-10 Regional balancing charges allocation (Millions): 2016

| Charge | Allocation | RTO | | East | | West | | Total | |
|---|---|---|---|---|---|---|---|---|---|
| Reliability Charges | Real-Time Load | $18.3 | 23.9% | $3.5 | 4.6% | $0.4 | 0.6% | $22.2 | 29.0% |
| | Real-Time Exports | $0.7 | 0.9% | $0.1 | 0.1% | $0.0 | 0.0% | $0.8 | 1.0% |
| | Total | $18.9 | 24.8% | $3.6 | 4.7% | $0.5 | 0.6% | $23.0 | 30.1% |
| Deviation Charges | Demand | $28.3 | 37.1% | $3.0 | 3.9% | $0.5 | 0.7% | $31.8 | 41.6% |
| | Supply | $9.2 | 12.0% | $0.8 | 1.1% | $0.1 | 0.2% | $10.1 | 13.3% |
| | Generator | $10.1 | 13.2% | $1.2 | 1.5% | $0.2 | 0.3% | $11.5 | 15.0% |
| | Total | $47.6 | 62.3% | $5.0 | 6.5% | $0.9 | 1.1% | $53.5 | 69.9% |
| Total Regional Balancing Charges | | $66.6 | 87.0% | $8.6 | 11.3% | $1.3 | 1.7% | $76.5 | 100% |

## Table 4-11 Regional balancing charges allocation (Millions): 2017

| Charge | Allocation | RTO | | East | | West | | Total | |
|---|---|---|---|---|---|---|---|---|---|
| Reliability Charges | Real-Time Load | $21.8 | 26.5% | $4.0 | 4.8% | $0.4 | 0.5% | $26.1 | 31.9% |
| | Real-Time Exports | $0.8 | 0.9% | $0.2 | 0.2% | $0.0 | 0.0% | $0.9 | 1.1% |
| | Total | $22.5 | 27.5% | $4.1 | 5.0% | $0.4 | 0.5% | $27.1 | 33.0% |
| Deviation Charges | Demand | $31.0 | 37.8% | $2.2 | 2.6% | $0.5 | 0.6% | $33.7 | 41.1% |
| | Supply | $9.4 | 11.5% | $0.7 | 0.8% | $0.1 | 0.1% | $10.2 | 12.4% |
| | Generator | $10.3 | 12.5% | $0.7 | 0.9% | $0.1 | 0.2% | $11.1 | 13.5% |
| | Total | $50.6 | 61.7% | $3.5 | 4.3% | $0.8 | 1.0% | $55.0 | 67.0% |
| Total Regional Balancing Charges | | $73.2 | 89.2% | $7.6 | 9.3% | $1.2 | 1.5% | $82.0 | 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.[7]

Figure 4-1 shows the daily day-ahead operating reserve rate for 2016 and 2017. The average rate in 2017 was $0.030 per MWh, $0.039 per MWh lower than the average in 2016. The highest rate of 2017 occurred on November 30, when the rate reached $0.346 per MWh, $0.056 per MWh lower than the $0.402 per MWh reached in 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 2017.

### Figure 4-1 Daily day-ahead operating reserve rate ($/MWh): 2016 and 2017

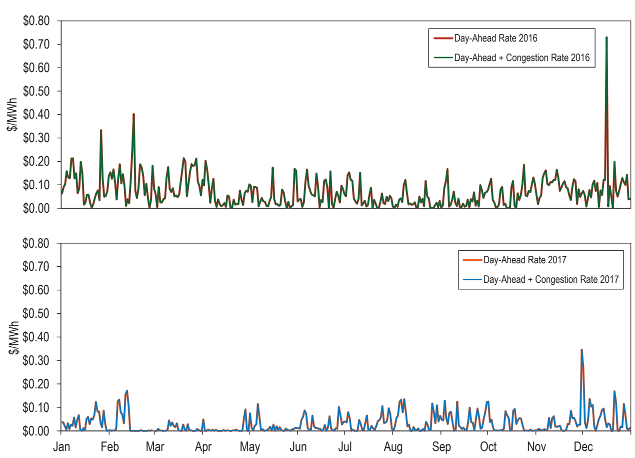



Figure 4-2 shows the RTO and the regional reliability rates for 2016 and 2017. The average daily RTO reliability rate was $0.029 per MWh. The highest RTO reliability rate in 2017 occurred on January 8, when the rate reached $0.390 per MWh, $0.155 per MWh higher than the $0.234 per MWh rate reached in 2016, on August 12.

### Figure 4-2 Daily balancing operating reserve reliability rates ($/MWh): 2016 and 2017

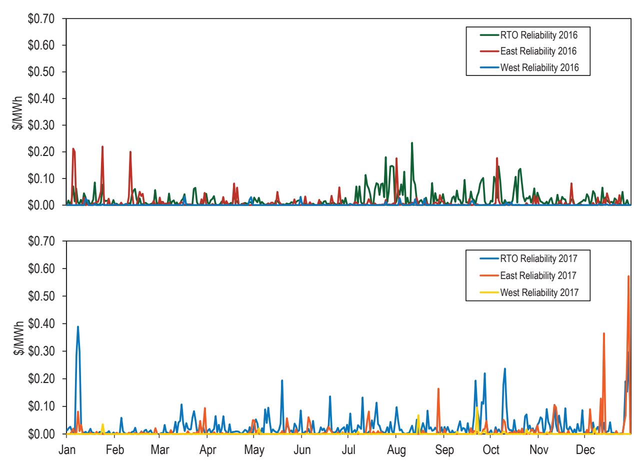



Figure 4-3 shows the RTO and regional deviation rates for 2016 and 2017. The average daily RTO deviation rate was $0.238 per MWh. The highest daily rate of 2017 occurred on January 9, when the RTO deviation rate reached $2.177 per MWh, $0.135 per MWh higher than the $2.042 per MWh rate reached in 2016, on October 19, 2016.

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

Figure 4-3 Daily balancing operating reserve deviation rates ($/MWh): 2016 and 2017

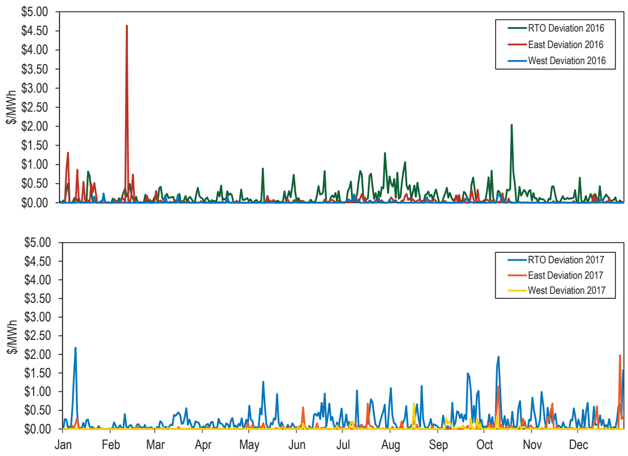



Figure 4-4 shows the daily lost opportunity cost rate and the daily canceled resources rate for 2016 and 2017. The lost opportunity cost rate averaged $0.097 per MWh. The highest lost opportunity cost rate occurred on December 26, when it reached $2.042 per MWh, $0.732 per MWh higher than the $1.294 per MWh rate reached in 2016, on April 14.

Figure 4-4 Daily lost opportunity cost and canceled resources rates ($/MWh): 2016 and 2017

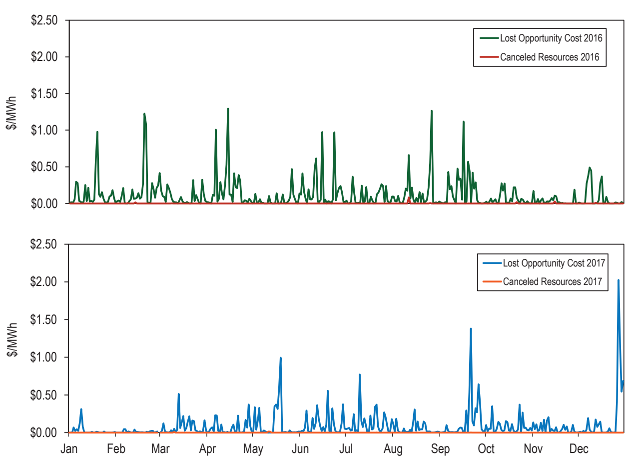



Table 4-12 shows the average rates for each region in each category in 2016 and 2017.

Table 4-12 Operating reserve rates ($/MWh): 2016 and 2017

| Rate | 2016 ($/MWh) | 2017 ($/MWh) | Difference ($/MWh) | Percent Difference |
|---|---|---|---|---|
| Day-Ahead | 0.069 | 0.030 | (0.039) | (55.9%) |
| Day-Ahead with Unallocated Congestion | 0.069 | 0.030 | (0.039) | (55.9%) |
| RTO Reliability | 0.024 | 0.029 | 0.005 | 21.4% |
| East Reliability | 0.010 | 0.011 | 0.002 | 15.9% |
| West Reliability | 0.001 | 0.001 | (0.000) | (3.4%) |
| RTO Deviation | 0.184 | 0.238 | 0.054 | 29.1% |
| East Deviation | 0.061 | 0.045 | (0.016) | (26.7%) |
| West Deviation | 0.012 | 0.011 | (0.001) | (4.3%) |
| Lost Opportunity Cost | 0.119 | 0.097 | (0.023) | (18.9%) |
| Canceled Resources | 0.001 | 0.000 | (0.000) | (80.1%) |

Table 4-13 shows the operating reserve cost of a one MW transaction in 2017. For example, a decrement bid in the Eastern Region (if not offset by other transactions) paid an average rate of $0.386 per MWh with a maximum rate of $3.860 per MWh, a minimum rate of $0.002 per MWh and a standard deviation of $0.498 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): 2017

| | | Rates Charged ($/MWh) | | | |
|---|---|---|---|---|---|
| Region | Transaction | Maximum | Average | Minimum | Standard Deviation |
| East | INC | 3.793 | 0.355 | 0.000 | 0.498 |
| | DEC | 3.860 | 0.386 | 0.002 | 0.498 |
| | DA Load | 0.346 | 0.030 | 0.000 | 0.042 |
| | RT Load | 0.869 | 0.037 | 0.000 | 0.073 |
| | Deviation | 3.793 | 0.355 | 0.000 | 0.498 |
| West | INC | 2.782 | 0.327 | 0.000 | 0.438 |
| | DEC | 2.816 | 0.357 | 0.002 | 0.437 |
| | DA Load | 0.346 | 0.030 | 0.000 | 0.042 |
| | RT Load | 0.390 | 0.028 | 0.000 | 0.048 |
| | Deviation | 2.782 | 0.327 | 0.000 | 0.438 |

## 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.

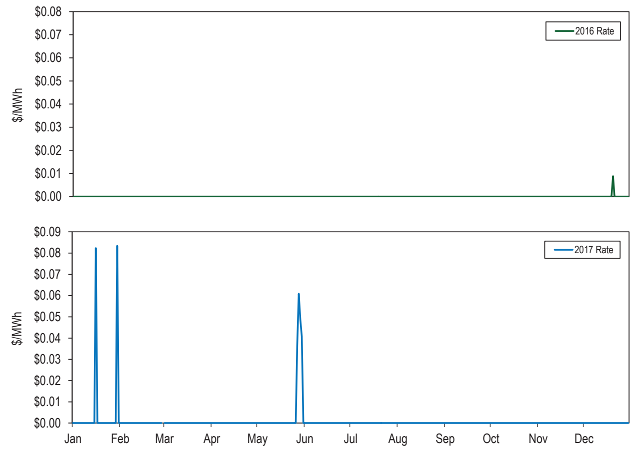
While reactive services rates are not posted by PJM, a local voltage support rate for each control zone can be calculated and a reactive transfer interface support rate can be calculated for the entire RTO. Table 4-14 shows the reactive services rates associated with local voltage support in 2016 and 2017. Table 4-14 shows that in 2017 the ComEd Control Zone had the highest rate. Real-time load in the ComEd Control Zone paid an average of $0.139 per MWh for reactive services associated with local voltage support, $0.129 or 1,236.1 percent higher than the average rate paid in 2016.

Table 4-14 Local voltage support rates: 2016 and 2017

| Control Zone | 2016 ($/MWh) | 2017 ($/MWh) | Difference ($/MWh) |
|---|---|---|---|
| AECO | 0.000 | 0.000 | 0.000 |
| AEP | 0.001 | 0.000 | (0.000) |
| APS | 0.000 | 0.002 | 0.002 |
| ATSI | 0.000 | 0.000 | 0.000 |
| BGE | 0.000 | 0.055 | 0.055 |
| ComEd | 0.010 | 0.139 | 0.129 |
| DAY | 0.000 | 0.000 | 0.000 |
| DEOK | 0.000 | 0.000 | 0.000 |
| DLCO | 0.000 | 0.000 | 0.000 |
| Dominion | 0.000 | 0.000 | 0.000 |
| DPL | 0.043 | 0.073 | 0.030 |
| EKPC | 0.013 | 0.001 | (0.012) |
| JCPL | 0.000 | 0.000 | 0.000 |
| Met-Ed | 0.001 | 0.004 | 0.003 |
| PECO | 0.000 | 0.002 | 0.002 |
| PENELEC | 0.015 | 0.099 | 0.084 |
| Pepco | 0.004 | 0.054 | 0.049 |
| PPL | 0.000 | 0.000 | (0.000) |
| PSEG | 0.000 | 0.000 | 0.000 |
| RECO | 0.000 | 0.000 | 0.000 |

Figure 4-5 shows the daily RTO wide reactive transfer interface rate in 2016 and 2017. RTO wide reactive charges were incurred only once in 2016 (December) and three times in 2017. 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 2016 and 2017. Total real-time load and real-time exports were 16,016,057 MWh, 2.0 percent lower in 2017 compared to 2016. Total deviations summed across the demand, supply, and generator categories were 5,677,771 MWh, 3.6 percent lower in 2017 compared to 2016.

## Table 4-15 Balancing operating reserve determinants (MWh): 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 |
| 2016 | RTO | 778,268,661 | 26,912,664 | 805,181,325 | 92,336,602 | 31,071,990 | 33,717,607 | 157,126,199 |
| 2016 | East | 367,239,524 | 11,097,604 | 378,337,128 | 46,107,993 | 17,766,995 | 18,124,169 | 81,999,156 |
| 2016 | West | 411,029,137 | 15,815,060 | 426,844,197 | 45,694,031 | 12,971,113 | 15,593,438 | 74,258,582 |
| 2017 | RTO | 759,025,009 | 30,140,259 | 789,165,268 | 91,653,951 | 30,537,035 | 29,257,443 | 151,448,428 |
| 2017 | East | 359,340,463 | 11,612,111 | 370,952,574 | 46,903,090 | 17,940,636 | 14,141,817 | 78,985,543 |
| 2017 | West | 399,684,546 | 18,528,148 | 418,212,694 | 44,252,495 | 12,291,544 | 15,115,626 | 71,659,665 |
| Difference | RTO | (19,243,652) | 3,227,595 | (16,016,057) | (682,651) | (534,955) | (4,460,164) | (5,677,771) |
| | East | (7,899,061) | 514,507 | (7,384,554) | 795,097 | 173,641 | (3,982,352) | (3,013,614) |
| | West | (11,344,591) | 2,713,088 | (8,631,503) | (1,441,536) | (679,569) | (477,812) | (2,598,918) |

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 2017, 30.2 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 69.8 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: 2017

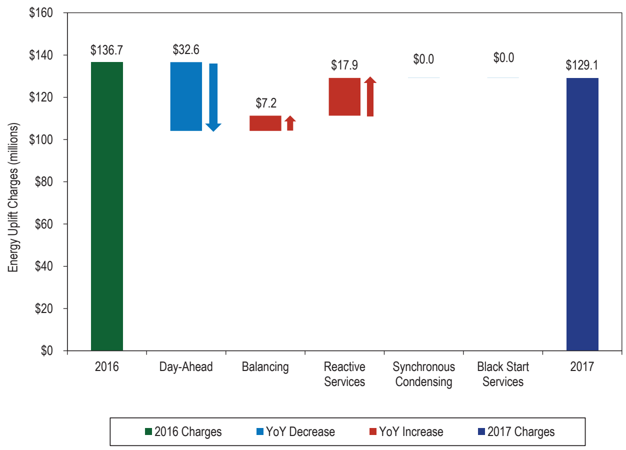
| Deviation | | Deviation (MWh) | | | Share | | |
|---|---|---|---|---|---|---|---|
| Category | Transaction | RTO | East | West | RTO | East | West |
| Demand | Bilateral Sales Only | 2,587,117 | 2,525,862 | 61,255 | 1.7% | 3.2% | 0.1% |
| | DECs Only | 15,678,629 | 6,869,201 | 8,311,062 | 10.4% | 8.7% | 11.6% |
| | Exports Only | 6,411,305 | 3,302,423 | 3,108,882 | 4.2% | 4.2% | 4.3% |
| | Load Only | 61,298,318 | 30,926,070 | 30,372,247 | 40.5% | 39.2% | 42.4% |
| | Combination with DECs | 4,172,095 | 2,429,675 | 1,742,420 | 2.8% | 3.1% | 2.4% |
| | Combination without DECs | 1,506,486 | 849,859 | 656,627 | 1.0% | 1.1% | 0.9% |
| Supply | Bilateral Purchases Only | 369,597 | 308,212 | 61,385 | 0.2% | 0.4% | 0.1% |
| | Imports Only | 4,255,838 | 3,202,113 | 1,053,725 | 2.8% | 4.1% | 1.5% |
| | INCs Only | 22,854,489 | 12,703,752 | 9,845,882 | 15.1% | 16.1% | 13.7% |
| | Combination with INCs | 2,981,382 | 1,663,585 | 1,317,796 | 2.0% | 2.1% | 1.8% |
| | Combination without INCs | 75,729 | 62,973 | 12,756 | 0.1% | 0.1% | 0.0% |
| Generators | | 29,257,443 | 14,141,817 | 15,115,626 | 19.3% | 17.9% | 21.1% |
| Total | | 151,448,428 | 78,985,543 | 71,659,665 | 100.0% | 100.0% | 100.0% |

# Year over Year Energy Uplift Charges Analysis

Energy uplift charges decreased by $7.5 million (5.5 percent), from $136.7 million in 2016 to $129.1 million in 2017. This change was the result of a decrease of $32.6 million in day-ahead operating reserve charges, an increase of $7.2 million in balancing operating reserve charges, and an increase of $17.9 million in reactive service charges. Other categories had smaller or no changes. There was a decrease of $0.02 million for black start service charges and there was no change in synchronous condensing charges.

Figure 4-6 shows the impact of each category on the change in total energy uplift charges from the 2016 level to the 2017 level. The outside bars show the total energy uplift charges in 2016 (left side) and total energy uplift charges in 2017 (right side). The other bars show the change in each energy uplift category. For example, the second bar from the left shows the change in day-ahead operating reserve charges in 2017 compared to 2016 (a decrease of $36.2 million).

Figure 4-6 Energy uplift charges change from 2016 to 2017 by category




## Energy Uplift Credits

Table 4-17 shows the totals for each credit category in 2016 and 2017. During 2017, 64.8 percent of total energy uplift credits were in the balancing operating reserve category, an increase of 8.7 percentage points from 56.1 in 2016.

Table 4-17 Energy uplift credits by category: 2016 and 2017

| Category | Type | 2016 Credits (Millions) | 2017 Credits (Millions) | Change | Percent Change | 2016 Share | 2017 Share |
|---|---|---|---|---|---|---|---|
| Day-Ahead Operating Reserve | Generators | $57.3 | $24.7 | ($32.6) | (56.9%) | 42.0% | 19.2% |
| | Imports | $0.0 | $0.0 | ($0.0) | (70.1%) | 0.0% | 0.0% |
| | Load Response | $0.0 | $0.0 | $0.0 | 1,882.0% | 0.0% | 0.0% |
| Balancing Operating Reserve | Canceled Resources | $0.1 | $0.0 | ($0.1) | (80.8%) | 0.1% | 0.0% |
| | Generators | $57.1 | $67.4 | $10.2 | 17.9% | 41.8% | 52.2% |
| | Imports | $0.0 | $0.0 | ($0.0) | (57.3%) | 0.0% | 0.0% |
| | Load Response | $0.1 | $0.4 | $0.3 | 317.5% | 0.1% | 0.3% |
| | Local Constraints Control | $0.4 | $1.4 | $0.9 | 219.6% | 0.3% | 1.1% |
| | Lost Opportunity Cost | $18.7 | $14.6 | ($4.1) | (22.0%) | 13.7% | 11.3% |
| Reactive Services | Day-Ahead | $1.4 | $19.3 | $17.9 | 1,261.2% | 1.0% | 14.9% |
| | Local Constraints Control | $0.0 | $0.0 | ($0.0) | (100.0%) | 0.0% | 0.0% |
| | Lost Opportunity Cost | $0.0 | $0.2 | $0.2 | 532.5% | 0.0% | 0.2% |
| | Reactive Services | $1.0 | $0.9 | ($0.1) | (8.0%) | 0.7% | 0.7% |
| | Synchronous Condensing | $0.1 | $0.0 | ($0.0) | (39.8%) | 0.0% | 0.0% |
| Synchronous Condensing | | $0.0 | $0.0 | ($0.0) | (100.0%) | 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 | 698.7% | 0.0% | 0.0% |
| | Testing | $0.3 | $0.2 | ($0.0) | (14.9%) | 0.2% | 0.2% |
| Total | | $136.5 | $129.1 | ($7.4) | (5.5%) | 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 2016 and 2017. The decrease in energy uplift in 2017 compared to 2016 was the result of lower credits paid to coal fired steam turbines and combined cycle units. Credits to these units decreased by $15.1 million or 21.3 percent.

Table 4-18 Energy uplift credits by unit type: 2016 and 2017

| Unit Type | 2016 Credits (Millions) | 2017 Credits (Millions) | Change | Percent Change | 2016 Share | 2017 Share |
|---|---|---|---|---|---|---|
| Combined Cycle | $14.7 | $10.1 | ($4.6) | (31.5%) | 10.8% | 7.8% |
| Combustion Turbine | $58.8 | $64.1 | $5.3 | 9.1% | 43.1% | 49.8% |
| Diesel | $0.6 | $1.0 | $0.4 | 57.4% | 0.4% | 0.7% |
| Hydro | $0.1 | $0.1 | $0.0 | 38.0% | 0.0% | 0.1% |
| Nuclear | $1.2 | $0.1 | ($1.1) | (93.3%) | 0.9% | 0.1% |
| Solar | $0.0 | $0.0 | $0.0 | 0.0% | 0.0% | 0.0% |
| Steam - Coal | $56.1 | $45.6 | ($10.5) | (18.6%) | 41.1% | 35.4% |
| Steam - Other | $3.3 | $5.8 | $2.5 | 74.6% | 2.4% | 4.5% |
| Wind | $1.7 | $2.0 | $0.3 | 15.0% | 1.3% | 1.5% |
| Total | $136.4 | $128.8 | ($7.7) | (5.6%) | 100.0% | 100.0% |

Table 4-19 shows the distribution of energy uplift credits by category and by unit type in 2017. Coal fired steam turbines received 78.7 percent of the day-ahead generator credits in 2017, 2.3 percentage points lower than the share received in 2016. Combustion turbines received 76.3 percent of the balancing operating reserve generator credits in 2017, 3.0 percentage points higher than the share received in 2016. Combustion turbines received 67.3 percent of the lost opportunity cost credits in 2017, 7.8 percentage points lower than the share received in 2016.

Table 4-19 Energy uplift credits by unit type: 2017

| Unit Type | Day-Ahead Operating Reserve | Balancing Operating Reserve | Canceled Resources | Local Constraints Control | Lost Opportunity Cost | Reactive Services | Synchronous Condensing | Black Start Services |
|---|---|---|---|---|---|---|---|---|
| Combined Cycle | 9.2% | 8.0% | 0.0% | 0.0% | 10.7% | 3.9% | 0.0% | 20.2% |
| Combustion Turbine | 3.4% | 76.3% | 2.7% | 90.3% | 67.3% | 2.9% | 0.0% | 79.8% |
| Diesel | 0.1% | 0.7% | 0.0% | 2.1% | 3.0% | 0.1% | 0.0% | 0.0% |
| Hydro | 0.0% | 0.0% | 97.3% | 0.0% | 0.4% | 0.0% | 0.0% | 0.0% |
| Nuclear | 0.0% | 0.0% | 0.0% | 0.0% | 0.5% | 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 | 78.7% | 11.8% | 0.0% | 7.6% | 5.7% | 84.9% | 0.0% | 0.0% |
| Steam - Others | 8.7% | 3.0% | 0.0% | 0.0% | 0.2% | 8.2% | 0.0% | 0.0% |
| Wind | 0.0% | 0.3% | 0.0% | 0.0% | 12.2% | 0.0% | 0.0% | 0.0% |
| Total (Millions) | $24.7 | $67.4 | $0.0 | $1.4 | $14.6 | $20.4 | $0.0 | $0.3 |

Table 4-19 also shows the distribution of reactive service credits and black start services credits by unit type. In 2017, coal units received 84.9 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 4-7 shows the concentration of energy uplift credits. The top 10 units received 33.1 percent of total energy uplift credits in 2017, compared to 36.0 percent in 2016. In 2017, 265 units received 90 percent of all energy uplift credits, compared to 274 units in 2016.

### Figure 4-7 Cumulative share of energy uplift credits: 2016 and 2017 by unit

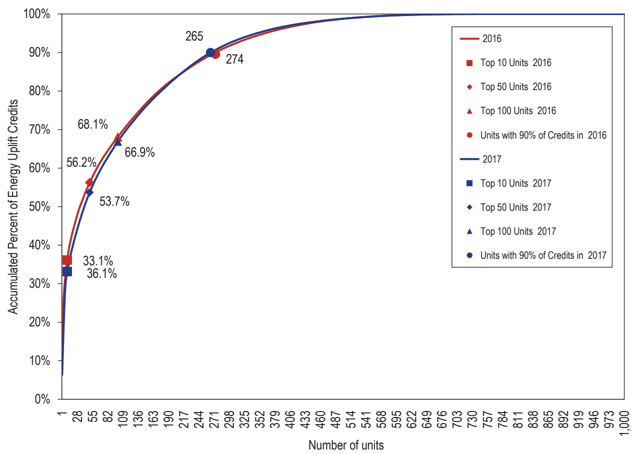



Table 4-20 shows the credits received by the top 10 units and top 10 organizations in each of the energy uplift categories paid to generators.

### Table 4-20 Top 10 units and organizations energy uplift credits: 2017

| | | Top 10 Units | | Top 10 Organizations | |
|---|---|---|---|---|---|
| Category | Type | Credits (Millions) | Credits Share | Credits (Millions) | Credits Share |
| Day-Ahead Operating Reserve | Generators | $19.0 | 77.0% | $24.0 | 97.0% |
| Balancing Operating Reserve | Canceled Resources | $0.0 | 100.0% | $0.0 | 100.0% |
| | Generators | $9.1 | 13.6% | $48.8 | 72.4% |
| | Local Constraints Control | $1.0 | 75.1% | $1.4 | 100.0% |
| | Lost Opportunity Cost | $3.0 | 20.3% | $10.3 | 70.7% |
| Reactive Services | | $18.8 | 92.1% | $20.4 | 99.9% |
| Synchronous Condensing | | $0.0 | 0.0% | $0.0 | 0.0% |
| Black Start Services | | $0.1 | 40.8% | $0.2 | 93.6% |
| Total | | $42.6 | 33.1% | $100.3 | 77.9% |

Table 4-21 shows balancing operating reserve credits received by the top 10 units identified for reliability or for deviations in each region. In 2017, 57.8 percent of all credits paid to these units were allocated to deviations while the remaining 42.2 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: 2017

| | Reliability | | | Deviations | | | |
|---|---|---|---|---|---|---|---|
| | RTO | East | West | RTO | East | West | Total |
| Credits (Millions) | $3.2 | $0.7 | $0.0 | $4.4 | $0.9 | $0.0 | $9.1 |
| Share | 34.6% | 7.6% | 0.0% | 47.9% | 9.9% | 0.0% | 100.0% |

In 2017, concentration in all energy uplift credit categories was high.[8] [9] 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 7486, for balancing operating reserve credits to generators was 3334, for lost opportunity cost credits was 5538 and for reactive services credits was 9123.

8 See *2017 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).

9 Table 4-22 excludes local constraints control categories.

### Table 4-22 Daily energy uplift credits HHI: 2017

| Category | Type | Average | Minimum | Maximum | Highest Market Share (One day) | Highest Market Share (All days) |
|---|---|---|---|---|---|---|
| Day-Ahead Operating Reserve | Generators | 7486 | 2229 | 10000 | 100.0% | 53.5% |
| | Imports | 10000 | 10000 | 10000 | 100.0% | 100.0% |
| | Load Response | 10000 | 10000 | 10000 | 100.0% | 96.1% |
| Balancing Operating Reserve | Canceled Resources | 10000 | 10000 | 10000 | 100.0% | 100.0% |
| | Generators | 3334 | 770 | 10000 | 100.0% | 15.7% |
| | Imports | 10000 | 10000 | 10000 | 100.0% | 100.0% |
| | Load Response | 9777 | 5281 | 10000 | 100.0% | 88.4% |
| | Lost Opportunity Cost | 5538 | 1481 | 10000 | 100.0% | 17.7% |
| Reactive Services | | 9123 | 3537 | 10000 | 100.0% | 80.3% |
| Synchronous Condensing | | NA | NA | NA | NA | NA |
| Black Start Services | | 9630 | 4997 | 10000 | 100.0% | 43.0% |
| Total | | 3325 | 747 | 9824 | 99.1% | 29.5% |

## Uplift Eligibility

In PJM, units can have either a pool scheduled or self-scheduled commitment status. Pool scheduled units are committed by PJM as a result of the day-ahead market clearing auction while self-scheduled units are committed by generation owners. Table 4-23 provides a description of commitment and dispatch status, uplift eligibility and the ability to set price.[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 follow PJM's dispatch are eligible for balancing operating reserve credits. Units are paid day-ahead operating reserve credits based on their scheduled operation for the entire day. Balancing 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. Resources receive day-ahead and balancing operating reserve credits only when they are eligible and are noneconomic for the day or segment. [11]

### Table 4-23 Dispatch status, commitment status and uplift eligibility

| | | | Commitment Status | |
|---|---|---|---|---|
| Dispatch Status | Dispatch Description | Eligible to Set LMP | Self Scheduled (units committed by the generation owner) | Pool Scheduled (units committed by PJM) |
| Block Loaded | MWh offered to PJM as a single MWh block which is not dispatchable | No | Not eligible to receive uplift | Eligible to receive uplift |
| Economic Minimum | MWh from the nondispatchable economic minimum component for units that offer a dispatchable range to PJM | No | Not eligible to receive uplift | Eligible to receive uplift |
| Dispatchable | MWh above the economic minimum level for units that offer a dispatchable range to PJM. | Yes | Only eligible to receive LOC credits if dispatched down by PJM | Eligible to receive uplift |

Table 4-24 shows that in 2017, 34.9 percent of generation was pool-scheduled in the Day-Ahead Energy Market and 34.3 percent was pool-scheduled in the Real-Time Energy Market. Thus the majority of generation in both the day-ahead and real-time markets is not eligible to receive uplift credits. This occurs because the majority of nuclear and coal resources, which make up 67.5 percent of real-time generation, are self-scheduled.

10 PJM has modified the basic rules of eligibility to set price in its CT price setting logic. Under CT price setting logic, the economic minimum of a block loaded CT is assumed to be lower than the actual offer. The result is that the CT may set price at its incremental energy offer for a MWh output level that it cannot produce, and thus at a price that does not represent actual marginal cost. The reduction appears to be at the discretion of the operators and does not appear to be applied to all CTs. The rules are not clearly stated in the PJM tariff or manuals. Not all CTs with a reduced economic minimum are marginal.

11 Noneconomic resources are those whose market revenues for the day or segment are less than the short run marginal cost defined by the startup, no load, and incremental offer curve.

### Table 4-24 Day-ahead and real-time generation by commitment status, dispatch status and eligibility to set LMP (GWh): 2017

| | Self Scheduled | | | Pool Scheduled | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Dispatchable | Ecomin | Block Loaded | Dispatchable | Ecomin | Block Loaded | Total GWh | Total Pool Scheduled | Total Self Scheduled | Total Generation Eligible to Set Price |
| Day Ahead Generation | 100,329 | 175,247 | 248,652 | 110,251 | 144,342 | 26,154 | 804,975 | 280,747 | 524,228 | 210,580 |
| Share of Day Ahead | 12.5% | 21.8% | 30.9% | 13.7% | 17.9% | 3.2% | 100.0% | 34.9% | 65.1% | 26.2% |
| Real Time Generation | 94,620 | 167,846 | 269,722 | 102,165 | 146,932 | 28,677 | 809,962 | 277,774 | 532,188 | 196,785 |
| Share of Real Time | 11.7% | 20.7% | 33.3% | 12.6% | 18.1% | 3.5% | 100.0% | 34.3% | 65.7% | 24.3% |

## Economic and Noneconomic Generation[12]

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 in real time at an incremental offer higher than the LMP and the unit's bus. 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 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 and startup cost. A unit could be noneconomic for multiple hours and not receive operating reserve credits whenever the total revenues covered the total offer (including no load and startup cost) for the entire day or segment.

Table 4-26 shows the day-ahead and real-time economic and noneconomic generation from units eligible for operating reserve credits. In 2017, 85.1 percent of the day-ahead generation eligible for operating reserve credits was economic and 73.4 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 4-26 shows the separate amounts of economic and noneconomic generation even if the daily or segment generation was economic.

### Table 4-25 Day-ahead and real-time economic and noneconomic generation from units eligible for operating reserve credits (GWh): 2017

| Energy Market | Economic Generation | Noneconomic Generation | Economic Generation Percent | Noneconomic Generation Percent |
|---|---|---|---|---|
| Day-Ahead | 238,876 | 41,871 | 85.1% | 14.9% |
| Real-Time | 196,096 | 70,913 | 73.4% | 26.6% |

Noneconomic generation only leads to operating reserve credits when units' generation for the day or segment, scheduled or committed, is noneconomic, including no load and startup costs. Table 4-26 shows the generation receiving day-ahead and balancing operating reserve credits. In 2017, 2.8 percent of the day-ahead generation eligible for operating reserve credits received credits and 2.4 percent of the real-time generation eligible for operating reserve credits received credits.

### Table 4-26 Day-ahead and real-time generation receiving operating reserve credits (GWh): 2017

| Energy Market | Generation Eligible for Operating Reserve Credits | Generation Receiving Operating Reserve Credits | Generation Receiving Operating Reserve Credits Percent |
|---|---|---|---|
| Day-Ahead | 280,747 | 7,756 | 2.8% |
| Real-Time | 267,009 | 6,357 | 2.4% |

## 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 that would have otherwise not been committed in the day-ahead. Such reliability issues include black start service and reactive service or reactive transfer interface control needed to maintain system reliability in a zone.[13] Participants can submit units as self-scheduled (must run), meaning that the unit must be committed, but a unit submitted as must run by a participant is not eligible for day-

12 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.

13 See PJM. OATT 3.2.3 (b).

ahead operating reserve credits.[14] Units committed for reliability by PJM may set LMP if raised above economic minimum and following the dispatch signal and are eligible for day-ahead operating reserve credits. Table 4-27 shows the total day-ahead generation and the subset of that generation committed for reliability by PJM. In 2017, 1.2 percent of the total day-ahead generation was committed for reliability by PJM, 0.2 percentage points lower than in 2016.

### Table 4-27 Day-ahead generation committed for reliability by PJM (GWh): 2016 and 2017

| | 2016 | | | 2017 | | |
|---|---|---|---|---|---|---|
| | Total Day-Ahead Generation | Generation Committed for Reliability by PJM | Share | Total Day-Ahead Generation | Generation Committed for Reliability by PJM | Share |
| Jan | 73,821 | 935 | 1.3% | 71,967 | 1,051 | 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% | 58,457 | 334 | 0.6% |
| May | 59,078 | 429 | 0.7% | 61,164 | 952 | 1.6% |
| Jun | 70,573 | 772 | 1.1% | 69,964 | 634 | 0.9% |
| Jul | 81,801 | 981 | 1.2% | 79,334 | 1,157 | 1.5% |
| Aug | 83,021 | 1,694 | 2.0% | 74,129 | 876 | 1.2% |
| Sep | 69,962 | 1,682 | 2.4% | 65,211 | 1,047 | 1.6% |
| Oct | 60,950 | 1,066 | 1.7% | 61,308 | 1,013 | 1.7% |
| Nov | 59,983 | 819 | 1.4% | 61,980 | 589 | 1.0% |
| Dec | 72,478 | 1,112 | 1.5% | 73,448 | 1,025 | 1.4% |
| Total | 814,803 | 12,031 | 1.5% | 804,975 | 9,926 | 1.2% |

### Table 4-28 Day-ahead generation committed for reliability by PJM by category (GWh): 2017

| | Reactive Services | Day-Ahead Operating Reserves | Economic | Total |
|---|---|---|---|---|
| Jan | 318 | 256 | 477 | 1,051 |
| Feb | 411 | 172 | 141 | 725 |
| Mar | 215 | 2 | 306 | 523 |
| Apr | 106 | 31 | 197 | 334 |
| May | 213 | 166 | 573 | 952 |
| Jun | 162 | 157 | 315 | 634 |
| Jul | 226 | 300 | 630 | 1,157 |
| Aug | 266 | 385 | 224 | 876 |
| Sep | 257 | 330 | 459 | 1,047 |
| Oct | 344 | 287 | 383 | 1,013 |
| Nov | 220 | 165 | 204 | 589 |
| Dec | 259 | 205 | 561 | 1,025 |
| Total | 2,998 | 2,456 | 4,473 | 9,926 |
| Share | 30.2% | 24.7% | 45.1% | 100.0% |

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 committed for reliability by PJM are only paid day-ahead operating reserve credits when their total offer is greater than the revenues from the Day-Ahead Energy Market.

It is illogical and unnecessary to pay units day-ahead operating reserves because units do not incur any costs to run and any revenue shortfalls are addressed by balancing operating reserve payments.

Table 4-28 shows the total day-ahead generation committed for reliability by PJM by category. In 2017, 54.9 percent of the day-ahead generation committed for reliability by PJM received operating reserve credits, 24.7 percent paid as day-ahead operating reserve credits and 30.2 percent paid as reactive services. The remaining 45.1 percent of the day-ahead generation committed for reliability by PJM did not need to be made whole.

Total day-ahead operating reserve credits in 2017 were $24.7 million, of which $19.1 million or 77.4 percent was paid to units committed for reliability by PJM, and not scheduled to provide black start or reactive services.

## Geography of Charges and Credits

Table 4-29 shows the geography of charges and credits in 2017. Table 4-29 includes only day-ahead operating reserve charges and balancing operating reserve reliability and deviation charges since these categories are allocated regionally, while other charges, such as reactive services, synchronous condensing and black start services are allocated by control zone, and balancing local constraint charges are charged to the requesting party.

Charges are categorized by the location (control zone, hub, aggregate or interface) where they are allocated according to PJM's operating reserve rules. Credits are categorized by the location where the resources are located. The shares columns reflect the operating reserve credits and charges balance for each location. For example, transactions in the ATSI Control Zone paid 7.0 percent of all operating reserve charges allocated regionally while resources in the ATSI Control Zone

14 See PJM. "PJM Markets Gateway User Guide," Section Managing Unit Data (version July 18, 2017) p. 32, <http://www.pjm.com/-/media/etools/markets-gateway/markets-gateway-user-guide.ashx?la=en>.

were paid 3.2 percent of the corresponding credits. The ATSI Control Zone received less operating reserve credits than operating reserve charges paid and had 11.3 percent of the deficit. The deficit is the sum of the negative entries in the balance column. Transactions in the BGE Control Zone paid 4.1 percent of all operating reserve charges allocated regionally, and resources in the BGE Control Zone were paid 11.7 percent of the corresponding credits. The BGE Control Zone received more operating reserve credits than operating reserve charges paid and had 22.9 percent of the surplus. The surplus is the sum of the positive entries in the balance column. Table 4-29 also shows that 89.2 percent of all charges were allocated in control zones, 4.4 percent in hubs and aggregates and 6.4 percent in interfaces.

## Table 4-29 Geography of regional charges and credits: 2017

| | | | | | Shares | | | |
|---|---|---|---|---|---|---|---|---|
| Location | | Charges (Millions) | Credits (Millions) | Balance | Total Charges | Total Credits | Deficit | Surplus |
| Zones | AECO | $1.4 | $1.2 | ($0.2) | 1.3% | 1.1% | 0.6% | 0.0% |
| | AEP | $13.7 | $11.6 | ($2.1) | 12.9% | 10.9% | 5.9% | 0.0% |
| | APS | $5.9 | $3.2 | ($2.7) | 5.5% | 3.0% | 7.6% | 0.0% |
| | ATSI | $7.5 | $3.4 | ($4.0) | 7.0% | 3.2% | 11.3% | 0.0% |
| | BGE | $4.3 | $12.5 | $8.1 | 4.1% | 11.7% | 0.0% | 22.9% |
| | ComEd | $11.3 | $15.4 | $4.1 | 10.6% | 14.4% | 0.0% | 11.4% |
| | DAY | $1.9 | $3.3 | $1.4 | 1.8% | 3.1% | 0.0% | 4.0% |
| | DEOK | $3.1 | $1.2 | ($2.0) | 2.9% | 1.1% | 5.5% | 0.0% |
| | DLCO | $1.4 | $0.3 | ($1.2) | 1.3% | 0.3% | 3.3% | 0.0% |
| | Dominion | $11.0 | $15.4 | $4.4 | 10.3% | 14.4% | 0.0% | 12.4% |
| | DPL | $2.9 | $7.4 | $4.5 | 2.7% | 6.9% | 0.0% | 12.7% |
| | EKPC | $1.5 | $1.8 | $0.3 | 1.4% | 1.7% | 0.0% | 0.8% |
| | External | $0.0 | $1.6 | $1.6 | 0.0% | 1.5% | 0.0% | 4.5% |
| | JCPL | $2.9 | $0.8 | ($2.1) | 2.7% | 0.8% | 5.8% | 0.0% |
| | Met-Ed | $2.2 | $0.9 | ($1.4) | 2.1% | 0.8% | 3.9% | 0.0% |
| | PECO | $5.3 | $1.3 | ($4.0) | 4.9% | 1.2% | 11.2% | 0.0% |
| | PENELEC | $3.9 | $2.8 | ($1.2) | 3.7% | 2.6% | 3.3% | 0.0% |
| | Pepco | $4.0 | $15.1 | $11.1 | 3.7% | 14.2% | 0.0% | 31.3% |
| | PPL | $5.3 | $2.4 | ($2.9) | 4.9% | 2.3% | 8.0% | 0.0% |
| | PSEG | $5.4 | $5.2 | ($0.2) | 5.1% | 4.9% | 0.7% | 0.0% |
| | RECO | $0.2 | $0.0 | ($0.2) | 0.2% | 0.0% | 0.6% | 0.0% |
| | All Zones | $95.2 | $106.7 | $11.5 | 89.2% | 100.0% | 67.7% | 100.0% |
| Hubs and Aggregates | AEP - Dayton | $0.4 | $0.0 | ($0.4) | 0.4% | 0.0% | 1.2% | 0.0% |
| | Dominion | $0.2 | $0.0 | ($0.2) | 0.2% | 0.0% | 0.6% | 0.0% |
| | Eastern | $0.2 | $0.0 | ($0.2) | 0.2% | 0.0% | 0.5% | 0.0% |
| | New Jersey | $0.2 | $0.0 | ($0.2) | 0.2% | 0.0% | 0.5% | 0.0% |
| | Ohio | $0.1 | $0.0 | ($0.1) | 0.1% | 0.0% | 0.2% | 0.0% |
| | Western Interface | $0.1 | $0.0 | ($0.1) | 0.1% | 0.0% | 0.2% | 0.0% |
| | Western | $3.6 | $0.0 | ($3.6) | 3.4% | 0.0% | 10.1% | 0.0% |
| | RTEP B0328 Source | $0.0 | $0.0 | ($0.0) | 0.0% | 0.0% | 0.0% | 0.0% |
| | All Hubs and Aggregates | $4.7 | $0.0 | ($4.7) | 4.4% | 0.0% | 13.3% | 0.0% |
| Interfaces | CPLE Imp | $0.0 | $0.0 | $0.0 | 0.0% | 0.0% | 0.0% | 0.0% |
| | Hudson | $0.1 | $0.0 | ($0.1) | 0.1% | 0.0% | 0.2% | 0.0% |
| | IMO | $0.3 | $0.0 | ($0.3) | 0.3% | 0.0% | 0.9% | 0.0% |
| | Linden | $0.4 | $0.0 | ($0.4) | 0.3% | 0.0% | 1.0% | 0.0% |
| | MISO | $2.5 | $0.0 | ($2.5) | 2.3% | 0.0% | 7.0% | 0.0% |
| | Neptune | $0.4 | $0.0 | ($0.4) | 0.4% | 0.0% | 1.1% | 0.0% |
| | NIPSCO | $0.0 | $0.0 | ($0.0) | 0.0% | 0.0% | 0.1% | 0.0% |
| | Northwest | $0.1 | $0.0 | ($0.1) | 0.1% | 0.0% | 0.4% | 0.0% |
| | NYIS | $1.0 | $0.0 | ($1.0) | 0.9% | 0.0% | 2.7% | 0.0% |
| | OVEC | $0.0 | $0.0 | ($0.0) | 0.0% | 0.0% | 0.1% | 0.0% |
| | South Exp | $0.7 | $0.0 | ($0.7) | 0.7% | 0.0% | 2.0% | 0.0% |
| | South Imp | $1.3 | $0.0 | ($1.3) | 1.2% | 0.0% | 3.7% | 0.0% |
| | All Interfaces | $6.8 | $0.0 | ($6.8) | 6.4% | 0.0% | 19.1% | 0.0% |
| Total | | $106.7 | $106.7 | $0.0 | 100.0% | 100.0% | 100.0% | 100.0% |

# Energy Uplift Issues

## Lost Opportunity Cost Credits

Balancing operating reserve lost opportunity cost (LOC) credits are an incentive for units to follow PJM's dispatch instructions when PJM's dispatch instructions deviate from a unit's desired or scheduled output. They are paid under two different scenarios. The first scenario occurs if a unit generating in real time with an offer price lower than the real-time LMP at the unit's bus is reduced or suspended by PJM due to a transmission constraint or other reliability issue. In this scenario the unit will receive a credit for LOC based on the desired output. For purposes of this report, this LOC will be referred to as real-time LOC. The second scenario occurs if a combustion turbine or diesel engine is schedule to operate in the Day-Ahead Energy Market, but it is not requested by PJM in real time. In this scenario the unit will receive a credit which covers the day-ahead financial position of the unit plus balancing spot energy market charges that the unit has to pay. For purposes of this report, this LOC will be referred to as day-ahead LOC.[15]

Table 4-30 shows monthly day-ahead and real-time LOC credits in 2016 and 2017. In 2017, LOC credits decreased by $4.1 million or 22.0 percent compared to 2016. The decrease of $4.1 million is comprised of a $4.0 million decrease in day-ahead LOC and a decrease of $0.1 million in real-time LOC. Table 4-31 shows for combustion turbines and diesels scheduled day-ahead generation, scheduled day-ahead generation not requested in real time, and the subset of day-ahead generation receiving LOC credits. In 2017 11.4 percent of day-ahead generation by combustion turbines and diesels was not requested in real time, 1.5 percentage points lower than in 2016.

### Table 4-30 Monthly lost opportunity cost credits (Millions): 2016 and 2017

| | 2016 | | | 2017 | | |
|---|---|---|---|---|---|---|
| | Day-Ahead Lost Opportunity Cost | Real-Time Lost Opportunity Cost | Total | Day-Ahead Lost Opportunity Cost | Real-Time Lost Opportunity Cost | Total |
| Jan | $1.5 | $0.2 | $1.7 | $0.1 | $0.3 | $0.4 |
| Feb | $2.0 | $0.1 | $2.1 | $0.1 | $0.1 | $0.1 |
| Mar | $0.7 | $0.3 | $0.9 | $0.9 | $0.2 | $1.1 |
| Apr | $1.9 | $0.6 | $2.4 | $0.5 | $0.3 | $0.8 |
| May | $0.5 | $0.1 | $0.7 | $0.8 | $1.0 | $1.8 |
| Jun | $1.7 | $0.9 | $2.6 | $0.7 | $0.8 | $1.5 |
| Jul | $0.8 | $0.5 | $1.4 | $1.5 | $0.2 | $1.7 |
| Aug | $1.6 | $0.4 | $2.0 | $0.5 | $0.1 | $0.6 |
| Sep | $2.2 | $0.2 | $2.4 | $1.5 | $0.5 | $1.9 |
| Oct | $0.8 | $0.2 | $0.9 | $0.8 | $0.2 | $0.9 |
| Nov | $0.3 | $0.1 | $0.4 | $0.5 | $0.2 | $0.7 |
| Dec | $0.3 | $0.8 | $1.1 | $2.5 | $0.6 | $3.0 |
| Total | $14.3 | $4.4 | $18.7 | $10.3 | $4.3 | $14.6 |
| Share | 76.2% | 23.8% | 100.0% | 70.4% | 29.6% | 100.0% |

### Table 4-31 Day-ahead generation from combustion turbines and diesels (GWh): 2016 and 2017

| | 2016 | | | 2017 | | |
|---|---|---|---|---|---|---|
| | Day-Ahead Generation | Day-Ahead Generation Not Requested in Real Time | Day-Ahead Generation Not Requested in Real Time Receiving LOC Credits | Day-Ahead Generation | Day-Ahead Generation Not Requested in Real Time | Day-Ahead Generation Not Requested in Real Time Receiving LOC Credits |
| Jan | 705 | 211 | 115 | 359 | 33 | 9 |
| Feb | 746 | 192 | 92 | 318 | 27 | 9 |
| Mar | 1,090 | 162 | 66 | 778 | 128 | 49 |
| Apr | 1,531 | 276 | 95 | 473 | 88 | 28 |
| May | 1,349 | 115 | 48 | 669 | 75 | 38 |
| Jun | 1,433 | 231 | 80 | 1,153 | 120 | 61 |
| Jul | 2,697 | 227 | 76 | 1,815 | 265 | 123 |
| Aug | 2,402 | 143 | 58 | 1,341 | 121 | 51 |
| Sep | 1,774 | 239 | 97 | 2,205 | 123 | 66 |
| Oct | 1,360 | 155 | 60 | 1,850 | 138 | 65 |
| Nov | 512 | 68 | 25 | 757 | 106 | 38 |
| Dec | 462 | 48 | 21 | 898 | 213 | 110 |
| Total | 16,062 | 2,068 | 831 | 12,616 | 1,438 | 646 |
| Share | 100.0% | 12.9% | 5.2% | 100.0% | 11.4% | 5.1% |

15 A unit's day-ahead financial position equals the revenues from the Day-Ahead Energy Market minus the expected costs (valued at the unit's offer curve cleared in day ahead). A unit scheduled in the Day-Ahead Energy Market and not committed in real time incurs balancing spot energy charges since it has to cover its day-ahead scheduled energy position in real time.

Table 4-32 shows for combustion turbines and diesels the historical scheduled day-ahead generation, scheduled day-ahead generation not requested in real time, and total day-ahead LOC credits. The decrease in day-ahead LOC credits is attributable to several factors. As shown in Table 4-32 since 2014 there has been a continuous decrease in the share of day-ahead generation not requested in real time. In September 2015, PJM adopted three recommendations proposed by the MMU to improve the calculation of LOC payments.

### Table 4-32 Historical day-ahead generation from combustion turbines and diesels and day-ahead lost opportunity cost credits (GWh): 2013 through 2017

| | Day-Ahead Generation | Day-Ahead Generation Not Requested in Real Time | Share of Day-Ahead Generation Not Requested in Real Time | Day-Ahead LOC Credits (Millions) |
|---|---|---|---|---|
| 2013 | 13,001 | 5,620 | 43.2% | $63.4 |
| 2014 | 14,628 | 5,636 | 38.5% | $112.1 |
| 2015 | 18,734 | 5,128 | 27.4% | $83.0 |
| 2016 | 16,062 | 2,068 | 12.9% | $18.6 |
| 2017 | 12,616 | 1,438 | 11.4% | $14.6 |

PJM may not run units in real time if the real-time value of the energy (generation multiplied by the real-time LMP) is lower than the units' total offer (including no load and startup costs). Table 4-33 shows the total day-ahead generation from combustion turbines and diesels that were not committed in real time by PJM and received LOC credits. Table 4-33 shows the scheduled generation that had a total offer (including no load and startup costs) lower than its real-time value (generation multiplied by the real-time LMP), defined here as economic scheduled generation, and the scheduled generation that had a total offer greater than its real-time value or noneconomic scheduled generation. In 2017, 60.0 percent of the scheduled generation not committed by PJM from units receiving LOC credits was economic and the remaining 40.0 percent was noneconomic.

The MMU recommends that PJM initiate an analysis of the reasons why some combustion turbines and diesels scheduled in the Day-Ahead Energy Market are not committed by PJM in real time when they are economic.

### Table 4-33 Day-ahead generation (GWh) from combustion turbines and diesels receiving lost opportunity cost credits by value: 2016 and 2017[16]

| | 2016 | | | 2017 | | |
|---|---|---|---|---|---|---|
| | Economic Scheduled Generation (GWh) | Noneconomic Scheduled Generation (GWh) | Total (GWh) | Economic Scheduled Generation (GWh) | Noneconomic Scheduled Generation (GWh) | Total (GWh) |
| Jan | 142 | 43 | 185 | 11 | 11 | 22 |
| Feb | 104 | 63 | 167 | 8 | 11 | 19 |
| Mar | 72 | 71 | 143 | 58 | 42 | 99 |
| Apr | 124 | 110 | 234 | 38 | 28 | 67 |
| May | 58 | 41 | 99 | 45 | 16 | 61 |
| Jun | 100 | 63 | 163 | 67 | 29 | 96 |
| Jul | 79 | 50 | 129 | 130 | 74 | 204 |
| Aug | 67 | 31 | 97 | 54 | 37 | 91 |
| Sep | 99 | 85 | 184 | 73 | 29 | 102 |
| Oct | 69 | 52 | 121 | 71 | 49 | 121 |
| Nov | 20 | 35 | 55 | 42 | 39 | 81 |
| Dec | 21 | 24 | 44 | 103 | 102 | 205 |
| Total | 954 | 667 | 1,621 | 700 | 467 | 1,167 |
| Share | 58.9% | 41.1% | 100.0% | 60.0% | 40.0% | 100.0% |

16 The total generation in Table 4-33 is lower than the day-ahead generation not requested in real time in Table 4-31 because the former only includes generation from units that received lost opportunity costs during at least one hour of the day. Table 4-31 includes all generation, including generation from units that were not committed in real time and did not receive LOC credits.

## Closed Loop Interfaces

PJM implemented closed loop interfaces with the stated purpose of improving the incorporation of reactive constraints into energy prices and to allow emergency DR to set price.[17] PJM applies closed loop interfaces so that it can use units needed for reactive support to set the energy price when they would not otherwise set price under the LMP algorithm. PJM also applies closed loop interfaces so that it can use emergency DR resources to set the real-time LMP when DR resources would not otherwise set price under the fundamental LMP logic. Of the 17 closed loop interface definitions, 11 (65 percent) were created for the purpose of allowing emergency DR to set price.

Closed loop interfaces are used to model the transfer capability into a specific area. Areas or regions are defined in PJM by hubs, aggregates or control zones, all comprised of buses. Closed loop interfaces are not defined by buses, but defined by the transmission facilities that connect the buses inside the loop with the rest of PJM. When PJM wants a closed loop interface to bind, PJM reduces the capacity of the transmission facilities to a level that will artificially make marginal the resource selected by PJM. Table 4-34 shows the closed loop interfaces that PJM has defined and PJM's objective in defining each closed loop interface.

### Table 4-34 PJM closed loop interfaces[18 19 20]

| Interface | Control Zone(s) | Objective | Effective Date | Limit Calculation |
|---|---|---|---|---|
| APS-East | AP | Allow emergency DR resources / unit(s) needed for reactive to set real-time LMP | June 19, 2015 | Limit equal to actual flow |
| ATSI | ATSI | Allow emergency DR resources / unit(s) needed for reactive to set real-time LMP | July 17, 2013 | Limit equal to actual flow |
| BC | BGE | Allow emergency DR resources / unit(s) needed for reactive to set real-time LMP | June 19, 2015 | Limit equal to actual flow |
| BC/PEP | BGE and Pepco | Reactive Interface (not an IROL). Used to model import capability into the BGE/PEPCO/Doubs/Northern Virginia area | NA | PJM Transfer Limit Calculator |
| Black River | ATSI | Allow emergency DR resources set real-time LMP | September 1, 2014 | Limit equal to actual flow |
| Cleveland | ATSI | Reactive Interface (IROL) | NA | PJM Transfer Limit Calculator |
| COMED | ComEd | Reactive Interface (IROL) | NA | PJM Transfer Limit Calculator |
| DOM-Chesapeake | Dominion | Allow emergency DR resources / unit(s) needed for reactive to set real-time LMP | August 14, 2015 | Limit equal to actual flow |
| DPL | DPL | Allow emergency DR resources / unit(s) needed for reactive to set real-time LMP | June 19, 2015 | Limit equal to actual flow |
| New Castle | ATSI | Allow emergency DR resources set real-time LMP | July 1, 2014 | Limit equal to actual flow |
| PENELEC | PENELEC | Allow emergency DR resources / unit(s) needed for reactive to set real-time LMP | April 22, 2015 | Limit equal to actual flow |
| Pepco | Pepco | Allow emergency DR resources / unit(s) needed for reactive to set real-time LMP | June 19, 2015 | Limit equal to actual flow |
| PL-Wescosville | PPL | Allow emergency DR resources / unit(s) needed for reactive to set real-time LMP | July 24, 2014 | Limit equal to actual flow |
| PN-Erie | PENELEC | Allow emergency DR resources set real-time LMP | April 22, 2015 | Limit equal to actual flow |
| PS North | PSEG | Objective not identified. Interface was modeled in 2014/2015 Annual FTR auction | NA | NA |
| Seneca | PENELEC | Allow unit(s) needed for reactive to set day-ahead and real-time LMP | February 1, 2014 | Limit equal to actual flow |
| Warren | PENELEC | Allow unit(s) needed for reactive to set day-ahead and real-time LMP | September 26, 2014 | Limit equal to actual flow |

17 See PJM/Alstom. "Approaches to Reduce Energy Uplift and PJM Experiences," presented at the FERC Technical Conference: Increasing Real-Time and Day-Ahead Market Efficiency Through Improved Software in Docket No. AD10-12-006 <http://www.ferc.gov/june-tech-conf/2015/presentations/m2-3.pdf> (June 23, 2015).

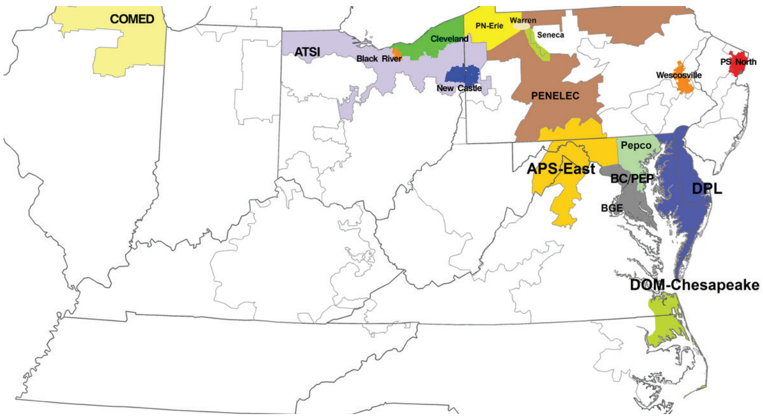
18 See PJM. "Manual 3: Transmission Operations," Rev. 48 (Dec. 1, 2015) at "Section 3.8: Transfer Limits (Reactive/Voltage Transfer Limits)," for a description of reactive interfaces.

19 See closed loop interfaces definitions at <http://www.pjm.com/markets-and-operations/etools/oasis/system-information.aspx>.

20 See the PS North interface definition at <http://www.pjm.com/pub/account/auction-user-info/model-annual/Annual-PJM-interface-definitions-limits.csv>.

Figure 4-8 shows the approximate geographic location of PJM's closed loop interfaces.

**Figure 4-8 PJM Closed loop interfaces map**




PJM's uses closed loop interfaces to artificially allow the strike price of emergency DR to set LMP. This use of closed loop interfaces permits subjective price setting by PJM. PJM has not explained why the economic fundamentals require that DR strike prices set LMP when the resource is not marginal. Although DR should be nodal, DR is not nodal and cannot routinely set price in an LMP model. The MMU has recommended that DR be nodal so that it can set price when appropriate. The current PJM rules permit emergency DR to set a strike price as high as $1,849. There are no incentives for DR to set strike prices at an economically rational level because emergency DR is guaranteed the payment of its strike price whenever called. The MMU has recommended that emergency DR have an offer cap no higher than generation resources, that emergency DR be required to make offers in the Day-Ahead Energy Market like other capacity resources and the emergency DR be paid LMP rather than a guaranteed strike price when called on. PJM's use of closed loop interfaces is a result of significant deficiencies in the rules governing DR. PJM's use of closed loop interfaces is also result of significant issues with PJM's scarcity pricing model which is not adequately locational. PJM uses closed loop interfaces and emergency DR strike prices as a substitute for improved, more locational scarcity pricing.

In a DC power flow model, such as the one used by PJM for dispatch and pricing, units scheduled for reactive support are only marginal when they are needed to supply energy above their economic minimum. With the use of closed loop interface, these units are forced to be marginal in the model even when not needed for energy, by adjusting the limit of the closed loop interface. This artificially creates congestion in the area that can only be relieved by the units providing reactive support inside the loop. The goal is to reduce energy uplift from the noneconomic operation of units needed for reactive support by forcing these units to be marginal when they are not, raising energy prices and thereby reducing uplift.[21]

The MMU has recommended and supports PJM's goal of having dispatcher decisions reflected in transparent market outcomes, preferably LMP, to the maximum extent possible and to minimize the level and rate of energy uplift charges. But part of that goal is to avoid distortion of the way in which the transmission network is modeled. The use of closed loop interfaces is a distortion of the model.

The MMU recommends that PJM not use closed loop interface constraints to artificially override the nodal prices that are based on fundamental LMP logic in order to: accommodate rather than resolve the inadequacies of the demand side resource capacity product; address the inability of the power flow model to incorporate the need for reactive power; accommodate rather than resolve the flaws in PJM's approach to scarcity pricing; or for any other reason.

Market prices should be a function of market fundamentals and energy market prices should be a function of energy market fundamentals. PJM has not explained why the other consequences of deviating from market fundamentals do not outweigh any benefits of artificially creating constraints in order to let reactive resources set price when they are not in fact marginal. PJM has not explained why the use of closed loop interfaces to permit emergency DR to set price is not simply a crude workaround to a viable solution, consistent with the LMP model, which would be to make DR nodal. The need for closed loop interfaces to let emergency DR set price is primarily a result of the fact that DR is zonal, or subzonal with one day's

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

notice, and therefore cannot be dispatched nodally or set price nodally. The reduction of uplift is a reasonable goal in general, but the reduction of uplift is not a goal that justifies creating distortions in the price setting mechanism.

## Price Setting Logic

In November 2014, PJM implemented a software change to its day ahead and real time market solution tools that would enable PJM to reduce energy uplift by artificially selecting the marginal unit for any constraint. The goal is to make marginal any unit committed by PJM to provide reactive services, black start or transmission constraint relief if such unit would otherwise run with an incremental offer greater than the correctly calculated LMP. PJM calls this approach price setting logic.

The application of the price setting logic reduces energy uplift payments by artificially increasing the LMP. The price setting logic is a form of subjective pricing because it varies from fundamental LMP logic based on an administrative decision to reduce energy uplift.

PJM and Alstom presented examples of this approach at the FERC Technical Conference, "Increasing Real-Time and Day-Ahead Market Efficiency Through Improved Software."[22] The presentation shows a two bus model connected by one transmission line, three generators (A, B and C) and load at one of the buses. Solution 1: In the solution based on the fundamental LMP logic that PJM has used since the inception of markets, two of the generators are committed (A at 50 MW and B at 50 MW) to serve load (100 MW). The LMP is set at $50 per MWh (the offer of generator A) at both buses. Generator B has to be made whole (paid energy uplift) because the LMP ($50 per MWh) does not cover the generator's offer ($100 per MWh). Generator B does not set the LMP because its economic minimum is higher than the relief needed to relieve the constraint. This solution is not acceptable for PJM because the most expensive generator would have to be made whole. In order to reduce energy uplift, PJM shows two alternatives. Solution 2: Artificially redefine the economic minimum of generator B to zero MW. Solution 3: Artificially redefine the limit of the transmission line to a level that would make the LMP higher at the bus where the most expensive generator is connected.

In solution 2, generator B is dispatched at 10 MW, despite the fact that this is physically impossible. This allows generator A to increase its output to 80 MW, which makes the transmission constraint binding and causes price separation between the two buses. This is an artificial result, not consistent with actual dispatch, designed to achieve an administrative goal.

In solution 3, the line limit is reduced from 80 MW to 40 MW, despite the fact that this is not the actual limit. As a result, generator A is dispatched to 40 MW (10 MW less than the original solution), the transmission line constraint is binding and congestion occurs. The goal is met and energy uplift is reduced to zero because the LMPs at both buses are increased so that they equal or exceed the generators' offers. Again, this is an artificial result, not consistent with actual dispatch, designed to achieve an administrative goal.

Attempting to reduce uplift at the expense of fundamental LMP logic is not consistent with the objective of clearing the market using a least cost approach. The result of PJM's price setting logic in this example is to increase total production costs.

The MMU recommends that PJM not use price setting logic to artificially override the nodal prices that are based on fundamental LMP logic in order to reduce uplift.

The MMU supports efforts to ensure that LMP reflects the appropriate marginal resource. The MMU recommends that if PJM believes it appropriate to modify the 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.

## Confidentiality of Energy Uplift Information

All data posted publicly by PJM or the MMU must comply with confidentiality rules. Prior to March 31, 2016, confidentiality rules did not allow posting data for three or fewer PJM participants and did not permit

22 See PJM/Alstom. "Approaches to Reduce Energy Uplift and PJM Experiences," presented at the FERC Technical Conference: "Increasing Real-Time and Day-Ahead Market Efficiency Through Improved Software," in Docket No. AD10-12-006 <http://www.ferc.gov/june-tech-conf/2015/presentations/m2-3.pdf> (June 23, 2015).

aggregation for a geographic area smaller than a control zone.[23]

Energy uplift charges are out of market, nontransparent payments made to resources operating at PJM's direction. Energy uplift charges are highly concentrated in a small number of zones and paid to a small number of PJM participants. These costs are not reflected in PJM market prices. Current confidentiality rules prevent the publication of detailed data concerning the reasons and locations of these payments, making it difficult for other participants to compete with the resources receiving energy uplift payments. Uplift charges are not included in the transmission planning process meaning that transmission solutions are not considered. The confidentiality rules were implemented in order to protect competition. The application of confidentiality rules in the case of energy uplift information does exactly the opposite. Energy uplift is not a market and the absence of relevant information creates a barrier to entry. The MMU recommends that PJM revise the current energy uplift confidentiality rules in order to allow the disclosure of energy uplift credits by zone, by owner and by resource. PJM partially adopted the MMU recommendation at the March 31, 2016, Markets and Reliability Committee (MRC).[24] PJM adopted a rule permitting the posting of energy uplift information by control zone, regardless of the number of PJM participants receiving energy uplift payments in that control zone.

# Energy Uplift Recommendations

## Recommendations for Calculation of Credits

### Day-Ahead Operating Reserve Elimination

The only reason to pay energy uplift in the Day-Ahead Energy Market is that a day-ahead schedule could cause a unit to incur losses as a result of differences between the Day-Ahead and Balancing Markets. Units cannot incur losses in the Day-Ahead Energy Market. Units do not incur costs in the Day-Ahead Energy Market. There is no reason to pay energy uplift in the Day-Ahead Energy Market. All energy uplift should be paid in real time including energy uplift that results from differences between day-ahead and real-time schedules. Paying energy uplift in the Day-Ahead Energy Market results in overpayments.

Day-ahead operating reserve credits are paid to market participants under specific conditions in order to ensure that units are not scheduled in the Day-Ahead Energy Market by PJM to operate at a loss in real time. Balancing operating reserve credits are paid to market participants under specific conditions in order to ensure that units are not operated by PJM at a loss in real time. Units are paid day-ahead operating reserve credits whenever their total offer (including no load and startup costs and based on their day-ahead scheduled output) is not covered by the day-ahead energy revenues (day-ahead LMP times day-ahead scheduled output). Units are paid balancing operating reserve credits whenever their total offer (including no load and startup costs and based on their real-time output) are not covered by their day-ahead energy revenues, balancing energy revenues and a subset of net ancillary services revenues.[25]

Units scheduled in the Day-Ahead Energy Market do not operate until committed or dispatched in real time. Therefore, it cannot be determined if a unit was operated at a loss until the unit actually operates or does not operate. The current operating reserve rules governing the day-ahead operating reserve credits assume that units are going to operate exactly as scheduled because they are made whole based on their day-ahead scheduled output. A unit's real-time output may be greater or lower than their day-ahead scheduled output. Units dispatched in real time by PJM above their day-ahead scheduled output could be paid energy uplift in the form of balancing operating reserve credits if by increasing their output they operate at a loss because their offers are greater than the real-time LMP. Units dispatched in real time by PJM below their day-ahead scheduled output could be paid energy uplift in the form of balancing operating reserve credits if by decreasing their output the units operate at a loss or incur opportunity costs because real-time LMP is greater than the day-ahead LMP. The balancing operating reserve credits and lost opportunity costs credits ensure that units recover their total offers or keep their net revenues in real time.

23 See PJM. "Manual 33: Administrative Services for the PJM Interconnection Operating Agreement," Rev. 12 (March 31, 2016) at "Market Data Postings."

24 See the Markets and Reliability Committee (March 31, 2016) minutes <http://www.pjm.com/~/media/committees-groups/committees/mrc/20160418-special/20160418-item-01-draft-minutes-mrc.ashx>.

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

Units scheduled in the Day-Ahead Energy Market that receive day-ahead operating reserve credits and for which real-time operation results in additional losses, are paid energy uplift in the form of balancing operating reserve or lost opportunity cost credits to ensure that they do not operate at a loss. This determination is not symmetrical because units scheduled in the Day-Ahead Energy Market that receive day-ahead operating reserve credits and for which real-time operation results in reduced losses or not loss do not have a reduction in energy uplift payments.

Units that follow PJM dispatch instructions are made whole through operating reserve credits to ensure that they do not operate at a loss. In order to determine if a unit operated at a loss, it needs to be committed or dispatched. The day-ahead scheduled output is one of PJM's dispatch instructions, but it does not determine if a unit actually operated at a loss. In order to determine if a unit operated at a loss it is necessary to take into account the unit's real-time output and both the day-ahead and balancing energy revenues and ancillary services net revenues.

In order to properly compensate units, the MMU recommended enhancing the day-ahead operating reserve credits calculation to ensure that units receive an energy uplift payment based on their real-time output and not their day-ahead scheduled output whenever their real time operation results in a lower loss or no loss at all. The MMU also recommended including net DASR revenues as part of the offsets used in determining day-ahead operating reserve credits.[26] These recommendations are superseded by the MMU's recommendation to eliminate day-ahead operating reserve payments.[27] The elimination of day-ahead operating reserve payments also ensures that units are always made whole based on their actual operation and actual revenues.

The MMU calculated the impact of this recommendation for 2016 and 2017. In 2016 and 2017, energy uplift costs associated with units scheduled in the Day-Ahead Energy Market would have had been reduced by $23.8 million or 20.2 percent ($2.9 million paid to units providing reactive support $20.8 million paid to units as day-ahead and balancing operating reserves).

The elimination of the day-ahead operating reserve category would change the allocation of such charges under the current energy uplift rules. If the day-ahead operating reserve category were eliminated but the MMU's uplift allocation recommendations were not implemented, units that clear the Day-Ahead Energy Market would be made whole through balancing operating reserve credits, which under the current rules are allocated to deviations or real-time load plus real-time exports. Therefore, this recommendation should be implemented concurrently with the MMU's allocation recommendations.

## Net Regulation Revenues Offset

On October 1, 2008, PJM filed revisions to the Operating Agreement and Tariff with FERC related to the PJM Regulation Market. The filing included four elements: implement the TPS test in the PJM Regulation Market; increase the regulation offer adder from $7.50 per MW to $12.00 per MW; eliminate the use of net regulation revenues as an offset in the balancing operating reserve calculation; and calculate the lost opportunity cost on the lower of a unit's price-based or cost-based offer. The four elements were based on a settlement rather than a rational evaluation of an efficient market design.

The elimination of the use of net regulation revenues as an offset in the balancing operating reserve calculation had a direct impact on the level of energy uplift paid to participants that regulate while operating noneconomic. The result of not using the net regulation revenues as an offset in the balancing operating reserve credit calculation is that PJM does not accurately calculate whether a unit is running at a loss. PJM procures energy, regulation, synchronized and nonsynchronized reserves in a jointly optimized manner. PJM determines the mix of resources that could provide all of those services in a least-cost manner. Excluding the net regulation revenues from the balancing operating reserve credit calculation is inconsistent with the process used by PJM to procure these services and inconsistent with the basic PJM uplift logic. Whether a unit is running for PJM at a loss defined by marginal costs cannot be determined if some of the revenues are arbitrarily excluded.

26 See *2013 State of the Market Report for PJM*, Volume 2 Section 4: "Energy Uplift," at "Day-Operating Reserve Credits," and at "Net DASR Revenues Offset" for an explanation of these recommendations.

27 PJM agrees with this recommendation. See "Explanation of PJM Proposals," from the Energy Market Uplift Senior Task Force (April 30, 2014). <http://www.pjm.com/~/media/committees-groups/task-forces/emustf/20140417/20140417-explanation-of-pjm-proposals.ashx>.

Another issue related to this exclusion is the treatment of pool-scheduled units that elect to self-schedule a portion of their capacity for regulation. A unit can be pool-scheduled for energy, which means PJM may commit or dispatch the unit based on economics, but it can also self-schedule some of its capacity for regulation. When this happens the capacity self-scheduled for regulation is treated as a price taker, but in the energy market any increase in MW to provide regulation are treated as additional costs, which can result in increased balancing operating reserve credits whenever the real-time LMP is lower than the unit's offer. For example, if a unit raises its economic minimum in order to provide regulation and the additional costs resulting from operating at a higher economic minimum are not covered by the real-time LMP, the unit will be made whole for the additional costs through balancing operating reserve credits.

The MMU recommends reincorporating the use of net regulation revenues as an offset in the calculation of balancing operating reserve credits. In 2016 and 2017, using net regulation revenues as an offset in the balancing operating reserve calculation would have resulted in a net decrease of balancing operating reserve charges of $2.3 million, of which $1.3 million or 54.5 percent was a result of generators that elected to self-schedule for regulation while being noneconomic in the energy market and receiving balancing operating reserve credits.[28]

## Self Scheduled Start

Participants may offer their units as pool-scheduled (economic) or self-scheduled (must run).[29] Units offered as pool-scheduled clear the Day-Ahead Energy Market based on their offers and operate in real time following PJM dispatch instructions. Units offered as self-scheduled clear the Day-Ahead Energy Market regardless of their offers and may operate in real time following PJM dispatch instructions. Units offered as self-scheduled follow PJM dispatch instructions when they are offered with a minimum must run output from which the units may be dispatched up but not down. Self-scheduled units are not eligible to receive day-ahead or balancing operating reserve credits. The current rules determine if a unit is pool-scheduled or self-scheduled for operating reserve credits purposes separately for each hour using the hourly commitment status flag. If the flag is set as economic the unit is assumed to be pool-scheduled, if the flag is set as must run the unit is assumed to be self-scheduled. When a unit submits different flags within a day, the day-ahead operating reserve credit calculation treats each group of hours separately. The day-ahead operating reserve credit calculation only uses the hours flagged as economic and excludes any hours flagged as must run.

Units offered as self-scheduled for some hours of the day and pool-scheduled for the remaining hours are made whole for startup costs when they should not be. For example, if a unit is offered as self-scheduled for hours 10 through 24 and as pool-scheduled for the balance of the day and PJM selects the unit to start for hour nine, the unit will be made whole for its startup cost if the hourly revenues do not cover the costs. The only hour used in the day-ahead or balancing operating reserve credit calculation is hour nine because the unit is not eligible for operating reserve credits for hours 10 through 24. The result is that any net revenue from hours 10 through 24 will not be used to offset the unit's startup cost despite the fact that the unit would have started and incurred those costs regardless of PJM dispatch instructions.

The MMU recommends that self-scheduled units not be paid energy uplift for their startup cost when the units are scheduled by PJM to start before the self-scheduled hours.

## Lost Opportunity Cost Calculation

The current energy LOC calculations are inaccurate and create unreasonable compensation. The MMU recommended four modifications, of which three were adopted on September 1, 2015.[30] [31] The one outstanding modification not adopted by PJM is the calculation of LOC using segments of hours. Current rules calculate LOC on an hourly basis; each hour is treated as a standalone calculation. This means that units receive an LOC payment during hours in which it is economic for them to run and receive the benefit of not being called on during hours in which it is not economic for them to

28 These estimates take into account the elimination of the day-ahead operating reserve category.
29 See "PJM eMkt Users Guide," Section Managing Unit Data (version July 9, 2015) p. 42. <http://www.pjm.com/~/media/etools/emkt/ts-userguide.ashx>.
30 See *2015 State of the Market Report for PJM*, Volume 2 Section 4, "Energy Uplift," at "Lost Opportunity Cost Calculation" for an explanation of the adopted recommendations.
31 152 FERC ¶ 61,165 (2015)

run. PJM dispatchers might make the right decision to not call a unit in real time because the operation of the unit during all the hours in which the unit cleared the Day-Ahead Energy Market would not be economic, but the unit could still receive an LOC payment.

This is inconsistent with the basic PJM energy uplift logic. If a unit does not run in real time, it loses net revenues if the real-time LMP is greater than the unit's offer but it gains net revenues if the real-time LMP is lower than the unit's offer. The correct lost opportunity costs for units that clear the Day-Ahead Energy Market and are not committed in real time cannot be determined if profitable hours are arbitrarily excluded. In the case of separate hourly calculations, units are overcompensated compared to the net revenues they would have received had they run.

The MMU recommends calculating LOC based on 24 hour daily periods or multi-hour segments of hours for combustion turbines and diesels scheduled in the Day-Ahead Energy Market but not committed in real time. This recommendation has not been adopted. The MMU calculated the impact of this recommendation for 2017. In 2017, lost opportunity cost payments would have had been reduced by $7.6 million or 52.2 percent.

In addition to the initial four recommendations, the MMU recommends three additional steps to address issues with the current LOC calculations:

- **Achievable Output:** CTs and diesels are compensated for LOC when scheduled in the Day-Ahead Energy Market and not committed in real time. This LOC calculation uses the day-ahead scheduled output as the achievable output for which units are entitled to receive LOC compensation. Units are paid LOC based on the difference between the real-time energy price (RT LMP) and the unit's offer times the day-ahead scheduled output.

  The actual LOC is a function of the real-time desired and achievable output rather than the day-ahead scheduled output. If a unit is capable of profitably producing more or fewer MWh in real time than the day-ahead scheduled MWh, it is the actual foregone MWh in real time that define actual LOC. Also, if a unit is not capable of producing at the day-ahead scheduled output level in real time it should not be compensated based on an output that cannot be achieved.

  The MMU recommends that units scheduled in the Day-Ahead Energy Market and not committed in real time should be compensated for LOC based on their real-time desired and achievable output, not their scheduled day-ahead output.

- **Intra-Hour Calculations:** CTs and diesels scheduled in the Day-Ahead Energy Market and not committed in real time are compensated for LOC based on their real-time hourly integrated output. In order to compensate a unit for LOC, PJM must determine if the unit was scheduled in the Day-Ahead Energy Market and if the unit was not committed in real time. Units clear the Day-Ahead Energy Market for full hours. That means that if a unit cleared the Day-Ahead Energy Market in an hour it is expected to produce energy in real time for the entire hour. The determination by PJM of whether a unit is committed or not committed in real time is based on the unit's hourly integrated output. If the hourly integrated output is greater than zero that means the unit was committed during that hour. But in real time a unit may be committed for part of an hour. The calculation of LOC does not reflect the exact time at which the unit was turned on.

  The MMU recommends that units scheduled in the Day-Ahead Energy Market and not committed in real time be compensated for LOC incurred within an hour.

- **LOC Unit Type Eligibility:** The current rules compensate only CTs and diesels for LOC when scheduled in the Day-Ahead Energy Market and not committed in real time. The reason for this difference is that other unit types have a commitment obligation when scheduled in the Day-Ahead Energy Market. For example, steam turbines and combined cycle units commitment instructions are their day-ahead schedule. Units of these types that clear the Day-Ahead Energy Market are automatically committed to be on or remain on in real time. These units are eligible for LOC compensation only if PJM explicitly cancels their day-ahead commitment for reliability purposes. CT and diesel commitment instructions occur in real time even if these units were committed in the Day-Ahead Energy Market. CTs and diesels are committed in real time, after PJM dispatch has a more complete knowledge of real-time conditions. The goal is to permit the dispatch of flexible units in real time based on real-time conditions as they evolve. The reason for this special treatment of CTs and diesels is that historically, such units were usually more flexible to commit than other unit types. But that is no longer correct and should not be assumed to be correct.

The MMU recommends that only flexible fast start units (startup plus notification times of 30 minutes or less) and short minimum run times (one hour or less) be eligible by default for the LOC compensation to units scheduled in the Day-Ahead Energy Market and not committed in real time.

### Actual Cost Reimbursement

PJM Manual 11 (Energy and Ancillary Services Market Operations) Attachment C describes an after the fact cost recovery procedure that is not consistent with the PJM tariff. The MMU recommends that PJM revise Manual 11 Attachment C Procedure for Cost Reimbursement to be consistent with the PJM tariff. Manual 11 incorrectly states that the purpose of this procedure is to address "differences between cost-based offers and actually incurred costs for resettlement." The PJM tariff rules for compensation greater than LMP payments are covered by the OA Schedule 1 Section 3.2.3, which specifies that compensation shall be made based on the "applicable offer" or "offered price" and not based actually incurred costs which can be known only after the fact.

The MMU recommends that PJM revise Manual 11 consistent with the tariff to limit compensation to offered costs. The Manual 11 procedure should describe the steps market participants can take to change the availability of cost-based energy offers that have been submitted day ahead. This procedure only applies for units that have not been committed by PJM in the Day-Ahead Energy Market or in real time. This enables PJM dispatchers to select the most appropriate cost-based energy offer to set the LMP and possible uplift payments. The MMU recommends that PJM eliminate this procedure when hourly offers (ER16-372-000) are implemented as this rule was a short term solution for the absence of hourly offers.

## Recommendations for Allocation of Charges

### Up to Congestion Transactions

Up to congestion transactions do not pay energy uplift charges. An up to congestion transaction affects unit commitment and dispatch in the same way that increment offers and decrement bids affect unit commitment and dispatch in the Day-Ahead Energy Market. All such virtual transactions affect the results of the Day-Ahead Energy Market and contribute to energy uplift costs. Up to congestion transactions are currently receiving preferential treatment, relative to increment offers and decrement bids and other transactions because they are not charged energy uplift.

The MMU recommends that up to congestion transactions be required to pay energy uplift charges for both the injection and the withdrawal sides of the UTC.

The MMU calculated the impact on energy uplift rates if up to congestion transactions had paid energy uplift charges based on deviations in the same way that increment offers and decrement bids do along with other recommendations that impact the total costs of energy uplift and its allocation.

Up to congestion transactions would have paid an average rate between \$0.044 and \$0.055 per MWh in 2016 and between \$0.021 and \$0.024 per MWh in 2017 if the MMU's recommendations regarding energy uplift had been in place.[32] [33]

### Internal Bilateral Transactions

Market participants are allocated a portion of the costs of balancing operating reserves based on their deviations. Deviations are calculated in three categories, demand, supply and generation. Generators deviate when their real-time output is different than the desired output or their day-ahead scheduled output.[34] Load, interchange transactions, internal bilateral transactions, demand

32 The range of operating reserve rates paid by up to congestion transactions depends on the location of the transactions' source and sink.

33 This analysis assumes that not all costs associated with units providing support to the Con Edison – PJM Transmission Service Agreements would be reallocated under the MMU's proposal. The *2013 State of the Market Report for PJM* analysis assumed that all such costs would be reallocated. This analysis also assumes that only 50 percent of all cleared up to congestion transactions would have cleared had this recommendation been in place prior to September 8, 2014 and all cleared up to congestion transactions would have cleared after September 8, 2014. The *2013 State of the Market Report for PJM* analysis showed that more than 66.7 percent of up to congestion transactions would have remained under the MMU proposal.

34 See PJM. OATT 3.2.3 (o) for a complete description of how generators deviate.

resources, increment offers and decrement bids also incur deviations.

Generators are allowed to offset their deviations with other generators at the same bus if the generators have the same electrical impact on the transmission system For example, a generator with a negative deviation (generation below the desired level) can offset such deviation if a generator at the same bus has a positive deviation (generation above the desired level) if this occurs in the same hour.

Load, interchange transactions, internal bilateral transactions, demand resources, increment offers and decrement bids are also allowed to offset their deviations. These transactions are grouped by demand and supply, and then aggregated by location. A negative deviation from one transaction can offset a positive deviation from another transaction in the same category, as long as both transactions are at the same location at the same hour.[35] Demand transactions such as load, exports, internal bilateral sales and decrement bids may offset. The same applies to supply transactions such as imports, internal bilateral purchases and increment offers. Unlike all other transaction types, internal bilateral sales and purchases do not impact dispatch or market prices. Internal bilateral transactions (IBTs) are used by participants to transfer the financial responsibility or right of the energy withdrawn or injected into the system in the Day-Ahead and Real-Time Energy Markets.

IBTs should not pay for balancing operating reserves and should not be used to offset other transactions that deviate. IBTs shift the responsibility for an injection or withdrawal in PJM from one participant to another but IBTs are not part of the day-ahead unit commitment process, do not set energy prices and do not impact the energy flows in either the Day-Ahead or the Real-Time Energy Market, and thus IBTs should not be considered in the allocation of balancing operating reserve charges. The use of IBTs has been extended to offset deviations from other transactions that do impact the energy market. The elimination of the use of IBTs in the deviation calculation would eliminate the balancing operating reserve charges to participants that use IBTs only in real time. Such elimination would increase the balancing operating reserve charges to participants that use IBTs to offset deviations from day-ahead transactions.

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

## Day-Ahead Reliability Energy Uplift Allocation

PJM may schedule units as must run in the Day-Ahead Energy Market when needed in real time to address reliability issues in four categories: voltage issues (high and low); black start requirements (from automatic load rejection units); local contingencies not modeled in the Day-Ahead Energy Market; and long lead time units not able to be scheduled in the Day-Ahead Energy Market.[36] The energy uplift paid to units scheduled for voltage is allocated to real-time load. The energy uplift associated with units scheduled for black start is allocated to real-time load and interchange reservations. The energy uplift paid to units scheduled because of local contingencies not modeled in the Day-Ahead Energy Market and scheduled because of their long lead times is allocated to day-ahead demand, day-ahead exports and decrement bids.

The MMU recommends allocating the energy uplift payments to units scheduled as must run in the Day-Ahead Energy Market for reasons other than voltage/reactive or black start services as a reliability charge to real-time load, real-time exports and real-time wheels.

## Reactive Services Credits and Balancing Operating Reserve Credits

Energy uplift credits to resources providing reactive services are separate from balancing operating reserve credits.[37] Under the current rules regarding energy uplift credits for reactive services, units are not assured recovery of the entire offer including no load and startup costs as they are under the operating reserve credits rules. Units providing reactive services at the request of PJM are made whole through reactive service

35 Locations can be control zones, hubs, aggregates and interfaces. See "Determinants and Deviation Categories" in this section for a description of balancing operating reserve locations.

36 See PJM. "Item 12 - October 2012 MIC DAM Cost Allocation," PJM presentation to the Market Implementation Committee (October 12, 2012).

37 PJM. OATT Attachment K - Appendix § 3.2.3B (f).

credits. But when the reactive services credits do not cover a unit's entire offer, the unit is made whole for the balance through balancing operating reserves. The result is a misallocation of the costs of providing reactive services. Reactive services credits are paid by real-time load in the control zone or zones where the service is provided while balancing operating reserve charges are paid by deviations from day-ahead or real-time load plus exports in the RTO, Eastern or Western Region depending on the allocation process rather than by zone.

In 2017, units providing reactive services were paid $0.6 million in balancing operating reserve credits in order to cover their total energy offer. In 2016, this misallocation was $0.3 million.

The MMU recommends that reactive services credits be calculated consistent with the balancing operating reserve credit calculation. The MMU also recommends including real-time exports and real-time wheels in the allocation of the cost of providing reactive support to the 500 kV system or above, in addition to real-time load.[38]

## Allocation Proposal

The elimination of the day-ahead operating reserve category and other MMU recommendations require enhancements to the current method of energy uplift allocation.

The current method allocates day-ahead operating reserve charges to day-ahead load, day-ahead exports and decrement bids. The elimination of the day-ahead operating reserve category would shift these costs to the balancing operating reserve category which would be paid by deviations or by real-time load plus real-time exports depending on the balancing operating reserve allocation rules.

The MMU recommends creating a new category for energy uplift payments to units scheduled in the Day-Ahead Energy Market (for reasons other than reactive or black start services), which would be allocated to all day-ahead transactions and resources. All these transaction types have an impact on the outcome of the day-ahead scheduling process, so allocating these costs to all day-ahead transactions ensures that all transactions that affect the way the Day-Ahead Energy Market clears are responsible for any energy uplift credits paid to the units scheduled in the Day-Ahead Energy Market. Energy uplift payments to units scheduled as must run in the Day-Ahead Energy Market (for reasons related to expected conditions in the real-time market not including reactive or black start services) should be allocated to real-time load, real-time exports and real-time wheels.

The MMU recommends allocating energy uplift payments to units not scheduled in the Day-Ahead Energy Market and committed in real time, but before the operating day, to the current deviation categories with the addition of up to congestion, wheels and units that clear the Day-Ahead Scheduling Reserve Market but do not perform.

The MMU recommends the exclusion of offsets based on internal bilateral transactions. These costs should be allocated to the current deviation categories whenever the units receiving energy uplift payments are committed before the operating day.

The MMU recommends allocating energy uplift payments to units committed during the operating day to a new deviation category which would include physical transactions or resources (day-ahead minus real-time load, day-ahead minus real-time interchange transactions, generators and DR not following dispatch). This allocation would ensure that commitment changes that occur during the operating day and that result in energy uplift payments are paid by transactions or resources affecting the commitment of units during the operating day. For example, real-time load or interchange transactions that do not bid in the Day-Ahead Energy Market, generators and DR resources that do not follow dispatch would be allocated these costs. Any reliability commitment should be allocated to real-time load, real-time exports and real-time wheels independently of the timing of the commitment.

The MMU recommends changing the allocation of lost opportunity cost and canceled resources. LOC paid to units scheduled in the Day-Ahead Energy Market and not committed in real time should be allocated to deviations based on the proposed definition of deviations. LOC paid

38 See the Day-Ahead Reliability and Reactive Cost Allocation Final Report (December 13, 2013) for a complete description of the issues discussed in that group. <http://www.pjm.com/~/media/committees-groups/task-forces/emustf/20131220/20131220-item-02b-darrca-final-report.ashx>.

to units reduced for reliability in real time and payments to canceled resources should be allocated to real-time load, real-time exports and real-time wheels.

Table 4-35 shows the current allocation by energy uplift reason. For example, energy uplift payments to units scheduled in the Day-Ahead Energy Market are called day-ahead operating reserves, these costs are paid by day-ahead load, day-ahead exports and decrement bids. Any additional payment resulting from the real-time operation of these units are called balancing operating reserves, these costs are paid by either deviations or real-time load and real-time exports depending on the amount of intervals the units are economic.

### Table 4-35 Current energy uplift allocation

| Reason | Energy Uplift Category | Allocation Logic | Allocation |
|---|---|---|---|
| Units scheduled in the Day-Ahead Energy Market | Day-Ahead Operating Reserve | NA | Day-Ahead Load, Day-Ahead Exports and Decrement Bids |
| Units scheduled in the Day-Ahead Energy Market | Balancing Operating Reserve | LMP < Offer for at least four intervals | Real-Time Load and Real-Time Exports |
| | | LMP > Offer for at least four intervals | Deviations |
| Unit not scheduled in the Day-Ahead Energy Market and committed in real time | Balancing Operating Reserve | Committed before the operating day for reliability | Real-Time Load and Real-Time Exports |
| | | Committed before the operating day to meet forecasted load and reserves | Deviations |
| | | Committed during the operating day and LMP < Offer for at least four intervals | Real-Time Load and Real-Time Exports |
| | | Committed during the operating day and LMP > Offer for at least four intervals | Deviations |
| Units scheduled in the Day-Ahead Energy Market not committed in real time | LOC Credit | NA | Deviations |
| Units reduced for reliability in real time | LOC Credit | NA | Deviations |
| Units canceled before coming online | Cancellation Credit | NA | Deviations |

Table 4-36 shows the MMU allocation proposal by energy uplift reason. The proposal eliminates the day-ahead operating reserve category and creates a new category for any energy uplift payments to units scheduled in the Day-Ahead Energy Market and committed in real time. This new category would be allocated to day-ahead transactions and resources. The proposal also eliminates the need to determine the number of intervals that units are economic to determine if the energy uplift charge should be allocated to deviations or to real-time load and real-time exports. In the proposal, any commitment instruction before the operating day would be allocated based on the proposed definition of deviations; any commitment instruction during the operating day would be allocated to physical deviations.

### Table 4-36 MMU energy uplift allocation proposal

| Reason | Energy Uplift Category | Allocation Logic | Allocation |
|---|---|---|---|
| Units scheduled in the Day-Ahead Energy Market and committed in real time | Day-Ahead Segment Make Whole Credit | Scheduled by the day ahead model (not must run) | Day-Ahead Transactions and Day-Ahead Resources |
| | | Scheduled as must run in the day ahead model | Real-Time Load, Real-Time Exports and Withdrawal Side of Real-Time Wheels |
| Units not scheduled in the Day-Ahead Energy Market and committed in real time | Real Time Segment Make Whole Credit | Committed before the operating day | Deviations |
| | | Committed during the operating day | Physical Deviations |
| | | Any commitment for reliability | Real-Time Load, Real-Time Exports and Withdrawal Side of Real-Time Wheels |
| Units scheduled in the Day-Ahead Energy Market not committed in real time | Day-Ahead LOC | NA | Deviations |
| Units reduced for reliability in real time | Real-Time LOC | NA | Real-Time Load, Real-Time Exports and Withdrawal Side of Real-Time Wheels |
| Units canceled before coming online | Cancellation Credit | NA | Real-Time Load, Real-Time Exports and Withdrawal Side of Real-Time Wheels |

## Quantifiable Recommendations Impact

Table 4-37 shows energy uplift charges based on the current allocation and energy uplift charges based on the MMU allocation proposal including the MMU recommendations regarding energy uplift credit calculations. Total charges (excluding black start and reactive services charges) would have been reduced by $33.9 million or 14.1 percent in 2016 and 2017 if three recommendations regarding energy uplift credit calculations proposed by the MMU had been implemented. The elimination of the day-ahead operating reserve credit would have resulted in a decrease of $20.8 million, the proposed changes to lost opportunity cost calculations would have resulted in a decrease of $10.3 million and the use of net regulation revenues offset would have resulted in a decrease of $2.3 million.[39] Table 4-37 shows that deviations charges would have been reduced by $87.1 million or 79.9 percent. The reason for this change is that, besides the reduction in the overall charges, under the MMU proposal, a subset of charges is reallocated to a new physical deviation category (based on the timing of the commitment of the resource being paid energy uplift) and another subset of charges is allocated to real-time load, real-time exports and real-time wheels (based on reliability actions).

### Table 4-37 Current and proposed energy uplift charges by allocation (Millions): 2016 and 2017[40]

| Allocation | 2016 | 2017 | Total |
|---|---|---|---|
| **Current** | | | |
| Day-Ahead Demand, Day-Ahead Exports and Decrement Bids | $57.3 | $24.7 | $82.1 |
| Real-Time Load and Real-Time Exports | $22.5 | $27.1 | $49.5 |
| Deviations | $53.7 | $55.3 | $109.0 |
| Total | $133.5 | $107.1 | $240.6 |
| **Proposal** | | | |
| Day-Ahead Transactions and Day-Ahead Resources | $10.7 | $7.4 | $18.1 |
| Real-Time Load and Real-Time Exports | $44.5 | $21.1 | $65.6 |
| Deviations | $16.0 | $6.0 | $21.9 |
| Physical Deviations | $44.7 | $56.5 | $101.2 |
| Total | $115.8 | $90.9 | $206.7 |
| **Impact** | | | |
| Impact ($) | ($17.7) | ($16.2) | ($33.9) |
| Impact (%) | (13.2%) | (15.1%) | (14.1%) |

The MMU calculated the rates that participants would have paid in 2016 and 2017 if all the MMU's recommendations on energy uplift had been in place. These recommendations have been included in the analysis: day-ahead operating reserve elimination; net regulation revenues offset; implementation of the proposed changes to lost opportunity cost calculations; reallocation of operating reserve credits paid to units scheduled as must run in the Day-Ahead Energy Market (for reasons other than reactive or black start services); reallocation of operating reserve credits paid to units supporting the Con Edison – PJM Transmission Service Agreements; elimination of internal bilateral transactions from the deviations calculation; allocation of energy uplift charges to up to congestion transactions and the MMU energy uplift allocation proposal.

Table 4-38 shows the energy uplift cost of a 1 MW transaction if these recommendations had been implemented in 2016 and 2017. Table 4-38 assumes two scenarios under the MMU proposal. The first scenario assumes all the up to congestion transactions volume cleared. The second scenario assumes zero volume of up to congestion transactions in 2016 and 2017, in this scenario, the cost reflects the expected cost for the first 1 MWh cleared up to congestion transaction. Table 4-38 shows for example that a decrement bid in the Eastern Region (if not offset by other transactions) would have paid an average rate of $0.027 and $0.012 per MWh in the 2016 and 2017, under the first scenario, $0.391 and $0.374 per MWh less than the actual average rate paid. Up to congestion transactions sourced in the Eastern Region and sinking in the Western Region would have paid an average rate of $0.049 and $0.023 per MWh in 2016 and 2017 under the first scenario. Table 4-38 shows the current and proposed averages energy uplift rates for all transactions.

39 The total impact of the elimination of the day-ahead operating reserve credit and the impact of net regulation revenues offset is greater because they also impact black start and reactive services charges.

40 These energy uplift charges do not include black start and reactive services charges.

## Table 4-38 Current and proposed average energy uplift rate by transaction: 2016 and 2017[41]

| | | 2016 | | | 2017 | | |
|---|---|---|---|---|---|---|---|
| Transaction | | Current Rates ($/MWh) | Proposed Rates - 100% UTC ($/MWh) | Proposed Rates - 0% UTC ($/MWh) | Current Rates ($/MWh) | Proposed Rates - 100% UTC ($/MWh) | Proposed Rates - 0% UTC ($/MWh) |
| East | INC | 0.347 | 0.027 | 0.093 | 0.355 | 0.012 | 0.040 |
| | DEC | 0.418 | 0.027 | 0.093 | 0.386 | 0.012 | 0.040 |
| | DA Load | 0.071 | 0.004 | 0.006 | 0.030 | 0.003 | 0.004 |
| | RT Load | 0.031 | 0.058 | 0.058 | 0.037 | 0.027 | 0.027 |
| | Deviation | 0.347 | 0.387 | 0.451 | 0.355 | 0.504 | 0.531 |
| West | INC | 0.302 | 0.022 | 0.078 | 0.327 | 0.011 | 0.037 |
| | DEC | 0.372 | 0.022 | 0.078 | 0.357 | 0.011 | 0.037 |
| | DA Load | 0.071 | 0.004 | 0.006 | 0.030 | 0.003 | 0.004 |
| | RT Load | 0.023 | 0.058 | 0.058 | 0.028 | 0.027 | 0.027 |
| | Deviation | 0.302 | 0.312 | 0.366 | 0.327 | 0.415 | 0.440 |
| UTC | East to East | NA | 0.055 | 0.186 | NA | 0.024 | 0.081 |
| | West to West | NA | 0.044 | 0.156 | NA | 0.021 | 0.074 |
| | East to/from West | NA | 0.049 | 0.171 | NA | 0.023 | 0.077 |

41 The deviation transaction means load, interchange transactions, generators and DR deviations.

# 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 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. But the net CONE times B offer cap under the capacity performance design, in the absence of performance assessment hours, exceeds the competitive level and should be reevaluated for each BRA. 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 unforced capacity resource shortage exceeded 100 MW of unforced capacity due to a load forecast

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. In the 2018/2019 RPM Second Incremental Auction, 35 participants in the RTO market passed the 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.

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, the 2020/2021 RPM Base Residual Auction, the 2018/2019 RPM Second Incremental Auction, and the 2019/2020 RPM First Incremental Auction were conducted in 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 nonperformance 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 2017, PJM installed capacity increased 1,470.9 MW or 0.8 percent, from 182,410.7 MW on January 1 to 183,881.6 MW on December 31. Installed capacity includes net capacity imports and exports and can vary on a daily basis.
- **PJM Installed Capacity by Fuel Type.** Of the total installed capacity on December 31, 2017, 35.4 percent was coal; 36.8 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 0.2 percent was solar.

6 See Letter Order, FERC Docket No. ER10-366-000 (January 22, 2010).
7 See 126 FERC ¶ 61,275 (2009) at P 88.
8 See 151 FERC ¶ 61,208 (2015).
9 See "PJM Manual 18: PJM Capacity Market," Rev. 38 (July 27, 2017) at 9.
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.

- **Supply.** Total internal capacity available to offer in the Base Residual Auction for the relevant delivery year decreased 7,225.8 MW from 200,848.1 MW on June 1, 2016, to 193,622.3 MW on June 1, 2017. This decrease was the result of new generation (5,179.3 MW), reactivated generation (1,025.7 MW), net generation capacity modifications (cap mods) (-7,943.1 MW), demand resource (DR) modifications (-3,472.4 MW), energy efficiency (EE) modifications (158.9 MW), the EFORd effect due to higher sell offer EFORds (-2,167.1 MW), and lower load management UCAP conversion factor (-7.1 MW).
- **Demand.** There was a 787.1 MW decrease in the RPM reliability requirement from 180,332.2 MW on June 1, 2016, to 179,545.1 MW on June 1, 2017. The 787.1 MW decrease in the RTO Reliability Requirement was a result of a 1,017.4 MW decrease in the forecast peak load in UCAP terms holding the Forecast Pool Requirement (FPR) constant at the 2016/2017 level offset by a 230.3 MW increase attributable to the change in FPR. On June 1, 2017, PJM EDCs and their affiliates maintained a large market share of load obligations under RPM, together totaling 63.6 percent, down from 64.1 percent on June 1, 2016.
- **Market Concentration.** In the 2018/2019 RPM Second Incremental Auction, 35 participants in the RTO passed the three pivotal supplier (TPS) test. In the 2017/2018 RPM Base Residual Auction, 2017/2018 RPM First Incremental Auction, 2017/2018 RPM Second Incremental Auction, 2017/2018 RPM Third Incremental Auction, 2018/2019 RPM Base Residual Auction, 2018/2019 RPM First Incremental Auction, 2019/2020 RPM Base Residual Auction, 2019/2020 RPM First Incremental Auction, and the 2020/2021 RPM Base Residual Auction all participants in the total PJM market as well as the LDA RPM markets failed the three pivotal supplier (TPS) test.[11] The TPS test was not applied in the 2016/2017 Capacity Performance (CP) Transition Incremental Auction and the 2017/2018 CP Transition Incremental Auction. All offers in the CP Transition Auctions were subject to overall offer caps. Offer caps were applied to all sell offers for resources which were subject to mitigation when the Capacity Market Seller did not pass the test, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, increased the market clearing price.[12 13 14]
- **Imports and Exports.** Of the 4,961.8 MW of imports in the 2020/2021 RPM Base Residual Auction, 3,997.2 MW cleared. Of the cleared imports, 1,671.2 MW (41.8 percent) were from MISO.
- **Demand-Side and Energy Efficiency Resources.** Capacity in the RPM load management programs was 10,117.8 MW for June 1, 2017, as a result of cleared capacity for demand resources and energy efficiency resources in RPM Auctions for the 2017/2018 Delivery Year (13,793.0 MW) less replacement capacity from sources other than demand resources and energy efficiency (3,675.2 MW).

## Market Conduct

- **2017/2018 RPM Base Residual Auction.** Of the 1,202 generation resources that submitted offers, the MMU calculated offer caps for 531 generation resources (44.2 percent), of which 400 (33.3 percent) were based on the technology specific default (proxy) ACR values and 131 (10.9 percent) were unit-specific offer caps.
- **2017/2018 Capacity Performance Transition Incremental Auction.** All 785 generation resources which submitted offers in the 2017/2018 CP Transition Incremental Auction were subject to an offer cap of $210.83 per MW-day, which is 60 percent of the Net Cost of New Entry (CONE) used in the 2017/2018 RPM Base Residual Auction.
- **2017/2018 RPM First Incremental Auction.** Of the 118 generation resources that submitted offers, the MMU calculated offer caps for 53 generation resources (44.9 percent), of which 36 (30.5 percent) were based on the technology specific default

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 § 5.10(a)(ii).

12 See 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 at P 30 (2009).

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).

(proxy) ACR values and 17 (14.4 percent) were unit-specific offer caps.

- **2017/2018 RPM Second Incremental Auction.** Of the 95 generation resources that submitted offers, the MMU calculated offer caps for 35 generation resources (36.8 percent), of which 15 (15.8 percent) were based on the technology specific default (proxy) ACR values and 20 (21.1 percent) were unit-specific offer caps.
- **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 (1.6 percent) were based on the technology specific default (proxy) ACR values and four (1.3 percent) were unit-specific offer caps.
- **2018/2019 RPM Base Residual Auction.** Of the 473 generation resources that submitted Base Capacity offers, the MMU calculated offer caps for 219 generation resources (46.3 percent), of which 166 (35.1 percent) were based on the technology specific default (proxy) ACR values and 53 (11.2 percent) were unit-specific offer caps. Of the 992 generation resources that submitted Capacity Performance offers, the MMU calculated unit specific offer caps for 35 generation resources (3.5 percent).
- **2018/2019 RPM First Incremental Auction.** Of the 80 generation resources that submitted Base Capacity offers, the MMU calculated offer caps for 30 generation resources (37.5 percent), of which 18 (22.5 percent) were based on the technology specific default (proxy) ACR values and 12 (15.0 percent) were unit-specific offer caps. Of the 293 generation resources that submitted Capacity Performance offers, the MMU calculated unit specific offer caps for nine generation resources (3.1 percent).
- **2018/2019 RPM Second Incremental Auction.** Of the 68 generation resources that submitted Base Capacity offers, the MMU calculated offer caps for 23 generation resources (33.8 percent), of which 12 (17.6 percent) were based on the technology specific default (proxy) ACR values and 11 (16.2 percent) were unit-specific offer caps. Of the 344 generation resources that submitted Capacity Performance offers, the MMU calculated unit specific offer caps for five generation resources (1.5 percent).
- **2019/2020 RPM Base Residual Auction.** Of the 505 generation resources that submitted Base Capacity offers, the MMU calculated offer caps for 212 generation resources (42.0 percent), of which 171 (33.9 percent) were based on the technology specific default (proxy) ACR values and 41 (8.1 percent) were unit-specific offer caps. Of the 1,003 generation resources that submitted Capacity Performance offers, the MMU calculated unit specific offer caps for 25 generation resources (2.5 percent).
- **2019/2020 RPM First Incremental Auction.** Of the 81 generation resources that submitted Base Capacity offers, the MMU calculated offer caps for 28 generation resources (34.6 percent), of which 17 (21.0 percent) were based on the technology specific default (proxy) ACR values and 11 (13.6 percent) were unit-specific offer caps. Of the 382 generation resources that submitted Capacity Performance offers, the MMU calculated unit specific offer caps for six generation resources (1.6 percent).
- **2020/2021 RPM Base Residual Auction.** Of the 1,114 generation resources that submitted offers, the MMU calculated unit specific offer caps for 14 generation resources (1.3 percent).

## Market Performance

- The 2017/2018 RPM Third Incremental Auction, the 2020/2021 RPM Base Residual Auction, the 2018/2019 RPM Second Incremental Auction, and the 2019/2020 RPM First Incremental Auction were conducted in 2017. The weighted average capacity price for the 2017/2018 Delivery Year is $141.19 per MW-day, including all RPM Auctions for the 2017/2018 Delivery Year held through 2017. The weighted average capacity price for the 2018/2019 Delivery Year is $175.58, including all RPM auctions for the 2018/2019 Delivery Year held through 2017. The weighted average capacity price for the 2019/2020 Delivery Year is $113.41, including all RPM Auctions for the 2019/2020 Delivery Year held through 2017.
- 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 $141.19 per MW-day in 2017/2018.

## Reliability Must Run Service

- Of the seven companies (23 units) that have provided RMR service, two companies (seven units) filed to be paid for RMR service under the deactivation avoidable cost rate (DACR), the formula rate. The other five companies (16 units) filed to be paid for RMR service under the cost of service recovery rate.

## Generator Performance

- **Forced Outage Rates.** The average PJM EFORd for 2017 was 6.8 percent, an increase from 6.5 percent for 2016.[15]
- **Generator Performance Factors.** The PJM aggregate equivalent availability factor for 2017 was 84.1 percent, an increase from 83.4 percent for 2016.
- **Outages Deemed Outside Management Control (OMC).** In 2017, 2.9 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 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]

### Definition of Capacity

- 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 definition of demand side resources be modified 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.)

### Market Design and Parameters

- 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 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 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, unlike the situation when EE was first added to the capacity market. However, the MMU recommends that the PJM load forecast method should be modified so that EE impacts immediately affect the forecast without the long lag times incorporated in the current forecast method.

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 January 24, 2018. 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.

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, 2017," <http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Report_on_Capacity_Replacement_Activity_4_20171214.pdf> (December 14, 2017).

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 2, Section 6: Net Revenue.

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 offer to sell back capacity in incremental auctions only at the BRA clearing price for the relevant delivery year. (Priority: Medium. First reported Q1, 2017. Status: Not adopted.)
- The MMU recommends that the use of the 2.5 percent demand adjustment (Short Term Resource Procurement Target) be terminated immediately. The 2.5 percent should be added back to the overall market demand curve. (Priority: Medium. First reported 2013. Status: Adopted 2015.)
- The MMU recommends changing the RPM solution method to explicitly incorporate the cost of make whole payments in the objective function. (Priority: Medium. First reported 2014. Status: Not adopted.)
- The MMU recommends that PJM clear the capacity market based on nodal capacity resource locations and the characteristics of the transmission system consistent with the actual electrical facts of the grid. The current nested LDA structure used in the capacity market does not adequately represent all the capacity transfers that are feasible among LDAs. Absent a fully nodal capacity market clearing process, the MMU recommends that PJM use a nonnested model for all LDAs and specify a VRR curve for each LDA separately. Each LDA requirement should be met with the capacity resources located within the LDA and exchanges from neighboring LDAs up to the transmission limit. LDAs should price separate if that is the result of the LDA supply curves and the transmission constraints. (Priority: Medium. First reported Q3, 2017. Status: Not adopted.)

## Offer Caps and Offer Floors

- The MMU recommends the extension of the minimum offer price rule (MOPR) to all existing and proposed units (MOPR-Ex) in order to protect competition in the capacity market from external subsidies. (Priority: High. First reported 2016. 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 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 the RPM market power mitigation rule be modified to apply offer caps in all cases when the three pivotal supplier test is failed and the sell offer is greater than the offer cap. This will ensure that market power does not result in an increase in make whole payments. (Priority: Medium. First reported Q3, 2017. Status: Not adopted.)
- The MMU recommends that PJM develop a forward looking estimate for the expected number of Performance Assessment Hours (H) to use in calculating the Non-Performance Charge Rate. The MMU recommends that PJM develop a forward looking estimate for the Balancing Ratio (B) during Performance Assessment Hours to use in calculating the default offer cap. Both H and B parameters should be included in the annual review of planning parameters for the Base Residual Auction. (Priority: High. First reported Q3, 2017. Status: Not adopted.)

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).

- The MMU recommends that when expected H and B are not the same as the assumed levels used to calculate the default market seller offer cap of Net CONE*B, the offer cap be recalculated for each BRA using the fundamental economic logic for a competitive offer of a CP resource. (Priority: High. New Recommendation. Status: Not adopted.)

## Performance Incentive Requirements of RPM

- The MMU recommends that a unit which is not capable of supplying energy consistent with its day-ahead offer reflect an appropriate outage. (Priority: Medium. First reported 2009. Status: Not adopted. Pending before FERC.)
- The Market Monitor recommends that retroactive replacement transactions associated with a failure to perform during a PAH not be allowed and that, more generally, retroactive replacement capacity transactions not be permitted. (Priority: Medium. First reported 2016. Status: Not adopted.)
  - 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.)
- 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.)

## Capacity Imports and Exports

- 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 full substitutes for internal, physical capacity resources. (Priority: High. First reported 2014. Status: Adopted 2015.)
- 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 full substitutes for internal, physical capacity resources. 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 that all capacity imports have firm transmission to the PJM border prior to offering in an RPM auction. (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 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 the rules need additional clarification and operational details. (Priority: Low. First reported 2010. Status: Partially adopted.)

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, joint report, "*Capacity in the PJM Market*," (August 20, 2012).<http://www.monitoringanalytics.com/reports/Reports/2012/IMM_And_PJM_Capacity_White_Papers_On_OPSI_Issues_20120820.pdf>

## Deactivations/Retirements

- 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 that RMR units recover all and only 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. Customers should bear no responsibility for paying previously incurred costs, including a return on or of prior investments. (Priority: Low. First reported 2010. Status: Not adopted.)
- The MMU recommends elimination of the cost of service recovery rate in OATT Section 119, and that RMR service should be provided under the deactivation avoidable cost rate in Part V. The MMU also recommends specific improvements to the DACR provisions. (Priority: Medium. New recommendation. Status: Not adopted.)

# Conclusion

The analysis of PJM Capacity Markets begins with market structure, which provides the framework for the actual behavior or conduct of market participants. The analysis examines participant behavior within that market structure. In a competitive market structure, 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 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 exception was that some seasonal resources were paid additional make whole based on a failure of the market power rules to apply offer capping. 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.[24 25 26 27 28 29] 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 2017. 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 and the request in Pennsylvania to subsidize the TMI nuclear power plant and the DOE NOPR, 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 new 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

24 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).

25 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).

26 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).

27 See "Analysis of the 2020/2021 RPM Base Residual Auction," <<http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Analysis_of_the_20202021_RPM_BRA_20171117.pdf>> (November 11, 2017).

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).

29 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2017," <http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Report_on_Capacity_Replacement_Activity_4_20171214.pdf> (December 14, 2017).

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 extended (MOPR-Ex) 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: 2016 through 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 |
| 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 |

## Table 5-2 RPM related MMU reports: 2016 through 2017

| Date | Name |
|---|---|
| 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 |
| May 11, 2017 | Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2018/2019, 2019/2020 and 2020/2021 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/RPM_Must_Offer_Obligation_20170509.pdf |
| June 27, 2017 | MMU Incremental Auction Recommendation - Package B http://www.monitoringanalytics.com/reports/Presentations/2017/IMM_IASTF_MMU_Package_B_Summary_20170627.pdf |
| June 27, 2017 | Replacement Capacity Issues http://www.monitoringanalytics.com/reports/Presentations/2017/IMM_IASTF_Replacement_Capacity_Issues_20170627.pdf |
| August 30, 2017 | IMM Answer re IMM MOPR Exemption Complaint Docket No. EL17-82 http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Answer_Docket_No_EL17-82_20170830.pdf |
| August 30, 2017 | Incremental Auction Design Changes, Package B http://www.monitoringanalytics.com/reports/Presentations/2017/IMM_IASTF_Package_B_Executive_Summary_20170830.pdf |
| September 5, 2017 | IMM Comments re PJM Deficiency Letter Compliance Docket No. ER17-775-002 http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Comments_Docket_No_ER17-775-002_20170905.pdf |
| September 8, 2017 | Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2018/2019, 2019/2020 and 2020/2021 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/RPM_Must_Offer_Obligation_20170509.pdf |
| September 11, 2017 | IMM CCPPSTF Proposal http://www.monitoringanalytics.com/reports/Presentations/2017/IMM_CCPPSTF_Proposal_20170911.pdf |
| September 12, 2017 | IMM Answer re Pleasants Transfer Docket No. EC17-88 http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Answer_Docket_No_EC17-88_20170912.pdf |
| October 17, 2017 | Revised IMM MOPR-Ex Proposal for CCPPSTF http://www.monitoringanalytics.com/reports/Presentations/2017/IMM_Letter_CCPPSTF_IM_%20Proposal_Summary_Revised_20171017.pdf |
| November 2, 2017 | IMM MOPR-Ex Proposal for the CCPPSTF http://www.monitoringanalytics.com/reports/Presentations/2017/IMM_CCPPSTF_Proposal_Summary_Revised_20171103.pdf |
| November 12, 2017 | IMM MOPR-Ex Proposal for the CCPPSTF http://www.monitoringanalytics.com/reports/Presentations/2017/IMM_CCPPSTF_Proposal_Summary_Revised_3_Redline_20171112.pdf |
| November 14, 2017 | IMM Answer re MOPR Reforms Docket No. ER13-535 http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Answer_Docket_No_ER13-535_20171114.pdf |
| November 17, 2017 | Analysis of 2020/2021 RPM Base Residual Auction http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Analysis_of_the_20202021_RPM_BRA_20171117.pdf |
| December 12, 2017 | IMM MOPR-Ex RPS Status http://www.monitoringanalytics.com/reports/Presentations/2017/IMM_MRC_Special_Session_MOPR-Ex_RPS_Status_20171212.pdf |
| December 12, 2017 | IMM MOPR-Ex Proposal Language - Revised http://www.monitoringanalytics.com/reports/Presentations/2017/IMM_MRC_Special_Session_MOPR_Ex_Proposal_Language_Revised_20171212.pdf |
| December 14, 2017 | Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2017 http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Report_on_Capacity_Replacement_Activity_4_20171214.pdf |
| December 21, 2017 | MOPR-Ex Proposal Language Revised - 2 http://www.monitoringanalytics.com/reports/Presentations/2017/IMM_MOPR-Ex_Proposal_Language_Revised_2_2017121.pdf |
| December 21, 2017 | MOPR-Ex Proposal Language - Revised 3 http://www.monitoringanalytics.com/reports/Presentations/2017/IMM_MOPR-Ex_Proposal_Language_Revised_3_20171213.pdf |
| December 21, 2017 | IMM MOPR-Ex RPS Status Revisions http://www.monitoringanalytics.com/reports/Presentations/2017/IMM_MRC_MOPR-Ex_RPS_Status_Revisions_20171214.pdf |
| December 21, 2017 | MOPR-Ex Proposal http://www.monitoringanalytics.com/reports/Presentations/2017/IMM_MRC_MOPR-Ex_Proposal_20171221.pdf |
| December 22, 2017 | IMM Parameter Limited Schedule Matrix (Annual) http://www.monitoringanalytics.com/reports/Market_Messages/Messages/IMM_Parameter_Limited_Schedule_Market_Notice_20171222.pdf |
| December 27, 2017 | Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2018/2019, 2019/2020 and 2020/2021 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/Messages/RPM_Must_Offer_Obligations_20171227.pdf |

## Installed Capacity

On January 1, 2017, PJM installed capacity was 182,410.7 MW (Table 5-3).[30] Over the next 12 months, new generation, unit deactivations, facility reratings, plus import and export shifts resulted in PJM installed capacity of 183,881.6 MW on December 31, 2017, an increase of 1,470.9 MW or 0.8 percent from the January 1 level.[31] [32] The 1,470.9 MW increase was the result of capacity modifications (599.6 MW), new or reactivated generation (3,828.9 MW), and a decrease in exports (267.1 MW), offset by deactivations (2,031.7 MW), derates (757.9 MW), and a decrease in imports (435.1 MW).

At the beginning of the new delivery year on June 1, 2017, PJM installed capacity was 183,099.2 MW, a decrease of 386.8 MW or 0.2 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, 2017, as well as the expected installed capacity for the next three delivery years, based on the results of all auctions held through December 31, 2017.[33] On June 1, 2007, coal comprised 40.7 percent of the installed capacity, reached a maximum of 42.9 percent in 2012, decreased to 35.9 percent on June 1, 2017 and is projected to decrease to 26.7 percent by June 1, 2020. The share of gas increased from 29.1 percent in 2007 to 36.3 percent in 2017 and is projected to increase to 47.9 percent in 2020.

Table 5-4 shows the PJM installed capacity on June 1, 2017, for the top five generation capacity resource owners.

30 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.

31 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.

32 Wind resources accounted for 1,136.7 MW, and solar resources accounted for 373.2 MW of installed capacity in PJM on December 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 (Jan. 1, 2017) at 19.

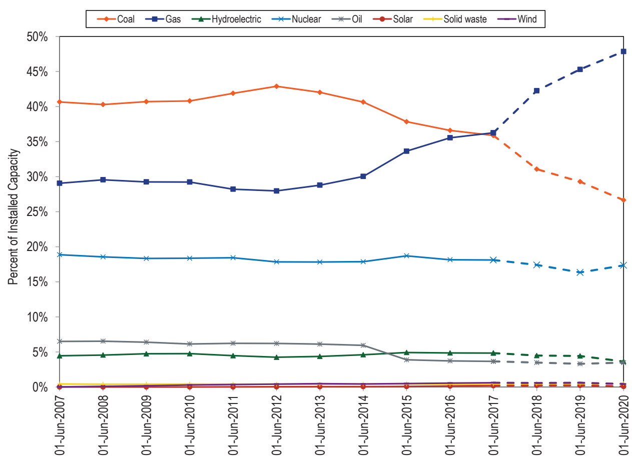
33 Due to EFORd values not being finalized for future delivery years, the projected installed capacity is based on cleared unforced capacity (UCAP) MW using the EFORd submitted with the offer.

### Table 5-3 PJM installed capacity (By fuel source): January 1, May 31, June 1, and December 31, 2017

| | 1-Jan-17 | | 31-May-17 | | 1-Jun-17 | | 31-Dec-17 | |
|---|---|---|---|---|---|---|---|---|
| | MW | Percent | MW | Percent | MW | Percent | MW | Percent |
| Coal | 66,622.2 | 36.5% | 66,941.3 | 36.5% | 65,688.0 | 35.9% | 65,144.0 | 35.4% |
| Gas | 65,110.3 | 35.7% | 65,787.1 | 35.9% | 66,397.6 | 36.3% | 67,726.4 | 36.8% |
| Hydroelectric | 8,850.4 | 4.9% | 8,850.4 | 4.8% | 8,870.2 | 4.8% | 8,856.2 | 4.8% |
| Nuclear | 33,043.4 | 18.1% | 33,103.7 | 18.0% | 33,163.5 | 18.1% | 33,163.5 | 18.0% |
| Oil | 6,733.6 | 3.7% | 6,687.0 | 3.6% | 6,684.4 | 3.7% | 6,672.2 | 3.6% |
| Solar | 262.3 | 0.1% | 268.0 | 0.1% | 366.8 | 0.2% | 373.2 | 0.2% |
| Solid waste | 769.4 | 0.4% | 769.4 | 0.4% | 814.4 | 0.4% | 809.4 | 0.4% |
| Wind | 1,019.1 | 0.6% | 1,079.1 | 0.6% | 1,114.3 | 0.6% | 1,136.7 | 0.6% |
| Total | 182,410.7 | 100.0% | 183,486.0 | 100.0% | 183,099.2 | 100.0% | 183,881.6 | 100.0% |

### Figure 5-1 Percent of PJM installed capacity (By fuel source): June 1, 2007 through June 1, 2020




### Table 5-4 PJM installed capacity by parent company: June 1, 2017

| | 01-Jun-17 | |
|---|---|---|
| Parent Company | ICAP (MW) | Rank |
| Exelon Corporation | 23,742.5 | 1 |
| Dominion Resources, Inc. | 21,298.0 | 2 |
| American Electric Power Company, Inc. | 17,132.1 | 3 |
| FirstEnergy Corp. | 16,680.2 | 4 |
| NRG Energy, Inc. | 16,288.2 | 5 |

## Fuel Diversity

Figure 5-2 shows the fuel diversity index ($FDI_c$) for PJM installed capacity.[34] 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.[35] 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.[36] The $FDI_c$ decreased on average 0.1 percent from 2016 to 2017. The average monthly capacity share of gas generators increased by 1.0 percentage point from 35.1 percent in 2016 to 36.1 percent in 2017. The average monthly capacity share of coal generators decreased by 0.8 percentage points from 36.9 percent in 2016 to 36.1 percent in 2017. Figure 5-2 also includes the expected $FDI_c$ through June 2020 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.[37] There were 118 units with installed capacity totaling 30.8 GW identified as the high estimate of being at risk. The dashed green line in Figure 5-2 shows the $FDI_c$ calculated assuming that the capacity from these 118 units that has cleared in a RPM auction is replaced by gas generation. The $FDI_c$ under these assumptions would decrease by 0.065 (9.4 percent) on average from the expected $FDI_c$ for the period January 1, 2018, through June 1, 2020.

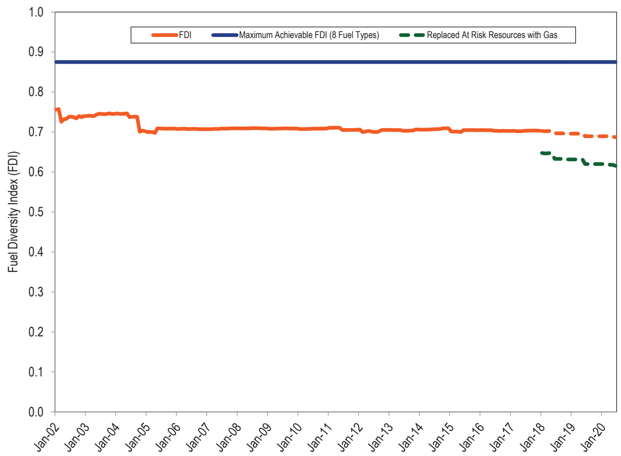
34 Monitoring Analytics developed the FDI to provide an objective metric of fuel diversity. The FDI metric is similar to the HHI used to measure market concentration. The FDI is calculated separately for energy output and for installed capacity.

35 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.

36 See the *2016 State of the Market Report for PJM*, Volume 2, 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.

37 See the *2017 State of the Market Report for PJM*, Volume 2, Section 7: Net Revenue, Units at Risk.

Figure 5-2 Fuel Diversity Index for PJM installed capacity: January 1, 2002 through June 1, 2020




# 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.[38] In 2017, the 2017/2018 RPM Third Incremental Auction, the 2020/2021 RPM Base Residual Auction, the 2018/2019 RPM Second Incremental Auction, and the 2019/2020 RPM First Incremental Auction were conducted.

## Market Structure

### Supply

Table 5-5 shows generation capacity changes since the implementation of the Reliability Pricing Model through the 2016/2017 Delivery Year. The 19,439.8 MW increase was the result of new generation capacity resources (17,822.7 MW), reactivated generation capacity resources (967.0 MW), uprates (6,100.1 MW), integration of external zones (18,109.0 MW), a net increase in capacity imports (4,987.5 MW), a net decrease in capacity exports (2,298.3 MW), offset by deactivations (27,608.0 MW) and derates (3,236.8 MW).

As shown in Table 5-6, total internal capacity available to offer in the Base Residual Auction for the relevant delivery year decreased 7,225.8 MW from 200,848.1 MW on June 1, 2016, to 193,622.3 MW on June 1, 2017. This decrease was the result of new generation (5,179.3 MW), reactivated generation (1,025.7 MW), net generation capacity modifications (cap mods) (-7,943.1 MW), demand resource (DR) modifications (-3,472.4 MW), energy efficiency (EE) modifications (158.9 MW), the EFORd effect due to higher sell offer EFORds (-2,167.1 MW), and lower load management UCAP conversion factor (-7.1 MW). The EFORd effect is the measure of the net internal capacity change attributable to EFORd changes and not capacity modifications.

In the 2018/2019, 2019/2020, and 2020/2021 auctions, new generation were 13,706.2 MW; reactivated generation were 5.3 MW; net generation cap mods were -6,554.7 and net generation winter cap mods were 409.2 MW. DR and energy efficiency (EE) modifications totaled -980.0 MW through June 1, 2020. An increase of 227.7 MW was due to lower EFORds, and an increase of 701.6 MW was due to a higher Load Management UCAP conversion factor. The net effect from June 1, 2017, through June 1, 2020, was an increase in total internal capacity available to offer in the Base Residual Auction for the relevant delivery year of 7,515.3 MW (3.9 percent) from 193,622.3 MW to 201,137.6 MW.

As shown in Table 5-6 and Table 5-15, in the 2017/2018 auction the 51 additional generation resources offered consisted of 32 new resources (5,103.3 MW), six repowered resources (941.6 MW), four resources that were excused and not offered in the 2016/2017 BRA (384.6 MW), three additional resources imported (714.1 MW), three resources that were previously entirely FRR committed (164.0 MW), two additional resources resulting from the disaggregation of RPM resources, and one reactivated resource (84.1 MW). The 32 new generation capacity resources consisted of 15 solar resources (27.0 MW), nine diesel resources (122.5 MW), six combined cycle resources (4,825.4 MW), one CT resource (122.7 MW), and one hydro resource (5.7 MW). In addition, there were new generation resources that were not offered in to the auction because they were

38 See *PJM Interconnection, L.L.C.*, Letter Order in Docket No. ER10-366-000 (January 22, 2010).

either exported or entirely committed to FRR for the 2017/2018 Delivery Year: one wind resource (26.0 MW). The 48 fewer generation resources offered consisted of 21 external resources not offered (2,630.4 MW), 18 deactivated resources (3,018.7 MW), three planned generation capacity resources not offered (1,171.7 MW), three resources excused from offering for reasons other than retirement (554.9 MW), two additional resources committed fully to FRR (168.3 MW), and one resource that is no longer a PJM capacity resource (1.7 MW). In addition, there were retirements of resources that were either exported, excused, or committed to an FRR capacity plan in the 2016/2017 BRA: 24 CT resources (964.4 MW) and 21 steam resources (2,716.2 MW).

As shown in Table 5-6 and Table 5-16, in the 2018/2019 auction the 36 additional generation resources offered consisted of 28 new resources (3,447.4 MW), six additional resources imported (483.2 MW), and two resources that were previously entirely FRR committed (2.9 MW). The 28 new generation capacity resources consisted of 11 solar resources (82.8 MW), six wind resources (127.1 MW), four combined cycle resources (2,257.8 MW), four CT resources (912.3 MW), and three diesel resources (67.4 MW). The 49 fewer generation resources offered consisted of 22 fewer resources resulting from aggregation of RPM resources, 17 deactivated resources (1,083.2 MW), four planned generation capacity resources not offered (874.4 MW), three external resources not offered (446.1 MW), one resource excused from offering for reasons other than retirement (1.4 MW), one additional resource committed fully to FRR (173.0 MW), and one resource that is no longer a PJM capacity resource (2.3 MW). In addition, there were retirements of resources that were either exported, excused, or committed to an FRR capacity plan in the 2017/2018 BRA: 16 steam resources (1,947.8 MW).

As shown in Table 5-6 and Table 5-17, in the 2019/2020 auction the 43 additional generation resources offered consisted of 39 new resources (6,685.5 MW), three additional resources imported (162.5 MW), and one resource that was unoffered in the 2018/2019 BRA (2.9 MW). The 39 new generation capacity resources consisted of 18 solar resources (152.3 MW), seven combined cycle resources (5,925.6 MW), five diesel resources (83.2 MW), five wind resources (73.0 MW), and four CT resources (451.4 MW). The 32 fewer generation resources offered consisted of 15 fewer resources resulting from aggregation of RPM resources, six deactivated resources (772.8 MW), five external resources not offered (956.6 MW), resources excused from offering for reasons other than retirement, and planned generation capacity resources not offered. In addition, there were retirements of resources that were either exported, excused, or committed to an FRR capacity plan in the 2018/2019 BRA: two steam resources (148.9 MW) and one combustion turbine (0.8 MW).

As shown in Table 5-6 and Table 5-18, in the 2020/2021 auction the 35 additional generation resources offered consisted of 16 new resources (2,496.2 MW), six additional resources imported (MW), five resources that were previously entirely FRR committed (271.4 MW), four resources that were unoffered in the 2019/2020 BRA (495.5 MW), two reactivated resources (5.3 MW), and two additional resources resulting from the disaggregation of RPM resources. The 16 new generation capacity resources consisted of eight solar resources (64.0 MW), three combined cycle resources (2,382.5 MW), three diesel resources (24.3 MW), and two wind resources (25.4 MW). The 121 fewer generation resources offered consisted of 82 intermittent resources not offered (863.9 MW), 17 deactivated resources (4,123.8 MW), 14 generation resources excused from offering for reasons other than retirement (218.7 MW), four external resources not offered (166.5 MW), additional resources committed fully to FRR, planned generation capacity resources not offered, and capacity storage resources not offered.[39]

Table 5-7 shows the calculated RPM reserve margin and reserve in excess of the defined installed reserve margin (IRM) and accounts for cleared capacity, replacement capacity, and deficiency MW for all auctions held and the final peak load forecast for the given delivery year.

## Future Changes in Generation Capacity[40]

As shown in Table 5-5, for the period from the introduction of the RPM capacity market design in the 2007/2008 Delivery Year through the 2016/2017 Delivery Year, internal installed capacity decreased by 5,955.0 MW after accounting for new capacity resources, reactivations, and uprates (24,889.8 MW) and capacity deactivations and derates (30,844.8 MW).

39 Some numbers not reported as a result of PJM confidentiality rules.

40 For more details on future changes in generation capacity, see "New Generation in the PJM Capacity Market: MW and Funding Sources for Delivery Years 2007/2008 through 2020/2021," <www.monitoringanalytics.com> (March 9, 2018).

For the current and future delivery years (2017/2018 through 2020/2021), new generation capacity is defined as capacity that cleared an RPM auction for the first time in the specified DY. Looking ahead, based on expected completion rates of cleared new generation capacity (10,245.9 MW) and pending deactivations (6,903.1 MW), PJM capacity is expected to increase by an additional 3,342.8 MW for the 2017/2018 through 2020/2021 Delivery Years.

## Sources of Funding[41]

Developers use a variety of sources to fund their projects, including Power Purchase Agreements (PPA), cost of service rates, and private funds (from internal sources or private lenders and investors). PPAs can be used for a variety of purposes and the use of a PPA does not imply a specific source of funding.

New generation capacity from the 2007/2008 DY through the 2016/2017 DY totaled 17,822.7 MW (71.6 percent of all additions), with 12,527.9 MW from market funding and 5,294.8 MW from non-market funding. Reactivated generation capacity from the 2007/2008 DY through the 2016/2017 DY totaled 967.0 MW (3.9 percent of all additions), with 892.0 MW from market funding and 75.0 MW from non-market funding. Uprates to existing generation capacity from the 2007/2008 DY through the 2016/2017 DY totaled 6,100.1 MW (24.5 percent of all additions), with 4,720.6 MW from market funding and 1,379.5 MW from nonmarket funding.

Of the 14,627.1 MW of the additional generation capacity (new resources, reactivated resources, and uprates) that cleared in RPM auctions for the 2017/2018 through 2020/2021 delivery years, that are not yet in service, 12,085.1 MW have market funding and 2,542.0 MW have non-market funding. Applying the historical completion rates, 8,414.6 MW, or 69.6 percent, of the market funded projects are expected to go into service. Similarly, 1,831.4 MW, or 72.0 percent, of nonmarket funded projects are expected to go into service. Together, 10,245.9 MW, or 70.0 percent, of new generation capacity that cleared MW in RPM and are not yet in service are expected to go into service through the 2020/2021 Delivery Year.

Of the 3,403.8 MW of the additional generation capacity that cleared in RPM auctions for the 2017/2018 through 2020/2021 delivery years and are already in service, 3,239.6 MW (95.2 percent) are based on market funding. In summary, 15,324.7 MW (85.0 percent) of the additional generation capacity (3,239.6 MW in service and 12,085.1 MW not yet in service) that cleared in RPM auctions for the 2017/2018 through 2020/2021 delivery years are based on market funding. Capacity additions based on nonmarket funding are 2,706.2 MW (15.0 percent) of proposed generation that cleared at least one RPM auction for the 2017/2018 through 2020/2021 delivery years.

### Table 5-5 Generation capacity changes: 2007/2008 to 2017/2018

| | 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 | 787.6 | 285.1 | 863.4 | 156.4 | 5,389.5 |
| 2016/2017 | 182,025.2 | 2,537.8 | 537.0 | 589.8 | 0.0 | (1,011.1) | (36.4) | 1,447.3 | 168.6 | 1,074.0 |
| 2017/2018 | 183,099.2 | | | | | | | | | |
| Total | | 17,822.7 | 967.0 | 6,100.1 | 18,109.0 | 4,987.5 | (2,298.3) | 27,608.0 | 3,236.8 | 19,439.8 |

41 For more details on sources of funding for generation capacity, see "New Generation in the PJM Capacity Market: MW and Funding Sources for Delivery Years 2007/2008 through 2020/2021," <www.monitoringanalytics.com> (March 9, 2018).

## Table 5-6 Internal capacity: June 1, 2016 to June 1, 2020[42 43]

| | UCAP (MW) | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | RTO | MAAC | EMAAC | SWMAAC | DPL South | PSEG | PSEG North | Pepco | ATSI | ATSI Cleveland | ComEd | BGE | PPL | DAY | DEOK |
| Total internal capacity @ 01-Jun-16 | 200,848.1 | 74,717.9 | 37,020.9 | 12,547.8 | 1,766.3 | 8,343.2 | 4,691.6 | 6,237.4 | 14,325.2 | 4,035.1 | 26,091.2 | 3,717.0 | 10,570.7 | | |
| Correction in resource modeling | 0.0 | 0.8 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | | |
| Adjusted internal capacity @ 01-Jun-16 | 200,848.1 | 74,718.7 | 37,020.9 | 12,547.8 | 1,766.3 | 8,343.2 | 4,691.6 | 6,237.4 | 14,325.2 | 4,035.1 | 26,091.2 | 3,717.0 | 10,570.7 | | |
| New generation | 5,179.3 | 3,599.6 | 1,663.2 | 856.3 | 0.0 | 2.8 | 0.0 | 0.0 | 770.2 | 0.0 | 3.4 | 122.7 | 959.9 | | |
| Reactivated generation | 1,025.7 | 1,025.7 | 84.1 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | | |
| Generation cap mods | (7,943.1) | (2,286.3) | (2,190.5) | (57.9) | 5.7 | (1,135.3) | (509.9) | 15.7 | (751.7) | (818.0) | 85.1 | 0.0 | (49.9) | | |
| DR mods | (3,472.4) | (941.6) | (407.6) | (198.9) | (33.0) | (167.9) | (50.2) | (54.4) | (889.9) | (208.7) | 497.8 | 635.1 | (171.2) | | |
| EE mods | 158.9 | 91.4 | 26.9 | 61.5 | 0.9 | 4.4 | 0.1 | 77.2 | (58.4) | (14.6) | 583.3 | 50.9 | | | |
| EFORd effect | (2,167.1) | (987.4) | (267.1) | (329.7) | (19.8) | (122.1) | (62.0) | 35.1 | (529.7) | (77.2) | 33.6 | (361.9) | (236.1) | | |
| DR and EE effect | (7.1) | (2.5) | (1.4) | (0.4) | (0.2) | (0.4) | (0.2) | (0.3) | (1.3) | (0.4) | | (0.1) | (0.3) | | |
| | | | | | | | | | | | | | | | |
| Total internal capacity @ 01-Jun-17 | 193,622.3 | 75,217.6 | 35,928.5 | 12,878.7 | 1,719.9 | 6,924.7 | 4,069.4 | 6,310.7 | 12,864.4 | 2,916.2 | 27,293.4 | 4,163.7 | 11,072.1 | | |
| Correction in resource modeling | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | (19.9) | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | | |
| Adjusted internal capacity @ 01-Jun-17 | 193,622.3 | 75,217.6 | 35,928.5 | 12,878.7 | 1,719.9 | 6,924.7 | 4,049.5 | 6,310.7 | 12,864.4 | 2,916.2 | 27,293.4 | 4,163.7 | 11,072.1 | | |
| New generation | 3,988.3 | 1,054.8 | 1,036.1 | 0.0 | 50.0 | 981.2 | 0.0 | 0.0 | 0.0 | 0.0 | 245.6 | 0.0 | 0.0 | | |
| Reactivated generation | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | | |
| Generation cap mods | (1,852.4) | 399.2 | (101.3) | (34.9) | (31.2) | (18.3) | (12.8) | 0.0 | (633.7) | (296.7) | (216.3) | (35.1) | 89.5 | | |
| DR mods | 746.6 | 198.4 | 67.6 | 28.7 | 30.5 | (53.7) | (13.4) | 23.9 | (119.1) | (18.4) | 589.6 | 5.0 | 69.1 | | |
| EE mods | (9.3) | (4.9) | (8.2) | 3.2 | (1.6) | 4.7 | 2.2 | (56.6) | (109.4) | (35.5) | 136.1 | 59.8 | 4.4 | | |
| EFORd effect | (1,858.8) | (417.7) | (623.1) | (20.4) | 12.3 | (357.7) | (170.6) | (153.1) | 39.2 | 89.7 | (708.1) | 131.9 | 24.6 | | |
| DR and EE effect | 626.1 | 239.9 | 85.4 | 79.7 | 5.1 | 19.5 | 7.9 | 36.1 | 44.8 | 14.3 | 117.8 | 43.6 | 41.4 | | |
| | | | | | | | | | | | | | | | |
| Total internal capacity @ 01-Jun-18 | 195,262.8 | 76,687.3 | 36,385.0 | 12,935.0 | 1,785.0 | 7,500.4 | 3,862.8 | 6,161.0 | 12,086.2 | 2,669.6 | 27,458.1 | 4,368.9 | 11,301.1 | | |
| Correction in resource modeling | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | | |
| Adjusted internal capacity @ 01-Jun-18 | 195,262.8 | 76,687.3 | 36,385.0 | 12,935.0 | 1,785.0 | 7,500.4 | 3,862.8 | 6,161.0 | 12,086.2 | 2,669.6 | 27,458.1 | 4,368.9 | 11,301.1 | | |
| New generation | 6,185.7 | 2,341.6 | 35.6 | 912.2 | 7.0 | 12.0 | 0.0 | 912.2 | 766.5 | 0.0 | 43.5 | 0.0 | 939.0 | | |
| Reactivated generation | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | | |
| Generation cap mods | (2,383.5) | (1,420.2) | (1,003.8) | (48.5) | (16.4) | (450.7) | 12.5 | 0.0 | (850.9) | (79.9) | 1.5 | (48.5) | 11.5 | | |
| DR mods | (326.8) | (409.7) | (71.3) | (266.8) | (15.3) | (9.1) | 14.8 | (157.4) | 282.3 | 79.0 | (236.4) | (109.4) | (71.7) | | |
| EE mods | 204.3 | 66.1 | 118.3 | (91.6) | 1.3 | 33.8 | 1.4 | (1.1) | 10.1 | (5.4) | (27.5) | (90.5) | 15.1 | | |
| EFORd effect | 1,058.9 | (8.6) | 28.3 | 78.9 | (29.5) | (135.0) | (1.2) | 29.1 | (70.1) | (52.0) | 560.4 | 42.3 | 24.2 | | |
| DR and EE effect | 64.1 | 22.0 | 8.0 | 6.8 | 0.6 | 1.8 | 0.8 | 3.2 | 5.5 | 1.8 | 11.5 | 3.6 | 3.9 | | |
| | | | | | | | | | | | | | | | |
| Total internal capacity @ 01-Jun-19 | 200,065.5 | 77,278.5 | 35,500.1 | 13,526.0 | 1,732.7 | 6,953.2 | 3,891.1 | 6,947.0 | 12,229.6 | 2,613.1 | 27,811.1 | 4,166.4 | 12,223.1 | 3,957.7 | 3,979.1 |
| Correction in resource modeling | 0.0 | 0.0 | 0.0 | 0.0 | 2.3 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | (939.0) | 0.0 | 0.0 |
| Adjusted internal capacity @ 01-Jun-19 | 200,065.5 | 77,278.5 | 35,500.1 | 13,526.0 | 1,735.0 | 6,953.2 | 3,891.1 | 6,947.0 | 12,229.6 | 2,613.1 | 27,811.1 | 4,166.4 | 11,284.1 | 3,957.7 | 3,979.1 |
| New generation | 3,532.2 | 1,059.7 | 59.7 | 0.0 | 37.5 | 0.0 | 0.0 | 0.0 | 870.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 3.4 |
| Reactivated generation | 5.3 | 1.3 | 1.3 | 0.0 | 0.0 | 1.3 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Generation cap mods | (2,318.8) | (2,031.3) | (2,033.3) | 6.3 | (0.9) | (1,022.0) | (312.8) | 13.8 | 26.0 | 2.4 | (12.2) | (7.5) | (1.6) | 0.0 | (1.6) |
| Generation winter cap mods | 409.2 | 54.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 123.3 | 0.0 | 20.0 | 0.0 | 0.0 |
| DR mods | (2,231.4) | (1,207.9) | (458.4) | (512.4) | (21.0) | (50.4) | (36.6) | (223.6) | (137.4) | (166.8) | 27.3 | (288.8) | (144.8) | 48.9 | 102.4 |
| EE mods | 636.6 | 236.1 | 148.7 | 63.1 | 7.9 | 58.2 | 16.3 | 4.6 | 7.9 | 2.5 | 92.0 | 58.5 | 6.1 | 46.5 | 50.9 |
| EFORd effect | 1,027.6 | 599.1 | (46.1) | 361.0 | (13.9) | (1.2) | (19.4) | 351.5 | (277.3) | 77.2 | 329.8 | 11.1 | (60.7) | (172.5) | 44.3 |
| DR and EE effect | 11.4 | 3.5 | 1.4 | 1.2 | 0.1 | 0.4 | 0.1 | 0.4 | 0.6 | 0.0 | 2.8 | 0.8 | 0.8 | 0.2 | 0.0 |
| | | | | | | | | | | | | | | | |
| Total internal capacity @ 01-Jun-20 | 201,137.6 | 75,993.2 | 33,173.4 | 13,445.2 | 1,744.7 | 5,939.5 | 3,538.7 | 7,093.7 | 12,719.4 | 2,528.4 | 28,374.1 | 3,940.5 | 11,103.9 | 3,880.8 | 4,178.5 |

## Table 5-7 RPM reserve margin: June 1, 2016 to June 1, 2020[44 45]

| | Generation and DR RPM Committed Less Deficiency UCAP (MW) | Forecast Peak Load | FRR Peak Load | PRD | RPM Peak Load | IRM | Pool Wide Average EFORd | Generation and DR RPM Committed Less Deficiency ICAP (MW) | Reserve Margin | Reserve Margin in Excess of IRM | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | Percent | ICAP (MW) |
| 01-Jun-16 | 160,883.3 | 152,356.6 | 12,511.6 | 0.0 | 139,845.0 | 16.4% | 5.91% | 170,988.7 | 22.3% | 5.9% | 8,209.2 |
| 01-Jun-17 | 163,871.2 | 153,230.1 | 12,837.5 | 0.0 | 140,392.6 | 16.6% | 5.94% | 174,219.9 | 24.1% | 7.5% | 10,522.1 |
| 01-Jun-18 | 168,841.6 | 152,407.9 | 12,732.9 | 0.0 | 139,675.0 | 16.1% | 6.07% | 179,752.6 | 28.7% | 12.6% | 17,589.9 |
| 01-Jun-19 | 166,715.0 | 154,510.0 | 12,559.0 | 0.0 | 141,951.0 | 16.6% | 6.59% | 178,476.6 | 25.7% | 9.1% | 12,961.7 |
| 01-Jun-20 | 163,399.0 | 153,915.0 | 12,200.6 | 558.0 | 141,156.4 | 16.6% | 6.59% | 174,926.7 | 23.9% | 7.3% | 10,338.3 |

42 The RTO includes MAAC, EMAAC, SWMAAC, and ATSI. MAAC includes EMAAC, SWMAAC, and PPL. EMAAC includes DPL South, PSEG and PSEG North. PSEG includes PSEG North. SWMAAC includes Pepco and BGE. ATSI includes ATSI Cleveland.

43 Unless otherwise specified, an annual equivalent MW quantity is used to report winter and summer capacity. For example, annual equivalent winter capacity is calculated as the winter capacity MW times the ratio of the number of days in the winter period (November through April of the delivery year) to the number of days in the delivery year.

44 The calculated reserve margins in this table do not include EE on the supply side or the EE add back on the demand side. The EE excluded from the supply side for this calculation includes annual EE and summer EE. This is how PJM calculates the reserve margin.

45 These reserve margin calculations do not consider Fixed Resource Requirement (FRR) load.

## Demand

As shown in Table 5-10, there was a 787.1 MW decrease in the RPM reliability requirement from 180,332.2 MW on June 1, 2016, to 179,545.1 MW on June 1, 2017. The 787.1 MW decrease in the RTO Reliability Requirement was a result of a 1,017.4 MW decrease in the forecast peak load in UCAP terms holding the Forecast Pool Requirement (FPR) constant at the 2016/2017 level offset by a 230.3 MW increase attributable to the change in FPR.

The MMU analyzed market sectors in the PJM Capacity Market to determine how they met their load obligations. The 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.
- **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, 2017 PJM EDCs and their affiliates maintained a large market share of load obligations under RPM, together totaling 63.6 percent (Table 5-8), down from 64.1 percent on June 1, 2016. The combined market share of LSEs not affiliated with any EDC and of non-PJM EDC affiliates was 36.4 percent, up from 35.9 percent on June 1, 2016. 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 63.6 percent on June 1, 2017. 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 36.4 percent on June 1, 2017. Prior to the 2012/2013 Delivery Year, obligation was defined as cleared and make whole MW in the Base Residual Auction and the Second Incremental Auction plus ILR forecast obligations. Effective with the 2012/2013 Delivery Year, obligation is defined as the sum of the unforced capacity obligations satisfied through all RPM auctions for the delivery year.

Figure 5-3 Capacity market load obligation served: June 1, 2007 through June 1, 2017

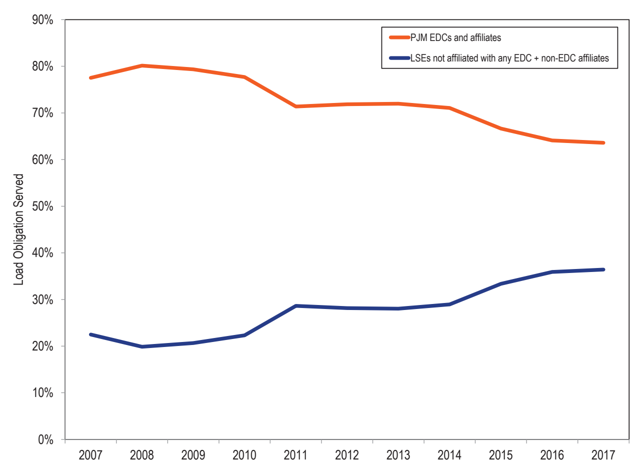



Table 5-8 Capacity market load obligation served: June 1, 2017

| | 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 | 62,326.1 | 19,471.6 | 27,584.8 | 6,093.0 | 19,408.2 | 1,016.5 | 36,127.8 | 172,028.1 |
| Percent of total obligation | 36.2% | 11.3% | 16.0% | 3.5% | 11.3% | 0.6% | 21.0% | 100.0% |

### 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 or charge equal to the Locational Price Adder multiplied by the MW of the LSEs' CTRs.

In the 2020/2021 RPM Base Residual Auction, MAAC had -755.9 MW of CTRs with a total value of -$2,623,808, EMAAC had 4,748.3 MW of CTRs with a total value of $176,485,896, ComEd had 1,192.7 MW of CTRs with a total value of $48,579,473, and DEOK had 2,619.7 MW of CTRs with a total value of $51,127,157.[46] Credits for ICTRs in EMAAC totaled 948 MW with a total value of $35,235,217. DOEK has 155 MW of ICTRs with a total value of $3,025,065.

The negative CTRs for MAAC represent capacity that cleared inside MAAC that was assigned to load in the Rest of RTO. In the BRA, 65,817.9 MW cleared in the MAAC LDA. However the capacity obligation for MAAC LDA for the 2020/2021 delivery year was only 65,138.7 MW, 679.2 MW less than the cleared capacity.[47] The 679.2 MW that cleared in excess of the capacity obligation was assigned to load in Rest of RTO. There was also an additional 76.7 MW of grandfathered, outgoing CTRs for MAAC, bringing the total to -755.9 MW of CTRs. The outgoing CTRs are valued at the capacity price difference between MAAC and the RTO, which is negative. The clearing price in MAAC was $86.04 and the clearing price in RTO was $76.53.

## Market Concentration

### Auction Market Structure

As shown in Table 5-9, in the 2017/2018 RPM Base Residual Auction, 2017/2018 RPM First Incremental Auction, 2017/2018 RPM Second Incremental Auction, 2017/2018 RPM Third Incremental Auction, 2018/2019 RPM Base Residual Auction, 2018/2019 RPM First Incremental Auction, 2019/2020 RPM Base Residual Auction, 2019/2020 RPM First Incremental Auction, and the 2020/2021 RPM Base Residual Auction all participants in the total PJM market as well as the LDA RPM markets failed the three pivotal supplier (TPS).[48] In the 2018/2019 RPM Second Incremental Auction, 35 participants in the RTO market passed the test. The TPS test was not applied in the 2016/2017 Capacity Performance (CP) Transition Incremental Auction and the 2017/2018 CP Transition Incremental Auction. All offers in the CP Transition Auctions were subject to overall offer caps. Offer caps were applied to all sell offers for resources which were subject to mitigation when the capacity market seller did not pass the test, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, increased the market clearing price.[49 50 51]

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

46 A negative value indicates that the amount of capacity cleared in the MAAC LDA exceeded the UCAP obligation for the MAAC LDA.

47 In the BRA, 8,800 MW cleared as imports from MAAC to EMAAC LDA. But CTR allocations are based on PJM's calculated capacity obligations by LDA. The imports calculated using the capacity obligation were 5,761.4. The inconsistency is due to the mismatch between the cleared MW in the BRA and the allocation of the capacity obligation. The CTRs are based on the allocation of the capacity obligation to each LDA, which is derived using the LDA's peak load scaling factors.

48 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.

49 See OATT Attachment DD § 6.5.

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

51 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).

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 5-9 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.

### Table 5-9 RSI results: 2017/2018 through 2020/2021 RPM Auctions[52]

| RPM Markets | $RSI_{1,\ 1.05}$ | $RSI_3$ | Total Participants | Failed $RSI_3$ Participants |
|---|---|---|---|---|
| 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 |
| 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 |
| 2018/2019 Second Incremental Auction | | | | |
| RTO | 0.64 | 0.87 | 44 | 9 |
| EMAAC | 0.25 | 0.06 | 5 | 5 |
| 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 |
| 2019/2020 First Incremental Auction | | | | |
| RTO | 0.63 | 0.50 | 53 | 53 |
| EMAAC | 0.00 | 0.00 | 5 | 5 |
| 2020/2021 Base Residual Auction | | | | |
| RTO | 0.81 | 0.69 | 119 | 119 |
| MAAC | 0.67 | 0.77 | 24 | 24 |
| EMAAC | 0.45 | 0.18 | 21 | 21 |
| ComEd | 0.47 | 0.20 | 14 | 14 |
| DEOK | 0.00 | 0.00 | 1 | 1 |

52 The RSI shown is the lowest RSI in the market.

## Locational Deliverability Areas (LDAs)

Under the PJM Tariff, PJM determines, in advance of each BRA, whether defined Locational Deliverability Areas (LDAs) will be modeled in the auction. Effective with the 2012/2013 Delivery Year, an LDA 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.[53] 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."[54] A reliability requirement and a Variable Resource Requirement (VRR) curve are established for each modeled LDA. Effective for the 2014/2015 through 2016/2017 Delivery Years, a Minimum Annual and a Minimum Extended Summer Resource Requirement are established for each modeled LDA. Effective for the 2017/2018 Delivery Year, Sub-Annual and Limited Resource Constraints, replacing the Minimum Annual and a Minimum Extended Summer Resource Requirements, are established for each modeled LDA.[55] 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

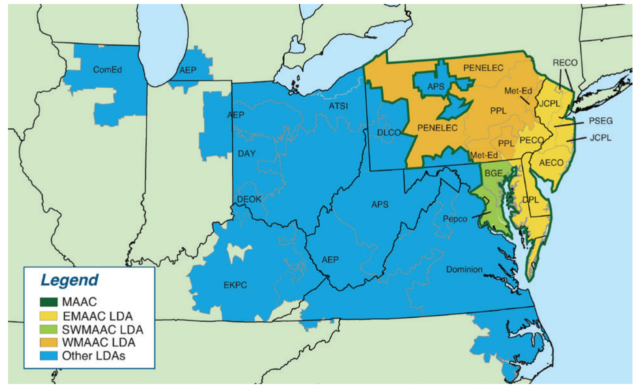



Figure 5-5 Map of PJM RPM EMAAC subzonal LDAs

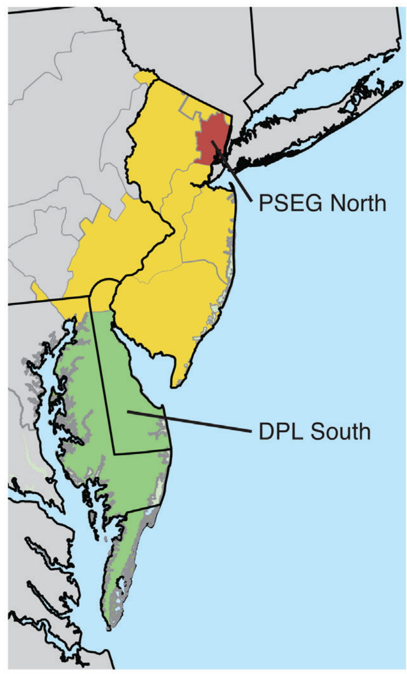
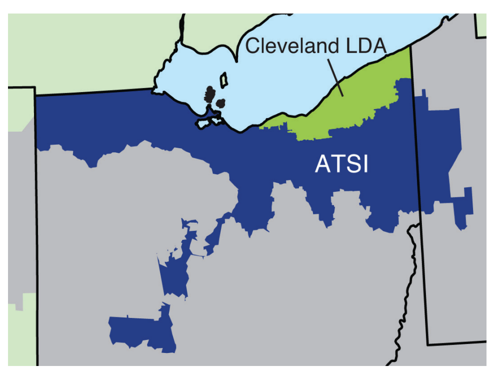



Figure 5-6 Map of PJM RPM ATSI subzonal LDA




53 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.
54 OATT Attachment DD § 5.10 (a) (ii).
55 146 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.[56]

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.

For the 2017/2018 through the 2019/2020 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.[57] Capacity Market Sellers may request an exception to the CIL for an external generation resource by committing that the resource will be pseudo tied prior to the start of the relevant delivery year, by demonstrating that it has long-term firm transmission service confirmed on the complete transmission path from the resource to PJM, and by agreeing to be subject to the same RPM must offer requirement as internal PJM generation resources.

Effective June 9, 2015, an external generation capacity resource must obtain an exception to the CILs to be eligible to offer as a Capacity Performance Resource, which means that effective with the 2020/2021 delivery year, CILs are no longer defined as an RPM parameter.[58]

As shown in Table 5-10, net exchange decreased 2,069.6 MW from June 1, 2016 to June 1, 2017. Net exchange, which is imports less exports, decreased due to a decrease in imports of 2,086.7 MW offset by a decrease in exports of 17.1 MW.

As shown in Table 5-11, of the 4,961.8 MW of imports in the 2020/2021 RPM Base Residual Auction, 3,997.2 MW cleared. Of the cleared imports, 1,671.2 MW (41.8 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.[59] [60] 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; 12 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

56 OATT Attachment DD § 5.6.6(b).
57 147 FERC ¶ 61,060 (2014).
58 151 FERC ¶ 61,208 (2015).
59 See "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Schedule 9 & 10.
60 See "PJM Manual 18: PJM Capacity Market," Rev. 38 (July 27, 2017) at 54-55 & 81.

from the unit is not recallable to any other balancing authority.

All external generation resources that have an RPM commitment or FRR capacity plan commitment or that are designated as replacement capacity must be offered in the PJM Day-Ahead Energy Market.[61]

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.[62] [63] 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.[64] 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.[65]

## 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.[66] The Capacity Market Seller must also identify the megawatt amount, export zone, and time period (in days) of the export.[67]

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.[68]

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.

61 OATT Schedule 1 § 1.10.1A.
62 See RAA § 1.69A.
63 See "PJM Manual 18: PJM Capacity Market," Rev. 38 (July 27, 2017) at 57–58.
64 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).
65 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).
66 OATT Attachment DD § 6.6(g).
67 *Id.*
68 OATT Attachment M-Appendix § II.C.2.

## Table 5-10 PJM capacity summary (MW): June 1, 2007, to June 1, 2020[69 70 71]

| | 01-Jun-07 | 01-Jun-08 | 01-Jun-09 | 01-Jun-10 | 01-Jun-11 | 01-Jun-12 | 01-Jun-13 | 01-Jun-14 | 01-Jun-15 | 01-Jun-16 | 01-Jun-17 | 01-Jun-18 | 01-Jun-19 | 01-Jun-20 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Installed capacity (ICAP) | 163,721.1 | 164,444.1 | 166,916.0 | 168,061.5 | 172,666.6 | 181,159.7 | 197,775.0 | 210,812.4 | 217,829.1 | 216,671.5 | 208,605.9 | 210,712.9 | 213,519.5 | 213,713.4 |
| Unforced capacity (UCAP) | 154,076.7 | 155,590.2 | 157,628.7 | 158,634.2 | 163,144.3 | 171,147.8 | 186,588.0 | 199,063.2 | 207,738.6 | 207,578.0 | 198,282.6 | 199,583.9 | 203,539.2 | 205,235.0 |
| Cleared capacity | 129,409.2 | 129,597.6 | 132,231.8 | 132,190.4 | 132,221.5 | 136,143.5 | 152,743.3 | 149,974.7 | 164,561.2 | 169,159.7 | 167,003.7 | 166,836.9 | 167,305.9 | 165,109.2 |
| Make-whole | 0.0 | 0.0 | 0.0 | 0.0 | 43.0 | 222.1 | 14.0 | 112.6 | 2.7 | 0.0 | 65.2 | 38.6 | 23.6 | 0.0 |
| RPM reliability requirement (pre-FRR) | 148,277.3 | 150,934.6 | 153,480.1 | 156,636.8 | 154,251.1 | 157,488.5 | 173,549.0 | 178,086.5 | 177,184.1 | 180,332.2 | 179,545.1 | 174,896.8 | 171,036.8 | 167,644.2 |
| RPM reliability requirement (less FRR) | 125,805.0 | 128,194.6 | 130,447.8 | 132,698.8 | 130,658.7 | 133,732.4 | 149,988.7 | 148,323.1 | 162,777.4 | 166,127.5 | 165,007.1 | 160,607.4 | 157,092.4 | 154,355.3 |
| RPM net excess | 5,240.5 | 5,011.1 | 8,265.5 | 7,728.0 | 10,638.4 | 5,976.5 | 6,518.3 | 5,472.3 | 5,855.9 | 7,185.4 | 6,187.0 | 6,268.1 | 8,722.0 | 9,043.7 |
| Imports | 2,809.2 | 2,460.3 | 2,505.4 | 2,750.7 | 6,420.0 | 3,831.6 | 4,348.2 | 4,055.5 | 4,395.5 | 7,941.5 | 5,854.8 | 5,603.4 | 4,762.3 | 5,390.7 |
| Exports | (3,938.5) | (3,838.1) | (2,194.9) | (3,147.4) | (3,158.4) | (2,637.1) | (2,438.4) | (1,228.1) | (1,214.2) | (1,211.6) | (1,194.5) | (1,282.3) | (1,288.6) | (1,293.3) |
| Net exchange | (1,129.3) | (1,377.8) | 310.5 | (396.7) | 3,261.6 | 1,194.5 | 1,909.8 | 2,827.4 | 3,181.3 | 6,729.9 | 4,660.3 | 4,321.1 | 3,473.7 | 4,097.4 |
| DR cleared | 127.6 | 536.2 | 892.9 | 939.0 | 1,364.9 | 7,047.2 | 9,281.9 | 14,118.4 | 14,832.8 | 12,408.1 | 10,974.8 | 11,084.4 | 10,348.0 | 7,677.1 |
| EE cleared | | | | | | 568.9 | 679.4 | 822.1 | 922.5 | 1,117.3 | 1,338.9 | 1,246.5 | 1,515.1 | 1,659.2 |
| EE cleared (non annual equivalent) | | | | | | | | | | | | | | 1,710.2 |
| ILR | 1,636.3 | 3,608.1 | 6,481.5 | 8,236.4 | 9,032.6 | | | | | | | | | |
| FRR DR | 445.6 | 452.8 | 423.6 | 452.9 | 452.9 | 488.1 | 488.6 | 518.1 | 356.8 | 501.9 | 556.2 | 650.2 | 642.1 | 357.8 |
| Short-Term Resource Procurement Target | | | | | | 3,343.3 | 3,749.7 | 3,708.1 | 4,069.4 | 4,153.2 | 4,125.2 | | | |

## Table 5-11 RPM imports: 2007/2008 through 2020/2021 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 |
| 2020/2021 | 2,511.8 | 1,671.2 | 2,450.0 | 2,326.0 | 4,961.8 | 3,997.2 |

## Demand Resources

There are three basic demand products incorporated in the RPM market design:[72]

- **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.[73]

69 Prior to the 2012/2013 Delivery Year, net excess under RPM was calculated as cleared capacity plus make-whole MW less the reliability requirement plus ILR. For 2007/2008 through 2011/2012, certified ILR was used in the calculation, because the certified ILR data are now available. For the 2012/2013 Delivery Year and beyond, net excess under RPM is calculated as cleared capacity plus make-whole MW less the reliability requirement plus the Short-Term Resource Procurement Target. For the 2018/2019 and subsequent delivery years, the net excess under RPM is calculated as cleared capacity plus make-whole MW less the reliability requirement. For the 2019/2020 and subsequent delivery years, the net excess under RPM is calculated as cleared generation and DR capacity plus make whole MW less the reliability requirement. For the 2020/2021 and subsequent delivery years, the EE excluded from the supply side for this calculation includes annual EE and summer EE.

70 The results for RPM Incremental Auctions are not included in this table.

71 Unless otherwise specified, an annual equivalent MW quantity is used to report winter and summer capacity. For example, annual equivalent winter capacity is calculated as the winter capacity MW times the ratio of the number of days in the winter period (November through April of the delivery year) to the number of days in the delivery year.

72 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.

73 Letter Order in Docket No. ER10-366-000 (January 22, 2010).

Effective for the 2014/2015 through the 2017/2018 Delivery Year, there are three types of remand Resource products included in the RPM market design:[74 75]

- **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 10 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 10 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:[76 77]

- **Base Capacity Resources**
  - **Base Capacity Demand Resources.** 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 10 hours only during the hours of 10:00 a.m. to 10:00 p.m. EPT.
  - **Base Capacity Energy Efficiency Resources.** 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 Resources**
  - **Annual Demand Resources.** 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 Resources.** 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.

74 134 FERC ¶ 61,066 (2011).
75 "Reliability Assurance Agreement among Load-Serving Entities in the PJM Region," Article 1.
76 151 FERC ¶ 61,208.
77 "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Article 1.

- Effective with the 2020/2021 Delivery Year, the Capacity Performance Product will be the only capacity product type, with two possible season types, annual and summer.
- **Annual Capacity Performance Resources**
  - Annual Demand Resources
  - Annual Energy Efficiency Resources
- **Seasonal Capacity Performance Resources**
  - **Summer-Period Demand Resources.** A demand resource that is required to be available on any day from June through October and the following May of the delivery year for an unlimited number of interruptions. Summer period DR is required to be capable of maintaining each interruption between the hours of 10:00 a.m. to 10:00 p.m. EPT.
  - **Summer-Period Energy Efficiency Resources.** A project designed to achieve a continuous (during summer 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 summer-period 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.

As shown in Table 5-12, Table 5-13, and Table 5-14, capacity in the RPM load management programs was 10,117.8 MW for June 1, 2017, as a result of cleared capacity for demand resources and energy efficiency resources in RPM auctions for the 2017/2018 Delivery Year (13,793.0 MW) less replacement capacity (3,675.2 MW).

### Table 5-12 RPM load management statistics by LDA: June 1, 2016 to June 1, 2020[78] [79] [80] [81]

| | | UCAP (MW) | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | RTO | MAAC | EMAAC | SWMAAC | DPL South | PSEG | PSEG North | Pepco | ATSI | ATSI Cleveland | ComEd | BGE | PPL | DAY | DEOK |
| 01-Jun-16 | 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) | | | | | |
| | Total RPM load management | 10,248.9 | 4,018.2 | 1,328.5 | 1,572.3 | 64.0 | 369.0 | 148.4 | 688.2 | 698.8 | 171.7 | | | | | |
| 01-Jun-17 | 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 | (3,870.8) | (1,461.6) | (555.7) | (344.8) | (39.5) | (107.9) | (30.6) | (136.5) | (457.2) | (163.1) | (279.2) | (208.3) | (299.2) | | |
| | EE net replacements | 195.6 | 145.8 | 20.6 | 98.3 | (0.4) | 4.4 | 2.6 | 26.2 | (41.9) | (11.7) | 10.3 | 72.1 | (9.9) | | |
| | Total RPM load management | 10,117.8 | 3,816.4 | 1,275.8 | 1,509.1 | 52.0 | 354.5 | 147.6 | 703.4 | 949.2 | 190.1 | 2,081.6 | 805.7 | 546.0 | | |
| 01-Jun-18 | DR cleared | 11,275.8 | 4,339.4 | 1,700.6 | 1,210.5 | 86.8 | 389.9 | 139.2 | 550.5 | 964.0 | 287.2 | 1,895.2 | 660.0 | 716.2 | | |
| | EE cleared | 1,785.9 | 526.7 | 211.9 | 261.3 | 5.4 | 59.9 | 18.7 | 155.6 | 90.0 | 16.8 | 762.7 | 105.7 | 32.0 | | |
| | 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 | | |
| | Total RPM load management | 12,829.3 | 4,784.7 | 1,843.6 | 1,471.8 | 92.2 | 438.9 | 157.9 | 706.1 | 1,038.0 | 304.0 | 2,562.9 | 765.7 | 748.2 | | |
| 01-Jun-19 | DR cleared | 10,375.9 | 3,796.3 | 1,650.3 | 745.1 | 91.3 | 380.7 | 176.5 | 488.7 | 900.9 | 289.9 | 1,757.4 | 256.4 | 739.8 | | |
| | EE cleared | 1,802.1 | 508.0 | 186.2 | 232.1 | 3.2 | 57.4 | 12.8 | 117.2 | 87.7 | 5.7 | 731.2 | 114.9 | 53.6 | | |
| | DR net replacements | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | | |
| | EE net replacements | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | | |
| | Total RPM load management | 12,178.0 | 4,304.3 | 1,836.5 | 977.2 | 94.5 | 438.1 | 189.3 | 605.9 | 988.6 | 295.6 | 2,488.6 | 371.3 | 793.4 | | |
| 01-Jun-20 | DR cleared | 7,820.4 | 2,699.0 | 1,114.8 | 458.4 | 72.6 | 327.7 | 141.4 | 211.9 | 688.7 | 168.9 | 1,512.9 | 246.5 | 579.9 | 164.6 | 152.8 |
| | EE cleared | 1,710.2 | 545.0 | 293.1 | 191.9 | 8.6 | 93.3 | 17.9 | 66.8 | 33.2 | 0.4 | 701.9 | 125.1 | 34.5 | 33.1 | 65.8 |
| | 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 | 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 | 0.0 | 0.0 |
| | Total RPM load management | 9,530.6 | 3,244.0 | 1,407.9 | 650.3 | 81.2 | 421.0 | 159.3 | 278.7 | 721.9 | 169.3 | 2,214.8 | 371.6 | 614.4 | 197.7 | 218.6 |

78 See 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.

79 Pursuant to OA § 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.

80 See 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.

81 See 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 5-13 RPM commitments, replacement, and registrations for Demand Resources: June 1, 2007 to June 1, 2020[82] [83] [84]

| | UCAP (MW) | | | | | | Registered DR | | |
|---|---|---|---|---|---|---|---|---|---|
| | RPM Cleared | Adjustments to Cleared | Net Replacements | RPM Commitments | RPM Commitment Shortage | RPM Commitments Less Commitment Shortage | ICAP (MW) | UCAP Conversion Factor | UCAP (MW) |
| 01-Jun-07 | 127.6 | 0.0 | 0.0 | 127.6 | 0.0 | 127.6 | 0.0 | 1.033 | 0.0 |
| 01-Jun-08 | 559.4 | 0.0 | (40.0) | 519.4 | (58.4) | 461.0 | 488.0 | 1.034 | 504.7 |
| 01-Jun-09 | 892.9 | 0.0 | (474.7) | 418.2 | (14.3) | 403.9 | 570.3 | 1.033 | 589.2 |
| 01-Jun-10 | 962.9 | 0.0 | (516.3) | 446.6 | (7.7) | 438.9 | 572.8 | 1.035 | 592.6 |
| 01-Jun-11 | 1,826.6 | 0.0 | (1,052.4) | 774.2 | 0.0 | 774.2 | 1,117.9 | 1.035 | 1,156.5 |
| 01-Jun-12 | 8,752.6 | (11.7) | (2,253.6) | 6,487.3 | (34.9) | 6,452.4 | 7,443.7 | 1.037 | 7,718.4 |
| 01-Jun-13 | 10,779.6 | 0.0 | (3,314.4) | 7,465.2 | (30.5) | 7,434.7 | 8,240.1 | 1.042 | 8,586.8 |
| 01-Jun-14 | 14,943.0 | 0.0 | (6,731.8) | 8,211.2 | (219.4) | 7,991.8 | 8,923.4 | 1.042 | 9,301.2 |
| 01-Jun-15 | 15,774.8 | (321.1) | (4,829.7) | 10,624.0 | (61.8) | 10,562.2 | 10,946.0 | 1.038 | 11,360.0 |
| 01-Jun-16 | 13,284.7 | (19.4) | (4,800.7) | 8,464.6 | (455.4) | 8,009.2 | 8,961.2 | 1.042 | 9,333.4 |
| 01-Jun-17 | 11,870.7 | 0.0 | (3,870.8) | 7,999.9 | (30.3) | 7,969.6 | 8,681.4 | 1.039 | 9,016.3 |
| 01-Jun-18 | 11,275.8 | 0.0 | (232.4) | 11,043.4 | 0.0 | 11,043.4 | 0.0 | 1.090 | 0.0 |
| 01-Jun-19 | 10,375.9 | 0.0 | 0.0 | 10,375.9 | 0.0 | 10,375.9 | 0.0 | 1.089 | 0.0 |
| 01-Jun-20 | 7,820.4 | 0.0 | 0.0 | 7,820.4 | 0.0 | 7,820.4 | 0.0 | 1.089 | 0.0 |

## Table 5-14 RPM commitments and replacements for Energy Efficiency Resources: June 1, 2007 to June 1, 2020[85]

| | UCAP (MW) | | | | | |
|---|---|---|---|---|---|---|
| | RPM Cleared | Adjustments to Cleared | Net Replacements | RPM Commitments | RPM Commitment Shortage | RPM Commitments Less Commitment Shortage |
| 01-Jun-07 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 01-Jun-08 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 01-Jun-09 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 01-Jun-10 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 01-Jun-11 | 76.4 | 0.0 | 0.2 | 76.6 | 0.0 | 76.6 |
| 01-Jun-12 | 666.1 | 0.0 | (34.9) | 631.2 | (5.1) | 626.1 |
| 01-Jun-13 | 904.2 | 0.0 | 120.6 | 1,024.8 | (13.5) | 1,011.3 |
| 01-Jun-14 | 1,077.7 | 0.0 | 204.7 | 1,282.4 | (0.2) | 1,282.2 |
| 01-Jun-15 | 1,189.6 | 0.0 | 335.9 | 1,525.5 | (0.9) | 1,524.6 |
| 01-Jun-16 | 1,723.2 | 0.0 | 61.1 | 1,784.3 | (0.5) | 1,783.8 |
| 01-Jun-17 | 1,922.3 | 0.0 | 195.6 | 2,117.9 | (7.4) | 2,110.5 |
| 01-Jun-18 | 1,785.9 | 0.0 | 0.0 | 1,785.9 | 0.0 | 1,785.9 |
| 01-Jun-19 | 1,802.1 | 0.0 | 0.0 | 1,802.1 | 0.0 | 1,802.1 |
| 01-Jun-20 | 1,710.2 | 0.0 | 0.0 | 1,710.2 | 0.0 | 1,710.2 |

82 See OATT Attachment DD § 8.4. The reported DR adjustments to cleared MW include reductions in the level of committed MW due to relief from Capacity Resource Deficiency Charges.

83 See OATT Attachment DD § 5.14C. The reported DR adjustments to cleared MW for the 2015/2016 and 2016/2017 Delivery Years include reductions in the level of committed MW due to the Demand Response Operational Resource Flexibility Transition Provision.

84 See OATT Attachment DD § 5.14E. The reported DR adjustments to cleared MW for the 2016/2017, 2017/2018, and 2018/2019 Delivery Years include reductions in the level of committed MW due to the Demand Response Legacy Direct Load Control Transition Provision.

85 Pursuant to PJM Operating Agreement § 15.1.6(c), PJM Settlement shall attempt to close out and liquidate forward capacity commitments for PJM members that are declared in collateral default. The replacement transactions reported for the 2014/2015 Delivery Year included transactions associated with RTP Controls, Inc., which was declared in collateral default on March 9, 2012.

# Market Conduct

## Offer Caps and Offer Floors

Market power mitigation measures were applied to capacity resources such that the sell offer was set equal to the defined offer cap when the Capacity Market Seller failed the market structure test for the auction, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, would have increased the market clearing price.[86] [87] [88] 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 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.[89] 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.[90] 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.[91]

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).[92] 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.

## Calculation of Offer Caps

The competitive offer of a Capacity Performance resource is based on a market seller's expectations of a number of variables, some of which are resource specific: the resource's net going forward costs (Net ACR); and the resource's performance during performance assessment hours (A) in the delivery year.[93]

86 See OATT Attachment DD § 6.5.

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

88 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).

89 OATT Attachment DD § 6.8 (b).

90 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).

91 OATT Attachment DD § 6.8 (a).

92 151 FERC ¶ 61,208.

93 The model is only applicable to generation resources and storage resources that have an annual obligation to perform with very limited specific excuses as defined in the PJM OATT.

The competitive offer of a Capacity Performance resource is also based on a market seller's expectations of system level variables: the number of performance assessment hours (PAH) in a delivery year (H) where the resource is located; the level of performance required to meet its capacity obligation during those performance assessment hours, measured as the average Balancing Ratio (B); and the level of the bonus performance payment rate (CPBR) compared to the nonperformance charge rate (PPR). The level of bonus performance payment rate depends on the level of underperforming MW net of the underperforming MW excused by PJM during performance assessment hours for reasons defined in the PJM OATT.[94]

The default offer cap defined in the PJM tariff, Net CONE times the average Balancing Ratio, is based on a number of assumptions:

1. The Net ACR of a resource is less than its expected energy only bonuses:

$$ACR \leq \sum_{i=1}^{H} (CPBR_i \times A_i)$$

$$or\ ACR \leq CPBR \times H \times \bar{A}$$

2. The expected number of performance assessment hours equals 30. (H = 30)
3. The expected value of the bonus performance payment rate (CPBR) is equal to the nonperformance charge rate (PPR)
4. The average expected performance of the resource during performance assessment hours $(\bar{A})$

The competitive offer of such a resource is:

$$p = CPBR \times H \times \bar{A} + PPR \times H \times (\bar{B} - \bar{A})$$

In other words, the competitive offer of such a resource is the opportunity cost of taking on the capacity obligation which equals the sum of the energy only bonuses it would have earned $(CPBR \times H \times \bar{A})$ and the net nonperformance charges it would incur by taking on the capacity obligation $(PPR \times H \times (\bar{B} - \bar{A}))$. Both the components are proportional to the expected number of performance assessment hours. If the expected number of performance assessment hours ($H$) is significantly lower than the value used to determine the non-performance charge rate (PPR), the opportunity of earning bonuses as an energy only resource, as well as the net non-performance charges incurred by taking on a capacity obligation are lower. Under such a scenario, the first assumption, the likelihood that that the resource's Net ACR is lower than the expected energy only bonuses is invalid. For resources whose Net ACR is greater than the expected energy only bonuses, the competitive offer is the Net ACR adjusted with any capacity performance bonuses or non-performance charges they expect to incur during the delivery year.

This means that when the expected number of performance assessment hours are lower than the value used to determine the non-performance charge rate, the default offer cap of Net CONE times B may overstate the competitive offer and the market seller offer cap.

## MOPR

Effective April 12, 2011, the RPM Minimum Offer Price Rule (MOPR) was changed.[95] 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.[96]

Effective May 3, 2013, the RPM Minimum Offer Price Rule (MOPR) was changed again.[97] 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

94 OATT Attachment DD § 10A (d).

95 135 FERC ¶ 61,022 (2011).

96 135 FERC ¶ 61,022 (2011), *order on reh'g*, 137 FERC ¶ 61,145 (2011).

97 143 FERC ¶ 61,090 (2013).

combined cycle (IGCC) technologies while excluding units primarily fueled with landfill gas or cogeneration units which are certified or self-certified as Qualifying Facilities (QFs); changing the applicability to increases in installed capacity of 20.0 MW or more combined for all units at a single point of interconnection to the transmission system; changing the applicability to include the full capability of repowering of plants based on combustion turbine, combined cycle, IGCC technology; increasing the screen from 90 percent to 100 percent of the applicable net CONE values; and broadening the region subject to MOPR to the entire RTO from constrained LDAs only.

## 2017/2018 RPM Base Residual Auction

As shown in Table 5-15, 1,202 generation resources submitted offers in the 2017/2018 RPM Base Residual Auction. Unit-specific offer caps were calculated for 131 generation resources (10.9 percent of all generation resources), of which 122 generation resources (10.1 percent) included an APIR component. The MMU calculated offer caps for 531 generation resources (44.2 percent), of which 400 were based on the technology specific default (proxy) ACR values (33.3 percent). Of the 1,202 generation resources, 28 Planned Generation Capacity Resources had uncapped offers (2.3 percent), while the remaining 637 generation resources were price takers (53.0 percent). Market power mitigation was applied to the sell offers for 39 generation resources, including 6,827.0 MW.

Of the 1,202 generation resources which submitted offers, 122 (10.1 percent) included an APIR component. As shown in Table 5-19, the weighted average gross ACR for units with APIR ($413.87 per MW-day) and the weighted-average offer caps, net of net revenues, for units with APIR ($256.02 per MW-day) increased from the 2016/2017 BRA values of $352.84 per MW-day and $180.23 per MW-day, due to higher weighted average gross ACRs for combined cycle, combustion turbine, subcritical/supercritical coal, and other units. The APIR component added an average of $217.84 per MW-day to the ACR value of the APIR units compared to $191.19 per MW-day in the 2016/2017 BRA. The highest APIR for a technology ($281.82 per MW-day) was for subcritical/supercritical coal units. The maximum APIR effect ($863.76 per MW-day) is the maximum amount by which an offer cap was increased by APIR.

## 2017/2018 CP Transition Incremental Auction

All 785 generation resources which submitted offers in the 2017/2018 CP Transition Incremental Auction were subject to an offer cap of $210.83 per MW-day, which is 60 percent of the Net Cost of New Entry (CONE) used in the 2017/2018 RPM Base Residual Auction.

## 2017/2018 RPM First Incremental Auction

As shown in Table 5-15, 118 generation resources submitted offers in the 2017/2018 RPM First Incremental Auction. The MMU calculated offer caps for 53 generation resources (44.9 percent), of which 36 were based on the technology specific default (proxy) ACR values, 17 were unit-specific offer caps with an APIR component (14.4 percent of all generation resources), six Planned Generation Capacity Resources had uncapped offers (5.1 percent), and the remaining 57 generation resources were price takers (48.3 percent). Market power mitigation was applied to the sell offers for six generation resources, including 26.1 MW.

## 2017/2018 RPM Second Incremental Auction

As shown in Table 5-15, 505 generation resources submitted offers in the 2017/2018 RPM Second Incremental Auction. The MMU calculated offer caps for 35 generation resources (36.8 percent), of which 15 were based on the technology specific default (proxy) ACR values and 20 were unit-specific offer caps (21.1 percent of all generation resources), of which 18 included an APIR component. Of the 95 generation resources, seven Planned Generation Capacity Resources had uncapped offers (7.4 percent), and the remaining 53 generation resources were price takers (55.8 percent). Market power mitigation was applied to the sell offers of four generation resources, including 157.0 MW.

## 2017/2018 RPM Third Incremental Auction

As shown in Table 5-15, 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, including 34.5 MW.

## 2018/2019 RPM Base Residual Auction

As shown in Table 5-16, 473 generation resources submitted Base Capacity offers in the 2018/2019 RPM Base Residual Auction. The MMU calculated offer caps for 219 generation resources (46.3 percent), of which 166 were based on the technology specific default (proxy) ACR values, 53 were unit-specific offer caps (11.2 percent of all generation resources), of which 45 included an APIR component, eight Planned Generation Capacity Resources had uncapped offers (1.7 percent), and the remaining 246 generation resources were price takers (52.0 percent). Market power mitigation was applied to the Base Capacity sell offers of 18 generation capacity resources, including 3,271.9 MW

As shown in Table 5-16, 992 generation resources submitted Capacity Performance offers in the 2018/2019 RPM Base Residual Auction. The MMU calculated offer caps for 35 generation resources (3.5 percent), all of which were unit-specific with an APIR component, 15 Planned Generation Capacity Resources had uncapped offers (1.5 percent), and the remaining 54 generation resources were price takers (5.4 percent). Market power mitigation was applied to the Capacity Performance sell offers of zero generation resources, including 0.0 MW.

Of the 473 generation resources which submitted Base Capacity offers, 45 (9.5 percent) included an APIR component. Of the 992 generation resources which submitted Capacity Performance offers, 35 (3.5 percent) included an APIR component. As shown in Table 5-20, the weighted average gross ACR for units with APIR was $406.58 per MW-day for Base Capacity Resources and $496.37 per MW-day for Capacity Performance Resources. The weighted average offer caps, net of net revenues, for units with APIR was $321.80 per MW-day for Base Capacity Resources and $356.54 per MW-day for Capacity Performance Resources. The APIR component added to the ACR value of the APIR units an average of $281.13 per MW-day for Base Capacity Resources and $344.93 for Capacity Performance Resources. The maximum APIR effect ($1,051.98 per MW-day for Base Capacity Resources and Capacity Performance Resources) is the maximum amount by which an offer cap was increased by APIR. The CPQR component added to the ACR value of the APIR units an average of $0.00 per MW-day for Base Capacity Resources and $10.08 per MW-day for Capacity Performance Resources.

## 2018/2019 RPM First Incremental Auction

As shown in Table 5-16, 80 generation resources submitted Base Capacity offers in the 2018/2019 RPM First Incremental Auction. The MMU calculated offer caps for 30 generation resources (37.5 percent), of which 18 were based on the technology specific default (proxy) ACR values and 12 were unit-specific offer caps (15.0 percent of all generation resources), of which all of which included an APIR component. Of the 30 generation resources with Base Capacity offers, four Planned Generation Capacity Resources had uncapped offers (5.0 percent), and the remaining 46 generation resources were price takers (57.5 percent). Market power mitigation was applied to the Base Capacity sell offers of three generation resources, including 8.2 MW.

As shown in Table 5-16, 293 generation resources submitted Capacity Performance offers in the 2018/2019 RPM First Incremental Auction. The MMU calculated offer caps for nine generation resources (3.1 percent), all of which were unit-specific with an APIR component. Of the 293 generation resources, 261 generation resources had the B times net CONE offer cap (89.1 percent), seven Planned Generation Capacity Resources had uncapped offers (2.4 percent), one generation resource had an uncapped planned uprate plus B times net CONE offer cap for the existing portion of the unit (0.3 percent), and the remaining 15 generation resources were price takers (5.1 percent). Market power mitigation was applied to the Capacity Performance sell offers of zero generation resources, including 0.0 MW.

## 2018/2019 RPM Second Incremental Auction

As shown in Table 5-16, 68 generation resources submitted Base Capacity offers in the 2018/2019 RPM Second Incremental Auction. The MMU calculated offer caps for 23 generation resources (33.8 percent), of which 12 were based on the technology specific default (proxy) ACR values and 11 were unit-specific offer caps (16.2 percent of all generation resources), of which all included an APIR component. Of the 68 generation resources with Base Capacity offers, six Planned Generation Capacity Resources had uncapped offers (8.8 percent), and the remaining 39 generation resources were price takers (57.4 percent). Market power mitigation was applied to the Base Capacity sell offers of zero generation resources, including 0.0 MW.

As shown in Table 5-16, 344 generation resources submitted Capacity Performance offers in the 2018/2019 RPM Second Incremental Auction. The MMU calculated offer caps for five generation resources (1.5 percent), all of which were unit-specific with an APIR component. Of the 344 generation resources, 327 generation resources had the B times net CONE offer cap (95.1 percent), four Planned Generation Capacity Resources had uncapped offers (1.2 percent), and the remaining eight generation resources were price takers (2.3 percent). Market power mitigation was applied to the Capacity Performance sell offers of zero generation resources, including 0.0 MW.

## 2019/2020 RPM Base Residual Auction

As shown in Table 5-17, 505 generation resources submitted Base Capacity offers in the 2019/2020 RPM Base Residual Auction. The MMU calculated offer caps for 212 generation resources (42.0 percent), of which 171 were based on the technology specific default (proxy) ACR values and 41 were unit-specific offer caps (8.1 percent of all generation resources), of which 34 included an APIR component. Of the 505 generation resources, nine Planned Generation Capacity Resources had uncapped offers (1.8 percent), and the remaining 284 generation resources were price takers (56.2 percent). Market power mitigation was applied to the Base Capacity sell offers of 34 generation resources, including 3,116.5 MW.

As shown in Table 5-17, 1,003 generation resources submitted Capacity Performance offers in the 2019/2020 RPM Base Residual Auction. The MMU calculated offer caps for 25 generation resources (2.5 percent), all of which were unit-specific with an APIR component. Of the 1,003 generation resources, 888 generation resources had the B times net CONE offer cap (88.5 percent), 14 Planned Generation Capacity Resources had uncapped offers (1.4 percent), two generation resources had uncapped planned uprates plus B times net CONE offer cap for the existing portion of the units (0.2 percent), and the remaining 74 generation resources were price takers (5.4 percent). Market power mitigation was applied to the Capacity Performance sell offers of three generation resources, including 50.8 MW.

Of the 505 generation resources which submitted Base Capacity offers, 34 (6.7 percent) included an APIR component. Of the 1,003 generation resources which submitted Capacity Performance offers, 25 (2.5 percent) included an APIR component. As shown in Table 5-21, the weighted average gross ACR for units with APIR was $341.40 per MW-day for Base Capacity Resources and $499.18 per MW-day for Capacity Performance Resources. The weighted average offer caps, net of net revenues, for units with APIR was $271.22 per MW-day for Base Capacity Resources and $323.27 per MW-day for Capacity Performance Resources. The APIR component added to the ACR value of the APIR units an average of $230.67 per MW-day for Base Capacity Resources and $375.38 for Capacity Performance Resources. The maximum APIR effect ($1,104.93 per MW-day for Base Capacity Resources and Capacity Performance Resources) is the maximum amount by which an offer cap was increased by APIR. The CPQR component added to the ACR value of the APIR units an average of $0.00 per MW-day for Base Capacity Resources and $1.53 per MW-day for Capacity Performance Resources.

## 2019/2020 RPM First Incremental Auction

As shown in Table 5-17, 81 generation resources submitted Base Capacity offers in the 2019/2020 RPM First Incremental Auction. The MMU calculated offer caps for 28 generation resources (34.6 percent), of which 17 were based on the technology specific default (proxy) ACR values and 11 were unit-specific offer caps (13.6 percent of all generation resources), of which all included an APIR component. Of the 81 generation resources with Base Capacity offers, the remaining 53 generation resources were price takers (65.4 percent). Market power mitigation was applied to the Base Capacity sell offers of zero generation resources, including 0.0 MW.

As shown in Table 5-17, 382 generation resources submitted Capacity Performance offers in the 2019/2020 RPM First Incremental Auction. The MMU calculated offer caps for seven generation resources (1.8 percent), of which six were unit-specific with an APIR component and one was based on the technology specific default (proxy) ACR value. Of the 382 generation resources, 362 generation resources had the B times net CONE offer cap (94.8 percent), one Planned Generation Capacity

Resource had an uncapped offer (0.3 percent), one generation resource had an uncapped planned uprate plus price taker status for the existing portion of the unit (0.3 percent), and the remaining 11 generation resources were price takers (2.9 percent). Market power mitigation was applied to the Capacity Performance sell offers of zero generation resources, including 0.0 MW.

## 2020/2021 RPM Base Residual Auction

As shown in Table 5-18, 1,114 generation resources submitted Capacity Performance offers in the 2020/2021 RPM Base Residual Auction. The MMU calculated offer caps for 14 generation resources that submitted Capacity Performance offers. Unit-specific ACR-based offer caps were calculated for 14 generation resources (1.3 percent) including 11 generation resources (1.0 percent) with an Avoidable Project Investment Recovery Rate (APIR) and a CPQR component and three generation resources (0.3 percent) with an APIR component and no CPQR component. Of the 1,114 generation resources offered as Capacity Performance, 956 generation resources had the net CONE times B offer cap, zero generation resources had opportunity cost-based offer caps, 12 Planned Generation Capacity Resources had uncapped offers, 18 generation resources had uncapped planned uprates plus net CONE times B offer cap for the existing portion of the units, two generation resource had an uncapped planned uprate plus price taker status for the existing portion of the unit, while the remaining 112 generation resources were price takers. Market power mitigation was applied to the sell offers of zero generation resources, including 0.0 MW.

Of the 1,114 generation resources which submitted Capacity Performance offers, 14 (1.3 percent) included an APIR component. As shown in Table 5-22, the weighted average gross ACR for units with APIR was $498.15 per MW-day for Capacity Performance Resources. The weighted average offer caps, net of net revenues, for units with APIR was $209.18 per MW-day for Capacity Performance Resources. The APIR component added to the ACR value of the APIR units an average of $235.67 per MW-day for Capacity Performance Resources. The maximum APIR effect ($464.71 per MW-day for Capacity Performance Resources) is the maximum amount by which an offer cap was increased by APIR. The CPQR component added to the ACR value of the APIR units an average of $0.23 per MW-day for Capacity Performance Resources.

## MOPR Statistics

Market power mitigation measures are applied to MOPR Screened Generation Resources such that the sell offer is set equal to the MOPR Floor Offer Price when the submitted sell offer is less than the MOPR Floor Offer Price and an exemption or exception was not granted, or the sell offer is set equal to the agreed upon minimum level of sell offer when the sell offer is less than the agreed upon minimum level of sell offer based on a Unit-Specific Exception. As shown in Table 5-23, of the 12,171.0 ICAP MW of MOPR Competitive Entry Exemption requests for the 2020/2021 RPM Base Residual Auction, all requests were granted. Of the 3,301.2 MW offered for MOPR Screened Generation Resources in the 2020/2021 RPM Base Residual Auction, 2,646.7 MW cleared and 654.5 MW did not clear.

## Table 5-15 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% |

## Table 5-16 ACR statistics: 2018/2019 RPM Auctions

| | 2018/2019 Base Residual Auction | | | | 2018/2019 First Incremental Auction | | | | 2018/2019 Second Incremental Auction | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Base Capacity | | Capacity Performance | | Base Capacity | | Capacity Performance | | Base Capacity | | Capacity Performance | |
| Offer Cap/Mitigation Type | Number of Generation Resources | Percent of Generation Resources Offered | Number of Generation Resources | Percent of Generation Resources Offered | 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 | 164 | 34.7% | 0 | 0.0% | 18 | 22.5% | 0 | 0.0% | 12 | 17.6% | 0 | 0.0% |
| Unit specific ACR (APIR) | 45 | 9.5% | 9 | 0.9% | 12 | 15.0% | 8 | 2.7% | 11 | 16.2% | 5 | 1.5% |
| Unit specific ACR (APIR and CPQR) | 0 | 0 | 26 | 2.6% | 0 | 0 | 1 | 0.3% | 0 | 0 | 0 | 0.0% |
| Unit specific ACR (non-APIR) | 1 | 0.2% | 0 | 0.0% | 0 | 0.0% | 0 | 0.0% | 0 | 0.0% | 0 | 0.0% |
| Unit specific ACR (non-APIR and CPQR) | 0 | 0 | 0 | 0.0% | 0 | 0 | 0 | 0.0% | 0 | 0 | 0 | 0.0% |
| Opportunity cost input | 7 | 1.5% | 0 | 0.0% | 0 | 0.0% | 0 | 0.0% | 0 | 0.0% | 0 | 0.0% |
| Default ACR and opportunity cost | 0 | 0.0% | 0 | 0.0% | 0 | 0.0% | 0 | 0.0% | 0 | 0.0% | 0 | 0.0% |
| Net CONE times B | NA | NA | 881 | 88.8% | NA | NA | 261 | 89.1% | NA | NA | 327 | 95.1% |
| Offer cap of 1.1 times BRA clearing price elected | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Uncapped planned uprate and default ACR | 2 | 0.4% | 0 | 0.0% | 0 | 0.0% | 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% | 0 | 0.0% | 0 | 0.0% |
| Uncapped planned uprate and Net CONE times B | NA | NA | 6 | 0.6% | NA | NA | 1 | 0.3% | NA | NA | 0 | 0.0% |
| Uncapped planned uprate and price taker | 0 | 0.0% | 1 | 0.1% | 0 | 0.0% | 0 | 0.0% | 0 | 0.0% | 0 | 0.0% |
| Uncapped planned uprate and 1.1 times BRA clearing price elected | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Uncapped planned generation resources | 8 | 1.7% | 15 | 1.5% | 4 | 5.0% | 7 | 2.4% | 6 | 8.8% | 4 | 1.2% |
| Existing generation resources as price takers | 246 | 52.0% | 54 | 5.4% | 46 | 57.5% | 15 | 5.1% | 39 | 57.4% | 8 | 2.3% |
| Total Generation Capacity Resources offered | 473 | 100.0% | 992 | 100.0% | 80 | 100.0% | 293 | 100.0% | 68 | 100.0% | 344 | 100.0% |

## Table 5-17 ACR statistics: 2019/2020 RPM Auctions

| | 2019/2020 Base Residual Auction | | | | 2019/2020 First Incremental Auction | | | |
|---|---|---|---|---|---|---|---|---|
| | Base Capacity | | Capacity Performance | | Base Capacity | | Capacity Performance | |
| Offer Cap/Mitigation Type | Number of Generation Resources | Percent of Generation Resources Offered | Number of Generation Resources | Percent of Generation Resources Offered | Number of Generation Resources | Percent of Generation Resources Offered | Number of Generation Resources | Percent of Generation Resources Offered |
| Default ACR | 171 | 33.9% | 0 | 0.0% | 17 | 21.0% | 1 | 0.3% |
| Unit specific ACR (APIR) | 34 | 6.7% | 8 | 0.8% | 11 | 13.6% | 5 | 1.3% |
| Unit specific ACR (APIR and CPQR) | 0 | 0 | 17 | 1.7% | 0 | 0 | 1 | 0.3% |
| Unit specific ACR (non-APIR) | 0 | 0.0% | 0 | 0.0% | 0 | 0.0% | 0 | 0.0% |
| Unit specific ACR (non-APIR and CPQR) | 0 | 0 | 0 | 0.0% | 0 | 0 | 0 | 0.0% |
| Opportunity cost input | 7 | 1.4% | 0 | 0.0% | 0 | 0.0% | 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 | 888 | 88.5% | NA | NA | 362 | 94.8% |
| Offer cap of 1.1 times BRA clearing price elected | NA | NA | NA | NA | NA | NA | NA | NA |
| Uncapped planned uprate and default ACR | 0 | 0.0% | 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 | 2 | 0.2% | NA | NA | 0 | 0.0% |
| Uncapped planned uprate and price taker | 0 | 0.0% | 0 | 0.0% | 0 | 0.0% | 1 | 0.3% |
| Uncapped planned uprate and 1.1 times BRA clearing price elected | NA | NA | NA | NA | NA | NA | NA | NA |
| Uncapped planned generation resources | 9 | 1.8% | 14 | 1.4% | 0 | 0.0% | 1 | 0.3% |
| Existing generation resources as price takers | 284 | 56.2% | 74 | 7.4% | 53 | 65.4% | 11 | 2.9% |
| Total Generation Capacity Resources offered | 505 | 100.0% | 1,003 | 100.0% | 81 | 100.0% | 382 | 100.0% |

## Table 5-18 ACR statistics: 2020/2021 RPM Auctions

| | 2020/2021 Base Residual Auction | |
|---|---|---|
| Offer Cap/Mitigation Type | Number of Generation Resources | Percent of Generation Resources Offered |
| Default ACR | NA | NA |
| Unit specific ACR (APIR) | 3 | 0.3% |
| Unit specific ACR (APIR and CPQR) | 11 | 1.0% |
| Unit specific ACR (non-APIR) | 0 | 0.0% |
| Unit specific ACR (non-APIR and CPQR) | 0 | 0.0% |
| Opportunity cost input | 0 | 0.0% |
| Default ACR and opportunity cost | NA | NA |
| Net CONE times B | 956 | 85.8% |
| Offer cap of 1.1 times BRA clearing price elected | NA | NA |
| Uncapped planned uprate and default ACR | NA | NA |
| Uncapped planned uprate and opportunity cost | 0 | 0.0% |
| Uncapped planned uprate and Net CONE times B | 18 | 1.6% |
| Uncapped planned uprate and price taker | 2 | 0.2% |
| Uncapped planned uprate and 1.1 times BRA clearing price elected | NA | NA |
| Uncapped planned generation resources | 12 | 1.1% |
| Existing generation resources as price takers | 112 | 10.1% |
| Total Generation Capacity Resources offered | 1,114 | 100.0% |

## Table 5-19 APIR Statistics: 2017/2018 RPM Base Residual Auction[98]

| | Weighted-Average ($ per MW-day UCAP) | | | | | |
|---|---|---|---|---|---|---|
| | Combined Cycle | Combustion Turbine | Oil or Gas Steam | Subcritical/ Supercritical Coal | Other | Total |
| Non-APIR units | | | | | | |
| ACR | $36.92 | $31.52 | $84.84 | $182.60 | $47.54 | $94.78 |
| Net revenues | $121.99 | $51.56 | $13.98 | $116.61 | $158.64 | $92.26 |
| Offer caps | $2.17 | $9.90 | $71.43 | $70.61 | $8.28 | $36.87 |
| | | | | | | |
| APIR units | | | | | | |
| ACR | $136.06 | $97.45 | $180.36 | $440.80 | $554.65 | $413.87 |
| Net revenues | $0.00 | $1.84 | $42.70 | $92.18 | $382.31 | $137.71 |
| Offer caps | $136.06 | $95.61 | $137.66 | $319.61 | $163.77 | $256.02 |
| APIR | $95.80 | $55.48 | $92.23 | $281.82 | $128.37 | $217.84 |
| | | | | | | |
| Maximum APIR effect | | | | | | $863.76 |

## Table 5-20 APIR Statistics: 2018/2019 RPM Base Residual Auction

| | Weighted-Average ($ per MW-day UCAP) | |
|---|---|---|
| | Base Capacity | Capacity Performance |
| Non-APIR units | | |
| ACR | $85.36 | $197.45 |
| Net revenues | $117.38 | $131.61 |
| Offer caps | $30.74 | $65.83 |
| | | |
| APIR units | | |
| ACR | $406.58 | $496.37 |
| Net revenues | $83.43 | $139.25 |
| Offer caps | $321.80 | $356.54 |
| APIR | $281.13 | $344.93 |
| CPQR | $0.00 | $10.08 |
| | | |
| Maximum APIR effect | $1,051.98 | $1,051.98 |

## Table 5-21 APIR Statistics: 2019/2020 RPM Base Residual Auction

| | Weighted-Average ($ per MW-day UCAP) | |
|---|---|---|
| | Base Capacity | Capacity Performance |
| Non-APIR units | | |
| ACR | $89.05 | |
| Net revenues | $150.86 | |
| Offer caps | $33.97 | |
| | | |
| APIR units | | |
| ACR | $341.40 | $499.18 |
| Net revenues | $65.48 | $167.61 |
| Offer caps | $271.22 | $323.27 |
| APIR | $230.67 | $375.38 |
| CPQR | $0.00 | $1.53 |
| | | |
| Maximum APIR effect | $1,104.93 | $1,104.93 |

## Table 5-22 APIR Statistics: 2020/2021 RPM Base Residual Auction

| | Weighted-Average ($ per MW-day UCAP) |
|---|---|
| Non-APIR units | |
| ACR | |
| Net revenues | |
| Offer caps | |
| | |
| APIR units | |
| ACR | $498.15 |
| Net revenues | $277.52 |
| Offer caps | $209.18 |
| APIR | $235.67 |
| CPQR | $0.23 |
| | |
| Maximum APIR effect | $464.71 |

98 Effective for the 2017/2018 and subsequent Delivery Years, the ACR technology classes of waste coal small and large were eliminated and combined with subcritical and supercritical coal to form the Coal Fired ACR technology class. Waste coal resources were included in the other category in prior versions of this table. For the 2017/2018 BRA, waste coal resources were included in the coal fired category.

### Table 5-23 MOPR Statistics: 2017/2018 through 2020/2021 RPM Base Residual Auctions[99]

| Base Residual Auction | Request Type | Requested ICAP (MW) | Granted ICAP (MW) | Offered ICAP (MW) | Offered UCAP (MW) | Cleared UCAP (MW) |
|---|---|---|---|---|---|---|
| 2017/2018 | Competitive Entry Exemption | 12,405.1 | 12,405.1 | 5,786.3 | 5,573.1 | 4,737.5 |
| 2017/2018 | Self-Supply Exemption | 940.0 | 940.0 | 940.0 | 906.1 | 906.1 |
| 2017/2018 | Unit-Specific Exception | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2017/2018 | Total | 13,345.1 | 13,345.1 | 6,726.3 | 6,479.2 | 5,643.6 |
| | | | | | | |
| 2018/2019 | Competitive Entry Exemption | 13,462.5 | 13,462.5 | 3,723.3 | 3,563.6 | 3,563.6 |
| 2018/2019 | Self-Supply Exemption | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2018/2019 | Unit-Specific Exception | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2018/2019 | Total | 13,462.5 | 13,462.5 | 3,723.3 | 3,563.6 | 3,563.6 |
| | | | | | | |
| 2019/2020 | Competitive Entry Exemption | 12,270.0 | 12,270.0 | 4,671.0 | 4,515.1 | 3,561.7 |
| 2019/2020 | Self-Supply Exemption | 1,827.2 | 1,827.2 | 1,779.5 | 1,697.8 | 1,697.8 |
| 2019/2020 | Unit-Specific Exception | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2019/2020 | Total | 14,097.2 | 14,097.2 | 6,450.5 | 6,212.9 | 5,259.5 |
| | | | | | | |
| 2020/2021 | Competitive Entry Exemption | 12,171.0 | 12,171.0 | 3,212.5 | 3,161.1 | 2,646.7 |
| 2020/2021 | Self-Supply Exemption | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2020/2021 | Unit-Specific Exception | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2020/2021 | Total | 12,171.0 | 12,171.0 | 3,212.5 | 3,161.1 | 2,646.7 |

## Extended Minimum Offer Price Rule (MOPR-Ex)

MOPR-Ex is a simple and straightforward approach to ensuring that the impact of state subsidies on markets is limited and the impact on other states is limited and that there is a disincentive for such subsidies. MOPR-Ex, with exemptions for competitive entry, for self supply by cost of service utilities, for self supply by public power entities and for competitive RPS programs is a practical and narrowly targeted approach to protecting competitive wholesale power markets. MOPR-Ex is a defined modification to the current MOPR rather than an elimination of all MOPR rules as proposed by PJM. MOPR-Ex is a better way to maintain PJM markets than the PJM proposal to permit subsidized units to displace competitive units that could result in the capacity market becoming a residual market and that will negatively affect the incentives of new generation to enter the 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.

MOPR Ex would apply to all existing and new resources, regardless of technology type, that will receive revenue outside of Market Revenue. Market Revenue is defined as revenue that is received under a tariff administered by PJM or other Regional Transmission System or Independent System Operator and regulated by the Commission. MOPR-Ex would require subsidized generation to offer at competitive levels in the PJM Capacity Market, thereby preserving the efficient market outcomes and accurate signals for entry and exit that are necessary for well functioning and competitive markets. Competitive investors rely on accurate signals to make decisions.

The rules governing the Self-Supply Exemption for non-public power entities and the Competitive Entry Exemption would be retained under MOPR-Ex.[100] The MMU proposes two additional MOPR exemptions, a public entity exemption and a renewable portfolio standard (RPS) exemption. A resource that will have a revenue source other than Market Revenue applicable to a forthcoming delivery year, and is not eligible for an exemption, will be required to offer into the PJM RPM auction at the MOPR offer price floor or at a level granted through the Unit Specific Exception process. The MOPR offer price floor is equal to the net CONE times B.

### Public Entity Exemption

The public entity exemption would apply for a public power entity if (1) the long-term resource plans are consistent with its business model and such resource plans are intended to be balanced with its load obligations; (2) in any delivery year the total capacity owned and contracted by the public power entity is less than or equal to 600 MW greater than the entity's load obligation, and (3) the cost and revenue criteria for the

99 There were additional MOPR Screened Generation Resources for which no exceptions or exemptions were requested and to which the MOPR floor was applied. Some numbers not reported as a result of PJM confidentiality rules.

100 On July 17, 2017, the U.S. Court of Appeals issued an opinion that vacated, in part, two FERC orders, 143 FERC ¶61,090 and 153 FERC ¶61,066, that had conditionally accepted a PJM filing that revised the MOPR to include a self-supply exemption and a competitive entry exemption. As a result, the current RPM rules do not include a self-supply exemption or a competitive entry exemption; however, the MOPR-Ex rules are expected to be filed with FERC in 2018 and the MMU supports the inclusion of the self-supply exemption and the competitive entry exemption.

self-supply exemption are satisfied.[101] Any excess supply would be subject to the MOPR floor unless it qualifies for a unit specific exception, where excess supply is the MW amount of owned and contracted capacity in excess of the sum of the entity's load obligation and 600 MW.

### RPS Exemption

The RPS exemption from MOPR would apply if the resource was procured in a program in compliance with a state mandated RPS program prior to December 31, 2018, or was based on a request for proposals (RFP) issued under a state mandated RPS program prior to December 31, 2018. Alternatively, resources that satisfy all of the following would be eligible for the RPS exemption:

- the resource complies with the requirements of a state mandated renewable portfolio standard or voluntary renewable portfolio standard;
- the terms of such program are competitive and non-discriminatory, meaning that (1) the program requires LSEs to procure a defined amount of renewable resources, (2) both new and existing resources may participate, (3) all suppliers of renewable resources may participate, (4) the requirements of the program are fully objective and transparent, (5) the program terms do not include selection criteria that could give preference to new or existing resources, (6) the program terms do not use indirect means to discriminate against new or existing capacity, (7) the program terms do not use any locational requirement, e.g. offshore wind, other than restricting imports from other states, and (8) the renewable characteristic is the only screen for participation in the program where renewable does not include coal, natural gas or nuclear thermal resources;
- if the program does not use an auction, the terms of such program: (1) are consistent with fair market value and standard industry practice and (2) provide that the price paid for renewable energy credits is determined by the contract terms between the seller and the buyer.
- if the program uses an auction either as a means of procuring renewable attributes to meet state requirements, or as a means to facilitate the procurement of renewable attributes by responsible LSEs, such auction must be competitive and non-discriminatory, meaning (1) winner(s) of auction based on lowest offer prices, (2) payments to winners based on auction clearing price, and (3) at least three nonaffiliated sellers participate.

## Replacement Capacity[102]

Table 5-24 shows the committed and replacement capacity for all capacity resources for June 1 of each year from 2007 through 2020. The 2018 through 2020 numbers are not final.

#### Table 5-24 RPM commitments and replacements for all Capacity Resources: June 1, 2007 to June 1, 2020

| | UCAP (MW) | | | | | |
|---|---|---|---|---|---|---|
| | RPM Cleared | Adjustments to Cleared | Net Replacements | RPM Commitments | RPM Commitment Shortage | RPM Commitments Less Commitment Shortage |
| 01-Jun-07 | 129,409.2 | 0.0 | 0.0 | 129,409.2 | (8.1) | 129,401.1 |
| 01-Jun-08 | 130,629.8 | 0.0 | (766.5) | 129,863.3 | (246.3) | 129,617.0 |
| 01-Jun-09 | 134,030.2 | 0.0 | (2,068.2) | 131,962.0 | (14.7) | 131,947.3 |
| 01-Jun-10 | 134,036.2 | 0.0 | (4,179.0) | 129,857.2 | (8.8) | 129,848.4 |
| 01-Jun-11 | 134,182.6 | 0.0 | (6,717.6) | 127,465.0 | (79.3) | 127,385.7 |
| 01-Jun-12 | 141,295.6 | (11.7) | (9,400.6) | 131,883.3 | (157.2) | 131,726.1 |
| 01-Jun-13 | 159,844.5 | 0.0 | (12,235.3) | 147,609.2 | (65.4) | 147,543.8 |
| 01-Jun-14 | 161,214.4 | (9.4) | (13,615.9) | 147,589.1 | (1,208.9) | 146,380.2 |
| 01-Jun-15 | 173,845.5 | (326.1) | (11,849.4) | 161,670.0 | (1,822.0) | 159,848.0 |
| 01-Jun-16 | 179,773.6 | (24.6) | (16,157.5) | 163,591.5 | (924.4) | 162,667.1 |
| 01-Jun-17 | 180,590.5 | 0.0 | (13,982.7) | 166,607.8 | (626.1) | 165,981.7 |
| 01-Jun-18 | 171,798.8 | 0.0 | (1,011.8) | 170,787.0 | 0.0 | 170,787.0 |
| 01-Jun-19 | 169,624.6 | 0.0 | (1,107.5) | 168,517.1 | 0.0 | 168,517.1 |
| 01-Jun-20 | 165,109.2 | 0.0 | 0.0 | 165,109.2 | 0.0 | 165,109.2 |

## 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 5-25 shows RPM clearing prices for all RPM auctions held through 2017.

101 Item (3) refers to the self-supply exemption as it existed prior to the opinion issued on July 17, 2017, by the U.S. Court of Appeals.

102 For more details on replacement capacity, see "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2017," <http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Report_on_Capacity_Replacement_Activity_4_20171214.pdf> (December 14, 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 2017. A summary of these weighted average prices is given in Table 5-26.

Table 5-27 shows RPM revenue by resource type for all RPM auctions held through 2017 with $7.5 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 5-28 shows RPM revenue by calendar year for all RPM auctions held through 2017. In 2016, RPM revenue was $8.8 billion. In 2017, RPM revenue was $8.8 billion.

Table 5-29 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 5-25 Capacity market clearing prices: 2007/2008 through 2020/2021 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 |
| 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 |

## Table 5-25 Capacity market clearing prices: 2007/2008 through 2020/2021 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 |
| 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 |
| 2018/2019 Second Incremental Auction | Base Capacity | $5.00 | $5.00 | $5.00 | $5.00 | $35.02 | $5.00 | $30.00 | $35.02 | $35.02 | $5.00 | $5.00 | $5.00 | $5.00 |
| 2018/2019 Second Incremental Auction | Base Capacity DR/EE | $5.00 | $5.00 | $5.00 | $5.00 | $35.02 | $5.00 | $30.00 | $35.02 | $35.02 | $5.00 | $5.00 | $5.00 | $5.00 |
| 2018/2019 Second Incremental Auction | Capacity Performance | $50.00 | $50.00 | $50.00 | $50.00 | $80.02 | $50.00 | $80.02 | $80.02 | $80.02 | $50.00 | $50.00 | $50.00 | $50.00 |
| 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 |
| 2020/2021 BRA | Capacity Performance | $76.53 | $86.04 | $76.53 | $86.04 | $187.87 | $86.04 | $187.87 | $187.87 | $187.87 | $86.04 | $76.53 | $188.12 | $86.04 |

## Table 5-26 Weighted average clearing prices by zone: 2017/2018 through 2020/2021

| | Weighted Average Clearing Price ($ per MW-day) | | | |
|---|---|---|---|---|
| LDA | 2017/2018 | 2018/2019 | 2019/2020 | 2020/2021 |
| RTO | | | | |
| AEP | $140.03 | $161.00 | $96.03 | $76.54 |
| APS | $140.03 | $161.00 | $96.03 | $76.54 |
| ATSI | $138.22 | $151.68 | $96.48 | $76.53 |
| Cleveland | $138.43 | $159.55 | $96.35 | $76.53 |
| ComEd | $140.48 | $207.32 | $195.55 | $188.13 |
| DAY | $140.03 | $161.00 | $96.03 | $76.54 |
| DEOK | $140.03 | $161.00 | $96.03 | $76.54 |
| DLCO | $140.03 | $161.00 | $96.03 | $76.54 |
| Dominion | $140.03 | $161.00 | $96.03 | $76.54 |
| EKPC | $140.03 | $161.00 | $96.03 | $76.54 |
| MAAC | | | | |
| EMAAC | | | | |
| AECO | $137.20 | $217.00 | $114.30 | $187.72 |
| DPL | $137.20 | $217.00 | $114.30 | $187.72 |
| DPL South | $133.72 | $218.65 | $117.45 | $187.87 |
| JCPL | $137.20 | $217.00 | $114.30 | $187.72 |
| PECO | $137.20 | $217.00 | $114.30 | $187.72 |
| PSEG | $205.58 | $218.93 | $117.10 | $187.75 |
| PSEG North | $212.51 | $222.39 | $117.81 | $187.87 |
| RECO | $137.20 | $217.00 | $114.30 | $187.72 |
| SWMAAC | | | | |
| BGE | $125.37 | $143.22 | $95.18 | $85.94 |
| Pepco | $133.34 | $149.40 | $91.94 | $86.01 |
| WMAAC | | | | |
| Met-Ed | $139.32 | $154.61 | $97.15 | $86.06 |
| PENELEC | $139.32 | $154.61 | $97.15 | $86.06 |
| PPL | $136.20 | $148.41 | $96.29 | $86.04 |

## Table 5-27 RPM revenue by type: 2007/2008 through 2020/2021[103] [104]

| | | | | Coal | | Gas | | Hydroelectric | | Nuclear | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | Demand Resources | Energy Efficiency Resources | Imports | Existing | New/repower/ reactivated | Existing | New/repower/ reactivated | Existing | New/repower/ reactivated | Existing | New/repower/ reactivated |
| 2007/2008 | $5,537,085 | $0 | $22,225,980 | $1,019,060,206 | $0 | $1,624,067,951 | $3,516,075 | $209,490,444 | $0 | $996,085,233 | $0 |
| 2008/2009 | $35,349,116 | $0 | $60,918,903 | $1,835,059,769 | $0 | $2,112,880,414 | $9,784,064 | $287,838,147 | $12,255 | $1,322,601,837 | $0 |
| 2009/2010 | $65,762,003 | $0 | $56,517,793 | $2,409,315,953 | $1,854,781 | $2,548,801,710 | $30,168,831 | $364,731,344 | $11,173 | $1,517,723,628 | $0 |
| 2010/2011 | $60,235,796 | $0 | $106,046,871 | $2,648,278,766 | $3,168,069 | $2,823,632,390 | $58,065,964 | $442,410,730 | $19,085 | $1,799,258,125 | $0 |
| 2011/2012 | $55,795,785 | $139,812 | $185,421,273 | $1,586,775,249 | $28,330,047 | $1,717,850,463 | $98,448,693 | $278,529,660 | $0 | $1,079,386,338 | $0 |
| 2012/2013 | $264,387,897 | $11,408,552 | $13,260,822 | $1,014,858,378 | $7,568,127 | $1,256,096,304 | $76,633,409 | $179,117,374 | $11,998 | $762,719,550 | $0 |
| 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 |
| 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 |
| 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 |
| 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 |
| 2017/2018 | $515,145,457 | $86,147,605 | $218,710,769 | $2,452,687,763 | $62,790,145 | $2,546,380,480 | $984,733,791 | $348,972,234 | $15,219,121 | $1,694,447,711 | $0 |
| 2018/2019 | $636,049,319 | $96,609,059 | $262,514,266 | $2,632,098,014 | $77,069,006 | $2,977,175,919 | $1,443,285,559 | $414,573,552 | $15,344,022 | $1,990,827,045 | $0 |
| 2019/2020 | $372,486,674 | $84,844,416 | $124,519,680 | $1,609,158,969 | $47,528,002 | $1,943,077,786 | $1,057,018,794 | $247,795,677 | $6,208,824 | $1,274,763,734 | $0 |
| 2020/2021 | $325,121,955 | $87,314,763 | $105,675,035 | $1,274,487,087 | $36,115,158 | $2,073,983,594 | $1,144,499,809 | $208,893,366 | $7,721,948 | $1,413,162,803 | $0 |

| | Oil | | Solar | | Solid waste | | Wind | | |
|---|---|---|---|---|---|---|---|---|---|
| | Existing | New/repower/ reactivated | Existing | New/repower/ reactivated | Existing | New/repower/ reactivated | Existing | New/repower/ reactivated | Total revenue |
| 2007/2008 | $340,362,114 | $0 | $0 | $0 | $31,512,230 | $0 | $430,065 | $0 | $4,252,287,381 |
| 2008/2009 | $378,756,365 | $4,837,523 | $0 | $0 | $35,011,991 | $0 | $1,180,153 | $2,917,048 | $6,087,147,586 |
| 2009/2010 | $450,523,876 | $5,676,582 | $0 | $0 | $42,758,762 | $523,739 | $2,011,156 | $6,836,827 | $7,503,218,157 |
| 2010/2011 | $446,000,462 | $4,339,539 | $0 | $0 | $40,731,606 | $413,503 | $1,819,413 | $15,232,177 | $8,449,652,496 |
| 2011/2012 | $266,483,502 | $967,887 | $0 | $66,978 | $25,636,836 | $261,690 | $1,072,929 | $9,919,881 | $5,335,087,023 |
| 2012/2013 | $248,611,128 | $2,772,987 | $0 | $1,246,337 | $26,840,670 | $316,420 | $812,644 | $5,052,036 | $3,871,714,635 |
| 2013/2014 | $386,561,718 | $5,670,399 | $0 | $3,523,555 | $43,943,130 | $1,977,705 | $1,373,205 | $13,538,988 | $6,799,778,047 |
| 2014/2015 | $323,630,668 | $4,106,697 | $0 | $3,836,582 | $34,281,137 | $1,709,533 | $1,524,551 | $32,766,219 | $7,437,267,646 |
| 2015/2016 | $401,718,239 | $5,947,275 | $0 | $7,064,983 | $35,862,368 | $6,179,607 | $1,829,269 | $42,994,253 | $10,161,726,902 |
| 2016/2017 | $265,547,984 | $4,030,823 | $0 | $7,057,256 | $32,648,789 | $6,380,604 | $1,144,873 | $26,189,042 | $7,993,888,695 |
| 2017/2018 | $280,738,408 | $3,888,126 | $0 | $10,899,883 | $34,771,100 | $9,036,976 | $1,529,251 | $40,577,901 | $9,306,676,719 |
| 2018/2019 | $343,333,510 | $2,922,855 | $0 | $15,939,493 | $38,078,648 | $9,645,386 | $1,166,553 | $53,665,227 | $11,010,297,432 |
| 2019/2020 | $187,309,985 | $1,723,692 | $0 | $11,594,905 | $21,205,162 | $5,326,702 | $753,594 | $45,510,662 | $7,040,827,258 |
| 2020/2021 | $214,430,999 | $1,406,926 | $0 | $5,734,079 | $26,917,827 | $5,428,707 | $25,124 | $33,760,562 | $6,964,679,740 |

## Table 5-28 RPM revenue by calendar year: 2007 through 2021[105]

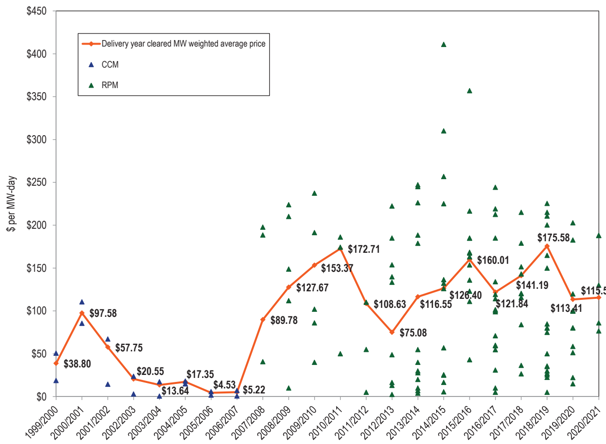
| Year | Weighted Average RPM Price ($ per MW-day) | Weighted Average Cleared UCAP (MW) | Effective Days | RPM Revenue |
|---|---|---|---|---|
| 2007 | $89.78 | 129,409.2 | 214 | $2,486,310,108 |
| 2008 | $111.93 | 130,223.2 | 366 | $5,334,880,241 |
| 2009 | $142.74 | 132,772.0 | 365 | $6,917,391,702 |
| 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 | $133.19 | 180,272.0 | 365 | $8,763,578,112 |
| 2018 | $161.36 | 174,981.4 | 365 | $10,305,511,877 |
| 2019 | $139.13 | 170,759.7 | 365 | $8,671,712,815 |
| 2020 | $114.67 | 166,963.8 | 366 | $7,007,460,680 |
| 2021 | $115.57 | 165,109.2 | 151 | $2,881,278,468 |

103 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.

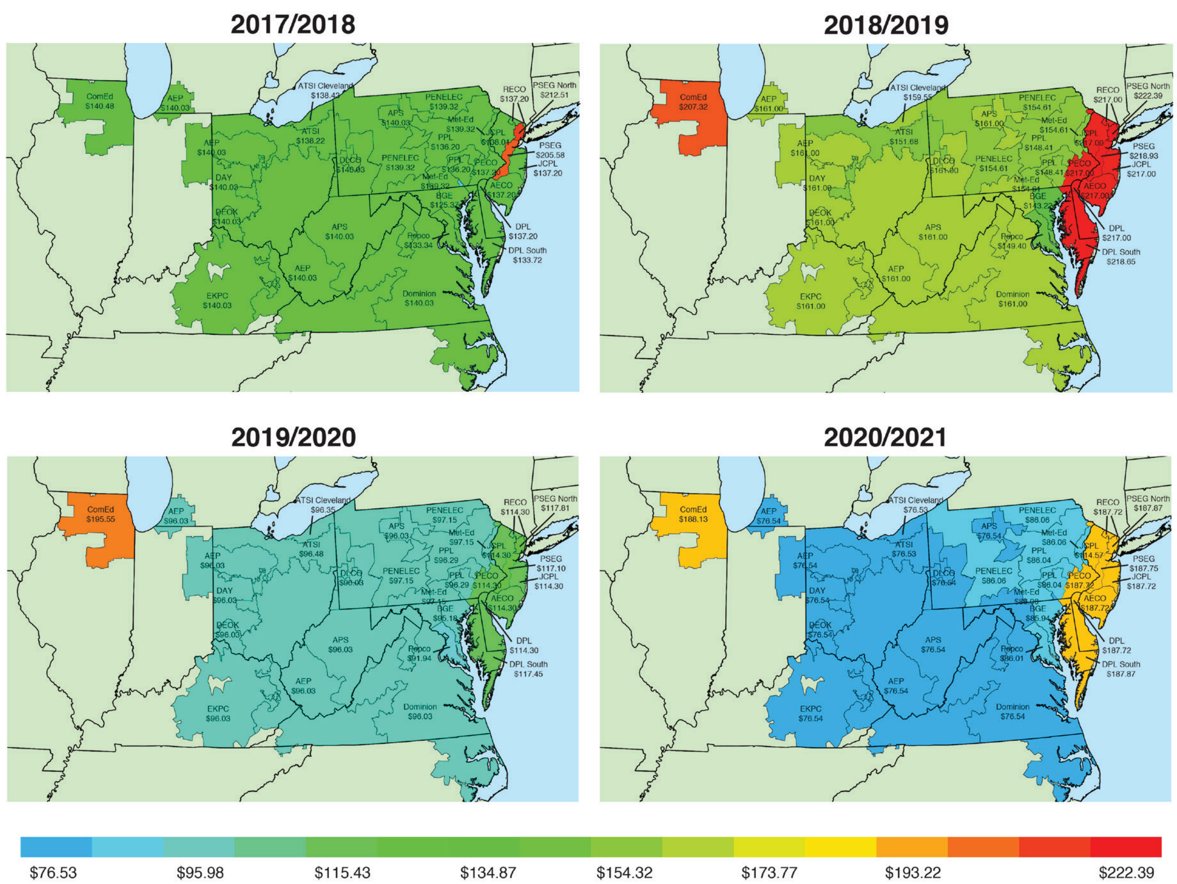
104 The results for the ATSI Integration Auctions are not included in this table.

105 The results for the ATSI Integration Auctions are not included in this table.

## Figure 5-7 History of PJM capacity prices: 1999/2000 through 2020/2021[106]




## Figure 5-8 Map of RPM capacity prices: 2017/2018 through 2020/2021




106 The 1999/2000-2006/2007 capacity prices are CCM combined market, weighted average prices. The 2007/2008-2020/2021 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.

### Table 5-29 RPM cost to load: 2016/2017 through 2020/2021 RPM Auctions[107 108 109]

| | Net Load Price ($ per MW-day) | UCAP Obligation (MW) | Annual Charges |
|---|---|---|---|
| 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 | $164.68 | 80,744.7 | $4,853,530,001 |
| Rest of MAAC | $218.96 | 31,062.7 | $2,482,513,646 |
| BGE | $158.21 | 7,735.7 | $446,719,430 |
| DPL | $219.00 | 4,525.0 | $362,693,243 |
| ComEd | $211.92 | 24,800.0 | $1,918,266,822 |
| Pepco | $156.94 | 7,393.5 | $423,512,918 |
| PPL | $155.03 | 8,244.4 | $466,513,972 |
| Total | | 164,506.1 | $10,953,750,032 |
| | | | |
| 2019/2020 | | | |
| Rest of RTO | $97.61 | 89,604.4 | $3,201,154,059 |
| Rest of EMAAC | $115.15 | 24,335.4 | $1,025,577,181 |
| BGE | $97.73 | 7,676.6 | $274,595,000 |
| ComEd | $190.88 | 25,311.9 | $1,768,321,123 |
| Pepco | $92.47 | 7,381.5 | $249,814,744 |
| PSEG | $115.40 | 11,299.1 | $477,218,187 |
| Total | | 165,609.0 | $6,996,680,295 |
| | | | |
| 2020/2021 | | | |
| Rest of RTO | $76.83 | 69,612.5 | $1,952,261,955.97 |
| Rest of MAAC | $86.63 | 29,769.1 | $941,266,092.93 |
| Rest of EMAAC | $174.85 | 35,369.6 | $2,257,334,820.17 |
| ComEd | $183.14 | 25,153.0 | $1,681,377,780.76 |
| DEOK | $103.39 | 5,205.0 | $196,428,322.59 |
| Total | | 165,109.2 | $7,028,668,972.43 |

107 The RPM annual charges are calculated using the rounded, net load prices as posted in the PJM RPM Auction results.

108 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.

109 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 2018/2019, 2019/2020, and 2020/2021 Net Load Prices are not finalized. The 2018/2019, 2019/2020, and 2020/2021 obligation MW are not finalized.

## Reliability Must Run (RMR) Service

PJM must make out of market payments to units for Reliability Must Run (RMR) service during periods when a unit that would otherwise have been deactivated is needed for reliability.[110] The need for RMR service reflects a flawed market design and/or planning process problems. If a unit is needed for reliability, the market should reflect a locational value consistent with that need which would result in the unit remaining in service or being replaced by a competitor unit. The planning process should evaluate the impact of the loss of units at risk and determine in advance whether transmission upgrades are required.[111]

When notified of an intended deactivation, the Market Monitor performs a market power study to ensure that the deactivation is economic, not an exercise of market power through withholding, and consistent with competition.[112] PJM performs a system study to determine whether the system can accommodate the deactivation on the desired date, and if not, when it could.[113] If PJM determines that it needs a unit for a period beyond the intended deactivation date, PJM will request a unit to provide RMR service.[114] The PJM market rules do not require an owner to provide RMR service, but owners must provide 90 days advance notice of a proposed deactivation.[115] The owner of a generation capacity resource must provide notice of a proposed deactivation in order to avoid a requirement to offer in RPM auctions.[116] In order to avoid submitting an offer for a unit in the next three-year forward RPM base residual auction, an owner must show "a documented plan in place to retire the resource," including a notice of deactivation filed with PJM, 120 days prior to such auction.[117]

110 OATT Part V.

111 *See, e.g.*, 140 FERC ¶ 61,237 at P 36 (2012) ("The evaluation of alternatives to an SSR designation is an important step that deserves the full consideration of MISO and its stakeholders to ensure that SSR Agreements are used only as a 'limited, last-resort measure.'"); 118 FERC ¶ 61,243 at P 41 (2007) ("the market participants that pay for the agreements pay out-of-market prices for the service provided under the RMR agreements, which broadly hinders market development and performance.[footnote omitted] As a result of these factors, we have concluded that RMR agreements should be used as a last resort."); 110 FERC ¶ 61,315 at P 40 (2005) ("The Commission has stated on several occasions that it shares the concerns . . . that RMR agreements not proliferate as an alternative pricing option for generators, and that they are used strictly as a last resort so that units needed for reliability receive reasonable compensation.").

112 OATT § 113.2; OATT Attachment M § IV.1.

113 OATT § 113.2.

114 *Id.*

115 OATT § 113.1.

116 OATT Attachment DD § 6.6(g).

117 *Id.*

Under the current rules, a unit providing RMR service can recover its costs under either the deactivation avoidable cost rate (DACR), which is a formula rate, or the cost of service recovery rate. The deactivation avoidable cost rate is designed to permit the recovery of the costs of the unit's "continued operation," termed "avoidable costs," plus an incentive adder.[118] Avoidable costs are defined to mean "incremental expenses directly required for the operation of a generating unit."[119] The incentives escalate for each year of service (first year, 10 percent; second year, 20 percent; third year, 35 percent; fourth year, 50 percent).[120] The rules provide terms for early termination of RMR service and for the repayment of project investment by owners of units that choose to keep units in service after the RMR period ends.[121] Project investment is capped at $2 million, above which FERC approval is required.[122] The cost of service rate is designed to permit the recovery of the unit's "cost of service rate to recover the entire cost of operating the generating unit" if the generation owner files a separate rate schedule at FERC.[123]

Table 5-30 shows units that have provided or are providing RMR service to PJM.

In each of the cost of service recovery rate filings for RMR service, the scope of recovery permitted under the cost of service approach defined in Section 119 has been a significant issue. Owners have sought to recover fixed costs, incurred prior to the noticed deactivation date, in addition to the cost of operating the generating unit. Owners have cited the cost of service reference to mean that the unit is entitled to file to recover costs that it was unable to recover in the competitive markets, in addition to recovery of costs of actually providing the RMR service.

The cost of service recovery rate approach has been interpreted by the companies using that approach to allow the company to establish a rate base including investment in the existing plant and new investment necessary to provide RMR service and to earn a return on that rate base and receive depreciation of that rate base. Companies developing the cost of service recovery rate have ignored the tariff's limitation to the costs of operating the unit during the RMR service period and have included costs incurred prior to the decision to the deactivate.[124] In one cost of service recovery rate, the filing included costs that already had been written off on the company's public books.[125] Unit owners have filed for revenues under the cost of service method that substantially exceed the actual incremental costs of providing RMR service.

### Table 5-30 RMR service summary

| Unit Names | Owner | ICAP (MW) | Cost Recovery Method | Docket Numbers | Start of Term | End of Term |
|---|---|---|---|---|---|---|
| B.L. England 2 | RC Cape May Holdings, LLC | 150.0 | Cost of Service Recovery Rate | ER17-1083 | 01-May-17 | 01-May-19 |
| Yorktown 1 | Dominion Virginia Power | 159.0 | Deactivation Avoidable Cost Rate | ER17-750 | 06-Jan-17 | 13-Mar-18 |
| Yorktown 2 | Dominion Virginia Power | 164.0 | Deactivation Avoidable Cost Rate | ER17-750 | 06-Jan-17 | 13-Mar-18 |
| B.L. England 3 | RC Cape May Holdings, LLC | 148.0 | Cost of Service Recovery Rate | ER17-1083 | 01-May-17 | 24-Jan-18 |
| Ashtabula | FirstEnergy Service Company | 210.0 | Deactivation Avoidable Cost Rate | ER12-2710 | 01-Sep-12 | 11-Apr-15 |
| Eastlake 1 | FirstEnergy Service Company | 109.0 | Deactivation Avoidable Cost Rate | ER12-2710 | 01-Sep-12 | 15-Sep-14 |
| Eastlake 2 | FirstEnergy Service Company | 109.0 | Deactivation Avoidable Cost Rate | ER12-2710 | 01-Sep-12 | 15-Sep-14 |
| Eastlake 3 | FirstEnergy Service Company | 109.0 | Deactivation Avoidable Cost Rate | ER12-2710 | 01-Sep-12 | 15-Sep-14 |
| Lakeshore | FirstEnergy Service Company | 190.0 | Deactivation Avoidable Cost Rate | ER12-2710 | 01-Sep-12 | 15-Sep-14 |
| Elrama 4 | GenOn Power Midwest, LP | 171.0 | Cost of Service Recovery Rate | ER12-1901 | 01-Jun-12 | 01-Oct-12 |
| Niles 1 | GenOn Power Midwest, LP | 109.0 | Cost of Service Recovery Rate | ER12-1901 | 01-Jun-12 | 01-Oct-12 |
| Cromby 2 and Diesel | Exelon Generation Company, LLC | 203.7 | Cost of Service Recovery Rate | ER10-1418 | 01-Jun-11 | 01-Jan-12 |
| Eddystone 2 | Exelon Generation Company, LLC | 309.0 | Cost of Service Recovery Rate | ER10-1418 | 01-Jun-11 | 01-Jun-12 |
| Brunot Island CT2A, CT2B, CT3 and CC4 | Orion Power MidWest, L.P. | 244.0 | Cost of Service Recovery Rate | ER06-993 | 16-May-06 | 05-Jul-07 |
| Hudson 1 | PSEG Energy Resources & Trade LLC and PSEG Fossil LLC | 355.0 | Cost of Service Recovery Rate | ER05-644, ER11-2688 | 25-Feb-05 | 08-Dec-11 |
| Sewaren 1-4 | PSEG Energy Resources & Trade LLC and PSEG Fossil LLC | 453.0 | Cost of Service Recovery Rate | ER05-644 | 25-Feb-05 | 01-Sep-08 |

Only two of seven owners have used the deactivation avoidable cost rate approach. The other five owners used the cost of service recovery rate, despite the greater administrative expense.

Because an RMR unit is needed by PJM for reliability reasons, and the provision of RMR service is voluntary in PJM, owners of RMR service have significant market power in establishing the terms of RMR service.

118 OATT § 114 (Deactivation Avoidable Credit = ((Deactivation Avoidable Cost Rate + Applicable Adder) * MW capability of the unit * Number of days in the month) – Actual Net Revenues).

119 OATT § 115.

120 *Id.*

121 OATT § 118.

122 OATT §§ 115, 117.

123 OATT § 119.

124 See, e.g., FERC Dockets Nos. ER10-1418-000, ER12-1901-000.

125 See GenOn Filing, Docket No. ER12-1901-000 (May 31, 2012) at Exh. No. GPM-1 at 9:16–21.

RMR service should be provided to PJM customers at reasonable rates, which reflect the riskless nature of providing such service to owners, the reliability need for such service and the opportunity for owners to be guaranteed recovery of 100 percent of the actual costs incurred to provide the service plus an incentive markup.

The cost of service recovery rates have been excessive compared to the actual costs of providing RMR service. The DACR method also provides excessive incentives for service longer than a year, given that customers bear the risks.

The MMU recommends elimination of the cost of service recovery rate in OATT Section 119, and that RMR service should be provided under the deactivation avoidable cost rate in Part V.

The MMU also recommends, based in part on its experience with application of the deactivation avoidable cost rate and proceedings filed under Section 119, the following improvements to the DACR provisions:

- Revise the applicable adders in Section 114 to be 15 percent for the second year of RMR service and 20 percent for the provision of RMR service in excess of two years.
- Add true up provisions that ensure that the RMR service provider is reimbursed for, and consumers pay for, the actual costs associated with the RMR service, plus the applicable adder.
- Eliminate the $2 million cap on project investment expenditures.
- Clearly distinguish operating expenses and project investment costs.
- Clarify the tariff language in Section 118 regarding the refund of project investment in the event the RMR unit continues operation beyond the RMR term.

# 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. Table 5-31 shows the capacity factors by unit type for 2016 and 2017. In 2017, nuclear units had a capacity factor of 94.1 percent, compared to 91.3 percent in 2016; combined cycle units had a capacity factor of 58.4 percent in 2017, compared to a capacity factor of 62.0 percent in 2016; all steam units had a capacity factor of 40.7 percent in 2017, compared to 41.1 percent in 2016; coal units had a capacity factor of 46.6 percent in 2017, compared to 46.2 percent in 2016.

### Table 5-31 PJM capacity factor (By unit type (GWh)): 2016 and 2017[126] [127]

| | 2016 | | 2017 | | Change in |
|---|---|---|---|---|---|
| Unit Type | Generation (GWh) | Capacity Factor | Generation (GWh) | Capacity Factor | 2017 from 2016 |
| Battery | 15.7 | 0.6% | 25.1 | 0.9% | 0.3% |
| Combined Cycle | 187,657.9 | 62.0% | 195,631.7 | 58.4% | (3.6%) |
| Combustion Turbine | 17,265.2 | 6.9% | 13,390.7 | 5.3% | (1.6%) |
| Diesel | 291.2 | 10.1% | 359.5 | 11.1% | 1.0% |
| Diesel (Landfill gas) | 1,489.0 | 50.3% | 1,642.2 | 50.5% | 0.2% |
| Fuel Cell | 227.6 | 86.4% | 226.7 | 86.2% | (0.1%) |
| Nuclear | 279,546.4 | 91.3% | 287,575.8 | 94.1% | 2.9% |
| Pumped Storage Hydro | 6,077.2 | 13.7% | 6,475.4 | 14.6% | 0.9% |
| Run of River Hydro | 7,609.6 | 31.4% | 8,393.0 | 32.0% | 0.6% |
| Solar | 1,000.9 | 17.3% | 1,463.1 | 17.0% | (0.2%) |
| Steam | 293,624.9 | 41.1% | 272,325.1 | 40.7% | (0.4%) |
| Coal | 276,539.4 | 46.2% | 258,498.3 | 46.6% | 0.4% |
| Natural Gas | 10,463.1 | 12.3% | 7,770.3 | 9.2% | (3.0%) |
| Oil | 258.4 | 1.3% | 154.6 | 0.8% | (0.5%) |
| Biomass | 6,364.0 | 64.0% | 5,901.9 | 59.5% | (4.5%) |
| Wind | 17,716.0 | 27.6% | 20,714.1 | 29.5% | 1.9% |
| Total | 812,521.7 | 47.2% | 808,222.4 | 47.0% | (0.2%) |

## Generator Performance Factors

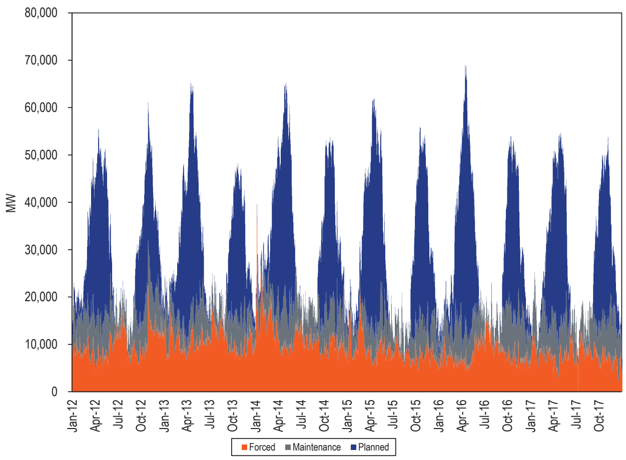
Generator outages fall into three categories: planned, maintenance, and forced. The MW on outage vary throughout the year. For example, the MW on planned outage are generally highest in the spring and fall, as shown in Figure 5-9, due to restrictions on planned

126 The capacity factors in this table are based on nameplate capacity values, and are calculated based on when the units come on line.

127 The subcategories of steam units are consolidated consistent with confidentiality rules. Coal is comprised of coal and waste coal. Natural gas is comprised of natural gas and propane. Oil is comprised of both heavy and light oil. Biomass is comprised of biomass, landfill gas, and municipal solid waste.

outages during the winter and summer. The effect of the seasonal variation in outages can be seen in the monthly generator performance metrics in Figure 5-12.

### Figure 5-9 PJM outages (MW): 2012 through 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 5-32.

### Figure 5-10 PJM equivalent outage and availability factors: 2007 to 2017

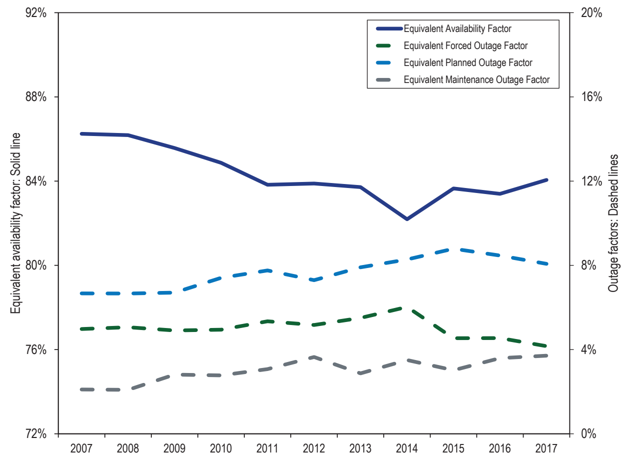


**Table 5-32 EFOF, EPOF, EMOF and EAF by unit type: 2007 through 2017**

| | Coal | | | | Combined Cycle | | | | Combustion Turbine | | | | Diesel | | | | Hydroelectric | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | EFOF | EPOF | EMOF | EAF | EFOF | EPOF | EMOF | EAF | EFOF | EPOF | EMOF | EAF | EFOF | EPOF | EMOF | EAF | EFOF | EPOF | EMOF | EAF |
| 2007 | 7.7% | 8.8% | 2.7% | 80.8% | 2.3% | 6.2% | 2.0% | 89.5% | 4.6% | 2.5% | 2.6% | 90.3% | 10.2% | 0.6% | 1.6% | 87.6% | 1.3% | 7.2% | 1.4% | 90.1% |
| 2008 | 7.8% | 7.6% | 2.5% | 82.1% | 2.1% | 5.9% | 1.7% | 90.3% | 2.8% | 4.1% | 2.3% | 90.8% | 9.1% | 1.0% | 1.2% | 88.7% | 1.3% | 7.8% | 2.1% | 88.8% |
| 2009 | 6.8% | 8.8% | 3.6% | 80.9% | 2.7% | 5.9% | 3.1% | 88.3% | 1.4% | 2.8% | 2.4% | 93.3% | 6.6% | 0.6% | 1.1% | 91.7% | 2.3% | 8.7% | 2.3% | 86.8% |
| 2010 | 7.8% | 9.3% | 4.1% | 78.9% | 2.3% | 8.1% | 2.7% | 86.9% | 1.9% | 2.9% | 2.1% | 93.1% | 4.4% | 0.4% | 1.5% | 93.6% | 0.7% | 8.6% | 1.9% | 88.8% |
| 2011 | 8.3% | 8.7% | 4.4% | 78.5% | 2.4% | 8.7% | 2.3% | 86.6% | 2.1% | 3.7% | 2.4% | 91.9% | 3.3% | 0.1% | 1.8% | 94.8% | 1.7% | 11.7% | 1.9% | 84.7% |
| 2012 | 7.8% | 8.4% | 5.8% | 77.9% | 3.7% | 8.3% | 2.6% | 85.5% | 2.9% | 3.2% | 1.7% | 92.2% | 3.9% | 0.7% | 2.4% | 93.1% | 2.8% | 6.3% | 2.1% | 88.9% |
| 2013 | 8.7% | 10.0% | 4.4% | 76.9% | 2.4% | 8.0% | 2.4% | 87.3% | 5.1% | 4.0% | 1.7% | 89.2% | 6.0% | 0.3% | 1.4% | 92.4% | 2.3% | 7.8% | 1.9% | 87.9% |
| 2014 | 9.4% | 9.2% | 5.5% | 75.9% | 2.6% | 10.1% | 2.4% | 84.8% | 6.2% | 3.9% | 1.9% | 88.0% | 13.8% | 0.4% | 2.2% | 83.5% | 2.5% | 9.3% | 3.0% | 85.3% |
| 2015 | 7.7% | 9.6% | 4.5% | 78.2% | 2.2% | 10.6% | 2.2% | 85.0% | 2.8% | 4.3% | 2.4% | 90.4% | 7.6% | 0.3% | 2.7% | 89.4% | 3.7% | 9.6% | 1.5% | 85.2% |
| 2016 | 8.4% | 8.9% | 6.2% | 76.5% | 2.8% | 10.6% | 1.8% | 84.9% | 2.1% | 5.4% | 2.7% | 89.8% | 5.3% | 0.2% | 2.6% | 92.0% | 2.6% | 7.7% | 3.1% | 86.6% |
| 2017 | 9.0% | 9.8% | 7.0% | 74.2% | 1.9% | 10.3% | 1.6% | 86.2% | 1.3% | 5.9% | 2.0% | 90.8% | 5.3% | 0.4% | 2.1% | 92.2% | 2.1% | 5.8% | 3.2% | 88.8% |

| | Nuclear | | | | Other | | | |
|---|---|---|---|---|---|---|---|---|
| | EFOF | EPOF | EMOF | EAF | EFOF | EPOF | EMOF | EAF |
| 2007 | 1.3% | 5.3% | 0.3% | 93.1% | 6.2% | 7.6% | 3.0% | 83.3% |
| 2008 | 1.8% | 5.1% | 0.8% | 92.3% | 8.7% | 10.4% | 3.1% | 77.8% |
| 2009 | 4.1% | 5.2% | 0.6% | 90.1% | 7.8% | 7.4% | 4.7% | 80.1% |
| 2010 | 2.3% | 5.4% | 0.5% | 91.8% | 8.2% | 9.8% | 3.5% | 78.6% |
| 2011 | 2.6% | 6.1% | 1.2% | 90.1% | 8.6% | 11.1% | 3.5% | 76.9% |
| 2012 | 1.5% | 6.4% | 1.1% | 91.1% | 8.1% | 10.6% | 4.8% | 76.5% |
| 2013 | 1.1% | 5.9% | 0.7% | 92.2% | 7.8% | 10.5% | 3.8% | 77.9% |
| 2014 | 1.8% | 5.8% | 0.9% | 91.5% | 7.1% | 14.7% | 5.4% | 72.8% |
| 2015 | 1.3% | 5.5% | 1.2% | 91.9% | 6.0% | 17.5% | 4.1% | 72.4% |
| 2016 | 1.7% | 5.5% | 1.2% | 91.7% | 4.7% | 15.8% | 4.4% | 75.1% |
| 2017 | 0.5% | 5.1% | 0.6% | 93.7% | 4.9% | 9.8% | 6.0% | 79.4% |

## 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.[128] The EFORd metric includes all forced outages, regardless of the reason for those outages.

The average PJM EFORd for 2017 was 6.8 percent, an increase from 6.5 percent for 2016. Figure 5-11 shows the average EFORd since 1999 for all units in PJM.[129]

128 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.

129 The universe of units in PJM changed as the PJM footprint expanded and as units retired from and entered PJM markets. See the *2017 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

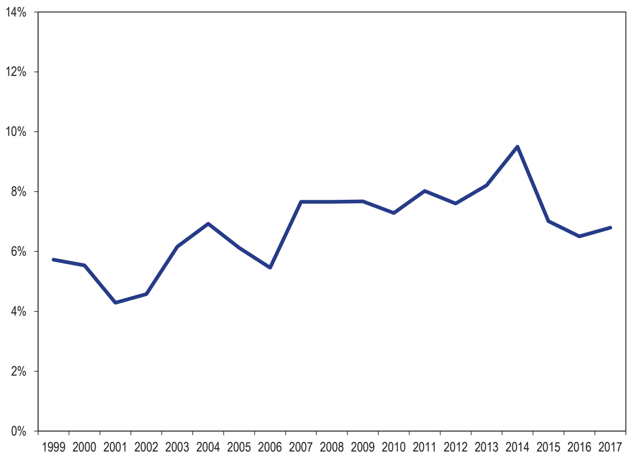



Table 5-33 shows the class average EFORd by unit type.

Table 5-33 PJM EFORd data for different unit types: 2007 through 2017

| | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Coal | 8.8% | 9.0% | 8.4% | 9.4% | 10.6% | 10.3% | 11.1% | 11.8% | 9.4% | 10.5% | 12.0% |
| Combined Cycle | 3.6% | 3.4% | 3.7% | 3.0% | 3.2% | 4.4% | 2.9% | 4.4% | 2.8% | 3.5% | 2.5% |
| Combustion Turbine | 11.4% | 11.2% | 9.7% | 9.1% | 8.2% | 8.5% | 11.0% | 15.9% | 9.0% | 6.0% | 5.5% |
| Diesel | 11.7% | 10.3% | 9.3% | 6.4% | 9.3% | 5.1% | 6.6% | 14.8% | 9.1% | 7.2% | 6.4% |
| Hydroelectric | 2.0% | 2.0% | 3.2% | 1.2% | 2.9% | 4.4% | 3.6% | 3.8% | 5.2% | 3.7% | 2.8% |
| Nuclear | 1.4% | 1.9% | 4.1% | 2.5% | 2.8% | 1.6% | 1.2% | 1.9% | 1.4% | 1.9% | 0.6% |
| Other | 11.2% | 15.6% | 14.5% | 12.4% | 15.3% | 12.3% | 15.3% | 14.2% | 13.2% | 9.3% | 13.9% |
| Total | 7.1% | 7.7% | 7.7% | 7.3% | 8.0% | 7.6% | 8.2% | 9.5% | 7.0% | 6.5% | 6.8% |

## 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.[130]

Table 5-34 shows OMC forced outages by cause code, as classified by PJM. OMC forced outages accounted for 2.9 percent of all forced outages in 2017. The largest contributor to OMC outages, lack of fuel, was the cause of 33.4 percent of OMC outages and 1.0 percent of all forced outages.

### Table 5-34 OMC outages: 2017

| OMC Cause Code | Percent of OMC Forced Outages | Percent of all Forced Outages |
|---|---|---|
| Lack of fuel | 33.4% | 1.0% |
| Flood | 21.2% | 0.6% |
| Lightning | 17.5% | 0.5% |
| Switchyard system protection devices | 6.4% | 0.2% |
| Transmission line | 5.3% | 0.2% |
| Switchyard circuit breakers | 3.8% | 0.1% |
| Other switchyard equipment | 3.1% | 0.1% |
| Lack of water (hydro) | 2.8% | 0.1% |
| Transmission equipment beyond the 1st substation | 2.2% | 0.1% |
| Transmission system problems other than catastrophes | 1.8% | 0.1% |
| Transmission equipment | 0.8% | 0.0% |
| Other miscellaneous external problems | 0.7% | 0.0% |
| Wet coal | 0.6% | 0.0% |
| Switchyard transformers and associated cooling systems | 0.2% | 0.0% |
| Tornado | 0.1% | 0.0% |
| Storms | 0.0% | 0.0% |
| Other fuel quality problems | 0.0% | 0.0% |
| Total | 100.0% | 2.9% |

## 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.[131] On a system wide basis, the resultant lost equivalent availability from the forced outages is equal to the equivalent forced outage factor (EFOF).[132]

PJM EFOF was 4.2 percent in 2017. This means there was 4.2 percent lost availability because of forced outages. Table 5-35 shows that forced outages for boiler tube leaks, at 22.6 percent of the systemwide EFOF, were the largest single contributor to EFOF.

130 "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Schedule 5.B.

131 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.

132 EFOF incorporates all outages regardless of their designation as OMC.

### Table 5-35 Contribution to EFOF by unit type by cause: 2017

| | Coal | Combined Cycle | Combustion Turbine | Diesel | Hydroelectric | Nuclear | Other | System |
|---|---|---|---|---|---|---|---|---|
| Boiler Tube Leaks | 28.1% | 4.8% | 0.0% | 0.0% | 0.0% | 0.0% | 18.9% | 22.6% |
| Feedwater System | 11.6% | 1.1% | 0.0% | 0.0% | 0.0% | 1.1% | 0.5% | 8.5% |
| Electrical | 5.6% | 28.5% | 10.5% | 5.1% | 3.2% | 10.1% | 3.2% | 7.3% |
| Wet Scrubbers | 8.6% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.7% | 6.2% |
| Boiler Air and Gas Systems | 6.2% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 4.5% | 4.9% |
| Low Pressure Turbine | 5.9% | 0.5% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 4.3% |
| Exciter | 1.1% | 4.0% | 1.6% | 0.0% | 12.7% | 0.0% | 23.6% | 4.0% |
| Miscellaneous (Pollution Control Equipment) | 4.1% | 0.0% | 4.2% | 0.0% | 0.0% | 0.0% | 3.3% | 3.5% |
| Reserve Shutdown | 1.2% | 4.7% | 14.1% | 28.1% | 17.9% | 12.9% | 4.8% | 3.3% |
| Boiler Fuel Supply from Bunkers to Boiler | 3.7% | 0.4% | 0.0% | 0.0% | 0.0% | 0.0% | 1.5% | 2.8% |
| Miscellaneous (Generator) | 1.3% | 2.6% | 3.4% | 5.4% | 17.0% | 17.7% | 1.0% | 2.3% |
| Condensing System | 2.6% | 3.1% | 0.0% | 0.0% | 0.0% | 1.7% | 0.5% | 2.2% |
| Boiler Piping System | 2.0% | 3.3% | 0.0% | 0.0% | 0.0% | 0.0% | 1.4% | 1.8% |
| Valves | 1.7% | 0.7% | 0.0% | 0.0% | 0.0% | 5.9% | 1.7% | 1.6% |
| Economic | 0.1% | 1.6% | 11.1% | 5.3% | 7.1% | 0.0% | 6.1% | 1.6% |
| Auxiliary Systems | 1.0% | 3.2% | 7.4% | 0.0% | 0.2% | 2.6% | 0.5% | 1.4% |
| Generator | 0.2% | 7.0% | 4.9% | 5.8% | 1.0% | 4.1% | 1.7% | 1.2% |
| Controls | 1.0% | 2.8% | 1.5% | 1.0% | 1.5% | 5.1% | 0.7% | 1.2% |
| Boiler Fuel Supply to Bunker | 0.4% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 8.5% | 1.2% |
| All Other Causes | 13.6% | 31.8% | 41.2% | 49.2% | 39.2% | 38.8% | 16.9% | 18.0% |
| Total | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% |

Table 5-36 shows the categories which are included in the economic category.[133] Lack of fuel that is considered outside management control accounted for 63.4 percent of all economic reasons.

OMC lack of fuel is described as "Lack of fuel where the operator is not in control of contracts, supply lines, or delivery of fuels."[134] Only a handful of units use other economic problems to describe outages. Other economic problems are not defined by NERC GADS and are best described as economic problems that cannot be classified by the other NERC GADS economic problem cause codes. Lack of water events occur when a hydroelectric plant does not have sufficient fuel (water) to operate.

### Table 5-36 Contributions to Economic Outages: 2017

| | Contribution to Economic Reasons |
|---|---|
| Lack of fuel (OMC) | 62.9% |
| Lack of fuel (Non-OMC) | 24.3% |
| Lack of water (hydro) | 5.2% |
| Other economic problems | 5.1% |
| Fuel conservation | 1.1% |
| Ground water or other water supply problems | 0.7% |
| Problems with primary fuel for units with secondary fuel operation | 0.7% |
| Wet fuel (biomass) | 0.3% |
| Total | 100.0% |

## EFORd, XEFORd and EFORp

The equivalent forced outage rate during peak hours (EFORp) is a measure of the probability that a generating unit will fail, either partially or totally, to perform when it is needed to operate during the peak hours of the day in the peak months of January, February, June, July and August. EFORp is calculated using historical performance data and is designed to measure if a unit would have run had the unit not been forced out. Like XEFORd, EFORp excludes OMC outages. PJM systemwide EFORp is a capacity-weighted average of individual unit EFORp.

133 The definitions of these outages are defined by NERC GADS.
134 The definitions of these outages are defined by NERC GADS.

Until the capacity performance market design is fully implemented for the 2020/2021 Delivery Year, EFORp will be used in the calculation of 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 next weekend.[135] 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 5-37 shows the capacity-weighted class average of EFORd, XEFORd and EFORp.

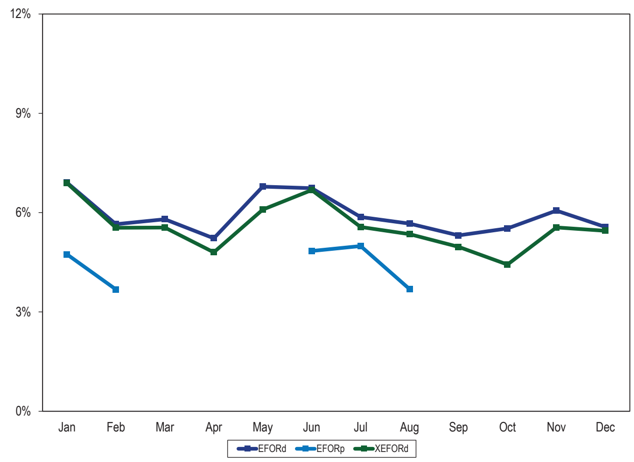
### Table 5-37 PJM EFORd, XEFORd and EFORp data by unit type: 2017[136]

| | EFORd | XEFORd | EFORp | Difference EFORd and XEFORd | Difference EFORd and EFORp |
|---|---|---|---|---|---|
| Coal | 12.0% | 12.0% | 10.3% | 0.1% | 1.7% |
| Combined Cycle | 2.5% | 2.3% | 1.2% | 0.2% | 1.3% |
| Combustion Turbine | 5.5% | 4.8% | 2.4% | 0.7% | 3.1% |
| Diesel | 6.4% | 5.8% | 3.8% | 0.6% | 2.6% |
| Hydroelectric | 2.8% | 2.8% | 2.3% | 0.0% | 0.5% |
| Nuclear | 0.6% | 0.6% | 1.0% | 0.0% | (0.4%) |
| Other | 13.9% | 10.6% | 3.9% | 3.3% | 10.0% |
| Total | 6.8% | 6.3% | 4.7% | 0.5% | 2.1% |

## Performance by Month

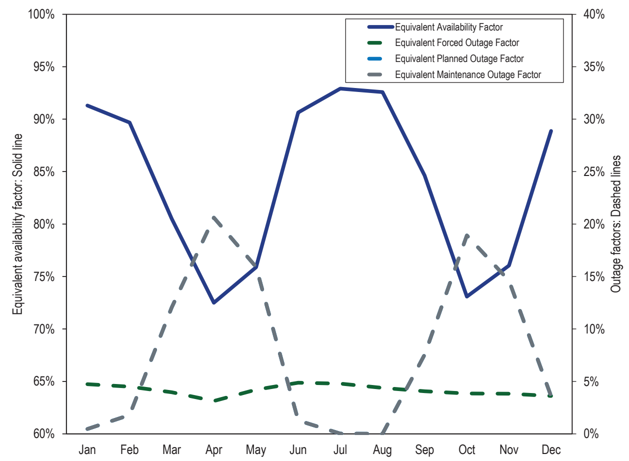
On a monthly basis, EFORp values were less than EFORd and XEFORd values as shown in Figure 5-12, demonstrating that units had fewer non-OMC outages during peak hours than would have been expected based on EFORd.

### Figure 5-12 PJM EFORd, XEFORd and EFORp: 2017




On a monthly basis, unit availability as measured by the equivalent availability factor is shown in Figure 5-13.

### Figure 5-13 PJM monthly generator performance factors: 2017




135 See "PJM Manual 22: Generator Resource Performance Indices," Rev. 17 (April 1, 2017), Definitions.

136 EFORp is only calculated for the peak months of January, February, June, July and August.

# Demand Response

Markets require both a supply side and a demand side to function effectively. The demand side of wholesale electricity markets is underdeveloped. Wholesale power markets will be more efficient when the demand side of the electricity market becomes fully functional without depending on special programs as a proxy for full participation.

## Overview

- **Demand Response Activity.** Demand response activity includes economic demand response (economic resources), emergency and pre-emergency demand response (demand resources), synchronized reserves and regulation. Economic demand response participates in the energy market. Emergency and pre-emergency demand response participates in the capacity market and energy market.[1] Demand response resources participate in the Synchronized Reserve Market. Demand response resources participate in the regulation market.

  In 2017, total demand response revenue decreased by $154.4 million, 23.5 percent, from $657.1 million in 2016 to $502.6 million in 2017. Emergency demand response revenue accounted for 98.5 percent of all demand response revenue, economic demand response for 0.5 percent, demand response in the Synchronized Reserve Market for 0.6 percent and demand response in the regulation for 0.4 percent.

  Total emergency demand response revenue decreased by $153.8 million, 23.7 percent, from $649.0 million in 2016 to $495.2 million in 2017. This consisted entirely of a $153.8 million, 23.7 percent, reduction in capacity market revenue from $649.0 million in 2016 to $495.2 million in 2017.[2]

  Economic demand response revenue decreased by $0.9 million, 26.3 percent, from $3.5 million in 2016 to $2.6 million in 2017.[3] Demand response revenue in the Synchronized Reserve Market decreased by $0.5 million, 13.4 percent, from $3.4 million in 2016 to $3.0 million in 2017. Demand response revenue in the regulation market increased by $0.8 million, 69.0 percent, from $1.1 million in 2016 to $1.8 million in 2017.

- **Demand Response Energy Payments are Uplift.** Energy payments to emergency and economic demand response resources are uplift. LMP does not cover energy payments although emergency and economic demand response can and does set LMP. Energy payments to emergency demand resources are paid by PJM market participants in proportion to their net purchases in the real-time market. Energy payments to economic demand resources are paid by real-time exports from PJM 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 or equal to the net benefits test price for that month.[4]

- **Demand Response Market Concentration.** The ownership of economic demand response resources was highly concentrated in 2016 and 2017. The HHI for economic resource reductions decreased from 7658 in 2016 to 7599 in 2017. The ownership of emergency demand response resources was moderately concentrated in 2017. The HHI for emergency demand response committed MW was 1433 for the 2017/2018 Delivery Year. In the 2017/2018 Delivery Year, the four largest companies contributed 69.6 percent of all committed emergency demand response MW.

- **Limited Locational Dispatch of Demand Resources.** Beginning with the 2014/2015 Delivery Year, demand resources are dispatchable for mandatory reductions 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. Nodal dispatch of demand resources in a nodal market would improve market efficiency. The goal should be nodal dispatch of demand resources with no advance notice required, as is the case for generation resources.

1 Emergency demand response refers to both emergency and pre-emergency demand response. With the implementation of the Capacity Performance design, there is no functional difference between the emergency and pre-emergency demand response resource.

2 The total credits and MWh numbers for demand resources were calculated as of February 19, 2018 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," Rev. 77 (Nov. 1, 2017) at 83.

## 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 December 31, 2017.

- The MMU recommends, as a preferred alternative to including demand resources as supply in the capacity market, that demand resources be on the demand side of the markets, that customers be able to avoid capacity and energy charges by not using capacity and energy at their discretion, that customer payments be determined only by metered load, and that PJM forecasts immediately incorporate the impacts of demand side behavior. (Priority: High. First reported 2014. Status: Not adopted.)
- The MMU recommends that the option to specify a minimum dispatch price (strike price) for demand resources 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 maximum offer for demand resources be the same as the maximum offer for generation resources. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that the demand resources be treated as an economic resource, responding to economic price signals like other capacity resources. The MMU recommends that demand resources not be treated as emergency resources, not trigger a PJM emergency and not trigger a Performance Assessment Hour. (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.)

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 October 17, 2017) 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 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: Partially 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 must terminate or modify registrations that are no longer capable of responding to PJM dispatch directives at defined levels because load has been reduced or eliminated, 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 subzones 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 in the capacity market, 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 setting 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 the Relative Root Mean Squared Test be required for all demand resources with a CBL. (Priority: Low. New recommendation. Status: Partially adopted.)
- The MMU recommends that PRD be required to respond during a PAH to be consistent with all CP resources. (Priority: High. New recommendation. Status: Not adopted.)
- The MMU recommends capping the baseline for measuring compliance under GLD, for the limited summer product, at the customers' PLC. (Priority: High. First reported 2010. Status: Adopted 2015.)
- The MMU recommends that demand resources whose technology type (load drop method) is designated as "Other" explicitly record the technology type. (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.

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.

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. The Capacity Performance demand response product definition in the PJM Capacity Performance capacity market design is a significant step in that direction, although performance obligations are still not identical to other capacity resources.

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. The fact that PJM currently defines demand resources as emergency resources and the fact that calling on demand resources triggers a performance assessment hour under the Capacity Performance design, both serve as a significant disincentive to calling on demand resources. Demand resources should be treated as economic resources like any other capacity resource. Demand resources should be called when economic and paid the LMP rather than an inflated strike price up to $1,849 per MWh that is set by the seller.

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 or modify registrations that are no longer capable of responding to PJM dispatch directives at the specified level, 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 resources should be on the demand side of the capacity market rather than on the supply side. Rather than detailed 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 and the level of usage paid for would be defined by metered usage rather than a complex and inaccurate measurement protocol.

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 CP design in the capacity market. 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 PJM demand response programs can be grouped into economic, emergency and pre-emergency programs or Price Responsive Demand (PRD). Under current rules, there is no functional difference between pre-emergency and emergency demand resources. Table 6-1 provides an overview of the key features of PJM demand response programs.

Demand response activity includes economic demand response (economic resources), emergency and pre-emergency demand response (demand resources), synchronized reserves and regulation. Economic demand response participates in the energy market. Emergency and pre-emergency demand response participates in the capacity market and energy market.[8] Demand response resources participate in the Synchronized Reserve Market. Demand response resources participate in the regulation 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 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 programs, but a participant can register as a PJM special member and become a CSP without any additional cost. PRD does not

8 Emergency demand response refers to both emergency and pre-emergency demand response. With the implementation of the Capacity Performance design, there is no functional difference between the emergency and pre-emergency demand response resource.

9 OA Schedule 1 § 8.5.

receive capacity or energy payments. PRD reduces the amount of capacity that must be purchased by the LSE and therefore reduces the LSE's payments for capacity. When PRD load is not on the system, that load also avoids paying for the associated energy. PRD meets its obligation by responding when LMP is at or above price thresholds defined in the PRD plan.[10] PRD does not have to respond during performance assessment hours (PAH) and therefore is inferior to other capacity resources and is not a substitute for other capacity resources in the capacity performance construct. The MMU recommends that PRD be required to respond during a PAH to be consistent with all CP resources. PRD cleared the capacity market in the BRA for the first time for the 2020/2021 Delivery Year.

### Table 6-1 Overview of demand response programs

| | Emergency and Pre-Emergency Load Response Program | | | Economic Load Response Program | Price Responsive Demand |
|---|---|---|---|---|---|
| | Load Management (LM) | | | | |
| Market | Capacity Only | Capacity and Energy | Energy Only | Energy Only | Capacity Only |
| Capacity Market | DR cleared in RPM | DR cleared in RPM | Not included in RPM | Not included in RPM | PRD cleared in RPM |
| Dispatch Requirement | Mandatory Curtailment | Mandatory Curtailment | Voluntary Curtailment | Dispatched Curtailment | Price Threshold |
| Penalties | RPM event or test compliance penalties | RPM event or test compliance penalties | NA | NA | RPM event or test compliance penalties |
| Capacity Payments | Capacity payments based on RPM clearing price | Capacity payments based on RPM clearing price | NA | NA | Avoided capacity costs |
| 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. | NA |

## Non-PJM Demand Response Programs

Within the PJM footprint, states may have additional demand response programs as part of a Renewable Portfolio Standard (RPS) or a separate program. Indiana, Ohio, Pennsylvania and North Carolina include demand response in their RPS.[11] If demand response is dispatched by a state run program, the demand response resources are ineligible to receive payments from PJM during the state dispatch.

## 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 included in customers' tariff rates.

On July 16, 2008, the Commission directed PJM to amend their market rules to accept bids from aggregators of retail customers of utilities with the permission of the relevant electric retail regulatory authority ("RERRA").[12] PJM implemented rules that require small EDCs to demonstrate approval of participation by the RERRA and require large EDCs to demonstrate that the RERRA has not prohibited participation.[13] [14] RERRAs have permitted EDCs, in a number of cases, to participate in the PJM Economic Load Response Program.[15]

Figure 6-1 shows all revenue from PJM demand response programs by market for 2008 through 2017. Since the implementation of the RPM Capacity Market on June 1,

10 The Demand Response Subcommittee (DRSC) is currently working to align PRD with the CP designed products.

11 *2017 State of the Market Report for PJM*, Volume 2, Section 8: Environmental and Renewables, Table 8-6.

12 *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, FERC Stats. & Regs. ¶ 31,281 at P 154 (2008), *order on reh'g*, Order No. 719-A, FERC Stats. & Regs. ¶ 31,292, *order on reh'g*, Order No. 719-B, 129 FERC ¶ 61,252 (2009).

13 OA Schedule 1 § 1.5A.3.01. An EDC is classified as a small EDC if it distributes less than four million MWh in the last fiscal year.

14 The evidence supplied must take the form of an order, resolution or ordinance of the RERRA, an opinion of the RERRA's legal counsel attesting to existence of an order, resolution, or ordinance, or an opinion of the state attorney general on behalf of the RERRA attesting to existence of an order, resolution or ordinance.

15 *Id.*; *see, e.g., Bear Island Paper Company, L.P.*, Va. S.C.C. Case No. PUE-2009-00133 (March 10, 2010); Petition for Approval of Demand Response Program and Associated Demand Response Tariffs on Behalf of Kingsport Power Company, Etc., Tenn. PUC, 304 P.U.R.4th 224 (March 1, 2013); *Application of East Kentucky Power Cooperative, Inc. for a Declaratory Order, Etc.*, 2017 Ky. P.U.C. LEXIS 569 (June 06, 2017); *The Investigation by the Commission of Relevant Electric Retail Regulatory Authority in Southern Maryland Electric Cooperative Service Territory*, 2017 Ky. 2009 Md. PSC LEXIS 32 (April 27, 2009).

2007, demand resources (capacity market) have been the primary source of demand response revenue.[16] In 2017, demand resource revenue, which includes capacity and emergency energy revenue, accounted for 98.5 percent of all revenue received by demand response providers, the economic program for 0.5 percent, synchronized reserve for 0.6 percent and the regulation market for 0.4 percent.

In 2017, total demand response revenue decreased by $154.4 million, 23.5 percent, from $657.1 million in 2016 to $502.6 million in 2017. Emergency demand response revenue accounted for 98.5 percent of all demand response revenue, economic demand response for 0.5 percent, demand response in the Synchronized Reserve Market for 0.6 percent and demand response in the regulation for 0.4 percent.

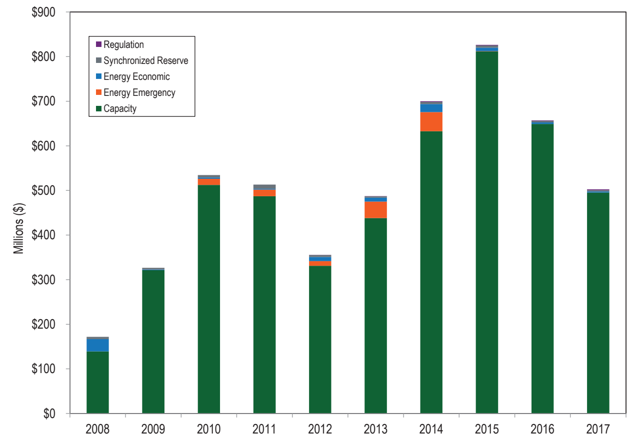
Total emergency demand response revenue decreased by $153.8 million, 23.7 percent, from $649.0 million in 2016 to $495.2 million in 2017. This consisted entirely of a $153.8 million, 23.7 percent, reduction in capacity market revenue from $649.0 million in 2016 to $495.2 million in 2017.[17]

Economic demand response revenue decreased by $0.9 million, 26.3 percent, from $3.5 million in 2016 to $2.6 million in 2017.[18] Demand response revenue in the Synchronized Reserve Market decreased by $0.5 million, 13.4 percent, from $3.4 million in 2016 to $3.0 million in 2017. Demand response revenue in the regulation market increased by $0.8 million, 69.0 percent, from $1.1 million in 2016 to $1.8 million in 2017.

Lower demand resource revenues were in part a result of lower capacity market prices in 2017. The capacity revenue in 2016 is from 2015/2016 and 2016/2017 RPM auction clearing prices and the capacity revenue in 2017 is from 2016/2017 and 2017/2018 RPM auction clearing prices. Weighted average capacity market prices decreased $10 per MW-day from $133 in the 2016 to $123 in the 2017, a 7.5 percent decrease.[19]

16 This includes both capacity market revenue and emergency energy revenue for capacity resources.
17 The total credits and MWh numbers for demand resources were calculated as of February 19, 2018 and may change as a result of continued PJM billing updates.
18 Economic credits are synonymous with revenue received for reductions under the economic load response program.
19 *2017 State of the Market Report for PJM*, Volume 2, Section 7: Net Revenues, Table 7-6.

**Figure 6-1 Demand response revenue by market: 2008 through 2017**




## Economic Program

FERC Order No. 831 requires all energy offers above $1,000 per MWh to provide supporting documentation.[20] Economic resources offer into the energy market and must provide supporting documentation to offer above $1,000 per MWh. FERC stated, "[t]he offer cap reforms, however, do not apply to capacity-only demand response resources that do not submit incremental energy offers into energy markets."[21] Demand resources participate in both the capacity and energy markets and are not capacity only resources. It is not clear whether FERC intended to exclude demand resources with high strike prices from the requirements of Order 831. Demand resources should not be permitted to make offers above $1,000 per MWh without the same verification requirements applied to economic resources or generation resources. The MMU recommends that the rules for maximum offer for the emergency and pre-emergency program match the maximum offer for generation resources.

Table 6-2 shows registered sites and MW for the last day of each month for the period January 1, 2010, through December 31, 2017. Registration is a prerequisite for CSPs to participate in the economic program. The monthly average number of registrations for economic demand response increased and the monthly average registered MW decreased in 2017 compared to 2016. Average monthly registrations decreased by 68, 8.8 percent, from 774 in 2016 to 706 in 2017. Average monthly registered

20 157 FERC ¶ 61,115 (2016).
21 *Id.* at 8.

MW decreased by 547 MW, 21.5 percent, from 2,547 MW in 2016 to 2,000 MW in 2017.

Several demand response resources are registered for both the economic and emergency demand response programs. There were 1,671 registrations and 1,265 nominated MW in the emergency program also registered in the economic program during 2017.

### Table 6-2 Economic program registrations on the last day of the month: 2010 through 2017

| | 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 | 2,578 |
| 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 | 2,576 |
| 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 | 897 | 2,574 |
| 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 | 977 | 2,626 |
| Jun | 813 | 1,608 | 1,143 | 1,912 | 803 | 2,347 | 1,302 | 2,144 | 928 | 2,943 | 871 | 2,614 | 518 | 2,500 | 577 | 1,305 |
| 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 | 589 | 1,548 |
| 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 | 590 | 1,541 |
| 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 | 588 | 1,663 |
| 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 | 574 | 1,660 |
| 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 | 559 | 1,662 |
| 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 | 556 | 1,659 |
| 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 | 706 | 2,000 |

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 up to the amount of MW registered in the program. Table 6-3 shows the sum of peak economic MW dispatched by registration each month from January 1, 2010, through December 31, 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 234 MW, 16.1 percent, from 1,451 MW in 2016 to 1,217 MW in 2017.[22] The peak dispatched MW in 2017, 1,217 MW, were 783 MW less than the average MW registered in 2017, 2,000 MW.

### Table 6-3 Sum of peak MW reductions for all registrations per month: 2010 through 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 | 83 |
| Mar | 115 | 81 | 72 | 127 | 369 | 198 | 120 | 111 |
| Apr | 111 | 80 | 108 | 133 | 146 | 143 | 118 | 54 |
| May | 172 | 98 | 143 | 192 | 151 | 161 | 131 | 169 |
| Jun | 209 | 561 | 954 | 433 | 483 | 833 | 121 | 240 |
| Jul | 999 | 561 | 1,631 | 1,088 | 665 | 1,362 | 1,316 | 936 |
| Aug | 794 | 161 | 952 | 497 | 358 | 272 | 249 | 141 |
| Sep | 276 | 84 | 451 | 530 | 795 | 816 | 263 | 140 |
| Oct | 118 | 81 | 242 | 168 | 214 | 136 | 150 | 88 |
| Nov | 111 | 86 | 165 | 155 | 166 | 127 | 116 | 81 |
| Dec | 114 | 88 | 98 | 168 | 155 | 122 | 147 | 83 |
| Annual | 1,202 | 840 | 1,942 | 1,486 | 1,739 | 1,858 | 1,451 | 1,217 |

Emergency and economic demand response energy payments are uplift and not compensated by LMP revenues. 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.[23] The zonal allocation is shown in Table 6-13.

22 The total credits and MWh numbers for demand resources were calculated as of February 19, 2018 and may change as a result of continued PJM billing updates.

23 "PJM Manual 28: Operating Agreement Accounting," Rev. 77 (Nov. 1, 2017) at 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 2010 through 2017. The average credits per MWh paid decreased by $1.51 per MWh, 3.5 percent, from $43.35 per MWh in 2016 to $41.83 per MWh in 2017. The load-weighted, average LMP was 6.0 percent higher in 2017 than in 2016, $30.85 per MWh versus $29.68 per MWh. Curtailed energy for the economic program decreased by 19,315 MWh, 23.6 percent, from 81,908 MWh in 2016 to 62,592 MWh in 2017. Total credits paid for economic DR in 2017 decreased by $0.9 million, 26.3 percent, from $3.6 million in 2016 to $2.6 million in 2017.

### Table 6-4 Credits paid to the PJM economic program participants: 2010 through 2017

| Year | Total MWh | Total Credits | $/MWh |
|---|---|---|---|
| 2010 | 72,757 | $3,088,049 | $42.44 |
| 2011 | 17,398 | $2,052,996 | $118.00 |
| 2012 | 144,285 | $9,278,942 | $64.31 |
| 2013 | 133,963 | $8,711,873 | $65.03 |
| 2014 | 146,301 | $17,820,063 | $121.80 |
| 2015 | 121,129 | $7,983,488 | $65.91 |
| 2016 | 81,908 | $3,550,535 | $43.35 |
| 2017 | 62,592 | $2,618,453 | $41.83 |

Economic demand response resources that are dispatched by PJM in both the economic and emergency programs are paid the higher price defined in the 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. Payment at a guaranteed strike price and the ability to set energy market prices at the strike price effectively grant the seller the right to exercise market power.

Figure 6-2 shows monthly economic demand response credits and MWh, from 2010 through 2017.

### Figure 6-2 Economic program credits and MWh by month: 2010 through 2017

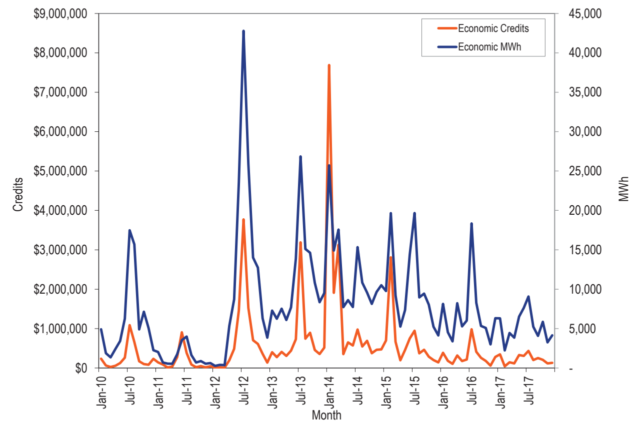



Table 6-5 shows performance for 2016 and 2017 in the economic program by control zone. Total reductions under the economic program decreased by 19,315 MWh, 23.6 percent, from 81,908 MW in 2016 to 62,592 MW in 2017. Total revenue under the economic program decreased by $0.9 million, 25.1 percent, from $3.5 million in 2016 to $2.6 million in 2017.[24]

24 Economic demand response reductions that are submitted to PJM for payment but have not received payment are not included in Table 6-5. Payments for Economic demand response reductions are settled monthly.

Table 6-5 PJM economic program participation by zone: 2016 and 2017

| | Credits | | | MWh Reductions | | | Credits per MWh Reduction | | |
|---|---|---|---|---|---|---|---|---|---|
| Zones | 2016 | 2017 | Percent Change | 2016 | 2017 | Percent Change | 2016 | 2017 | Percent Change |
| AECO | $5,900.85 | | NA | 110 | | NA | $53.78 | | |
| AEP | | $8.84 | NA | | 0 | NA | | $42.19 | |
| APS | $55,986.65 | $30,642.02 | (45.3%) | 1,294 | 715 | (44.7%) | $43.28 | $42.83 | (1.0%) |
| ATSI | $424,167.28 | $316,133.07 | (25.5%) | 10,615 | 7,157 | (32.6%) | $39.96 | $44.17 | 10.5% |
| BGE | $488,046.57 | $133,084.25 | (72.7%) | 8,608 | 2,503 | (70.9%) | $56.70 | $53.17 | (6.2%) |
| ComEd | $247,115.57 | $192,679.41 | (22.0%) | 6,363 | 5,861 | (7.9%) | $38.83 | $32.88 | (15.3%) |
| DEOK | $28,324.20 | $21,122.21 | (25.4%) | 287 | 159 | (44.7%) | $98.81 | $133.21 | 34.8% |
| Dominion | $1,053,247.70 | $513,393.00 | (51.3%) | 22,249 | 7,862 | (64.7%) | $47.34 | $65.30 | 37.9% |
| DPL | $3,554.14 | $11,019.81 | 210.1% | 410 | 516 | 25.8% | $8.66 | $21.36 | 146.6% |
| JCPL | $176,199.52 | $85,579.20 | (51.4%) | 3,051 | 1,242 | (59.3%) | $57.75 | $68.92 | 19.3% |
| Met-Ed | $5,611.67 | $12,250.98 | 118.3% | 137 | 287 | 110.2% | $41.03 | $42.62 | 3.9% |
| PECO | $44,694.83 | $72,852.17 | 63.0% | 495 | 572 | 15.5% | $90.27 | $127.44 | 41.2% |
| PENELEC | $397,384.52 | $359,721.07 | (9.5%) | 11,592 | 11,166 | (3.7%) | $34.28 | $32.22 | (6.0%) |
| Pepco | $0.00 | $53,642.85 | NA | 1,009 | 1,095 | 8.5% | | $49.00 | |
| PPL | $85,895.37 | $71,121.76 | (17.2%) | 1,764 | 1,890 | 7.1% | $48.69 | $37.64 | (22.7%) |
| PSEG | $478,481.07 | $745,202.52 | 55.7% | 13,924 | 21,568 | 54.9% | $34.36 | $34.55 | 0.5% |
| Total | $3,494,609.95 | $2,618,444.32 | (25.1%) | 81,908 | 62,592 | (23.6%) | $42.67 | $41.83 | (1.9%) |

Table 6-6 shows total settlements submitted for 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: 2010 through 2017

| Year | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 |
|---|---|---|---|---|---|---|---|---|
| Number of Settlements | 3,781 | 732 | 5,835 | 2,846 | 3,014 | 2,173 | 1,958 | 1,884 |

Table 6-7 shows the number of CSPs, and the number of participants in their portfolios, submitting settlements by year for 2010 through 2017. The number of active participants increased by 19, 32.8 percent, from 58 in 2016 to 77 in 2017. All participants must be registered through a CSP.

Table 6-7 Participants and CSPs submitting settlements in the economic program by year: 2010 through 2017

| | 2010 | | 2011 | | 2012 | | 2013 | | 2014 | | 2015 | | 2016 | | 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 | 16 | 258 | 15 | 203 | 22 | 428 | 20 | 276 | 18 | 165 | 18 | 116 | 12 | 58 | 13 | 77 |

The ownership of economic demand response resources was highly concentrated in 2016 and 2017.[25] Table 6-8 shows the average hourly HHI for each month and the average hourly HHI for 2016 and 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 2017, 85.8 percent of all economic DR reductions and 84.1 percent of economic DR revenue were attributable to the four largest parent companies. The HHI for economic demand response decreased 60 points, 0.8 percent, from 7658 in 2016 to 7599 in 2017.

25 Parent companies may own one CSP or multiple CSPs. All HHI calculations in this section are at the parent company level.

### Table 6-8 HHI and market concentration in the economic program: 2016 and 2017

| | 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 | 7434 | 8952 | 20.4% | 97.5% | 99.7% | 2.2% | 98.0% | 99.6% | 1.7% |
| Feb | 7697 | 9263 | 20.3% | 100.0% | 100.0% | 0.0% | 100.0% | 100.0% | 0.0% |
| Mar | 8587 | 8170 | (4.9%) | 98.9% | 99.4% | 0.5% | 99.4% | 98.1% | (0.0%) |
| Apr | 6754 | 6099 | (9.7%) | 100.0% | 100.0% | 0.0% | 100.0% | 100.0% | 0.0% |
| May | 8150 | 7046 | (13.5%) | 97.9% | 97.5% | (0.4%) | 96.3% | 92.7% | 1.2% |
| Jun | 7700 | 7702 | 0.0% | 100.0% | 91.6% | (8.4%) | 100.0% | 88.6% | (8.4%) |
| Jul | 7282 | 7876 | 8.2% | 96.0% | 94.3% | (1.7%) | 89.2% | 92.1% | 5.1% |
| Aug | 7557 | 8006 | 5.9% | 93.5% | 99.8% | 6.3% | 89.3% | 99.5% | 10.5% |
| Sep | 7631 | 7877 | 3.2% | 93.8% | 97.1% | 3.3% | 92.7% | 93.0% | 4.4% |
| Oct | 7710 | 6467 | (16.1%) | 100.0% | 99.4% | (0.6%) | 100.0% | 99.1% | (0.6%) |
| Nov | 8856 | 7334 | (17.2%) | 100.0% | 100.0% | 0.0% | 100.0% | 100.0% | 0.0% |
| Dec | 7541 | 7500 | (0.5%) | 93.4% | 100.0% | 6.6% | 92.5% | 100.0% | 7.5% |
| Total | 7658 | 7599 | (0.8%) | 90.6% | 85.8% | (4.8%) | 90.3% | 84.1% | (6.2%) |

### Table 6-9 Hourly frequency distribution of economic program MWh reductions and credits: 2016 and 2017

| | MWh Reductions | | | Program Credits | | |
|---|---|---|---|---|---|---|
| Hour Ending (EPT) | 2016 | 2017 | Percent Change | 2016 | 2017 | Percent Change |
| 1 through 6 | 768 | 641 | (17%) | $19,278 | $39,251 | 104% |
| 7 | 2,730 | 508 | (81%) | $168,162 | $28,022 | (83%) |
| 8 | 4,629 | 1,494 | (68%) | $237,835 | $64,812 | (73%) |
| 9 | 5,394 | 2,619 | (51%) | $201,220 | $86,467 | (57%) |
| 10 | 4,236 | 3,222 | (24%) | $139,874 | $102,158 | (27%) |
| 11 | 3,596 | 3,574 | (1%) | $115,932 | $116,134 | 0% |
| 12 | 3,785 | 3,825 | 1% | $126,167 | $127,195 | 1% |
| 13 | 3,951 | 4,071 | 3% | $136,722 | $147,136 | 8% |
| 14 | 5,592 | 4,907 | (12%) | $256,876 | $198,244 | (23%) |
| 15 | 6,477 | 5,505 | (15%) | $315,655 | $251,993 | (20%) |
| 16 | 7,719 | 5,832 | (24%) | $363,610 | $264,134 | (27%) |
| 17 | 8,170 | 6,028 | (26%) | $390,015 | $325,028 | (17%) |
| 18 | 8,133 | 6,181 | (24%) | $399,443 | $311,834 | (22%) |
| 19 | 6,608 | 5,227 | (21%) | $278,605 | $215,017 | (23%) |
| 20 | 4,841 | 4,403 | (9%) | $171,286 | $167,861 | (2%) |
| 21 | 3,660 | 3,134 | (14%) | $129,381 | $118,260 | (9%) |
| 22 | 934 | 856 | (8%) | $30,253 | $41,860 | 38% |
| 23 through 24 | 685 | 564 | (18%) | $14,296 | $13,046 | (9%) |
| Total | 81,908 | 62,592 | (24%) | $3,494,610 | $2,618,453 | (25%) |

### Table 6-10 Frequency distribution of economic program zonal, load-weighted, average LMP (By hours): 2016 and 2017

| | MWh Reductions | | | Program Credits | | |
|---|---|---|---|---|---|---|
| LMP | 2016 | 2017 | Percent Change | 2016 | 2017 | Percent Change |
| $0 to $25 | 11,422 | 5,145 | (55%) | $231,826 | $76,457 | (67%) |
| $25 to $50 | 53,837 | 42,135 | (22%) | $1,911,159 | $1,362,354 | (29%) |
| $50 to $75 | 8,973 | 9,148 | 2% | $538,363 | $531,066 | (1%) |
| $75 to $100 | 2,757 | 2,925 | 6% | $205,548 | $244,897 | 19% |
| $100 to $125 | 2,519 | 1,382 | (45%) | $254,719 | $134,989 | (47%) |
| $125 to $150 | 1,098 | 942 | (14%) | $139,635 | $114,021 | (18%) |
| $150 to $175 | 548 | 585 | 7% | $69,268 | $86,508 | 25% |
| > $175 | 739 | 324 | (56%) | $143,816 | $68,122 | (53%) |
| Total | 81,891 | 62,585 | (24%) | $3,494,334 | $2,618,413 | (25%) |

Table 6-9 shows average MWh reductions and credits by hour for 2016 and 2017. In 2016, 88.1 percent of reductions and 86.6 percent of credits occurred in hours ending 0900 to 2100, and in 2017, 93.5 percent of reductions and 92.9 percent of credits occurred in hours ending 0900 to 2100.

Table 6-10 shows the distribution of economic program MWh reductions and credits by ranges of real-time zonal, load-weighted, average LMP in 2016 and 2017. In 2017, 0.5 percent of MWh reductions and 2.6 percent of program credits occurred during hours when the applicable zonal LMP was higher than $175 per MWh.

Following 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 2017 was calculated using generation offers from February 2016. 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 one.[26] 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 threshold price used to trigger payments to economic demand response resources throughout the entire RTO, regardless of their location and regardless of locational prices.

The necessity for the NBT test is an illustration of the illogical approach to demand side compensation embodied in paying full LMP

26 "PJM Manual 11: Energy & Ancillary Services Market Operations," Rev. 92 (Nov. 1, 2017) at 146.

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.

When the zonal LMP is above the NBT threshold price, economic demand response resources that reduce their power consumption are paid the full zonal LMP. When the zonal 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 1, 2012, when Order No. 745 was implemented in PJM, through December 31, 2017.

### Table 6-11 Net benefits test threshold prices: April 1, 2012 through December 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 | $30.45 |
| May | $23.46 | $27.73 | $32.08 | $23.79 | $20.69 | $29.77 |
| Jun | $23.86 | $28.44 | $31.62 | $23.80 | $20.62 | $27.14 |
| Jul | $22.99 | $29.42 | $31.62 | $23.03 | $20.73 | $24.42 |
| Aug | $24.47 | $28.58 | $29.85 | $23.17 | $23.24 | $22.75 |
| Sep | $24.93 | $28.80 | $29.83 | $21.69 | $24.70 | $21.51 |
| Oct | $25.96 | $29.13 | $30.20 | $21.48 | $26.50 | $21.70 |
| Nov | $25.63 | $31.63 | $29.17 | $22.28 | $29.27 | $26.41 |
| Dec | $25.97 | $28.82 | $29.01 | $22.31 | $29.71 | $29.16 |
| Average | $24.80 | $28.09 | $30.91 | $23.97 | $23.99 | $27.34 |

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 2017, the highest zonal LMP in PJM was higher than the NBT threshold price 6,069 hours out of 8,760 hours, or 69.3 percent of all hours. Reductions occurred in 3,652 hours, 60.2 percent, of those 6,069 hours in 2017. The last three columns illustrate how often economic demand response activity occurred when LMPs exceeded NBT threshold prices for January 1, 2016 through December 31, 2017. There were 2.0 percent of hours with demand response below the NBT threshold price in 2016 and 5.2 percent of hours with demand response below the NBT threshold price in 2017.

### Table 6-12 Hours with price higher than NBT and DR occurrences in those hours: 2016 and 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 | 690 | 388 | (43.8%) | 47.5% | 63.4% | 15.9% |
| Feb | 696 | 672 | 595 | 414 | (30.4%) | 32.3% | 37.7% | 5.4% |
| Mar | 743 | 743 | 710 | 484 | (31.8%) | 29.0% | 64.3% | 35.2% |
| Apr | 720 | 720 | 692 | 407 | (41.2%) | 60.1% | 72.7% | 12.6% |
| May | 744 | 744 | 602 | 445 | (26.1%) | 70.1% | 76.0% | 5.9% |
| Jun | 720 | 720 | 576 | 421 | (26.9%) | 67.7% | 67.5% | (0.2%) |
| Jul | 744 | 744 | 697 | 546 | (21.7%) | 65.6% | 67.2% | 1.6% |
| Aug | 744 | 744 | 704 | 573 | (18.6%) | 64.2% | 55.7% | (8.5%) |
| Sep | 720 | 720 | 651 | 641 | (1.5%) | 49.0% | 52.4% | 3.4% |
| Oct | 744 | 744 | 693 | 742 | 7.1% | 48.6% | 61.2% | 12.6% |
| Nov | 721 | 721 | 401 | 499 | 24.4% | 52.1% | 59.1% | 7.0% |
| Dec | 744 | 744 | 519 | 509 | (1.9%) | 72.4% | 49.1% | (23.3%) |
| Total | 8,784 | 8,760 | 8,192 | 6,069 | (25.9%) | 59.8% | 60.2% | 0.4% |

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 2017.

### Table 6-13 Zonal DR charge: 2017

| Zone | January | February | March | April | May | June | July | August | September | October | November | December | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| AECO | $4,351 | $186 | $1,126 | $727 | $3,744 | $4,022 | $7,146 | $2,963 | $3,047 | $2,154 | $1,058 | $1,420 | $27,312 |
| AEP | $51,963 | $3,130 | $16,305 | $13,425 | $45,053 | $42,089 | $63,720 | $30,319 | $38,284 | $34,250 | $19,826 | $19,416 | $304,289 |
| APS | $22,797 | $1,432 | $6,373 | $5,307 | $17,411 | $16,590 | $24,253 | $11,580 | $13,926 | $12,875 | $7,941 | $8,622 | $119,667 |
| ATSI | $26,957 | $2,190 | $9,581 | $8,097 | $24,539 | $24,744 | $35,204 | $16,642 | $21,315 | $18,205 | $10,947 | $10,466 | $169,268 |
| BGE | $16,680 | $1,915 | $4,947 | $4,167 | $12,847 | $13,584 | $18,921 | $8,125 | $9,995 | $8,262 | $4,493 | $5,747 | $91,181 |
| ComEd | $17,767 | $1,894 | $9,538 | $7,797 | $23,901 | $35,092 | $54,834 | $23,991 | $34,399 | $24,993 | $13,269 | $9,203 | $209,214 |
| DAY | $6,596 | $584 | $2,295 | $2,352 | $6,831 | $6,129 | $8,898 | $4,363 | $5,642 | $4,772 | $2,821 | $2,711 | $43,690 |
| DEOK | $9,180 | $540 | $2,981 | $2,666 | $10,048 | $9,135 | $14,564 | $6,995 | $8,656 | $7,136 | $3,790 | $3,746 | $64,765 |
| Dominion | $50,509 | $2,916 | $13,496 | $12,459 | $40,095 | $37,828 | $58,576 | $25,472 | $29,869 | $25,860 | $14,145 | $17,571 | $271,219 |
| DPL | $9,422 | $3,025 | $2,399 | $1,638 | $6,513 | $6,897 | $11,370 | $4,752 | $5,202 | $4,464 | $2,157 | $3,270 | $51,217 |
| DLCO | $5,236 | $348 | $1,694 | $1,511 | $5,348 | $5,075 | $7,590 | $3,589 | $4,424 | $3,765 | $2,079 | $2,042 | $34,815 |
| EKPC | $5,657 | $280 | $1,511 | $1,080 | $4,171 | $3,929 | $6,827 | $2,971 | $3,628 | $3,143 | $1,614 | $1,588 | $30,055 |
| JCPL | $10,106 | $1,241 | $3,012 | $2,162 | $9,747 | $10,476 | $15,617 | $6,502 | $7,248 | $4,808 | $2,458 | $3,496 | $66,112 |
| Met-Ed | $6,970 | $560 | $2,270 | $2,586 | $5,881 | $5,603 | $8,117 | $3,730 | $4,537 | $3,171 | $2,042 | $2,637 | $40,254 |
| PECO | $17,178 | $695 | $4,851 | $4,196 | $15,575 | $14,885 | $23,282 | $10,095 | $12,135 | $9,139 | $4,407 | $6,227 | $102,894 |
| PENELEC | $7,453 | $830 | $2,271 | $2,774 | $5,916 | $4,998 | $7,223 | $3,678 | $4,798 | $4,683 | $2,760 | $2,907 | $39,943 |
| Pepco | $14,713 | $1,276 | $4,379 | $3,980 | $12,786 | $12,691 | $18,568 | $7,931 | $9,624 | $8,186 | $4,374 | $5,235 | $85,948 |
| PPL | $19,561 | $1,853 | $6,217 | $3,928 | $13,841 | $13,880 | $19,520 | $9,219 | $11,232 | $8,180 | $4,099 | $6,762 | $99,251 |
| PSEG | $18,859 | $2,788 | $5,675 | $4,265 | $17,954 | $18,984 | $27,026 | $11,588 | $13,710 | $10,350 | $5,445 | $6,685 | $120,849 |
| RECO | $601 | $89 | $175 | $146 | $703 | $751 | $1,044 | $438 | $515 | $364 | $197 | $217 | $4,464 |
| Exports | $24,075 | $14,581 | $11,475 | $23,798 | $22,268 | $17,656 | $15,086 | $5,113 | $8,910 | $6,988 | $5,068 | $10,159 | $142,962 |
| Total | $346,632 | $42,353 | $112,574 | $109,060 | $305,174 | $305,037 | $447,387 | $200,056 | $251,096 | $205,748 | $114,991 | $130,124 | $2,570,232 |

Table 6-14 shows the total zonal DR charge per MWh of real-time load and exports in 2017. On a dollar per MWh basis, real-time load and exports in JCPL and PSEG paid the highest charges for economic demand response in 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: 2017

| Zone | January | February | March | April | May | June | July | August | September | October | November | December | Zonal Average |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| AECO | $0.019 | $0.005 | $0.010 | $0.017 | $0.004 | $0.006 | $0.004 | $0.005 | $0.005 | $0.013 | $0.006 | $0.008 | $0.008 |
| AEP | $0.020 | $0.005 | $0.009 | $0.013 | $0.004 | $0.005 | $0.004 | $0.005 | $0.004 | $0.011 | $0.004 | $0.006 | $0.007 |
| APS | $0.019 | $0.005 | $0.009 | $0.014 | $0.004 | $0.005 | $0.004 | $0.006 | $0.004 | $0.011 | $0.004 | $0.006 | $0.008 |
| ATSI | $0.018 | $0.005 | $0.009 | $0.012 | $0.004 | $0.005 | $0.004 | $0.006 | $0.004 | $0.011 | $0.004 | $0.006 | $0.007 |
| BGE | $0.018 | $0.004 | $0.008 | $0.015 | $0.004 | $0.004 | $0.004 | $0.006 | $0.005 | $0.011 | $0.004 | $0.005 | $0.007 |
| ComEd | $0.013 | $0.005 | $0.009 | $0.010 | $0.004 | $0.005 | $0.005 | $0.006 | $0.004 | $0.010 | $0.005 | $0.007 | $0.007 |
| DAY | $0.018 | $0.005 | $0.008 | $0.012 | $0.004 | $0.005 | $0.004 | $0.006 | $0.005 | $0.011 | $0.004 | $0.006 | $0.007 |
| DEOK | $0.020 | $0.005 | $0.009 | $0.014 | $0.004 | $0.005 | $0.004 | $0.006 | $0.004 | $0.011 | $0.004 | $0.006 | $0.008 |
| Dominion | $0.019 | $0.004 | $0.009 | $0.013 | $0.004 | $0.005 | $0.004 | $0.006 | $0.004 | $0.011 | $0.004 | $0.005 | $0.007 |
| DPL | $0.019 | $0.004 | $0.010 | $0.017 | $0.004 | $0.006 | $0.004 | $0.006 | $0.006 | $0.013 | $0.005 | $0.007 | $0.008 |
| DLCO | $0.019 | $0.005 | $0.009 | $0.015 | $0.004 | $0.005 | $0.004 | $0.006 | $0.004 | $0.012 | $0.004 | $0.006 | $0.008 |
| EKPC | $0.022 | $0.004 | $0.009 | $0.014 | $0.004 | $0.005 | $0.004 | $0.005 | $0.004 | $0.011 | $0.004 | $0.006 | $0.008 |
| JCPL | $0.018 | $0.005 | $0.011 | $0.020 | $0.004 | $0.006 | $0.004 | $0.006 | $0.008 | $0.013 | $0.006 | $0.008 | $0.009 |
| Met-Ed | $0.018 | $0.005 | $0.011 | $0.016 | $0.004 | $0.006 | $0.004 | $0.008 | $0.006 | $0.013 | $0.006 | $0.007 | $0.009 |
| PECO | $0.019 | $0.005 | $0.010 | $0.017 | $0.004 | $0.006 | $0.004 | $0.006 | $0.004 | $0.014 | $0.006 | $0.008 | $0.008 |
| PENELEC | $0.018 | $0.005 | $0.008 | $0.014 | $0.004 | $0.005 | $0.004 | $0.008 | $0.007 | $0.011 | $0.005 | $0.006 | $0.008 |
| Pepco | $0.018 | $0.004 | $0.009 | $0.015 | $0.004 | $0.005 | $0.004 | $0.006 | $0.005 | $0.011 | $0.004 | $0.005 | $0.007 |
| PPL | $0.018 | $0.004 | $0.010 | $0.017 | $0.004 | $0.006 | $0.004 | $0.006 | $0.007 | $0.013 | $0.006 | $0.007 | $0.009 |
| PSEG | $0.018 | $0.005 | $0.010 | $0.018 | $0.004 | $0.006 | $0.004 | $0.006 | $0.009 | $0.013 | $0.006 | $0.007 | $0.009 |
| RECO | $0.017 | $0.005 | $0.011 | $0.019 | $0.004 | $0.006 | $0.004 | $0.006 | $0.008 | $0.013 | $0.006 | $0.008 | $0.009 |
| Exports | $0.008 | $0.003 | $0.005 | $0.007 | $0.004 | $0.002 | $0.004 | $0.009 | $0.009 | $0.006 | $0.003 | $0.003 | $0.005 |
| Monthly Average | $0.018 | $0.005 | $0.009 | $0.015 | $0.004 | $0.005 | $0.004 | $0.006 | $0.006 | $0.012 | $0.005 | $0.006 | $0.008 |

Table 6-15 shows the monthly day-ahead and real-time DR charges and the per MWh DR charges for January 1, 2016, through December 31, 2017. The day-ahead DR charges decreased by $0.3 million, 26.1 percent, from $1.1 million in 2016 to $0.8 million in 2017. The real-time DR charges decreased $0.6 million, 24.6 percent, from $2.4 million in 2016 to $1.8 million in 2017. The per MWh charge paid by all real-time load and exports for economic DR decreased $0.005/MWh, 39.5 percent, from $0.013/MWh in 2016 to $0.008/MWh in 2017.

Table 6-15 Monthly day-ahead and real-time economic DR charge: 2016 and 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 | $35,134 | (78.5%) | $222,281 | $311,498 | 40.1% | $0.010 | $0.018 | 78.3% |
| Feb | $64,230 | $25,562 | (60.2%) | $117,388 | $16,797 | (85.7%) | $0.022 | $0.005 | (79.3%) |
| Mar | $14,620 | $70,093 | 379.4% | $90,349 | $75,293 | (16.7%) | $0.002 | $0.009 | 360.9% |
| Apr | $94,264 | $87,514 | (7.2%) | $223,013 | $27,455 | (87.7%) | $0.009 | $0.015 | 62.9% |
| May | $64,480 | $75,756 | 17.5% | $111,839 | $251,622 | 125.0% | $0.010 | $0.004 | (61.3%) |
| Jun | $71,162 | $132,225 | 85.8% | $144,731 | $172,812 | 19.4% | $0.004 | $0.005 | 25.2% |
| Jul | $310,567 | $100,525 | (67.6%) | $621,940 | $334,151 | (46.3%) | $0.063 | $0.004 | (93.5%) |
| Aug | $98,494 | $64,713 | (34.3%) | $312,815 | $135,343 | (56.7%) | $0.010 | $0.006 | (39.2%) |
| Sep | $58,644 | $79,924 | 36.3% | $191,658 | $171,172 | (10.7%) | $0.014 | $0.006 | (59.6%) |
| Oct | $40,868 | $74,161 | 81.5% | $136,214 | $131,587 | (3.4%) | $0.003 | $0.012 | 285.0% |
| Nov | $24,038 | $23,472 | (2.4%) | $35,821 | $91,519 | 155.5% | $0.001 | $0.005 | 377.4% |
| Dec | $122,480 | $64,310 | (47.5%) | $159,075 | $65,814 | (58.6%) | $0.002 | $0.006 | 221.6% |
| Total | $1,127,485 | $833,390 | (26.1%) | $2,367,124 | $1,785,063 | (24.6%) | $0.013 | $0.008 | (37.5%) |

## Emergency and Pre-Emergency Programs

The emergency and pre-emergency load response programs consist of the limited, extended summer, annual and capacity performance demand response products. Full implementation of the Capacity Performance design for the 2020/2021 Delivery Year onward will require all emergency or pre-emergency demand resource to be registered as an annual capacity resource. Summer period demand response resources are allowed to aggregate with winter period capacity resources to fulfill the annual requirement of the CP design.[27] With the implementation of Capacity Performance, a performance assessment hour (PAH) occurs when emergency or pre-emergency is dispatched. PJM effectively eliminated the difference between pre-emergency and emergency by making both trigger a PAH. To participate as an emergency or pre-emergency demand resource, the CSP must clear MW in an RPM auction. Emergency and pre-emergency resources receive capacity revenue from the capacity market and also receive energy revenue at a predefined strike price from the energy market for reductions during a PJM initiated emergency or pre-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.[28]

The ownership of demand resources was moderately concentrated based on committed MW in the capacity market in the 2017/2018 Delivery Year. The HHI for demand resources was 1433 for the 2017/2018 Delivery Year. In the 2017/2018 Delivery Year, the four largest companies contributed 69.6 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. The ownership of DR was unconcentrated in one LDA in the 2017/2018 Delivery Year. The ownership of DR in four LDAs was moderately concentrated in the 2017/2018 Delivery Year. The ownership of DR in seven LDAs was highly concentrated in the 2017/2018 Delivery Year.

The closed loop interfaces created for the purpose of allowing emergency DR to set price are located in the RTO, MAAC, EMAAC, SWMAAC, DPL-SOUTH, ATSI,

27 Summer period demand response has the same obligations as extended summer demand response. It must be available for June through October and the following May between 10:00AM and 10:00PM. *See* PJM OATT RAA Article 1.

28 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).

ATSI-CLEVELAND and BGE LDAs. The ownership of DR in RTO, SWMAAC, ATSI and ATSI-CLEVELAND LDAs were highly concentrated, the ownership of DR in MAAC and EMAAC LDAs were moderately concentrated during the 2016/2017 Delivery Year. The ownership of DR in the RTO, DPL-SOUTH, ATSI, ATSI-CLEVELAND and BGE LDAs were highly concentrated and the ownership of DR in the MAAC and EMAAC LDAs were moderately concentrated during the 2017/2018 Delivery Year.

### Table 6-16 HHI value for LDAs by delivery year: 2016/2017 and 2017/2018 Delivery Years[29]

| Delivery Year | LDA | UCAP MW | HHI Value |
|---|---|---|---|
| 2016/2017 | RTO | 4,911.1 | 2522 |
| | MAAC | 1,743.3 | 1913 |
| | EMAAC | 1,270.0 | 2045 |
| | SWMAAC | 935.6 | 5178 |
| | DPL-SOUTH | 105.7 | 2338 |
| | PSEG | 395.5 | 1443 |
| | PS-NORTH | 223.4 | 1666 |
| | PEPCO | 663.9 | 3619 |
| | ATSI | 1,343.2 | 2817 |
| | ATSI-CLEVELAND | 468.7 | 3768 |
| 2017/2018 | RTO | 4,018.0 | 2593 |
| | MAAC | 655.7 | 1914 |
| | EMAAC | 1,057.3 | 2093 |
| | DPL-SOUTH | 86.3 | 3145 |
| | PSEG | 236.9 | 1409 |
| | PS-NORTH | 151.5 | 2043 |
| | PEPCO | 608.4 | 3726 |
| | ATSI | 720.8 | 3615 |
| | ATSI-CLEVELAND | 282.4 | 4927 |
| | COMED | 1,470.8 | 3353 |
| | BGE | 790.7 | 5309 |
| | PPL | 650.5 | 2167 |

Table 6-17 shows zonal monthly capacity market revenue to demand resources for 2017. Capacity market revenue decreased in 2017 by $153.8 million, 23.7 percent, from $649.0 million in 2016 to $495.2 million in 2017. This reduction was a result of lower RPM prices and fewer MW of DR cleared in RPM for the 2017/2018 delivery year.

### Table 6-17 Zonal monthly capacity revenue: 2017

| Zone | January | February | March | April | May | June | July | August | September | October | November | December | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| AECO | $638,888 | $577,060 | $638,888 | $618,278 | $638,888 | $474,310 | $490,121 | $490,121 | $474,310 | $490,121 | $474,310 | $490,121 | $6,495,414 |
| AEP, EKPC | $3,402,006 | $3,072,780 | $3,402,006 | $3,292,264 | $3,402,006 | $6,075,467 | $6,277,982 | $6,277,982 | $6,075,467 | $6,277,982 | $6,075,467 | $6,277,982 | $59,909,391 |
| APS | $1,666,929 | $1,505,613 | $1,666,929 | $1,613,157 | $1,666,929 | $3,518,353 | $3,635,631 | $3,635,631 | $3,518,353 | $3,635,631 | $3,518,353 | $3,635,631 | $33,217,137 |
| ATSI | $5,891,717 | $5,321,551 | $5,891,717 | $5,701,661 | $5,891,717 | $3,937,233 | $4,068,474 | $4,068,474 | $3,937,233 | $4,068,474 | $3,937,233 | $4,068,474 | $56,783,956 |
| BGE | $3,467,109 | $3,131,582 | $3,467,109 | $3,355,267 | $3,467,109 | $2,882,337 | $2,978,415 | $2,978,415 | $2,882,337 | $2,978,415 | $2,882,337 | $2,978,415 | $37,448,846 |
| ComEd | $3,079,815 | $2,781,769 | $3,079,815 | $2,980,466 | $3,079,815 | $5,739,694 | $5,931,017 | $5,931,017 | $5,739,694 | $5,931,017 | $5,739,694 | $5,931,017 | $55,944,829 |
| DAY | $463,438 | $418,589 | $463,438 | $448,489 | $463,438 | $732,787 | $757,213 | $757,213 | $732,787 | $757,213 | $732,787 | $757,213 | $7,484,606 |
| DEOK | $596,264 | $538,561 | $596,264 | $577,029 | $596,264 | $658,601 | $680,554 | $680,554 | $658,601 | $680,554 | $658,601 | $680,554 | $7,602,402 |
| DLCO | $2,475,103 | $2,235,577 | $2,475,103 | $2,395,261 | $2,475,103 | $4,301,456 | $4,444,838 | $4,444,838 | $4,301,456 | $4,444,838 | $4,301,456 | $4,444,838 | $42,739,865 |
| Dominion | $1,624,702 | $1,467,472 | $1,624,702 | $1,572,292 | $1,624,702 | $1,445,005 | $1,493,172 | $1,493,172 | $1,445,005 | $1,493,172 | $1,445,005 | $1,493,172 | $18,221,571 |
| DPL | $401,741 | $362,863 | $401,741 | $388,781 | $401,741 | $643,123 | $664,561 | $664,561 | $643,123 | $664,561 | $643,123 | $664,561 | $6,544,479 |
| JCPL | $824,053 | $744,306 | $824,053 | $797,470 | $824,053 | $596,570 | $616,455 | $616,455 | $596,570 | $616,455 | $596,570 | $616,455 | $8,269,464 |
| Met-Ed | $1,158,290 | $1,046,198 | $1,158,290 | $1,120,926 | $1,158,290 | $1,085,982 | $1,122,182 | $1,122,182 | $1,085,982 | $1,122,182 | $1,085,982 | $1,122,182 | $13,388,668 |
| PECO | $1,961,524 | $1,771,699 | $1,961,524 | $1,898,249 | $1,961,524 | $1,800,302 | $1,860,312 | $1,860,312 | $1,800,302 | $1,860,312 | $1,800,302 | $1,860,312 | $22,396,679 |
| PENELEC | $1,596,528 | $1,442,025 | $1,596,528 | $1,545,027 | $1,596,528 | $1,287,278 | $1,330,187 | $1,330,187 | $1,287,278 | $1,330,187 | $1,287,278 | $1,330,187 | $16,959,218 |
| Pepco | $2,458,692 | $2,220,754 | $2,458,692 | $2,379,380 | $2,458,692 | $2,245,984 | $2,320,851 | $2,320,851 | $2,245,985 | $2,320,851 | $2,245,985 | $2,320,851 | $27,997,566 |
| PPL | $3,690,484 | $3,333,341 | $3,690,484 | $3,571,436 | $3,690,484 | $2,410,862 | $2,491,224 | $2,491,224 | $2,410,862 | $2,491,224 | $2,410,862 | $2,491,224 | $35,173,715 |
| PSEG | $4,224,394 | $3,815,581 | $4,224,394 | $4,088,123 | $4,224,394 | $2,493,066 | $2,576,169 | $2,576,169 | $2,493,066 | $2,576,169 | $2,493,066 | $2,576,169 | $38,360,758 |
| RECO | $37,300 | $33,690 | $37,300 | $36,097 | $37,300 | $12,072 | $12,475 | $12,475 | $12,072 | $12,475 | $12,072 | $12,475 | $267,802 |
| Total | $39,658,975 | $35,821,010 | $39,658,975 | $38,379,653 | $39,658,975 | $42,340,483 | $43,751,832 | $43,751,832 | $42,340,483 | $43,751,832 | $42,340,483 | $43,751,832 | $495,206,365 |

Table 6-18 shows the amount of energy efficiency (EE) resources in PJM for the 2012/2013 through 2017/2018 delivery years. EE resources may participate in PJM without restrictions imposed by a state unless the Commission authorizes a state to impose restrictions.[30] Only Kentucky has been authorized by the Commission. Energy efficiency resources

29 The RTO LDA refers to the rest of RTO.

30 *See* 161 FERC ¶ 61,245 at P 57 (2017); 107 FERC ¶ 61,272 at P 8 (2008).

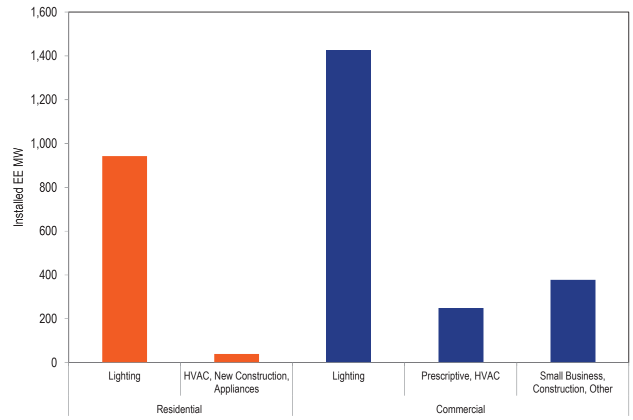
are offered in the PJM Capacity Market. The total MW of energy efficiency resources committed increased by 18.7 percent from 1,784.3 MW in the 2016/2017 Delivery Year to 2,117.9 MW in the 2017/2018 Delivery Year.[31]

### Table 6-18 Energy efficiency resources (MW): 2012/2013 through 2017/2018 Delivery Year

| | UCAP (MW) RPM Commitments |
|---|---|
| 01-Jun-12 | 631.2 |
| 01-Jun-13 | 1,024.8 |
| 01-Jun-14 | 1,282.4 |
| 01-Jun-15 | 1,525.5 |
| 01-Jun-16 | 1,784.3 |
| 01-Jun-17 | 2,117.9 |

Figure 6-3 shows the amount of installed EE MW in PJM by technology for the 2017/2018 Delivery Year. An installed EE resource may participate as a capacity resource for up to a maximum of four consecutive delivery years.[32] Energy efficiency MW procured by an incentive program for lighting, HVAC or appliances are listed as prescriptive MW. Prescriptive energy efficiency MW have an assumed savings calculated by an expected installation rate dependent on units sold and the difference between the current average electricity usage of what is being replaced and the new product. For example, if 100 lights are sold, an expected installation rate could be that 95 are installed and replacing a light that consumes more electricity. Instead of measuring each light replaced, the EE provider takes the difference between the industry average and the new light. The calculated MW are bid into PJM's Capacity Market as EE. The installed EE resources for the 2017/2018 Delivery Year include any installed EE resource between June 1, 2013 and May 31, 2017.

### Figure 6-3 Installed energy efficiency MW by type: 2017/2018 Delivery Year




FERC accepted PJM's proposed 30 minute lead time as a phased in approach on May 9, 2014, effective on June 1, 2015.[33] 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.[34] The quick lead time is the default lead time starting June 1, 2015, unless a CSP submits an exception request for 60 or 120 minute notification time due to a physical constraint.[35] 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 amount of nominated MW and locations by product type and lead time for the 2016/2017 Delivery Year. PJM approved 2,675 locations, or 16.8 percent of all locations, which have 3,593.1 nominated MW, or 38.5 percent of all nominated MW, for exceptions to the 30 minute lead time rule for the 2016/2017 Delivery Year.

31 *2017 State of the Market Report for PJM*: Volume 2, Section 5: Capacity Market, Table 5-10.
32 PJM. "Manual 18: Capacity Market," Rev. 38 (July 27, 2017), p. 80.

33 See 147 FERC ¶ 61,103 (2014).
34 See PJM Interconnection, L.L.C., Docket No. ER14-135-000 (October 20, 2014).
35 See "PJM Manual 18: Capacity Market," Rev. 38 (July 27, 2017) at 62.

## Table 6-19 Nominated MW and locations by product type and lead time: 2016/2017 Delivery Year

| | Pre-Emergency MW | | | | | Emergency MW | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Lead Type | Limited | Extended Summer | Annual | Capacity Performance | Pre-Emergency Total | Limited | Extended Summer | Annual | Capacity Performance | Emergency Total | Total |
| Quick Lead (30 Minutes) | 4,716.8 | 453.5 | 69.0 | 302.8 | 5,542.1 | 185.0 | 0.0 | 0.3 | 22.7 | 208.1 | 5,750.2 |
| Short Lead (60 Minutes) | 387.2 | 0.5 | 0.0 | 19.1 | 406.8 | 16.0 | 0.0 | 0.0 | 0.0 | 16.0 | 422.8 |
| Long Lead (120 Minutes) | 2,342.9 | 414.7 | 101.3 | 240.2 | 3,099.2 | 60.7 | 0.0 | 0.0 | 10.3 | 71.1 | 3,170.3 |
| Total | 7,446.9 | 868.7 | 170.4 | 562.1 | 9,048.1 | 261.7 | 0.0 | 0.3 | 33.1 | 295.1 | 9,343.3 |
| | Pre-Emergency Locations | | | | | Emergency Locations | | | | | |
| Lead Type | Limited | Extended Summer | Annual | Capacity Performance | Pre-Emergency Total | Limited | Extended Summer | Annual | Capacity Performance | Emergency Total | Total |
| Quick Lead (30 Minutes) | 11,928 | 658 | 127 | 93 | 12,806 | 375 | 0 | 1 | 24 | 400 | 13,206 |
| Short Lead (60 Minutes) | 276 | 1 | 0 | 3 | 280 | 33 | 0 | 0 | 0 | 33 | 313 |
| Long Lead (120 Minutes) | 1,959 | 21 | 307 | 23 | 2,310 | 51 | 0 | 0 | 1 | 52 | 2,362 |
| Total | 14,163 | 680 | 434 | 119 | 15,396 | 459 | 0 | 1 | 25 | 485 | 15,881 |

Table 6-20 shows the amount of nominated MW and locations by product type and lead time for the 2017/2018 Delivery Year. PJM approved 2,682 locations, or 17.1 percent of all locations, which have 3,681.5 nominated MW, or 40.2 percent of all nominated MW, for exceptions to the 30 minute lead time rule for the 2017/2018 Delivery Year.

## Table 6-20 Nominated MW and locations by product type and lead time: 2017/2018 Delivery Year

| | Pre-Emergency MW | | | | | Emergency MW | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Lead Type | Limited | Extended Summer | Annual | Capacity Performance | Pre-Emergency Total | Limited | Extended Summer | Annual | Capacity Performance | Emergency Total | Total |
| Quick Lead (30 Minutes) | 1,410.8 | 3,137.9 | 418.0 | 280.6 | 5,247.3 | 51.1 | 160.4 | 7.5 | 7.0 | 225.9 | 5,473.2 |
| Short Lead (60 Minutes) | 129.5 | 140.8 | 46.0 | 79.6 | 395.9 | 3.0 | 13.2 | 0.0 | 0.0 | 16.1 | 412.0 |
| Long Lead (120 Minutes) | 822.6 | 1,701.2 | 476.6 | 156.4 | 3,156.7 | 18.8 | 43.1 | 44.7 | 6.2 | 112.8 | 3,269.6 |
| Total | 2,362.9 | 4,979.8 | 940.6 | 516.6 | 8,799.9 | 72.8 | 216.7 | 52.2 | 13.2 | 354.8 | 9,154.7 |
| | Pre-Emergency Locations | | | | | Emergency Locations | | | | | |
| Lead Type | Limited | Extended Summer | Annual | Capacity Performance | Pre-Emergency Total | Limited | Extended Summer | Annual | Capacity Performance | Emergency Total | Total |
| Quick Lead (30 Minutes) | 3,712 | 7,587 | 1,205 | 126 | 12,630 | 84 | 269 | 8 | 23 | 384 | 13,014 |
| Short Lead (60 Minutes) | 97 | 155 | 47 | 6 | 305 | 17 | 6 | 0 | 0 | 23 | 328 |
| Long Lead (120 Minutes) | 380 | 617 | 1,288 | 15 | 2,300 | 12 | 35 | 6 | 1 | 54 | 2,354 |
| Total | 4,189 | 8,359 | 2,540 | 147 | 15,235 | 113 | 310 | 14 | 24 | 461 | 15,696 |

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 (LF). The Guaranteed Load Drop (GLD) method measures the minimum of: the comparison load minus real-time load multiplied by the loss factor; or the PLC minus the real-time load multiplied by the loss factor. The comparison load estimates what the load would have been if PJM did not declare a Load Management Event, similar to a CBL, by using a comparable day, same day, customer baseline, regression analysis or backup generation method. Limiting the GLD method to the minimum of the two calculations ensures reductions occur below the PLC, thus avoiding double counting of load reductions.[36] The implementation of a Winter Peak Load (WPL), effective for the 2017/2018 Delivery Year, measures capacity compliance during winter months from the WPL rather than the PLC. The principle is that a customer's actual use of capacity should be compared to the level of capacity that a customer is required to pay for. Capacity costs are allocated to LSEs by PJM based on the single coincident peak load method. In PJM, the single coincident peak occurs in the summer.[37] LSEs generally allocate capacity costs to customers based on the five coincident peak method.[38] The allocation of capacity costs to customers defines each customer's PLC. Customers pay for capacity based on the PLC, not the WPL. The MMU recommends setting the baseline for measuring capacity compliance under summer and winter compliance at the customer's PLC, similar to GLD, to avoid double counting, to avoid under counting and to ensure that a customer's purchase of capacity is calculated correctly. The Direct Load Control (DLC) method measures when the CSP turns on and turns off the direct load control switch to

36 135 FERC ¶ 61,212.
37 OATT Attachment DD.5.11.
38 OATT Attachment M-2.

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.[39] The FSL and GLD equations for calculating load reductions are:

FSL Reduction = PLC – (Load · LF)

GLD Reduction = Minimum of {(comparison load – Load) · LF; PLC – (Load · LF)}

Table 6-21 shows the MW registered by measurement and verification method and by technology type for the 2016/2017 Delivery Year. If a CSP does not submit a technology type for a registration, the MW are allocated to the Other category. For the 2016/2017 Delivery Year, 99.1 percent use the firm service level (FSL) method and 0.9 percent use the guaranteed load drop (GLD) measurement and verification method.

### Table 6-21 Reduction MW by each demand response method: 2016/2017 Delivery Year

| | Technology Type | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Measurement and Verification Method | 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 | 1,139.3 | 2,950.0 | 223.4 | 805.5 | 3,930.3 | 142.4 | 67.7 | 9,258.6 | 99.1% |
| Guaranteed Load Drop | 17.1 | 25.9 | 1.6 | 8.7 | 31.1 | 0.1 | 0.0 | 84.6 | 0.9% |
| Total | 1,156.4 | 2,976.0 | 225.1 | 814.2 | 3,961.4 | 142.6 | 67.7 | 9,343.3 | 100.0% |
| Percent by method | 12.4% | 31.9% | 2.4% | 8.7% | 42.4% | 1.5% | 0.7% | 100.0% | |

Table 6-22 shows the MW registered by measurement and verification method and by technology type for the 2017/2018 Delivery Year. For the 2017/2018 Delivery Year, 99.4 percent use the FSL method and 0.6 percent use the GLD measurement and verification method.

### Table 6-22 Reduction MW by each demand response method: 2017/2018 Delivery Year

| | Technology Type | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Measurement and Verification Method | 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 | 1,266.4 | 2,973.7 | 237.4 | 769.6 | 3,726.2 | 78.7 | 52.0 | 9,104.0 | 99.4% |
| Guaranteed Load Drop | 8.9 | 19.4 | 1.6 | 3.6 | 17.1 | 0.1 | 0.0 | 50.7 | 0.6% |
| Total | 1,275.4 | 2,993.1 | 239.0 | 773.2 | 3,743.2 | 78.8 | 52.0 | 9,154.7 | 100.0% |
| Percent by method | 13.9% | 32.7% | 2.6% | 8.4% | 40.9% | 0.9% | 0.6% | 100.0% | |

Table 6-23 shows the fuel type used in the onsite generators identified in Table 6-21 for the 2016/2017 Delivery Year. For the 2016/2017 Delivery Year, there are 284.7 MW, 24.6 percent, registered with an onsite generator in the emergency program. Of the 12.4 percent of nominated emergency and pre-emergency demand response MW identified as using onsite 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 gasoline, kerosene, oil, propane or waste products.

### Table 6-23 Onsite generation fuel type (MW): 2016/2017 Delivery Year

| | 2016/2017 | |
|---|---|---|
| Fuel Type | MW | Percent |
| Diesel | 855.6 | 74.0% |
| Natural Gas | 273.4 | 23.6% |
| Gasoline, Kerosene, Oil, Propane, Waste Products | 27.4 | 2.4% |
| Total | 1,156.4 | 100.0% |

39 "PJM Manual 18: PJM Capacity Market," Rev. 38 (July 27, 2017) at 63.

Table 6-24 shows the fuel type used in the onsite generators for the 2017/2018 Delivery Year. For the 2017/2018 Delivery Year, there are 354.5 MW, 27.8 percent, registered with an onsite generator in the emergency program. Of the 13.9 percent of nominated emergency and pre-emergency demand response MW identified as using onsite generation for the 2017/2018 Delivery Year, 74.5 percent of MW are diesel, 24.4 percent of MW are natural gas and 1.1 percent of MW are gasoline, kerosene, oil, propane or waste products.

### Table 6-24 Onsite generation fuel type (MW): 2017/2018 Delivery Year

| | 2017/2018 | |
|---|---|---|
| Fuel Type | MW | Percent |
| Diesel | 950.1 | 74.5% |
| Natural Gas | 311.3 | 24.4% |
| Gasoline, Kerosene, Oil, Propane, Waste Products | 13.9 | 1.1% |
| Total | 1,275.4 | 100.0% |

## Emergency and Pre-Emergency Event Reported Compliance

Table 6-25 shows the demand response cleared UCAP MW for PJM by Delivery Year. Total demand response cleared in PJM decreased by 1,284.6 MW, or 9.7 percent, from 13,265.3 MW in the 2016/2017 Delivery Year to 11,980.7 MW in the 2017/2018 Delivery Year. The DR percent of capacity decreased by 0.8 percent, from 5.1 percent in the 2016/2017 Delivery Year to 4.3 percent in the 2017/2018 Delivery Year.

### Table 6-25 Demand response cleared MW UCAP for PJM: 2011/2012 through 2017/2018 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% |
| 2017/2018 | 11,980.7 | 4.3% |

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 thirteen dispatchable subzones in PJM effective April 26, 2017: AEP_CANTON, ATSI_CLE, DPL_SOUTH, PS_NORTH, ATSI_NEWCASOE, PPL_WESCO, ATSI_BLKRIVER, PENELEC_ERIC, APS_EAST, DOM_CHES, DOM_YORKTOWN, AECO_ENGLAND, JCPL_REDBANK.[40] PJM can remove a defined subzone at their discretion. Subzones should not be removed once defined, 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 not remove any defined subzones and maintain a public record of all created and removed subzones.

The subzone design and closed loop interfaces 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.[41] 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.[42]

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.

Limited, extended summer and annual 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

40 See "Load Management Subzones," <http://www.pjm.com/~/media/markets-ops/demand-response/subzone-definition-workbook.ashx> (Accessed January 22, 2018).

41 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).

42 See the *2017 State of the Market Report for PJM*, Volume 2, Section 4, Energy Uplift, for additional information regarding all closed loop interfaces and the impacts to the PJM markets.

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.[43]

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).[44] When pre-emergency or emergency demand response is dispatched, a PAH is triggered for PJM. 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).[45] A CAA is an electrically connected area that has the same capacity market price. 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.[46] The multiple zone approach is even less locational than the zonal and subzonal approaches and creates larger mismatches between the locational need for the resources and the actual response. If multiple zones within a CAA are called by PJM, a CSP will dispatch the least cost resources across the zones to cover the CSP's obligation. This can result in more MW dispatched in one zone that are locationally distant from the relief needed and no MW dispatched in another zone, yet the CSP could be considered 100 percent compliant and pay no penalties. More locational deployment of load management resources would improve efficiency. The MMU recommends that demand resources be required to provide their nodal location. Nodal dispatch of demand resources would be consistent with the nodal dispatch of generation.

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.[47] 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 three day CBL type with the symmetrical additive adjustment for measuring energy reductions without the requirements of a Relative Root Mean Squared Error (RRMSE) Test required for all economic resources.[48] The MMU recommends the RRMSE test be required for all demand resources with a CBL. The correct CBL may more accurately measure reductions for demand resources.

43 "PJM Manual 18: Capacity Market," Rev. 38 (July 27, 2017) at 148.
44 OATT § 1 (Performance Assessment Hour).
45 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 § 1.
46 See "PJM Manual 18: Capacity Market," Rev. 38 (July 27, 2017) at 166.
47 OA Schedule 1 § 8.9.
48 157 FERC ¶ 61,067, (2016).

## 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.[49]

Limiting compliance to only positive values 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.

49 OA Schedule 1 § 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."[50] 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. Three proposals that included language to remove bankrupt customers from a CSP's portfolio failed at the June 7, 2017, Market Implementation Committee.[51] The registered customers that are bankrupt and the amount of registered MW cannot be released for reasons of confidentiality.

50 OA Schedule 1 § 8.2.

51 There was one proposal from PJM, one proposal from a market participant and one proposal from Monitoring Analytics. See *Approved Minutes from the Market Implementation Committee*, PJM, <http://www.pjm.com/-/media/committees-groups/committees/mic/20170607/20170607-minutes.ashx> (Accessed February 22, 2018).

When demand resources are not dispatched during a mandatory response window, each CSP must test their portfolio to the levels of capacity commitment.[52] A CSP picks the testing day, for one hour, on any non-holiday weekday during the applicable mandatory window. A CSP is able to retest if a resource fails to provide the required reduction by less than 25 percent. The ability of CSPs to pick the test time does not simulate emergency conditions. As a result, test compliance is not an accurate representation of the capability of the resource to respond to an actual PJM dispatch of the resource. 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.

Table 6-26 shows the test penalties by delivery year by product type for the 2015/2016 Delivery Year through the 2017/2018 Delivery Year. The shortfall MW are calculated for each CSP by zone. The weighted rate per MW is the average penalty rate paid per MW. The total penalty column is the sum of the daily test penalties by delivery year and type.[53] The testing window for the limited product is open through September. The testing window for the extended summer, annual and Capacity Performance product is open through the end of the delivery year.

## Emergency Energy Payments

Emergency and pre-emergency demand response dispatched during a load management event by PJM are eligible to receive emergency energy payments if registered under the full program option. 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.[54] There were 97.9 percent of nominated MW for the 2016/2017 Delivery Year and 98.2 percent of nominated MW for the 2017/2018 Delivery Year registered under the full program option. The strike 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 scarcity pricing rules allow a maximum DR energy price of $1,849 per MWh for the 2016/2017 Delivery Year and the 2017/2018 Delivery Year.[55] [56] Demand resources clear the capacity market like all other capacity resources and the dispatch of demand resources should not trigger a scarcity event. Demand resources should not be permitted to offer above $1,000 per MWh without cost justification or to include a shortage penalty in the offer.

Table 6-26 Test penalties by delivery year by product type: 2015/2016 through 2017/2018

| | 2015/2016 | | | 2016/2017 | | | 2017/2018 | | |
|---|---|---|---|---|---|---|---|---|---|
| Product Type | Shortfall MW | Weighted Rate per MW | Total Penalty | Shortfall MW | Weighted Rate per MW | Total Penalty | Shortfall MW | Weighted Rate per MW | Total Penalty |
| Limited | 96.4 | $165.35 | $5,836,255 | 48.9 | $166.41 | $2,967,158 | 13.9 | $124.08 | $370,346 |
| Extended Summer | 1.9 | $163.70 | $113,835 | 7.3 | $138.14 | $370,290 | | | |
| Annual | 3.7 | $184.67 | $250,621 | 4.8 | $137.45 | $241,406 | | | |
| Base | | | | | | | | | |
| Capacity Performance | | | | 2.1 | $160.80 | $124,310 | | | |
| Total | 102.0 | $166.02 | $6,200,711 | 63.1 | $160.72 | $3,703,163 | 13.9 | $124.08 | $370,346 |

52 The mandatory response time for Limited DR is June through September between 12:00PM to 8:00PM EPT, for Extended Summer is June through October and the following May between 10:00AM to 10:00PM EPT, for Annual DR is June through October and the following May between 10:00AM to 10:00PM and is November through April between 6:00AM to 9:00PM EPT, for Base Capacity DR is June through September between 10:00AM to 10:00PM EPT, Capacity Performance DR is June through October and the following May between 10:00AM to 10:00PM EPT and November through April between 6:00AM through 9:00PM EPT. *See* PJM. "Manual 18: Capacity Market," Rev. 38 (July 27, 2017), p. 69.

53 Penalties for 2017/2018 are calculated for June 1, 2017 through December 31, 2017.

54 *Id.*

55 139 FERC ¶ 61,057 (2012).

56 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.

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.[57]

Table 6-27 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, 78.6 percent of locations and 59.8 percent of nominated MW, have a minimum dispatch price between $1,550 and $1,849 per MWh, which is the maximum price allowed for the 2016/2017 Delivery Year, 4.6 percent of location and 3.6 percent of nominated MW have a dispatch price between $0 and $999 per MWh, and 95.4 percent of locations and 96.4 percent of nominated MW have a dispatch price above $1,000 per MWh. Energy offers are further increased by submitted shutdown costs, which, in the 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 $1,275 per MWh strike prices had the highest average at $184.65 per location and $143.22 per nominated MW.

### Table 6-27 Distribution of registrations and associated MW in the full option across ranges of minimum dispatch prices: 2016/2017 Delivery Year[58]

| 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-$999 | 728 | 4.6% | 331.1 | 3.6% | $51.81 | $49.15 |
| $1,000-$1,275 | 2,363 | 15.0% | 3,047.1 | 33.3% | $184.65 | $143.22 |
| $1,276-$1,549 | 287 | 1.8% | 300.3 | 3.3% | $56.00 | $53.51 |
| $1,550-$1,849 | 12,390 | 78.6% | 5,470.8 | 59.8% | $41.76 | $94.57 |
| Total | 15,768 | 100.0% | 9,149.3 | 100.0% | $62.12 | $107.06 |

Table 6-28 shows the distribution of registrations and associated MW in the emergency full option across ranges of minimum dispatch prices for the 2017/2018 Delivery Year. The majority of participants, 73.4 percent of locations and 65.7 percent of nominated MW, have a minimum dispatch price between $1,550 and $1,849 per MWh, which is the maximum price allowed for the 2017/2018 Delivery Year, 4.8 percent of location and 4.0 percent of nominated MW have a dispatch price between $0 and $999 per MWh, and 95.2 percent of locations and 96.0 percent of nominated MW have a dispatch price above $1,000 per MWh. The shutdown cost of resources with $999 to $1,100 per MWh strike prices had the highest average at $239.13 per location and $937.37 per nominated MW.

### Table 6-28 Distribution of registrations and associated MW in the full option across ranges of minimum dispatch: 2017/2018 Delivery Year

| 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 | 459 | 2.9% | 53.9 | 0.6% | $0.00 | $0.00 |
| $1-$999 | 291 | 1.9% | 305.4 | 3.4% | $77.61 | $73.94 |
| $999-$1,100 | 1,288 | 8.3% | 328.6 | 3.7% | $239.13 | $937.37 |
| $1,100-$1,275 | 1,789 | 11.5% | 2,925.9 | 32.5% | $94.68 | $57.89 |
| $1,275-$1,550 | 315 | 2.0% | 283.5 | 3.2% | $57.43 | $63.81 |
| $1,550-$1,849 | 11,437 | 73.4% | 5,093.4 | 56.7% | $44.54 | $100.01 |
| Total | 15,579 | 100.0% | 8,990.8 | 100.0% | $65.95 | $114.28 |

57 "PJM Manual 15: Cost Development Guidelines," Rev. 29 (May 15, 2017) at 59.
58 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 2017 than in 2016. Gas prices increased more than energy prices and CTs and CCs ran with lower margins as a result. Coal prices increased more than energy prices but less than gas prices and CPs ran for slightly more hours in 2017 than in 2016 and margins varied by zone.
- In 2017, average energy market net revenues decreased by 54 percent for a new CT, 9 percent for a new CC, 2 percent for a new CP, and 4 percent for a new solar installation compared to 2016. Average energy market net revenues increased by 49 percent for a new DS, 11 percent for a new nuclear plant, and 11 percent for a new wind installation compared to 2016.
- The relative prices of fuel varied during 2017. While the marginal cost of the new CC was consistently below that of the new CP in 2017, the marginal cost of the new CT was above that of the new CP in January and December. As a result, CT hours dropped significantly and CP hours increased.
- Capacity revenue accounted for 65 percent of total net revenues for a new CT, 38 percent for a new CC, 62 percent for a new CP, 95 percent for a new DS, and 20 percent for a new nuclear plant.
- In 2017, a new CT would not have received sufficient net revenue to cover levelized total costs in any zone but would have covered 95 percent of levelized costs in the PSEG Zone, as a result of higher locational capacity market prices.
- In 2017, a new CC would have received sufficient net revenue to cover levelized total costs in three of the twenty zones and to cover 90 percent or more of levelized costs in 11 zones.
- In 2017, a new CP would not have received sufficient net revenue to cover levelized total costs in any zone.
- In 2017, a new nuclear plant would not have received sufficient net revenue to cover levelized total costs in any zone.
- In 2017, net revenues covered more than 44 percent of the annual levelized total costs of a new entrant wind installation in ComEd, 65 percent of the annual levelized total costs of a new entrant wind installation in PENELEC and 167 percent of the annual levelized total costs of a new entrant solar installation in PSEG. Renewable energy credits accounted for five percent of the total net revenue of a wind installation in ComEd and 37 percent of the total net revenue of a wind installation in PENELEC. Renewable energy credits accounted for 81 percent of the total net revenue of a solar installation in PSEG.
- In 2017, most units did not achieve full recovery of avoidable costs through net revenue from energy markets alone, illustrating the critical role of the PJM Capacity Market in providing incentives for continued operation and investment. In 2017, capacity revenues were sufficient to cover the shortfall between energy revenues and avoidable costs for the majority of units and technology types in PJM, with the exception of some coal units and some nuclear units.
- The net revenue results show that there are between 108 and 118 units with between 22,929 MW and 30,785 MW of capacity in PJM at risk of retirement in addition to the units that are currently planning to retire. Coal and nuclear units account for most of the MW at risk. There are between 38 and 46 coal units, with between 17,302 MW and 21,039 MW, at risk. There are between three and five nuclear plants at risk, with between 2,939 MW and 7,058 MW at risk.

## 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 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 alone 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 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 2017, and have not covered their total costs in the ComEd Zone through 2017.

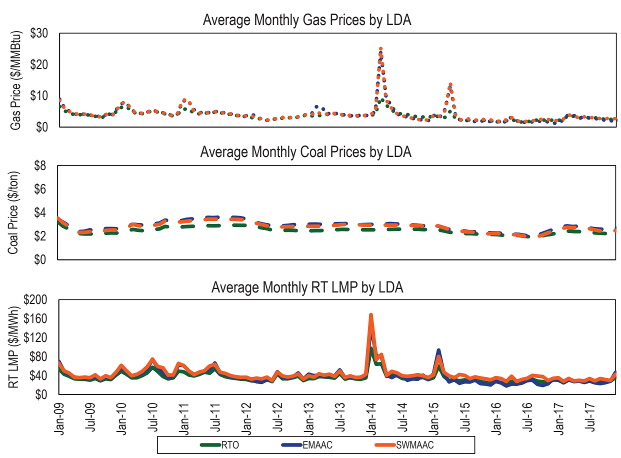
# Net Revenue

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 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 load-weighted average real-time LMP was 6.0 percent higher in 2017 than in 2016, $30.99 per MWh versus $29.23 per MWh. Natural gas prices and coal prices increased in 2017. The price of Northern Appalachian coal was 17.4 percent higher; the price of Central Appalachian coal was 25.3 percent higher; the price of Powder River Basin coal was 12.7 percent higher; the price of eastern natural gas was 35.1 percent higher; and the price of western natural gas was 23.7 percent higher (Figure 7-1).

### Figure 7-1 Energy market net revenue factor trends: 2009 through 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.

$$Spread\left(\frac{\$}{MWh}\right) = LMP\left(\frac{\$}{MWh}\right) - Fuel\ Price\left(\frac{\$}{MMBtu}\right) * Heat\ Rate\left(\frac{MMBtu}{MWh}\right)$$

Spread volatility is a result of fluctuations in LMP and the price of fuel. Spreads can be positive or negative.

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): 2011 through 2017

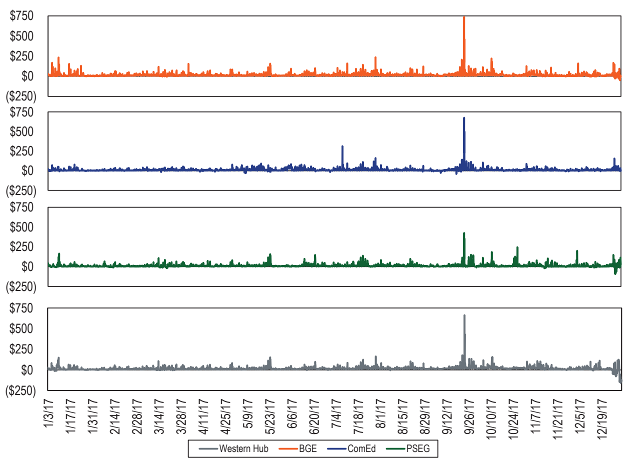
| | BGE | | | ComEd | | | PSEG | | | Western Hub | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Spark | Dark | Quark | Spark | Dark | Quark | Spark | Dark | Quark | Spark | Dark | Quark |
| 2011 | $26.27 | $33.76 | $48.66 | $12.47 | $33.68 | $30.85 | $22.99 | $28.15 | $47.70 | $19.50 | $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 | $16.77 | $18.41 | $33.20 | $11.81 | $25.40 | $28.19 | $12.80 | $10.89 | $29.97 | $16.30 | $15.71 | $30.50 |

### Table 7-2 Peak hour spread standard deviation ($/MWh): 2011 through 2017

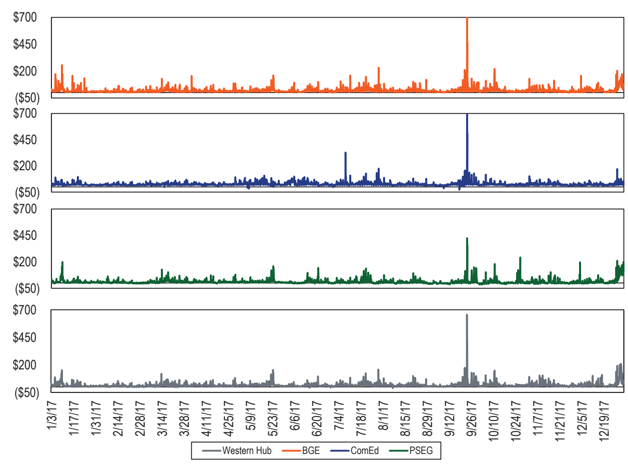
| | BGE | | | ComEd | | | PSEG | | | Western Hub | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Spark | Dark | Quark | Spark | Dark | Quark | Spark | Dark | Quark | Spark | Dark | Quark |
| 2011 | $50.7 | $51.1 | $51.1 | $26.3 | $26.9 | $26.9 | $43.6 | $45.3 | $45.3 | $37.2 | $37.5 | $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 | $23.5 | $25.0 | $25.0 | $19.8 | $19.9 | $19.9 | $19.9 | $22.9 | $23.0 | $23.2 | $22.5 | $22.6 |

Figure 7-2 shows the hourly spark spread for peak hours for BGE, ComEd, PSEG, and Western Hub.

### Figure 7-2 Hourly spark spread (gas) for peak hours ($/MWh): 2017[1]



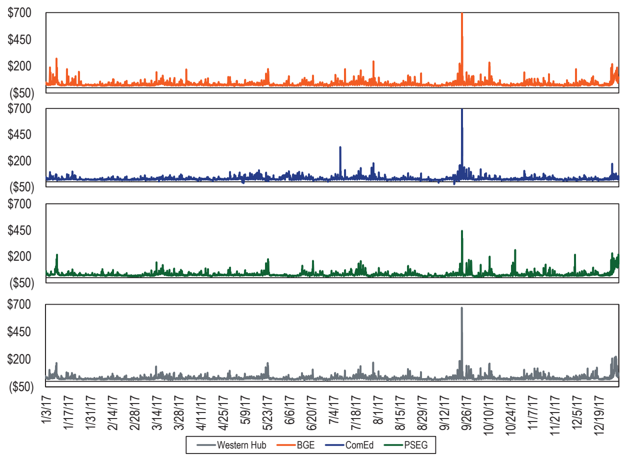

### Figure 7-3 Hourly dark spread (coal) for peak hours ($/MWh): 2017[2]




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.

2 Dark spreads use a heat rate of 10,000 Btu/kWh, zonal hourly LMPs and daily coal prices; Powder River Basin coal for ComEd, Northern Appalachian coal for BGE and Western Hub, and Central Appalachian coal for PSEG.

Figure 7-4 Hourly quark spread (uranium) for selected zones ($/MWh): 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 747.9 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.[4]
- The CC plant has an installed capacity of 1,137.2 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.[5 6]
- 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 21 Siemens 2.625 MW wind turbines totaling 55.1 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.[7 8] 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.[9]

A forced outage rate for each class of plant was calculated from PJM data and incorporated into all revenue calculations.[10] In addition, each CT, CC, CP, and DS plant was assumed to take a continuous 14 day planned annual outage in the fall season.

Ancillary service revenues for the provision of regulation service were calculated for the CP. The regulation clearing price was compared to the day-ahead LMP. If the reference CP could provide regulation more profitably than energy, the unit was assumed to provide regulation during that hour. No black start service capability is assumed for any of the unit types.

3 Quark spreads use a heat rate of 10,000 Btu/kWh, zonal hourly LMPs, and daily uranium prices.
4 GE Power, "7HA Power Plants," 7HA.02 unit capacity was updated based on GE unit specifications. (November 2017) <https://www.gepower.com/content/dam/gepower-pgdp/global/en_US/documents/product/gas%20turbines/Fact%20Sheet/2017-prod-specs/7ha-power-plants.pdf>.
5 The duct burner firing dispatch rate is developed using the same method as for the unfired dispatch rate, with adjustments to the duct burner fired heat rate and output.
6 GE Power, "7HA Power Plants," 7HA.02 unit capacity was updated based on GE unit specifications. (November 2017) <https://www.gepower.com/content/dam/gepower-pgdp/global/en_US/documents/product/gas%20turbines/Fact%20Sheet/2017-prod-specs/7ha-power-plants.pdf>.
7 Hourly ambient conditions supplied by DTN.
8 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.
9 $CO_2$, $NO_x$ and $SO_2$ emission daily prompt prices obtained from Evolution Markets, Inc.
10 Outage figures obtained from the PJM eGADS database.

CT revenues for the provision of reactive services are based on the average reactive revenue per MW-year received by all CTs with 20 or fewer operating years. CC revenues for the provision of reactive services are based on the average reactive revenue per MW-year received by all CC generators with 20 or fewer operating years. CP revenues for the provision of reactive services are based on the average reactive revenue per MW-year received by all CP generators with 60 or fewer operating years. Table 7-3 includes reactive capability revenue of $3,350/MW-Yr.[11]

### Table 7-3 New entrant ancillary service revenue (Dollars per MW-year)

| | Reactive | | | Regulation |
|---|---|---|---|---|
| | CT | CC | CP | CP |
| 2009 | $4,273 | $4,991 | $3,963 | $38 |
| 2010 | $7,765 | $4,280 | $3,980 | $6 |
| 2011 | $7,025 | $4,539 | $6,753 | $2 |
| 2012 | $4,261 | $6,065 | $6,216 | $20 |
| 2013 | $4,708 | $3,486 | $3,614 | $53 |
| 2014 | $3,712 | $4,046 | $3,501 | $168 |
| 2015 | $3,673 | $4,911 | $3,386 | $74 |
| 2016 | $3,436 | $4,573 | $3,470 | $19 |
| 2017 | $3,885 | $3,591 | $3,415 | $26 |

Zonal net revenues reflect zonal fuel costs based on locational fuel indices and zone specific delivery charges.[12] 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.[13] 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.[14]

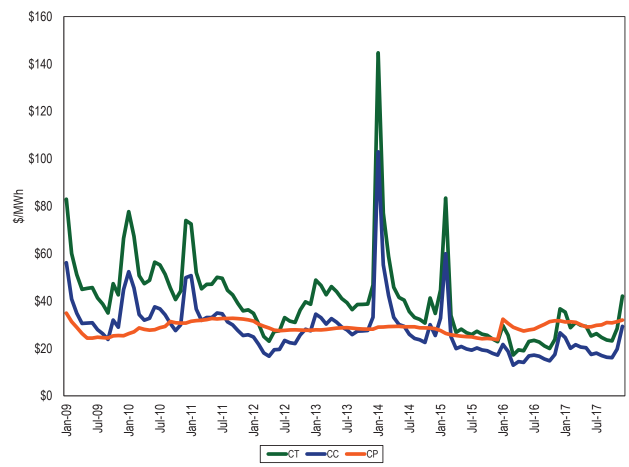
Short run marginal cost includes fuel costs, emissions costs, and VOM costs.[15] [16] Average short run marginal costs are shown in Table 7-4.

### Table 7-4 Average short run marginal costs: 2017

| Unit Type | Short Run Marginal Costs ($/MWh) | Heat Rate (Btu/kWh) | VOM ($/MWh) |
|---|---|---|---|
| CT | $28.95 | 9,437 | $0.25 |
| CC | $20.07 | 6,679 | $1.00 |
| CP | $30.52 | 9,250 | $4.00 |
| DS | $142.62 | 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 2009, shows that, on average, the short run marginal costs of the CC plant have been less than those of the CP plant since 2011 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).

### Figure 7-5 Average short run marginal costs: 2009 through 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 7-5 shows the average run hours by a new entrant unit.

11 $3,350/MW-Yr is the average of reactive capability payments of selected units obtained from FERC filings.
12 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.
13 Gas daily cash prices obtained from Platts.
14 Coal prompt prices obtained from Platts.
15 Fuel costs are calculated using the daily spot price and may not equal what participants actually paid.
16 VOM rates provided by Pasteris Energy, Inc.

### Table 7-5 Average run hours: 2009 through 2017

| | CT | CC | CP | DS | Nuclear | Wind | Solar |
|---|---|---|---|---|---|---|---|
| 2009 | 1,066 | 5,183 | 6,552 | 44 | 6,552 | | |
| 2010 | 1,788 | 5,641 | 6,552 | 117 | 6,552 | | |
| 2011 | 2,744 | 6,853 | 6,552 | 50 | 6,552 | | |
| 2012 | 4,595 | 7,812 | 6,576 | 27 | 6,576 | 5,073 | 2,954 |
| 2013 | 2,243 | 6,558 | 6,552 | 20 | 6,552 | 5,040 | 3,013 |
| 2014 | 3,681 | 6,732 | 6,552 | 176 | 6,552 | 6,758 | 1,748 |
| 2015 | 4,345 | 7,013 | 6,552 | 210 | 6,552 | 6,625 | 1,890 |
| 2016 | 4,845 | 7,535 | 2,999 | 68 | 6,576 | 6,496 | 1,859 |
| 2017 | 2,952 | 7,664 | 3,229 | 33 | 6,552 | 6,726 | 1,690 |

## Capacity Market Net Revenue

Generators receive revenue from the sale of capacity in addition to revenue from the energy and ancillary service markets. In the PJM market design, the sale of capacity provides an important source of revenues to cover generator going forward costs and fixed costs. Capacity revenue for 2017 includes five months of the 2016/2017 capacity market clearing price and seven months of the 2017/2018 RPM capacity market clearing price.[17]

### Table 7-6 Capacity revenue by PJM zones (Dollars per MW-year): 2009 through 2017[18]

| Zone | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | Average |
|---|---|---|---|---|---|---|---|---|---|---|
| AECO | $63,411 | $66,187 | $49,858 | $46,622 | $73,529 | $66,206 | $56,448 | $50,948 | $43,669 | $57,431 |
| AEP | $38,736 | $52,706 | $49,858 | $20,242 | $8,420 | $31,149 | $48,128 | $33,377 | $34,645 | $35,251 |
| APS | $57,842 | $66,187 | $49,858 | $20,242 | $8,420 | $31,149 | $48,128 | $33,377 | $34,645 | $38,872 |
| ATSI | NA | NA | NA | NA | NA | $31,149 | $95,422 | $78,709 | $42,929 | $62,052 |
| BGE | $82,515 | $73,135 | $49,858 | $45,261 | $68,535 | $63,360 | $56,448 | $50,948 | $43,669 | $59,303 |
| ComEd | $38,736 | $52,706 | $49,858 | $20,242 | $8,420 | $31,149 | $48,128 | $33,377 | $34,645 | $35,251 |
| DAY | $38,736 | $52,706 | $49,858 | $20,242 | $8,420 | $31,149 | $48,128 | $33,377 | $34,645 | $35,251 |
| DEOK | NA | NA | NA | NA | $8,420 | $31,149 | $48,128 | $33,377 | $34,645 | $31,144 |
| DLCO | $38,736 | $52,706 | $49,858 | $20,242 | $8,420 | $31,149 | $48,128 | $33,377 | $34,645 | $35,251 |
| Dominion | $38,736 | $52,706 | $49,858 | $20,242 | $8,420 | $31,149 | $48,128 | $33,377 | $34,645 | $35,251 |
| DPL | $63,411 | $67,098 | $50,501 | $52,309 | $77,542 | $66,206 | $56,448 | $50,948 | $43,669 | $58,681 |
| EKPC | NA | NA | NA | NA | NA | $31,149 | $48,128 | $33,377 | $34,645 | $36,825 |
| JCPL | $63,411 | $66,187 | $49,858 | $46,622 | $73,529 | $66,206 | $56,448 | $50,948 | $43,669 | $57,431 |
| Met-Ed | $57,842 | $66,187 | $49,858 | $45,261 | $68,535 | $63,360 | $56,448 | $50,948 | $43,669 | $55,790 |
| PECO | $63,411 | $66,187 | $49,858 | $46,622 | $73,529 | $66,206 | $56,448 | $50,948 | $43,669 | $57,431 |
| PENELEC | $57,842 | $66,187 | $49,858 | $45,216 | $68,503 | $63,360 | $56,448 | $50,945 | $43,667 | $55,781 |
| Pepco | $82,515 | $73,135 | $49,858 | $45,261 | $73,027 | $66,529 | $56,448 | $50,948 | $43,669 | $60,154 |
| PPL | $57,842 | $66,187 | $49,858 | $45,261 | $68,535 | $63,360 | $56,448 | $50,948 | $43,669 | $55,790 |
| PSEG | $63,411 | $66,187 | $49,858 | $49,957 | $75,882 | $72,567 | $60,936 | $67,224 | $73,401 | $64,380 |
| RECO | $63,411 | $66,187 | $49,858 | $46,622 | $73,529 | $66,206 | $56,448 | $50,948 | $43,669 | $57,431 |
| PJM | $52,370 | $60,604 | $49,878 | $32,806 | $36,601 | $46,247 | $54,646 | $48,568 | $44,809 | $47,392 |

## Net Revenue Adequacy

When total net revenues exceed the annual, nominal levelized total costs for the technology, that technology is covering all its costs including a return on and of capital and all the expenses of operating the facility.

The extent to which net revenues cover the levelized total costs of investment is significantly dependent on technology type and location, which affect both energy and capacity revenue. Table 7-7 includes new entrant levelized total costs for selected technologies. The levelized total costs of all the technologies decreased in 2017 over 2016 with the exception of the coal plant and nuclear plant.

Net revenues include net revenues from the PJM energy market, from the PJM Capacity Market and from any applicable ancillary services plus RECs for wind installations and SRECs for solar installations.

17 The RPM revenue values for PJM are load-weighted average clearing prices across the relevant base residual auctions.

18 See the *2017 State of the Market Report for PJM*, Appendix A: "PJM Geography," for details on the expansion of the PJM footprint.

## Levelized Total Costs

### Table 7-7 New entrant 20-year levelized total costs (By plant type (Dollars per installed MW-year))[19 20]

| | 20-Year Levelized Total Cost | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 |
| Combustion Turbine | $128,705 | $131,044 | $110,589 | $113,027 | $109,731 | $108,613 | $111,639 | $113,821 | $95,264 |
| Combined Cycle | $173,174 | $175,250 | $153,682 | $155,294 | $150,654 | $146,443 | $146,300 | $148,327 | $129,731 |
| Coal Plant | $446,550 | $465,455 | $473,835 | $480,662 | $491,240 | $504,050 | $517,017 | $523,540 | $528,701 |
| Diesel Plant | $153,143 | $153,143 | $153,143 | $153,143 | $153,143 | $161,746 | $170,500 | $173,182 | $158,817 |
| Nuclear Plant | $801,100 | $801,100 | $801,100 | $801,100 | $801,100 | $880,770 | $935,659 | $963,107 | $1,349,850 |
| Wind Installation (with 1603 grant) | | | | $196,186 | $196,148 | $198,033 | $202,874 | $231,310 | $188,747 |
| Solar Installation (with 1603 grant) | | | | $394,855 | $263,824 | $236,289 | $234,151 | $218,937 | $200,931 |

## Levelized Cost of Energy

The levelized cost of energy is a measure of the total cost per MWh of energy from a technology, including all fixed and variable costs. If a unit's revenues cover its levelized cost of energy, it is covering all its costs and earning the target rate of return. Table 7-8 shows the levelized cost of energy for a new entrant unit by technology type operating at a defined capacity factor for the new entrant unit type. CCs had a low levelized cost of energy in 2017 because low gas prices resulted in low short run marginal costs which increased dispatch and the capacity factor, which increased the MWh over which costs are spread. DS units had a high levelized cost of energy in 2017 because DS units ran for extremely few hours in 2017, which decreased the capacity factor, which decreased the MWh over which costs are spread. The levelized cost of wind is comparable to or less than that of all other resources except CCs. The levelized cost of solar is high as a result of a low capacity factor.

### Table 7-8 Levelized cost of energy: 2017

| | CT | CC | CP | DS | Nuclear | Wind (ComEd) | Wind (PENELEC) | Solar (PSEG) |
|---|---|---|---|---|---|---|---|---|
| Levelized cost ($/MW-Yr) | $95,264 | $129,731 | $528,701 | $158,817 | $1,349,850 | $188,747 | $188,747 | $200,931 |
| Short run marginal costs ($/MWh) | $28.95 | $20.07 | $30.52 | $142.62 | $8.50 | $0.00 | $0.00 | $0.00 |
| Capacity factor (%) | 34% | 87% | 37% | 0% | 99% | 35% | 30% | 14% |
| Levelized cost of energy ($/MWh) | $61 | $37 | $194 | $5,007 | $163 | $62 | $73 | $166 |

## 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.

The new entrant CT is larger and more efficient than most CTs currently operating in PJM. The economically dispatched new entrant CT ran for more than twice as many hours as large CTs currently operating in PJM. The new entrant CT energy market net revenue results must therefore be interpreted carefully when comparing to existing CTs which are generally smaller and less efficient than the newest CT technology used by the new entrant CT.

19 Levelized total costs provided by Pasteris Energy, Inc.

20 Under Section 1603 of the American Recovery and Reinvestment Tax Act of 2009 the United States Department of the Treasury makes payments to owners who place in service specified energy property and apply for such payments. The purpose of the payment is to reimburse eligible applicants for a portion of the capital cost of such property. Solar and wind energy properties are eligible for a 30 percent payment of the total eligible capital cost of the project. This 30 percent payment reduced the calculated fixed nominal levelized revenue requirements of the solar and wind technologies.

New entrant CT plant energy market net revenues were lower across all zones in 2017 than in 2016 (Table 7-9). The increase in gas prices reduced both energy margins and run hours.

### Table 7-9 Energy net revenue for a new entrant gas fired CT under economic dispatch (Dollars per installed MW-year): 2009 through 2017[21 22]

| Zone | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | Change in 2017 from 2016 |
|---|---|---|---|---|---|---|---|---|---|---|
| AECO | $10,270 | $41,776 | $63,064 | $50,716 | $31,431 | $62,488 | $51,404 | $48,167 | $21,522 | (55%) |
| AEP | $3,798 | $12,246 | $29,569 | $39,768 | $19,169 | $58,738 | $37,225 | $31,391 | $16,897 | (46%) |
| APS | $12,211 | $34,656 | $49,411 | $49,941 | $26,767 | $78,655 | $58,192 | $73,765 | $33,728 | (54%) |
| ATSI | NA | NA | $23,275 | $43,763 | $25,509 | $67,762 | $40,147 | $28,048 | $17,537 | (37%) |
| BGE | $14,738 | $52,514 | $63,755 | $71,707 | $42,986 | $89,712 | $80,641 | $107,070 | $28,146 | (74%) |
| ComEd | $2,253 | $9,555 | $18,515 | $25,156 | $12,992 | $26,298 | $13,595 | $16,106 | $9,330 | (42%) |
| DAY | $3,011 | $11,984 | $30,125 | $44,423 | $19,910 | $59,033 | $37,710 | $26,092 | $16,375 | (37%) |
| DEOK | NA | NA | NA | $36,426 | $19,775 | $78,150 | $84,960 | $28,275 | $17,290 | (39%) |
| DLCO | $3,247 | $16,803 | $33,064 | $42,347 | $20,903 | $52,608 | $31,438 | $66,431 | $33,309 | (50%) |
| Dominion | $14,746 | $47,122 | $49,223 | $53,638 | $31,175 | $43,721 | $37,802 | $37,027 | $14,134 | (62%) |
| DPL | $11,306 | $40,871 | $57,501 | $62,542 | $35,129 | $78,702 | $41,079 | $49,806 | $20,644 | (59%) |
| EKPC | NA | NA | NA | NA | $15,244 | $75,630 | $75,433 | $24,563 | $11,472 | (53%) |
| JCPL | $9,267 | $39,408 | $59,820 | $49,343 | $37,511 | $64,876 | $49,777 | $43,113 | $24,016 | (44%) |
| Met-Ed | $8,092 | $38,275 | $50,960 | $47,325 | $29,546 | $55,100 | $47,292 | $46,106 | $28,324 | (39%) |
| PECO | $8,598 | $37,178 | $59,087 | $49,037 | $27,857 | $56,752 | $45,876 | $41,989 | $22,027 | (48%) |
| PENELEC | $7,418 | $26,960 | $47,419 | $53,552 | $40,971 | $120,385 | $112,826 | $63,471 | $28,929 | (54%) |
| Pepco | $17,071 | $49,586 | $56,858 | $64,640 | $39,789 | $80,268 | $59,478 | $48,736 | $14,498 | (70%) |
| PPL | $7,426 | $31,826 | $52,511 | $43,024 | $28,268 | $61,271 | $46,193 | $42,792 | $22,510 | (47%) |
| PSEG | $7,067 | $35,863 | $49,340 | $46,919 | $30,673 | $47,870 | $23,810 | $30,019 | $13,512 | (55%) |
| RECO | $5,805 | $32,934 | $39,366 | $42,708 | $32,271 | $47,536 | $25,602 | $31,633 | $13,080 | (59%) |
| PJM | $8,607 | $32,915 | $46,270 | $48,262 | $28,394 | $65,278 | $50,024 | $44,230 | $20,364 | (54%) |

In 2017, a new CT would not have received sufficient net revenue to cover levelized total costs in any zone but would have covered 95 percent of levelized costs in the PSEG Zone, primarily as a result of higher capacity revenue in PSEG (Table 7-10).

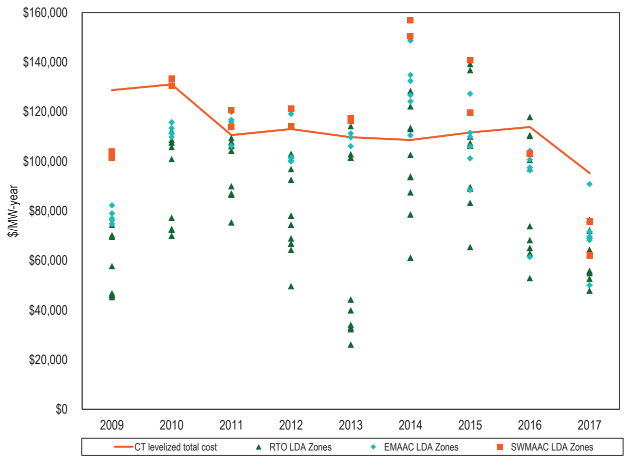
### Table 7-10 Percent of 20-year levelized total costs recovered by CT energy and capacity net revenue: 2009 through 2017

| Zone | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 |
|---|---|---|---|---|---|---|---|---|---|
| AECO | 64% | 88% | 108% | 90% | 100% | 122% | 100% | 90% | 73% |
| AEP | 36% | 55% | 78% | 57% | 29% | 86% | 80% | 60% | 58% |
| APS | 58% | 83% | 96% | 66% | 36% | 105% | 99% | 97% | 76% |
| ATSI | NA | NA | NA | NA | NA | 94% | 125% | 97% | 68% |
| BGE | 79% | 102% | 109% | 107% | 106% | 144% | 126% | 142% | 79% |
| ComEd | 35% | 53% | 68% | 44% | 24% | 56% | 59% | 46% | 50% |
| DAY | 36% | 55% | 79% | 61% | 30% | 86% | 80% | 55% | 58% |
| DEOK | NA | NA | NA | NA | NA | 104% | 123% | 57% | 59% |
| DLCO | 36% | 59% | 81% | 59% | 31% | 81% | 75% | 91% | 75% |
| Dominion | 45% | 82% | 96% | 69% | 40% | 72% | 80% | 65% | 55% |
| DPL | 61% | 88% | 104% | 105% | 107% | 137% | 91% | 92% | 72% |
| EKPC | NA | NA | NA | NA | NA | 102% | 114% | 54% | 52% |
| JCPL | 60% | 87% | 106% | 89% | 105% | 124% | 98% | 86% | 75% |
| Met-Ed | 55% | 86% | 98% | 86% | 94% | 112% | 96% | 88% | 80% |
| PECO | 59% | 85% | 105% | 88% | 97% | 117% | 95% | 85% | 73% |
| PENELEC | 54% | 77% | 94% | 91% | 104% | 173% | 155% | 104% | 80% |
| Pepco | 81% | 100% | 103% | 101% | 107% | 139% | 107% | 91% | 65% |
| PPL | 54% | 81% | 99% | 82% | 93% | 118% | 95% | 85% | 74% |
| PSEG | 58% | 84% | 96% | 89% | 101% | 114% | 79% | 88% | 95% |
| RECO | 57% | 82% | 87% | 83% | 101% | 108% | 77% | 76% | 64% |
| PJM | 55% | 79% | 95% | 80% | 77% | 110% | 98% | 82% | 69% |

21 The energy net revenues presented for the PJM area in this section represent the zonal average energy net revenues.
22 The energy net revenues presented for 2016 have been updated since the 2016 State of the Market Report.

Figure 7-6 shows zonal net revenue and the annual levelized total cost for the new entrant CT by LDA.

**Figure 7-6 New entrant CT net revenue and 20-year levelized total cost by LDA (Dollars per installed MW-year): 2009 through 2017**




## 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.[23] 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 15 of 20 zones in 2017 than in 2016 (Table 7-11). Gas prices increased more than the LMP increased, resulting in lower margins and lower energy net revenues.

**Table 7-11 Energy net revenue for a new entrant CC under economic dispatch (Dollars per installed MW-year): 2009 through 2017[24 25]**

| Zone | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | Change in 2017 from 2016 |
|---|---|---|---|---|---|---|---|---|---|---|
| AECO | $37,852 | $79,328 | $111,306 | $92,466 | $70,012 | $123,761 | $90,646 | $78,013 | $70,631 | (9%) |
| AEP | $15,920 | $32,720 | $70,273 | $81,290 | $52,898 | $94,541 | $73,584 | $69,313 | $69,198 | (0%) |
| APS | $41,013 | $70,232 | $101,830 | $93,060 | $66,602 | $121,059 | $97,044 | $105,413 | $89,818 | (15%) |
| ATSI | NA | NA | $47,083 | $87,078 | $64,344 | $108,904 | $77,638 | $64,124 | $66,412 | 4% |
| BGE | $46,193 | $91,219 | $111,996 | $113,212 | $86,520 | $160,024 | $123,490 | $145,186 | $91,292 | (37%) |
| ComEd | $9,224 | $20,318 | $31,890 | $53,616 | $28,188 | $38,964 | $30,984 | $43,630 | $40,484 | (7%) |
| DAY | $14,063 | $30,879 | $69,799 | $86,887 | $56,071 | $96,827 | $75,212 | $63,809 | $67,072 | 5% |
| DEOK | NA | NA | NA | $75,534 | $55,985 | $131,815 | $126,326 | $63,796 | $64,571 | 1% |
| DLCO | $14,210 | $35,028 | $69,664 | $81,852 | $49,647 | $80,373 | $63,351 | $96,607 | $88,010 | (9%) |
| Dominion | $48,720 | $88,838 | $98,117 | $94,554 | $67,136 | $87,913 | $74,747 | $79,224 | $64,856 | (18%) |
| DPL | $39,572 | $76,906 | $105,344 | $104,125 | $73,857 | $144,248 | $75,044 | $82,446 | $69,520 | (16%) |
| EKPC | NA | NA | NA | NA | $34,714 | $127,207 | $116,344 | $58,759 | $56,372 | (4%) |
| JCPL | $37,944 | $77,772 | $109,562 | $92,010 | $77,489 | $128,858 | $89,489 | $72,909 | $74,785 | 3% |
| Met-Ed | $31,635 | $70,703 | $95,417 | $87,492 | $65,530 | $112,744 | $82,109 | $75,696 | $80,021 | 6% |
| PECO | $33,551 | $73,009 | $105,795 | $89,597 | $63,132 | $115,652 | $83,816 | $70,623 | $70,541 | (0%) |
| PENELEC | $31,352 | $61,287 | $97,938 | $98,591 | $91,135 | $188,435 | $149,842 | $96,217 | $86,626 | (10%) |
| Pepco | $45,176 | $89,540 | $103,337 | $105,910 | $82,294 | $144,086 | $99,510 | $94,523 | $67,694 | (28%) |
| PPL | $29,740 | $62,518 | $94,143 | $83,418 | $62,900 | $113,566 | $82,866 | $72,205 | $71,852 | (0%) |
| PSEG | $33,366 | $73,323 | $94,698 | $85,877 | $67,412 | $103,746 | $48,489 | $56,283 | $56,257 | (0%) |
| RECO | $28,128 | $67,511 | $76,967 | $80,214 | $68,794 | $103,181 | $48,869 | $58,456 | $56,867 | (3%) |
| PJM | $31,627 | $64,772 | $88,620 | $88,778 | $64,233 | $116,295 | $85,470 | $77,362 | $70,144 | (9%) |

23 All starts associated with combined cycle units are assumed to be hot starts.
24 The energy net revenues presented for the PJM area in this section represent the zonal average energy net revenues.
25 The energy net revenues presented for 2016 have been updated since the 2016 State of the Market Report.

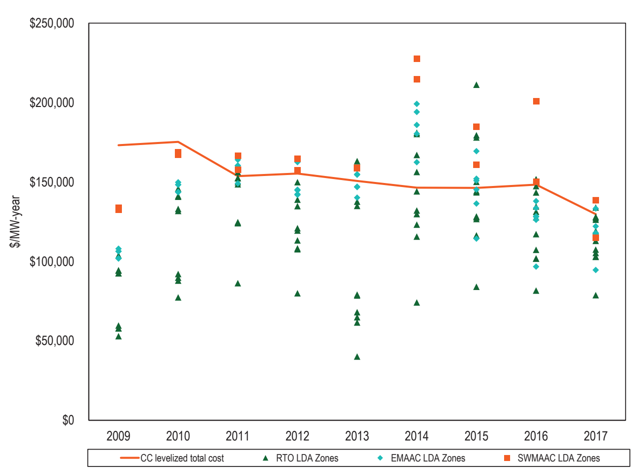
In 2017, a new CC would have received sufficient net revenue to cover levelized total costs in three zones and to cover 90 percent or more of levelized costs in 11 of 20 zones (Table 7-12).

### Table 7-12 Percent of 20-year levelized total costs recovered by CC energy and capacity net revenue: 2009 through 2017

| Zone | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 |
|---|---|---|---|---|---|---|---|---|---|
| AECO | 61% | 85% | 108% | 93% | 98% | 132% | 104% | 90% | 91% |
| AEP | 34% | 51% | 81% | 69% | 43% | 89% | 87% | 72% | 83% |
| APS | 60% | 80% | 102% | 77% | 52% | 107% | 103% | 97% | 99% |
| ATSI | NA | NA | NA | NA | NA | 98% | 122% | 99% | 87% |
| BGE | 77% | 96% | 108% | 106% | 105% | 155% | 126% | 135% | 107% |
| ComEd | 31% | 44% | 56% | 51% | 27% | 51% | 57% | 55% | 61% |
| DAY | 33% | 50% | 81% | 73% | 45% | 90% | 88% | 69% | 81% |
| DEOK | NA | NA | NA | NA | NA | 114% | 123% | 69% | 79% |
| DLCO | 33% | 53% | 81% | 70% | 41% | 79% | 80% | 91% | 97% |
| Dominion | 53% | 83% | 99% | 78% | 52% | 84% | 87% | 79% | 79% |
| DPL | 62% | 85% | 104% | 105% | 103% | 146% | 93% | 93% | 90% |
| EKPC | NA | NA | NA | NA | NA | 111% | 116% | 65% | 73% |
| JCPL | 61% | 85% | 107% | 93% | 103% | 136% | 103% | 87% | 94% |
| Met-Ed | 55% | 81% | 97% | 89% | 91% | 123% | 98% | 88% | 98% |
| PECO | 59% | 82% | 104% | 92% | 93% | 127% | 99% | 85% | 91% |
| PENELEC | 54% | 75% | 99% | 97% | 108% | 175% | 144% | 102% | 103% |
| Pepco | 77% | 95% | 103% | 101% | 105% | 147% | 110% | 101% | 89% |
| PPL | 53% | 76% | 97% | 87% | 90% | 124% | 99% | 86% | 92% |
| PSEG | 59% | 82% | 97% | 91% | 97% | 123% | 78% | 86% | 103% |
| RECO | 56% | 79% | 85% | 86% | 97% | 118% | 75% | 77% | 80% |
| PJM | 54% | 75% | 95% | 86% | 79% | 116% | 100% | 86% | 89% |

Figure 7-7 shows zonal net revenue and the annual levelized total cost for the new entrant CC by LDA.

### Figure 7-7 New entrant CC net revenue and 20-year levelized total cost by LDA (Dollars per installed MW-year): 2009 through 2017




## 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 2017 in 12 of 20 zones (Table 7-13).

## Table 7-13 Energy net revenue for a new entrant CP (Dollars per installed MW-year): 2009 through 2017[26 27]

| Zone | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | Change in 2017 from 2016 |
|---|---|---|---|---|---|---|---|---|---|---|
| AECO | $103,766 | $146,624 | $92,802 | $34,149 | $57,755 | $177,470 | $73,776 | $21,635 | $19,895 | (8%) |
| AEP | $46,160 | $94,385 | $85,512 | $34,944 | $66,604 | $130,312 | $60,723 | $24,173 | $25,137 | 4% |
| APS | $99,655 | $145,822 | $105,988 | $47,572 | $76,645 | $154,779 | $79,952 | $25,333 | $27,170 | 7% |
| ATSI | NA | NA | $41,354 | $42,673 | $74,835 | $143,552 | $61,397 | $24,503 | $26,732 | 9% |
| BGE | $121,146 | $184,563 | $121,183 | $62,567 | $91,820 | $228,990 | $145,506 | $56,405 | $32,765 | (42%) |
| ComEd | $109,938 | $135,212 | $129,279 | $111,542 | $130,283 | $178,450 | $97,010 | $21,963 | $21,851 | (1%) |
| DAY | $44,900 | $89,635 | $81,825 | $33,023 | $72,665 | $135,377 | $59,299 | $22,403 | $25,111 | 12% |
| DEOK | NA | NA | NA | $26,451 | $62,130 | $122,282 | $54,717 | $21,493 | $24,449 | 14% |
| DLCO | $43,907 | $68,504 | $49,251 | $27,035 | $43,321 | $97,572 | $47,474 | $22,968 | $25,003 | 9% |
| Dominion | $105,884 | $167,920 | $101,391 | $44,651 | $72,880 | $180,306 | $106,299 | $31,704 | $29,239 | (8%) |
| DPL | $114,738 | $166,793 | $117,229 | $57,505 | $81,303 | $222,872 | $103,772 | $32,950 | $27,701 | (16%) |
| EKPC | NA | NA | NA | NA | $32,626 | $118,063 | $45,675 | $20,383 | $18,934 | (7%) |
| JCPL | $103,162 | $144,597 | $90,057 | $32,724 | $64,305 | $181,578 | $73,488 | $17,593 | $21,131 | 20% |
| Met-Ed | $104,285 | $152,922 | $101,258 | $43,092 | $68,531 | $177,954 | $74,648 | $19,879 | $25,961 | 31% |
| PECO | $98,600 | $139,859 | $88,317 | $32,534 | $52,526 | $170,974 | $70,211 | $18,342 | $20,229 | 10% |
| PENELEC | $78,821 | $113,244 | $77,113 | $39,044 | $67,118 | $149,924 | $70,797 | $19,527 | $19,212 | (2%) |
| Pepco | $111,966 | $164,693 | $88,212 | $38,656 | $73,063 | $202,767 | $114,025 | $37,737 | $28,615 | (24%) |
| PPL | $92,013 | $125,723 | $77,783 | $26,866 | $52,125 | $167,421 | $68,996 | $17,010 | $20,650 | 21% |
| PSEG | $96,099 | $146,842 | $89,665 | $31,754 | $77,582 | $201,663 | $83,728 | $16,277 | $21,056 | 29% |
| RECO | $89,060 | $137,591 | $71,676 | $28,196 | $83,010 | $196,735 | $84,679 | $16,666 | $20,176 | 21% |
| PJM | $92,006 | $136,761 | $89,439 | $41,841 | $70,056 | $166,952 | $78,809 | $24,447 | $24,051 | (2%) |

In 2017, a new CP would not have received sufficient net revenue to cover levelized total costs in any zone (Table 7-14). This has been the consistent result for a new CP for the entire nine year period of the analysis.

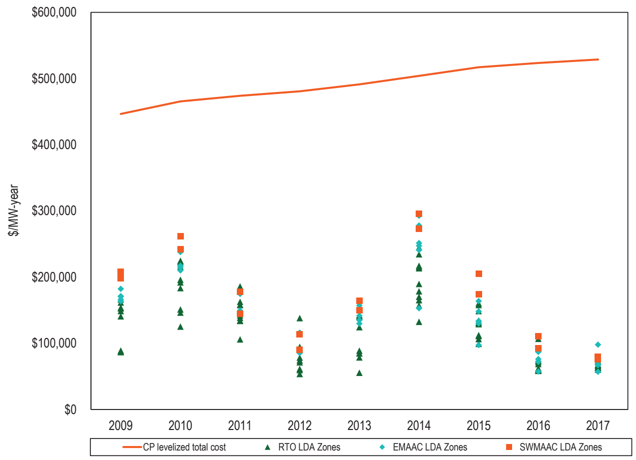
## Table 7-14 Percent of 20-year levelized total costs recovered by CP energy and capacity net revenue: 2009 through 2017

| Zone | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 |
|---|---|---|---|---|---|---|---|---|---|
| AECO | 38% | 47% | 32% | 18% | 27% | 49% | 26% | 15% | 13% |
| AEP | 20% | 32% | 30% | 13% | 16% | 33% | 22% | 12% | 12% |
| APS | 36% | 46% | 34% | 15% | 18% | 38% | 25% | 12% | 12% |
| ATSI | NA | NA | NA | NA | NA | 35% | 31% | 20% | 14% |
| BGE | 47% | 56% | 38% | 24% | 33% | 59% | 40% | 21% | 15% |
| ComEd | 34% | 41% | 39% | 29% | 29% | 42% | 29% | 11% | 11% |
| DAY | 20% | 31% | 29% | 12% | 17% | 34% | 21% | 11% | 12% |
| DEOK | NA | NA | NA | NA | NA | 31% | 21% | 11% | 12% |
| DLCO | 19% | 27% | 22% | 11% | 11% | 26% | 19% | 11% | 12% |
| Dominion | 33% | 48% | 33% | 15% | 17% | 43% | 31% | 13% | 13% |
| DPL | 41% | 51% | 37% | 24% | 33% | 58% | 32% | 17% | 14% |
| EKPC | NA | NA | NA | NA | NA | 30% | 19% | 11% | 11% |
| JCPL | 38% | 46% | 31% | 18% | 29% | 50% | 26% | 14% | 13% |
| Met-Ed | 37% | 48% | 33% | 20% | 29% | 49% | 26% | 14% | 14% |
| PECO | 37% | 45% | 31% | 18% | 26% | 48% | 25% | 14% | 13% |
| PENELEC | 32% | 39% | 28% | 19% | 28% | 43% | 25% | 14% | 13% |
| Pepco | 44% | 52% | 31% | 19% | 30% | 54% | 34% | 18% | 14% |
| PPL | 34% | 42% | 28% | 16% | 25% | 47% | 25% | 14% | 13% |
| PSEG | 37% | 47% | 31% | 18% | 32% | 55% | 29% | 17% | 19% |
| RECO | 35% | 45% | 27% | 17% | 33% | 53% | 28% | 14% | 13% |
| PJM | 34% | 44% | 31% | 18% | 26% | 44% | 27% | 14% | 13% |

26 The energy net revenues presented for the PJM area in this section represent the zonal average energy net revenues.
27 The energy net revenues presented for 2016 have been updated since the 2016 State of the Market Report.

Figure 7-8 shows zonal net revenue and the annual levelized total cost for the new entrant CP by LDA.

Figure 7-8 New entrant CP net revenue and 20-year levelized total cost by LDA (Dollars per installed MW-year): 2009 through 2017




## 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.[28]

New entrant nuclear plant energy market net revenues were higher in all but two zones in 2017 (Table 7-15). The increase in LMP resulted in higher margins and higher net revenues in 18 of 20 zones.

Table 7-15 Energy net revenue for a new entrant nuclear plant (Dollars per installed MW-year): 2009 through 2017[29 30]

| Zone | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | Change in 2017 from 2016 |
|---|---|---|---|---|---|---|---|---|---|---|
| AECO | $288,632 | $367,483 | $335,035 | $223,539 | $262,810 | $387,883 | $220,023 | $141,415 | $166,619 | 18% |
| AEP | $218,504 | $261,098 | $262,335 | $198,385 | $230,716 | $311,569 | $204,723 | $169,693 | $182,261 | 7% |
| APS | $256,721 | $314,729 | $293,355 | $210,232 | $244,428 | $337,998 | $228,936 | $174,898 | $186,514 | 7% |
| ATSI | NA | NA | $153,888 | $204,058 | $242,705 | $325,433 | $208,372 | $171,111 | $187,815 | 10% |
| BGE | $298,473 | $391,960 | $341,862 | $245,538 | $285,910 | $444,433 | $304,148 | $243,694 | $211,305 | (13%) |
| ComEd | $179,104 | $217,838 | $212,423 | $175,450 | $206,746 | $272,321 | $168,496 | $155,096 | $160,622 | 4% |
| DAY | $214,090 | $258,210 | $262,111 | $203,992 | $234,102 | $314,747 | $206,825 | $170,886 | $187,977 | 10% |
| DEOK | NA | NA | NA | $192,158 | $221,863 | $299,618 | $201,391 | $166,192 | $183,433 | 10% |
| DLCO | $208,801 | $257,065 | $258,686 | $199,094 | $227,732 | $291,888 | $193,791 | $164,782 | $182,956 | 11% |
| Dominion | $281,069 | $373,737 | $319,215 | $223,740 | $263,891 | $388,295 | $260,516 | $194,597 | $201,989 | 4% |
| DPL | $291,154 | $370,565 | $335,597 | $236,441 | $272,775 | $428,044 | $250,192 | $167,484 | $186,693 | 11% |
| EKPC | NA | NA | NA | NA | $127,631 | $294,606 | $190,936 | $160,897 | $174,511 | 8% |
| JCPL | $287,875 | $365,408 | $332,717 | $222,496 | $271,028 | $392,479 | $218,452 | $136,192 | $171,550 | 26% |
| Met-Ed | $279,022 | $354,677 | $317,652 | $217,622 | $257,748 | $374,408 | $211,003 | $139,412 | $177,070 | 27% |
| PECO | $282,937 | $359,927 | $329,530 | $220,535 | $256,201 | $378,894 | $212,675 | $133,703 | $166,558 | 25% |
| PENELEC | $250,469 | $310,481 | $291,867 | $215,338 | $256,535 | $349,950 | $217,124 | $157,475 | $177,336 | 13% |
| Pepco | $298,215 | $389,389 | $332,675 | $238,119 | $281,722 | $427,666 | $279,006 | $211,892 | $205,068 | (3%) |
| PPL | $275,067 | $343,190 | $316,501 | $213,393 | $255,433 | $374,962 | $211,595 | $135,684 | $168,294 | 24% |
| PSEG | $292,089 | $371,365 | $338,912 | $226,944 | $289,418 | $416,439 | $230,273 | $141,064 | $177,559 | 26% |
| RECO | $284,023 | $360,820 | $317,521 | $221,087 | $295,509 | $411,345 | $232,025 | $142,225 | $178,340 | 25% |
| PJM | $263,897 | $333,408 | $297,327 | $215,166 | $249,245 | $361,149 | $222,525 | $163,920 | $181,724 | 11% |

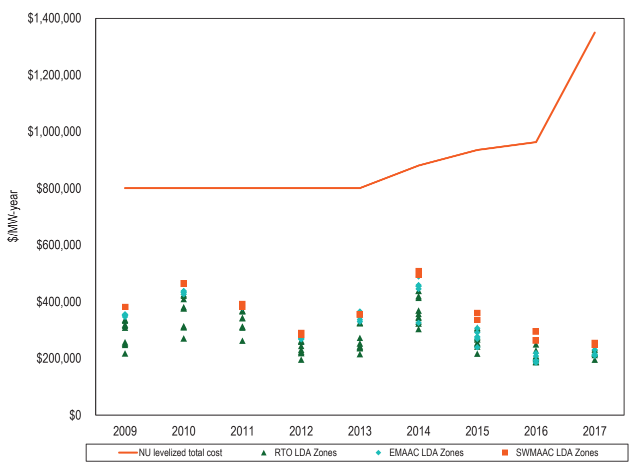
28 The class average forced outage rate was applied to total energy market net revenues.
29 The energy net revenues presented for the PJM area in this section represent the zonal average energy net revenues.
30 The energy net revenues presented for 2016 have been updated since the 2016 State of the Market Report for PJM.

In 2017, a new nuclear plant would not have received sufficient net revenue to cover levelized total costs in any zone (Table 7-16). This has been the consistent result for a new nuclear plant for the entire nine year period of the analysis.

Table 7-16 Percent of 20-year levelized total costs recovered by nuclear energy and capacity net revenue: 2009 through 2017

| Zone | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 |
|---|---|---|---|---|---|---|---|---|---|
| AECO | 44% | 54% | 48% | 34% | 42% | 52% | 30% | 20% | 16% |
| AEP | 32% | 39% | 39% | 27% | 30% | 39% | 27% | 21% | 16% |
| APS | 39% | 48% | 43% | 29% | 32% | 42% | 30% | 22% | 16% |
| ATSI | NA | NA | NA | NA | NA | 40% | 32% | 26% | 17% |
| BGE | 48% | 58% | 49% | 36% | 44% | 58% | 39% | 31% | 19% |
| ComEd | 27% | 34% | 33% | 24% | 27% | 34% | 23% | 20% | 14% |
| DAY | 32% | 39% | 39% | 28% | 30% | 39% | 27% | 21% | 16% |
| DEOK | NA | NA | NA | NA | NA | 38% | 27% | 21% | 16% |
| DLCO | 31% | 39% | 39% | 27% | 29% | 37% | 26% | 21% | 16% |
| Dominion | 40% | 53% | 46% | 30% | 34% | 48% | 33% | 24% | 18% |
| DPL | 44% | 55% | 48% | 36% | 44% | 56% | 33% | 23% | 17% |
| EKPC | NA | NA | NA | NA | NA | 37% | 26% | 20% | 15% |
| JCPL | 44% | 54% | 48% | 34% | 43% | 52% | 29% | 19% | 16% |
| Met-Ed | 42% | 53% | 46% | 33% | 41% | 50% | 29% | 20% | 16% |
| PECO | 43% | 53% | 47% | 33% | 41% | 51% | 29% | 19% | 16% |
| PENELEC | 38% | 47% | 43% | 33% | 41% | 47% | 29% | 22% | 16% |
| Pepco | 48% | 58% | 48% | 35% | 44% | 56% | 36% | 27% | 18% |
| PPL | 42% | 51% | 46% | 32% | 40% | 50% | 29% | 19% | 16% |
| PSEG | 44% | 55% | 49% | 35% | 46% | 56% | 31% | 22% | 19% |
| RECO | 43% | 53% | 46% | 33% | 46% | 54% | 31% | 20% | 16% |
| PJM | 40% | 49% | 44% | 32% | 38% | 47% | 30% | 22% | 17% |

Figure 7-9 New entrant NU net revenue and 20-year levelized total cost by LDA (Dollars per installed MW-year): 2009 through 2017



## 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 higher in all but four zones in 2017 (Table 7-17).

### Table 7-17 Energy market net revenue for a new entrant DS (Dollars per installed MW-year): 2009 through 2017[31]

| Zone | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | Change in 2017 from 2016 |
|---|---|---|---|---|---|---|---|---|---|---|
| AECO | $1,763 | $11,217 | $6,708 | $1,552 | $1,082 | $37,123 | $15,506 | $1,730 | $2,805 | 62% |
| AEP | $112 | $499 | $1,717 | $820 | $484 | $15,855 | $6,002 | $807 | $1,296 | 61% |
| APS | $886 | $1,771 | $2,007 | $1,061 | $741 | $20,542 | $10,490 | $992 | $1,317 | 33% |
| ATSI | NA | NA | $308 | $1,083 | $23,643 | $15,553 | $5,777 | $1,959 | $1,607 | (18%) |
| BGE | $3,712 | $14,147 | $7,870 | $2,577 | $2,654 | $55,866 | $27,241 | $7,924 | $3,131 | (60%) |
| ComEd | $11 | $480 | $811 | $909 | $384 | $12,427 | $3,720 | $652 | $1,276 | 96% |
| DAY | $186 | $554 | $1,894 | $946 | $517 | $15,671 | $6,083 | $905 | $1,494 | 65% |
| DEOK | NA | NA | NA | $689 | $462 | $14,814 | $5,829 | $1,200 | $2,509 | 109% |
| DLCO | $674 | $2,987 | $2,165 | $914 | $1,231 | $14,403 | $5,428 | $2,279 | $1,382 | (39%) |
| Dominion | $3,639 | $10,967 | $4,108 | $1,664 | $1,545 | $46,961 | $15,836 | $2,120 | $2,636 | 24% |
| DPL | $2,721 | $9,892 | $5,769 | $2,381 | $1,083 | $43,946 | $25,593 | $3,690 | $5,798 | 57% |
| EKPC | NA | NA | NA | NA | $289 | $15,816 | $4,856 | $646 | $926 | 43% |
| JCPL | $1,895 | $8,673 | $6,610 | $1,704 | $2,016 | $37,086 | $15,065 | $718 | $2,974 | 314% |
| Met-Ed | $1,620 | $8,711 | $5,032 | $1,833 | $1,254 | $35,789 | $15,174 | $679 | $3,673 | 441% |
| PECO | $1,558 | $8,570 | $5,379 | $1,936 | $1,004 | $36,186 | $14,033 | $666 | $3,083 | 363% |
| PENELEC | $240 | $1,124 | $2,642 | $2,141 | $1,104 | $18,141 | $8,154 | $791 | $1,684 | 113% |
| Pepco | $4,036 | $13,277 | $6,077 | $2,009 | $2,249 | $56,830 | $18,222 | $3,256 | $2,489 | (24%) |
| PPL | $1,428 | $7,704 | $5,317 | $1,747 | $1,054 | $36,712 | $14,906 | $626 | $3,022 | 383% |
| PSEG | $1,394 | $7,394 | $5,447 | $1,695 | $1,257 | $36,629 | $14,566 | $803 | $3,479 | 333% |
| RECO | $1,201 | $6,241 | $4,255 | $1,737 | $2,387 | $34,756 | $16,108 | $970 | $3,155 | 225% |
| PJM | $1,593 | $6,718 | $4,118 | $1,547 | $2,322 | $30,055 | $12,429 | $1,671 | $2,487 | 49% |

In 2017, the new entrant DS would not have received sufficient net revenue to cover levelized total costs in any zone. This has been the consistent result for a new DS for the entire nine year period of the analysis.

### Table 7-18 Percent of 20-year levelized total costs recovered by DS energy and capacity net revenue: 2009 through 2017

| Zone | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 |
|---|---|---|---|---|---|---|---|---|---|
| AECO | 43% | 51% | 37% | 31% | 49% | 64% | 42% | 30% | 29% |
| AEP | 25% | 35% | 34% | 14% | 6% | 29% | 32% | 20% | 23% |
| APS | 38% | 44% | 34% | 14% | 6% | 32% | 34% | 20% | 23% |
| ATSI | NA | NA | NA | NA | NA | 29% | 59% | 47% | 28% |
| BGE | 56% | 57% | 38% | 31% | 46% | 74% | 49% | 34% | 29% |
| ComEd | 25% | 35% | 33% | 14% | 6% | 27% | 30% | 20% | 23% |
| DAY | 25% | 35% | 34% | 14% | 6% | 29% | 32% | 20% | 23% |
| DEOK | NA | NA | NA | NA | NA | 28% | 32% | 20% | 23% |
| DLCO | 26% | 36% | 34% | 14% | 6% | 28% | 31% | 21% | 23% |
| Dominion | 28% | 42% | 35% | 14% | 7% | 48% | 38% | 20% | 23% |
| DPL | 43% | 50% | 37% | 36% | 51% | 68% | 48% | 32% | 31% |
| EKPC | NA | NA | NA | NA | NA | 29% | 31% | 20% | 22% |
| JCPL | 43% | 49% | 37% | 32% | 49% | 64% | 42% | 30% | 29% |
| Met-Ed | 39% | 49% | 36% | 31% | 46% | 61% | 42% | 30% | 30% |
| PECO | 42% | 49% | 36% | 32% | 49% | 63% | 41% | 30% | 29% |
| PENELEC | 38% | 44% | 34% | 31% | 45% | 50% | 38% | 30% | 29% |
| Pepco | 57% | 56% | 37% | 31% | 49% | 76% | 44% | 31% | 29% |
| PPL | 39% | 48% | 36% | 31% | 45% | 62% | 42% | 30% | 29% |
| PSEG | 42% | 48% | 36% | 34% | 50% | 68% | 44% | 39% | 48% |
| RECO | 42% | 47% | 35% | 32% | 50% | 62% | 43% | 30% | 29% |
| PJM | 38% | 46% | 35% | 26% | 33% | 50% | 40% | 28% | 28% |

31 The energy net revenues presented for 2016 have been updated since the 2016 State of the Market Report for PJM.

## New Entrant Wind Installation

Energy market net revenues for a wind installation located in the ComEd Zone and in the PENELEC Zone were calculated hourly assuming the unit generated 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.[32] 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).[33]

Wind energy market net revenues were higher in both zones in 2017 as a result of higher energy prices.

### Table 7-19 Net revenue for a wind installation (Dollars per installed MW-year): 2012 through 2017

| | ComEd | | | | PENELEC | | | |
|---|---|---|---|---|---|---|---|---|
| | Energy | RECs | Capacity | Total | Energy | RECs | Capacity | Total |
| 2012 | $52,229 | - | $2,632 | $54,860 | $48,210 | $3,271 | $5,878 | $57,359 |
| 2013 | $59,854 | - | $1,095 | $60,948 | $63,471 | $13,686 | $8,905 | $86,063 |
| 2014 | $108,044 | $3,233 | $4,049 | $115,326 | $125,923 | $33,337 | $8,237 | $167,497 |
| 2015 | $81,393 | $2,080 | $6,257 | $89,730 | $82,385 | $35,739 | $7,338 | $125,463 |
| 2016 | $69,319 | $2,621 | $4,339 | $76,279 | $63,327 | $41,221 | $6,623 | $111,172 |
| 2017 | $74,413 | $4,247 | $4,504 | $83,164 | $72,282 | $44,870 | $5,677 | $122,829 |
| Change in 2017 from 2016 | 7% | 62% | 4% | 9% | 14% | 9% | (14%) | 10% |

In 2017, a new wind installation would not have received sufficient net revenue to cover levelized total costs in either zone. This has been the consistent result for a new wind installation for the entire six year period of the analysis. Renewable energy credits accounted for five percent of the total net revenue of a wind installation in ComEd and 37 percent of the total net revenue of a wind installation in PENELEC.

### Table 7-20 Percent of 20-year levelized total costs recovered by wind net revenue (Dollars per installed MW-year): 2012 through 2017

| Zone | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 |
|---|---|---|---|---|---|---|
| ComEd | 28% | 31% | 58% | 44% | 33% | 44% |
| PENELEC | 29% | 44% | 85% | 62% | 48% | 65% |

## 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).[34]

Solar energy market net revenues were slightly lower in 2017 than in 2016 with higher LMPs not offsetting fewer run hours.

### Table 7-21 PSEG net revenue for a solar installation (Dollars per installed MW-year): 2012 through 2017

| | PSEG | | | |
|---|---|---|---|---|
| | Energy | RECs | Capacity | Total |
| 2012 | $39,831 | $255,001 | $18,984 | $313,815 |
| 2013 | $69,202 | $234,868 | $28,835 | $332,905 |
| 2014 | $68,341 | $212,315 | $27,575 | $308,231 |
| 2015 | $52,679 | $272,943 | $23,156 | $348,778 |
| 2016 | $38,225 | $284,155 | $25,545 | $347,926 |
| 2017 | $36,722 | $271,908 | $27,892 | $336,522 |
| Change in 2017 from 2016 | (4%) | (4%) | 9% | (3%) |

In 2017, a new solar installation would have received sufficient net revenue to cover levelized total costs in PSEG. Renewable energy credits accounted for 81 percent of the total net revenue of a solar installation.

### Table 7-22 Percent of 20-year levelized total costs recovered by solar net revenue (Dollars per installed MW-year): 2012 through 2017

| Zone | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 |
|---|---|---|---|---|---|---|
| PSEG | 79% | 126% | 130% | 149% | 159% | 167% |

32 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.

33 The 1603 payment is a direct payment of 30 percent of the project cost.

34 The 1603 payment is a direct payment of 30 percent of the project cost.

## Historical New Entrant CT and CC Revenue Adequacy

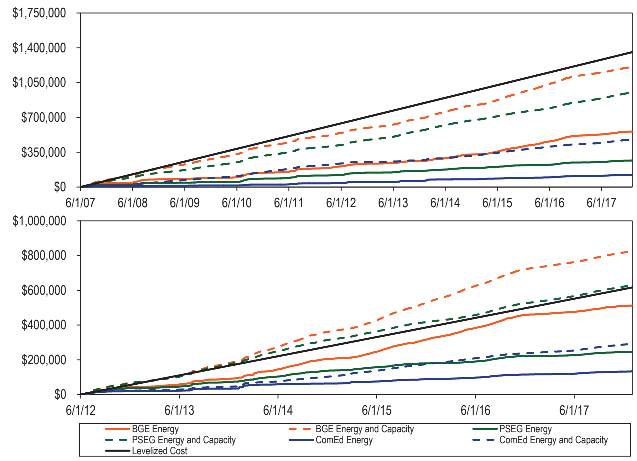
Total unit net revenues include energy and capacity revenues. Analysis of the total unit revenues of theoretical new entrant CTs and CCs for three representative locations shows that units that entered the PJM markets in 2007 have not covered their total costs, including the return on and of capital, on a cumulative basis through 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.

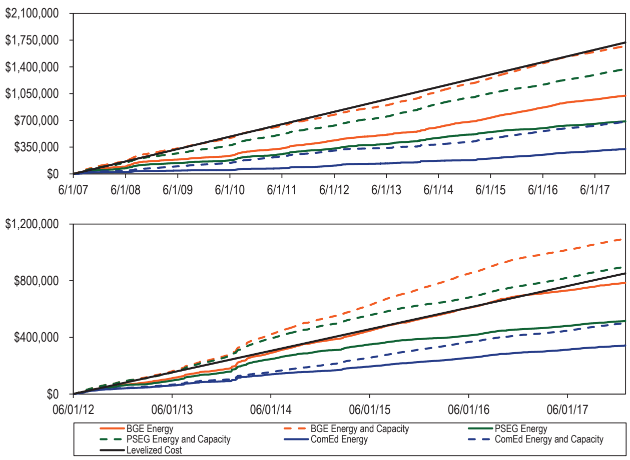
For the ComEd Zone, the PSEG Zone and the BGE Zone, Figure 7-10 compares cumulative energy market net revenues and energy market net revenues plus capacity market revenues to cumulative levelized costs for a new CT that began operation on June 1, 2007, and for a new CT that began operation on June 1, 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 7-10 Historical new entrant CT revenue adequacy: June 1, 2007 through December 31, 2017 and June 1, 2012 through December 31, 2017**




For the ComEd Zone, the PSEG Zone and the BGE Zone, Figure 7-11 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 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 7-11 Historical new entrant CC revenue adequacy: June 1, 2007 through December 31, 2017 and June 1, 2012 through December 31, 2017




Assumptions used for this analysis are shown in Table 7-23.

### Table 7-23 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 |

## Factors in Net Revenue Adequacy

Although it can be expected that in the long run, in a competitive market, net revenue from all sources will cover the fixed and variable costs of investing in new generating resources, including a competitive return on investment, actual results are expected to vary from year to year. Wholesale energy markets, like other markets, are cyclical. When the markets are long, prices will be lower and when the markets are short, prices will be higher.

The net revenue for a new generation resource varied significantly with the input fuel type and the efficiency of the reference technology. In 2017, the average short run marginal cost of the CC was lower than the average short run marginal cost of the CP in every month and the operating cost of the CT was lower than the CP all months except January, May, and December. (Figure 7-5)

The net revenue results illustrate some fundamentals of the PJM wholesale power market. Higher energy prices, higher gas prices, and higher coal prices meant that gas units ran with smaller margins than in prior year and results for coal units were mixed. High demand hours result in less efficient units setting prices, which results in higher net revenues for more efficient units. Scarcity revenues in the energy market also contribute to covering fixed costs, when they occur, but scarcity revenues are not a predictable and systematic source of net revenue in the PJM design. In the PJM design, the balance of the net revenue required to cover the fixed costs of peaking units comes from the capacity market.

However, there may be a lag in capacity market prices which either offsets the reduction in energy market revenues or exacerbates the reduction in energy market revenues. Capacity market prices are a function of a three year historical average net revenue offset which is generally an inaccurate estimate of actual net revenues in the current operating year and an inaccurate estimate of expected net revenues for the forward capacity market. Capacity market prices and revenues have a substantial impact on the profitability of investing in CTs and CCs. In 2017, capacity market prices decreased in some zones and increased in others.

The returns earned by investors in generating units are a direct function of net revenues, the cost of capital, and the fixed costs associated with the generating unit. Positive returns may be earned at less than the annualized fixed costs, although the returns are less than the target. A sensitivity analysis was performed to determine the impact of changes in net revenue on the return on investment for a new generating unit. The internal rate of return (IRR) was calculated for a range of 20-year levelized net revenue streams, using 20-year levelized total costs from Table 7-7 . The results are shown in Table 7-24.[35]

### Table 7-24 Internal rate of return sensitivity for CT, CC and CP generators

| | CT | | CC | | CP | |
|---|---|---|---|---|---|---|
| | 20-Year Levelized Net Revenue | 20-Year After Tax IRR | 20-Year Levelized Net Revenue | 20-Year After Tax IRR | 20-Year Levelized Net Revenue | 20-Year After Tax IRR |
| Sensitivity 1 | $102,764 | 14.2% | $139,731 | 14.2% | $558,701 | 13.5% |
| Base Case | $95,264 | 12.0% | $129,731 | 12.0% | $528,701 | 12.0% |
| Sensitivity 2 | $87,764 | 9.7% | $119,731 | 9.7% | $498,701 | 10.4% |
| Sensitivity 3 | $80,264 | 7.2% | $109,731 | 7.2% | $468,701 | 8.8% |
| Sensitivity 4 | $72,764 | 4.4% | $99,731 | 4.5% | $438,701 | 7.1% |
| Sensitivity 5 | $65,264 | 1.0% | $89,731 | 1.4% | $408,701 | 5.3% |
| Sensitivity 6 | $57,764 | (4.0%) | $79,731 | (2.5%) | $378,701 | 3.3% |

Additional sensitivity analyses were performed for the CT and the CC technologies for the debt to equity ratio; the term of the debt financing; and the costs of interconnection. Table 7-25 shows the levelized annual revenue requirements associated with a range of debt to equity ratios holding the 12 percent IRR constant. The base case assumes 50/50 debt to equity ratio. As the percent of equity financing decreases, the levelized annual revenue required to earn a 12 percent IRR falls.

### Table 7-25 Debt to equity ratio sensitivity for CT and CC assuming 20 year debt term and 12 percent internal rate of return

| | Equity as a percent of total financing | CT levelized annual revenue requirement | CC levelized annual revenue requirement |
|---|---|---|---|
| Sensitivity 1 | 60% | $101,039 | $137,070 |
| Sensitivity 2 | 55% | $98,151 | $133,400 |
| Base Case | 50% | $95,264 | $129,731 |
| Sensitivity 3 | 45% | $92,376 | $126,063 |
| Sensitivity 4 | 40% | $89,489 | $122,394 |
| Sensitivity 5 | 35% | $86,601 | $118,725 |
| Sensitivity 6 | 30% | $83,713 | $115,057 |

Table 7-26 shows the levelized annual revenue requirement associated with various terms for the debt financing, assuming a 50/50 debt to equity ratio and 12 percent rate of return. As the term of the debt financing decreases, more net revenue is required annually to maintain a 12 percent rate of return.

### Table 7-26 Debt term sensitivity for CT and CC assuming 50/50 debt to equity ratio and 12 percent internal rate of return

| | Term of debt in years | CT levelized annual revenue requirement | CC levelized annual revenue requirement |
|---|---|---|---|
| Sensitivity 1 | 30 | $86,222 | $118,245 |
| Sensitivity 2 | 25 | $89,638 | $122,585 |
| Base Case | 20 | $95,264 | $129,731 |
| Sensitivity 3 | 15 | $100,004 | $135,740 |
| Sensitivity 4 | 10 | $106,294 | $143,710 |

Table 7-27 shows the impact of a range of assumed interconnection costs on the levelized annual revenue requirement for the CT and the CC technologies. Interconnection costs vary significantly by location across PJM and even within PJM zones and can significantly impact the profitability of investing in peaking and midmerit generation technologies in a specific location. The impact on the annualized revenue requirements is more substantial for CTs than for CCs as interconnection costs are a larger proportion of overall project costs for CTs and as the new entrant

35 This analysis was performed for the MMU by Pasteris Energy, Inc. The annual costs were based on a 20-year project life, 50/50 debt to equity capital structure with a target IRR of 12 percent and a debt rate of 7 percent. For depreciation, the analysis assumed a 15-year modified accelerated cost-recovery schedule (MACRS) for the CT plant and 20-year MACRS for the CC and CP plants. An annual rate of cost inflation of 2.5 percent was used in all calculations.

CC has a higher energy output over which to spread the costs than the new entrant CT.

Table 7-27 Interconnection cost sensitivity for CT and CC

| | CT | | | CC | | |
|---|---|---|---|---|---|---|
| | Capital cost ($000) | Percent of total capital cost | Annualized revenue requirement ($/ICAP-Year) | Capital cost ($000) | Percent of total capital cost | Annualized revenue requirement ($/ICAP-Year) |
| Sensitivity 1 | $0 | 0.0% | $91,531 | $0 | 0.0% | $125,727 |
| Sensitivity 2 | $9,834 | 2.1% | $93,398 | $14,954 | 1.7% | $127,729 |
| Base Case | $19,669 | 4.2% | $95,264 | $29,908 | 3.3% | $129,731 |
| Sensitivity 3 | $29,503 | 6.4% | $97,130 | $44,861 | 5.0% | $131,733 |
| Sensitivity 4 | $39,338 | 8.5% | $98,996 | $59,815 | 6.7% | $133,735 |
| Sensitivity 5 | $49,172 | 10.6% | $100,862 | $74,769 | 8.3% | $135,737 |
| Sensitivity 6 | $59,091 | 12.7% | $101,019 | $89,723 | 10.0% | $137,739 |
| Sensitivity 7 | $88,637 | 19.1% | $105,762 | $117,392 | 13.1% | $139,115 |
| Sensitivity 8 | $118,182 | 25.5% | $110,506 | $176,088 | 19.6% | $145,810 |

## Actual Net Revenue

This analysis of net revenues is based on actual net revenues for actual units operating in PJM. Net revenues from energy and capacity markets are compared to avoidable costs to determine the extent to which the revenues from PJM markets provide sufficient incentive for continued operations in PJM markets. Avoidable costs are the costs which must be paid each year in order to keep a unit operating. Avoidable costs are less than total costs, which include the return on and of capital, and more than marginal costs, which are the purely short run incremental costs of producing energy. It is rational to operate a unit whenever the price is greater than its short run marginal costs. It is rational for an owner to continue to operate a unit rather than retire the unit if the unit is covering or is expected to cover its avoidable costs and therefore contributing to covering fixed costs. It is not rational for an owner to continue to operate a unit rather than retire the unit if the unit is not covering and is not expected to cover its avoidable costs. As a general matter, under those conditions, retirement of the unit is the logical option. Thus, this comparison of actual net revenues to avoidable costs is a measure of the extent to which units in PJM may be at risk of retirement.

The definition of avoidable costs, based on the RPM rules, includes both avoidable costs and the annualized fixed costs of investments required to maintain a unit as a capacity resource (APIR). When actual net revenues are compared to actual avoidable costs in this analysis, the actual avoidable costs are adjusted to exclude APIR. Existing APIR is a sunk cost and a rational decision about retirement would ignore such sunk costs. For example, APIR may reflect investments in environmental technology which were made in prior years to keep units in service. These costs are sunk costs.

The MMU calculated actual unit specific energy and ancillary service net revenues for a range of technology classes. These net revenues were compared to avoidable costs to determine the extent to which PJM energy and ancillary service markets alone provide sufficient incentive for continued operations in PJM markets. Energy and ancillary service revenues were then combined with the actual capacity revenues, and compared to actual avoidable costs to determine the extent to which the capacity market revenues covered any shortfall between energy and ancillary net revenues and avoidable costs. The comparison of the two results is an indicator of the significance of the role of the capacity market in maintaining the viability of existing generating units.

Actual energy net revenues include day-ahead and balancing market energy revenues, less short run marginal costs, plus any applicable day-ahead or balancing operating reserve credits. Ancillary service revenues include actual unit credits for regulation services, synchronized reserves, black start service, and reactive revenues.

The MMU calculated average avoidable costs in dollars per MW-year based on submitted avoidable cost rate (ACR) data for units associated with the most recent 2016/2017 and 2017/2018 RPM Auctions.[36] For units that did not submit ACR data, the default ACR was used.

The PJM capacity market design provides supplemental signals to the market based on the locational and forward looking need for generation resources to maintain system reliability. For this analysis, unit specific capacity revenues associated with the 2016/2017 and 2017/2018 Delivery Years, reflecting commitments made in base residual auctions (BRA) and subsequent incremental

36 If a unit submitted updated ACR data for an incremental auction, that data was used instead of the ACR data submitted for the base residual auction.

auctions, net of any performance penalties, were added to unit specific energy and ancillary net revenues to determine total revenue from PJM markets in 2017. Any unit with a significant portion of installed capacity designated as FRR committed was excluded from the analysis.[37] For units exporting capacity, the applicable BRA clearing price was applied.

Net revenues were analyzed for most technologies for which avoidable costs are developed in the capacity market. The analysis is on a unit specific basis, using individual unit actual net revenues and individual unit avoidable costs. Net revenues are calculated using units' price-based offers for technologies other than coal and nuclear. For coal units, net revenues are calculated using the lower of the unit's price-based or cost-based offer. For nuclear units, public data on revenues and costs are used.[38]

The unit specific energy and ancillary net revenues, avoidable costs and capacity revenues, on which the class averages shown in Table 7-28 are based, include a wide range of results. In order to illustrate this underlying variability while preserving confidentiality of unit specific information, the data are aggregated and summarized by quartile.

Table 7-28 shows energy and ancillary service net revenues by quartile for select technology classes.[39] Differences in energy net revenue within technology classes reflect differences in incremental costs which are a function of plant efficiencies, input fuels, variable operating and maintenance (VOM) expenses and emission rates, as well as differences in location which affect both the LMP and delivered costs for input fuels. Unlike the other technologies, nuclear data is from public sources in order to avoid revealing confidential information. Nuclear unit revenue is based on day-ahead LMP from the relevant node. Nuclear unit capacity revenue assumes that the unit cleared its full installed capacity at the BRA locational clearing price.

Table 7-28 also includes new entrant net revenue from Table 7-9, Table 7-11, Table 7-13, Table 7-15, and Table 7-17 for comparison purposes. The new entrant net revenues are at the high end of existing unit CC net revenues, are not comparable to existing unit CT net revenues, are within the range of existing unit coal plant and nuclear plant net revenues and are at the low end of existing unit diesel net revenues.

### Table 7-28 Net revenue by quartile for select technologies: 2017

| | | ($/MW-Yr) | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | Total Installed | Energy and ancillary service net revenue | | | | Capacity revenue | | | Energy, ancillary, and capacity revenue | | |
| Technology | Capacity (ICAP) | New entrant | First quartile | Median | Third quartile | First quartile | Median | Third quartile | First quartile | Median | Third quartile |
| CC - Combined Cycle | 56,286 | $70,144 | $96 | $27,121 | $47,120 | $13,886 | $22,265 | $46,672 | $44,468 | $55,014 | $71,718 |
| CT - Aero Derivative | 5,997 | $20,364 | ($771) | $1,371 | $5,893 | $38,273 | $45,964 | $50,371 | $41,187 | $47,832 | $53,162 |
| CT - Industrial Frame | 21,317 | - | ($965) | $1,094 | $3,078 | $36,208 | $43,859 | $49,862 | $36,694 | $45,074 | $50,927 |
| Coal Fired | 52,495 | $24,051 | ($1,469) | $7,067 | $23,949 | $42,546 | $45,689 | $48,955 | $43,470 | $52,944 | $67,864 |
| Diesel | 412 | $2,487 | ($854) | $2,803 | $23,702 | $39,596 | $43,668 | $49,099 | $41,896 | $48,685 | $65,270 |
| Hydro | 2,750 | - | $68,168 | $96,524 | $124,393 | $4,950 | $42,702 | $46,271 | $100,176 | $121,108 | $169,918 |
| Nuclear | 33,732 | $181,724 | $171,676 | $178,304 | $195,883 | $34,579 | $42,922 | $43,668 | $206,255 | $221,011 | $236,337 |
| Oil or Gas Steam | 8,178 | - | ($2,571) | ($773) | $1,919 | $33,438 | $42,754 | $47,424 | $34,829 | $43,621 | $49,002 |
| Pumped Storage | 4,721 | - | $49,623 | $49,623 | $121,759 | $5,432 | $6,265 | $42,640 | $55,055 | $80,528 | $127,934 |

37 The MMU cannot assess the risk of FRR designated units because the incentives associated with continued operations for these units are not transparent and are not aligned with PJM market incentives. For the same reasons, units with significant FRR commitments are excluded from the analysis of units potentially facing significant capital expenditures associated with environmental controls.

38 *See* 148 FERC ¶ 61,140 (2014). FERC directed that price based offers be used in the calculation of net revenues used in calculating capacity market offer caps. It is more accurate to use the lower of the unit's price-based or cost-based offers. Coal is the only technology for which there is a significant impact.

39 The quartile numbers in the table are the dividing line between the quartiles. The first quartile result means that 25 percent of units have lower net revenues, the median result means that 50 percent of units have lower net revenues and the third quartile result means that 75 percent of units have lower net revenues.

Table 7-29 shows the percent of avoidable costs covered by net revenue from PJM energy and ancillary services markets by quartiles. In 2017, 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 and it is not the case for coal units or for nuclear units.

### Table 7-29 Avoidable cost recovery by quartile: 2017

| | | Recovery of avoidable costs from energy and ancillary net revenue | | | Recovery of avoidable costs from all markets | | |
|---|---|---|---|---|---|---|---|
| Technology | Total Installed Capacity (ICAP) | First quartile | Median | Third quartile | First quartile | Median | Third quartile |
| CC - Combined Cycle | 56,286 | 1% | 182% | 362% | 283% | 424% | 545% |
| CT - Aero Derivative | 5,997 | 0% | 10% | 41% | 295% | 341% | 386% |
| CT - Industrial Frame | 21,317 | 0% | 11% | 27% | 340% | 427% | 481% |
| Coal Fired | 52,495 | 0% | 10% | 38% | 74% | 87% | 117% |
| Diesel | 412 | 0% | 25% | 212% | 386% | 443% | 583% |
| Hydro | 2,750 | 225% | 319% | 411% | 331% | 400% | 561% |
| Nuclear | 33,732 | 73% | 85% | 89% | 85% | 100% | 102% |
| Oil or Gas Steam | 8,178 | 0% | 0% | 6% | 139% | 161% | 183% |
| Pumped Storage | 4,721 | 397% | 397% | 973% | 440% | 749% | 1,023% |

### Table 7-30 Proportion of units recovering avoidable costs: 2011 through 2017

| | Units with full recovery fromenergy and ancillary net revenue | | | | | | | Units with full recovery from all markets | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Technology | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 |
| CC - Combined Cycle | 55% | 46% | 50% | 72% | 59% | 63% | 62% | 85% | 79% | 79% | 95% | 88% | 93% | 86% |
| CT - Aero Derivative | 15% | 6% | 6% | 53% | 15% | 8% | 23% | 100% | 96% | 76% | 98% | 100% | 99% | 99% |
| CT - Industrial Frame | 26% | 23% | 17% | 38% | 13% | 8% | 18% | 99% | 98% | 83% | 100% | 100% | 100% | 99% |
| Coal Fired | - | - | 25% | 78% | 18% | 19% | 19% | - | - | 54% | 83% | 69% | 40% | 52% |
| Diesel | 48% | 42% | 37% | 69% | 56% | 33% | 46% | 100% | 100% | 77% | 100% | 100% | 100% | 100% |
| Hydro | 74% | 61% | 95% | 97% | 81% | 79% | 95% | 81% | 77% | 97% | 98% | 100% | 100% | 97% |
| Nuclear | - | - | 79% | 100% | 53% | 16% | 21% | - | - | 95% | 100% | 89% | 58% | 68% |
| Oil or Gas Steam | 8% | 6% | 11% | 15% | 3% | 0% | 9% | 92% | 78% | 86% | 85% | 91% | 88% | 88% |
| Pumped Storage | 100% | 100% | 95% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |

The analysis of nuclear plants includes an estimate of annual avoidable costs and incremental capital expenditures from the Nuclear Energy Institute (NEI) based on NEI's calculations for a sample of nuclear plants.[40] [41] The NEI annual avoidable costs used in the analysis are for 2016. NEI's incremental capital expenditures include historical expenditures to meet regulatory requirements that resulted from reviews based on the accident at the Fukushima nuclear plant in Japan. For that reason, the analysis includes 50 percent of NEI's 2016 annual capital expenditures. For reference, the data including 100 percent of the NEI capital expenditures are included in Table 7-31. NEI incremental capital expenditures have been decreasing annually since 2012 (38.2 percent decrease from 2012 through 2016) and decreased 16.5 percent from 2015 to 2016. The analysis includes the most recent operating cost data published by NEI, for 2016. This is likely to be conservatively high given that NEI operating costs have been decreasing annually since 2012 (6.2 percent decrease from 2012 through 2016).

Table 7-30 shows the proportion of units recovering avoidable costs from energy and ancillary services markets and from all markets. In 2017, capacity revenues were sufficient to cover the shortfall between energy revenues and avoidable costs for the majority of units and technology types in PJM, with the exception of coal and nuclear units.[42] [43] [44]

40 Operating costs from: Nuclear Energy Institute (August, 2017) "Nuclear Costs in Context," <https://www.nei.org/CorporateSite/media/filefolder/Policy/Papers/Nuclear-Costs-in-Context.pdf?ext=.pdf>.

41 The NEI costs for Hope Creek and Salem were both treated as those associated with a two unit configuration because all three units are located in the same area.

42 Operating costs from: Nuclear Energy Institute (August, 2017) "Nuclear Costs in Context," <https://www.nei.org/CorporateSite/media/filefolder/Policy/Papers/Nuclear-Costs-in-Context.pdf?ext=.pdf>.

43 The NEI costs for Hope Creek and Salem were both treated as those associated with a two unit configuration because all three units are located in the same area.

44 Analysis excludes Catawba 1 which joined PJM with the integration of DEOK.

## Nuclear Net Revenue Analysis

The results for nuclear plants are sensitive to small changes in PJM energy and capacity prices.[45] In 2016, PJM energy prices were at the lowest level since the introduction of competitive markets on April 1, 1999, and remained low in 2017. As a result, in 2016 and 2017, a significant proportion of nuclear plants did not cover annual avoidable costs.[46]

Table 7-31 includes the publicly available data on energy market prices, capacity market prices and nuclear cost data for nineteen nuclear plants in PJM.

### Table 7-31 Nuclear unit public data: 2013 through 2017[47]

| | | Average DA LMP ($/MWh) | | | | | BRA Capacity Price ($/MWh) | | | | | 2016 NEI Costs ($/MWh) | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | ICAP | 2013 | 2014 | 2015 | 2016 | 2017 | 2013 | 2014 | 2015 | 2016 | 2017 | Fuel | Operating | Capital |
| Beaver Valley | 1,777 | $34.24 | $41.86 | $30.35 | $27.07 | $29.11 | $0.96 | $3.54 | $5.49 | $3.80 | $3.95 | $6.75 | $18.73 | $6.15 |
| Braidwood | 2,330 | $30.26 | $37.34 | $25.97 | $24.30 | $24.99 | $0.96 | $3.54 | $5.49 | $3.80 | $3.95 | $6.75 | $18.73 | $6.15 |
| Byron | 2,300 | $29.22 | $35.05 | $21.00 | $17.94 | $23.79 | $0.96 | $3.54 | $5.49 | $3.80 | $3.95 | $6.75 | $18.73 | $6.15 |
| Calvert Cliffs | 1,716 | $40.27 | $57.88 | $40.30 | $32.64 | $31.57 | $7.81 | $7.24 | $6.44 | $5.80 | $4.98 | $6.75 | $18.73 | $6.15 |
| Cook | 2,071 | $34.14 | $40.49 | $29.94 | $26.93 | $28.03 | $0.96 | $3.54 | $5.49 | $3.80 | $3.95 | $6.75 | $18.73 | $6.15 |
| Davis Besse | 894 | $36.10 | $47.21 | $31.94 | $27.80 | $28.85 | $0.96 | $3.54 | $10.86 | $8.97 | $4.90 | $6.77 | $25.95 | $8.67 |
| Dresden | 1,787 | $31.82 | $39.22 | $27.45 | $25.89 | $26.35 | $0.96 | $3.54 | $5.49 | $3.80 | $3.95 | $6.75 | $18.73 | $6.15 |
| Hope Creek | 1,161 | $37.43 | $51.99 | $32.41 | $23.20 | $26.78 | $8.38 | $7.57 | $6.44 | $5.80 | $4.98 | $6.75 | $18.73 | $6.15 |
| LaSalle | 2,238 | $30.94 | $37.88 | $26.28 | $23.95 | $24.71 | $0.96 | $3.54 | $5.49 | $3.80 | $3.95 | $6.75 | $18.73 | $6.15 |
| Limerick | 2,296 | $37.28 | $51.71 | $32.65 | $23.37 | $26.99 | $8.38 | $7.57 | $6.44 | $5.80 | $4.98 | $6.75 | $18.73 | $6.15 |
| North Anna | 1,891 | $38.55 | $53.37 | $38.05 | $30.50 | $31.27 | $0.96 | $3.54 | $5.49 | $3.80 | $3.95 | $6.75 | $18.73 | $6.15 |
| Oyster Creek | 615 | $38.62 | $52.85 | $33.10 | $23.79 | $27.52 | $8.38 | $7.57 | $6.44 | $5.80 | $4.98 | $6.77 | $25.95 | $8.67 |
| Quad Cities | 1,819 | $25.94 | $30.71 | $19.47 | $18.04 | $23.09 | $0.96 | $3.54 | $5.49 | $3.80 | $3.95 | $6.75 | $18.73 | $6.15 |
| Peach Bottom | 2,251 | $37.37 | $51.52 | $31.98 | $23.07 | $26.76 | $8.38 | $7.57 | $6.44 | $5.80 | $4.98 | $6.75 | $18.73 | $6.15 |
| Perry | 1,240 | $36.69 | $46.14 | $32.77 | $27.84 | $29.91 | $0.96 | $3.54 | $10.86 | $8.97 | $4.90 | $6.77 | $25.95 | $8.67 |
| Salem | 2,332 | $37.40 | $51.96 | $32.37 | $23.18 | $26.76 | $8.38 | $7.57 | $6.44 | $5.80 | $4.98 | $6.75 | $18.73 | $6.15 |
| Surry | 1,690 | $37.98 | $51.75 | $37.91 | $30.08 | $31.08 | $0.96 | $3.54 | $5.49 | $3.80 | $3.95 | $6.75 | $18.73 | $6.15 |
| Susquehanna | 2,520 | $36.76 | $50.93 | $32.47 | $23.66 | $27.14 | $7.81 | $7.24 | $6.44 | $5.80 | $4.98 | $6.75 | $18.73 | $6.15 |
| Three Mile Island | 805 | $36.83 | $50.47 | $30.94 | $22.96 | $27.12 | $7.81 | $7.24 | $6.44 | $5.80 | $4.98 | $6.77 | $25.95 | $8.67 |

Table 7-32 shows the surplus or shortfall for nineteen nuclear plants in PJM calculated using this data.[48] In Table 7-32, six nuclear plants with a total capacity of 7,673 MW did not recover their avoidable costs in two of the last three years assuming avoidable costs are equal to fuel costs, operating costs, and 50 percent of capital expenditures. If it is assumed that nuclear plants incurred 100 percent of their 2016 NEI incremental capital expenditures and that these costs are appropriately considered avoidable costs, nine plants with a total capacity of 14,027 MW did not recover their avoidable costs in two of the last three years.

Some nuclear plants did not clear the capacity market as a result of the interaction between the demand for capacity, the offers of other capacity resources, and the offers of the unit owners. Three Mile Island did not clear the 2018/2019 auction[49] and Three Mile Island, Quad Cities, and a portion of Byron's capacity did not clear the 2019/2020 auction.[50] Three Mile Island and Quad Cities also did not clear the 2020/2021 auction.[51]

45 A change in the capacity market price of $24 per MW-day translates into a change in market revenue of $1.00 per MWh for a nuclear power plant operating in every hour.

46 The IMM submitted testimony in New Jersey on the same issues of nuclear economics. *Establishing Nuclear Diversity Certificate Program.* Bill No. S-877 New Jersey Senate Environment and Energy Committee. (2018). *Revised Statement of Joseph Bowring*

47 All calculations are based on publicly available data. Energy and capacity prices are current market prices. Results could vary depending on whether unit costs are less than the benchmark NEI data and whether revenues are greater than market prices, for example as a result of forward energy sales. The results of the analysis are not based on actual, confidential data in order to ensure that the results can be provided without confidentiality concerns.

48 Analysis excludes Catawba 1 which is pseudo tied to PJM.

49 Exelon. "Exelon Announces Outcome of 2019-2020 PJM Capacity Auction," (May 25, 2016) <http://www.exeloncorp.com/newsroom/pjm-auction-results-2016>.

50 Exelon. "Exelon Announces Outcome of 2019-2020 PJM Capacity Auction" (May 25, 2016) <http://www.exeloncorp.com/newsroom/pjm-auction-results-2016>.

51 Exelon, "Exelon Announces Outcome of 2020-2021 PJM Capacity Auction," (May 24, 2017) <http://www.exeloncorp.com/newsroom/pjm-auction-results-release-2017>.

### Table 7-32 Nuclear unit surplus (shortfall) based on public data: 2013 through 2017[52]

| | | Surplus (Shortfall) ($/MWh) | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | 100% of NEI Capital Costs | | | | | 2/3 of NEI Capital Costs | | | | | 1/3 of NEI Capital Costs | | | | |
| | ICAP | 2013 | 2014 | 2015 | 2016 | 2017 | 2013 | 2014 | 2015 | 2016 | 2017 | 2013 | 2014 | 2015 | 2016 | 2017 |
| Beaver Valley | 1,777 | $3.6 | $13.8 | $4.2 | ($0.8) | $1.4 | $5.6 | $15.8 | $6.3 | $1.3 | $3.5 | $7.7 | $17.9 | $8.3 | $3.3 | $5.5 |
| Braidwood | 2,330 | ($0.4) | $9.3 | ($0.2) | ($3.5) | ($2.7) | $1.6 | $11.3 | $1.9 | ($1.5) | ($0.6) | $3.7 | $13.4 | $3.9 | $0.6 | $1.4 |
| Byron | 2,300 | ($1.5) | $7.0 | ($5.1) | ($9.9) | ($3.9) | $0.6 | $9.0 | ($3.1) | ($7.8) | ($1.8) | $2.6 | $11.1 | ($1.0) | ($5.8) | $0.2 |
| Calvert Cliffs | 1,716 | $16.4 | $33.5 | $15.1 | $6.8 | $4.9 | $18.5 | $35.5 | $17.2 | $8.9 | $7.0 | $20.5 | $37.6 | $19.2 | $10.9 | $9.0 |
| Cook | 2,071 | $3.5 | $12.4 | $3.8 | ($0.9) | $0.3 | $5.5 | $14.5 | $5.8 | $1.2 | $2.4 | $7.6 | $16.5 | $7.9 | $3.2 | $4.4 |
| Davis Besse | 894 | ($4.3) | $9.4 | $1.4 | ($4.6) | ($7.6) | ($1.4) | $12.2 | $4.3 | ($1.7) | ($4.8) | $1.5 | $15.1 | $7.2 | $1.2 | ($1.9) |
| Dresden | 1,787 | $1.2 | $11.1 | $1.3 | ($1.9) | ($1.3) | $3.2 | $13.2 | $3.4 | $0.1 | $0.7 | $5.3 | $15.2 | $5.4 | $2.2 | $2.8 |
| Hope Creek | 1,161 | $14.2 | $27.9 | $7.2 | ($2.6) | $0.1 | $16.2 | $30.0 | $9.3 | ($0.6) | $2.2 | $18.3 | $32.0 | $11.3 | $1.5 | $4.2 |
| LaSalle | 2,238 | $0.3 | $9.8 | $0.1 | ($3.9) | ($3.0) | $2.3 | $11.8 | $2.2 | ($1.8) | ($0.9) | $4.4 | $13.9 | $4.2 | $0.2 | $1.1 |
| Limerick | 2,296 | $14.0 | $27.7 | $7.5 | ($2.5) | $0.3 | $16.1 | $29.7 | $9.5 | ($0.4) | $2.4 | $18.1 | $31.8 | $11.6 | $1.6 | $4.4 |
| North Anna | 1,891 | $7.9 | $25.3 | $11.9 | $2.7 | $3.6 | $9.9 | $27.3 | $14.0 | $4.7 | $5.6 | $12.0 | $29.4 | $16.0 | $6.8 | $7.7 |
| Oyster Creek | 615 | $5.6 | $19.0 | ($1.9) | ($11.8) | ($8.9) | $8.5 | $21.9 | $1.0 | ($8.9) | ($6.0) | $11.4 | $24.8 | $3.9 | ($6.0) | ($3.1) |
| Quad Cities | 1,819 | ($4.7) | $2.6 | ($6.7) | ($9.8) | ($4.6) | ($2.7) | $4.7 | ($4.6) | ($7.7) | ($2.5) | ($0.6) | $6.7 | ($2.6) | ($5.7) | ($0.5) |
| Peach Bottom | 2,251 | $14.1 | $27.5 | $6.8 | ($2.8) | $0.1 | $16.2 | $29.5 | $8.8 | ($0.7) | $2.2 | $18.2 | $31.6 | $10.9 | $1.3 | $4.2 |
| Perry | 1,240 | ($3.7) | $8.3 | $2.2 | ($4.6) | ($6.6) | ($0.8) | $11.2 | $5.1 | ($1.7) | ($3.7) | $2.0 | $14.1 | $8.0 | $1.2 | ($0.8) |
| Salem | 2,332 | $14.1 | $27.9 | $7.2 | ($2.6) | $0.1 | $16.2 | $29.9 | $9.2 | ($0.6) | $2.2 | $18.2 | $32.0 | $11.3 | $1.5 | $4.2 |
| Surry | 1,690 | $7.3 | $23.7 | $11.8 | $2.3 | $3.4 | $9.4 | $25.7 | $13.8 | $4.3 | $5.5 | $11.4 | $27.8 | $15.9 | $6.4 | $7.5 |
| Susquehanna | 2,520 | $12.9 | $26.5 | $7.3 | ($2.2) | $0.5 | $15.0 | $28.6 | $9.3 | ($0.1) | $2.5 | $17.0 | $30.6 | $11.4 | $1.9 | $4.6 |
| Three Mile Island | 805 | $3.3 | $16.3 | ($4.0) | ($12.6) | ($9.3) | $6.1 | $19.2 | ($1.1) | ($9.7) | ($6.4) | $9.0 | $22.1 | $1.8 | ($6.8) | ($3.5) |

In order to further evaluate the viability of nuclear plants, analysis was performed based on forward energy market prices for 2018, 2019 and 2020 and known capacity market prices for 2018, 2019 and 2020. The purpose of the forward analysis is to evaluate whether current forward prices are consistent with nuclear plants covering their annual avoidable costs over the next three years. While the forward capacity market prices are known, actual energy prices will vary from forward values.

Table 7-33 shows PJM energy prices (LMP), capacity prices (BRA), and annual fuel, operating and capital expenditures for the 2018 through 2020 period. The LMPs are based on forward prices with a basis adjustment for the specific plant locations.[53] The 2018 LMPs include DA prices through January 2018 and forward prices for February through December 2018. The capacity prices are known based on PJM capacity auction results.

52 All calculations are based on publicly available data. Energy and capacity prices are current market prices. Results could vary depending on whether unit costs are less than the benchmark NEI data and whether revenues are greater than market prices, for example as a result of forward energy sales. The results of the analysis are not based on actual, confidential data in order to ensure that the results can be provided without confidentiality concerns.

53 Forward prices on February 1, 2018. Forward prices are reported for PJM trading hubs which must be adjusted to reflect the historical differences between prices at the trading hub and prices at the relevant plant locations. The basis adjustment is based on 2017 data.

## Table 7-33 Forward prices in PJM energy and capacity markets and annual costs[54]

| | | Average Forward LMP ($/MWh) | | | BRA Capacity Price ($/MWh) | | | 2016 NEI Costs ($/MWh) | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | ICAP | 2018 | 2019 | 2020 | 2018 | 2019 | 2020 | Fuel | Operating | Capital |
| Beaver Valley | 1,777 | $33.18 | $29.80 | $29.63 | $6.09 | $5.29 | $3.60 | $6.75 | $18.73 | $6.15 |
| Braidwood | 2,330 | $26.19 | $25.16 | $24.99 | $7.31 | $8.66 | $8.09 | $6.75 | $18.73 | $6.15 |
| Byron | 2,300 | $26.37 | $24.95 | $24.84 | $7.31 | $8.66 | $8.09 | $6.75 | $18.73 | $6.15 |
| Calvert Cliffs | 1,716 | $36.28 | $31.57 | $31.37 | $6.09 | $5.30 | $3.83 | $6.75 | $18.73 | $6.15 |
| Cook | 2,071 | $30.82 | $29.19 | $29.03 | $6.09 | $5.29 | $3.60 | $6.75 | $18.73 | $6.15 |
| Davis Besse | 894 | $32.33 | $30.00 | $29.83 | $6.09 | $5.29 | $3.60 | $6.77 | $25.95 | $8.67 |
| Dresden | 1,787 | $28.68 | $27.44 | $27.29 | $7.31 | $8.66 | $8.09 | $6.75 | $18.73 | $6.15 |
| Hope Creek | 1,161 | $32.53 | $27.64 | $27.45 | $7.56 | $6.82 | $6.65 | $6.75 | $18.73 | $6.15 |
| LaSalle | 2,238 | $26.25 | $25.21 | $25.04 | $7.31 | $8.66 | $8.09 | $6.75 | $18.73 | $6.15 |
| Limerick | 2,296 | $32.97 | $28.06 | $27.87 | $7.56 | $6.82 | $6.65 | $6.75 | $18.73 | $6.15 |
| North Anna | 1,891 | $36.08 | $31.26 | $31.06 | $6.09 | $5.29 | $3.60 | $6.75 | $18.73 | $6.15 |
| Oyster Creek | 615 | $33.31 | $28.37 | $28.18 | $7.56 | $6.82 | $6.65 | $6.77 | $25.95 | $8.67 |
| Quad Cities | 1,819 | $25.79 | $24.65 | $24.52 | $7.31 | $8.66 | $8.09 | $6.75 | $18.73 | $6.15 |
| Peach Bottom | 2,251 | $32.41 | $27.67 | $27.48 | $7.56 | $6.82 | $6.65 | $6.75 | $18.73 | $6.15 |
| Perry | 1,240 | $34.29 | $30.65 | $30.47 | $6.09 | $5.29 | $3.60 | $6.77 | $25.95 | $8.67 |
| Salem | 2,332 | $32.51 | $27.62 | $27.43 | $7.56 | $6.82 | $6.65 | $6.75 | $18.73 | $6.15 |
| Surry | 1,690 | $35.71 | $30.87 | $30.67 | $6.09 | $5.29 | $3.60 | $6.75 | $18.73 | $6.15 |
| Susquehanna | 2,520 | $32.62 | $27.83 | $27.64 | $6.09 | $5.29 | $3.83 | $6.75 | $18.73 | $6.15 |
| Three Mile Island | 805 | $32.28 | $27.58 | $27.41 | $6.09 | $5.29 | $3.83 | $6.77 | $25.95 | $8.67 |

Table 7-34 and Table 7-35 show the surplus or shortfall that would be received net of avoidable costs and incremental capital expenditures by year, based on forward prices, for the 2018 through 2020 period, on a per MWh basis and a total dollar basis. The fuel and operating costs are the 2016 NEI fuel and operating costs and the capital expenditures are 100 percent of the NEI 2016 incremental capital expenditures. Based on forward prices for energy and the known forward prices for capacity, all but four nuclear plants would cover their annual avoidable costs on average over the next three years (2018 through 2020) even when 100 percent of NEI's capital expenditures are included. The four plants are Davis Besse, Oyster Creek, Perry and Three Mile Island. Oyster Creek has been scheduled to retire since 2015, so there are three nuclear plants that would not cover avoidable costs on this basis.[55] These three plants are all single site nuclear plants which have higher costs than multiple unit sites.

## Table 7-34 Forward annual surplus (shortfall) in $/MWh

| | Surplus (Shortfall) ($/MWh) | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | 100% of NEI Capital Costs | | | 2/3 of NEI Capital Costs | | | 1/3 of NEI Capital Costs | | |
| | 2018 | 2019 | 2020 | 2018 | 2019 | 2020 | 2018 | 2019 | 2020 |
| Beaver Valley | $7.64 | $3.46 | $1.59 | $9.69 | $5.51 | $3.64 | $11.74 | $7.56 | $5.69 |
| Braidwood | $1.87 | $2.19 | $1.45 | $3.92 | $4.24 | $3.50 | $5.97 | $6.29 | $5.55 |
| Byron | $2.04 | $1.98 | $1.30 | $4.09 | $4.03 | $3.35 | $6.14 | $6.08 | $5.40 |
| Calvert Cliffs | $10.73 | $5.24 | $3.58 | $12.78 | $7.29 | $5.63 | $14.83 | $9.34 | $7.68 |
| Cook | $5.28 | $2.85 | $0.99 | $7.33 | $4.90 | $3.04 | $9.38 | $6.95 | $5.09 |
| Davis Besse | ($2.97) | ($6.10) | ($7.97) | ($0.08) | ($3.21) | ($5.08) | $2.81 | ($0.32) | ($2.19) |
| Dresden | $4.36 | $4.47 | $3.75 | $6.41 | $6.52 | $5.80 | $8.46 | $8.57 | $7.85 |
| Hope Creek | $8.46 | $2.84 | $2.46 | $10.51 | $4.89 | $4.51 | $12.56 | $6.94 | $6.56 |
| LaSalle | $1.93 | $2.24 | $1.50 | $3.98 | $4.29 | $3.55 | $6.03 | $6.34 | $5.60 |
| Limerick | $8.91 | $3.25 | $2.88 | $10.96 | $5.30 | $4.93 | $13.01 | $7.35 | $6.98 |
| North Anna | $10.54 | $4.92 | $3.03 | $12.59 | $6.97 | $5.08 | $14.64 | $9.02 | $7.13 |
| Oyster Creek | ($0.52) | ($6.19) | ($6.56) | $2.37 | ($3.30) | ($3.67) | $5.26 | ($0.41) | ($0.78) |
| Quad Cities | $1.47 | $1.68 | $0.98 | $3.52 | $3.73 | $3.03 | $5.57 | $5.78 | $5.08 |
| Peach Bottom | $8.35 | $2.87 | $2.50 | $10.40 | $4.92 | $4.55 | $12.45 | $6.97 | $6.60 |
| Perry | ($1.02) | ($5.45) | ($7.32) | $1.87 | ($2.56) | ($4.43) | $4.76 | $0.33 | ($1.54) |
| Salem | $8.44 | $2.82 | $2.44 | $10.49 | $4.87 | $4.49 | $12.54 | $6.92 | $6.54 |
| Surry | $10.17 | $4.53 | $2.64 | $12.22 | $6.58 | $4.69 | $14.27 | $8.63 | $6.74 |
| Susquehanna | $7.08 | $1.49 | ($0.16) | $9.13 | $3.54 | $1.89 | $11.18 | $5.59 | $3.94 |
| Three Mile Island | ($3.02) | ($8.52) | ($10.16) | ($0.13) | ($5.63) | ($7.27) | $2.76 | ($2.74) | ($4.38) |

54 All calculations are based on publicly available data. Energy and capacity prices are current market prices. Results could vary depending on whether unit costs are less than the benchmark NEI data and whether revenues are greater than market prices, for example as a result of forward energy sales. The results of the analysis are not based on actual, confidential data in order to ensure that the results can be provided without confidentiality concerns.

55 PJM. Generator Deactivation Summary Sheets, "Future Deactivation Requests," (February 26, 2018) <https://www.pjm.com/~/media/planning/gen-retire/pending-deactivation-requests.ashx>.

Table 7-35 Forward annual surplus (shortfall) ($ in millions)

| | Surplus (Shortfall) ($ in millions) | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | 100% of NEI Capital Costs | | | 2/3 of NEI Capital Costs | | | 1/3 of NEI Capital Costs | | |
| | 2018 | 2019 | 2020 | 2018 | 2019 | 2020 | 2018 | 2019 | 2020 |
| Beaver Valley | $118.9 | $53.9 | $24.8 | $150.8 | $85.8 | $56.7 | $182.7 | $117.7 | $88.6 |
| Braidwood | $38.1 | $44.7 | $29.6 | $80.0 | $86.5 | $71.4 | $121.8 | $128.3 | $113.2 |
| Byron | $41.2 | $39.9 | $26.3 | $82.5 | $81.2 | $67.6 | $123.8 | $122.5 | $108.9 |
| Calvert Cliffs | $161.4 | $78.7 | $53.8 | $192.2 | $109.5 | $84.6 | $223.0 | $140.4 | $115.4 |
| Cook | $95.8 | $51.8 | $18.0 | $133.0 | $89.0 | $55.2 | $170.2 | $126.1 | $92.4 |
| Davis Besse | ($23.3) | ($47.8) | ($62.4) | ($0.6) | ($25.2) | ($39.8) | $22.0 | ($2.5) | ($17.1) |
| Dresden | $68.3 | $70.0 | $58.8 | $100.4 | $102.1 | $90.8 | $132.5 | $134.1 | $122.9 |
| Hope Creek | $86.1 | $28.9 | $25.0 | $106.9 | $49.7 | $45.9 | $127.8 | $70.6 | $66.7 |
| LaSalle | $37.8 | $43.9 | $29.4 | $78.0 | $84.1 | $69.6 | $118.2 | $124.3 | $109.8 |
| Limerick | $179.1 | $65.4 | $57.9 | $220.4 | $106.6 | $99.2 | $261.6 | $147.9 | $140.4 |
| North Anna | $174.6 | $81.6 | $50.1 | $208.6 | $115.5 | $84.1 | $242.5 | $149.5 | $118.0 |
| Oyster Creek | ($2.8) | ($33.3) | ($35.3) | $12.8 | ($17.8) | ($19.8) | $28.3 | ($2.2) | ($4.2) |
| Quad Cities | $23.4 | $26.8 | $15.6 | $56.1 | $59.4 | $48.3 | $88.7 | $92.1 | $80.9 |
| Peach Bottom | $164.6 | $56.6 | $49.2 | $205.0 | $97.0 | $89.7 | $245.4 | $137.4 | $130.1 |
| Perry | ($11.0) | ($59.2) | ($79.5) | $20.4 | ($27.8) | ($48.1) | $51.7 | $3.6 | ($16.7) |
| Salem | $172.5 | $57.6 | $49.9 | $214.3 | $99.4 | $91.8 | $256.2 | $141.3 | $133.7 |
| Surry | $150.6 | $67.1 | $39.1 | $180.9 | $97.4 | $69.4 | $211.3 | $127.8 | $99.8 |
| Susquehanna | $156.2 | $32.8 | ($3.6) | $201.5 | $78.1 | $41.7 | $246.7 | $123.3 | $86.9 |
| Three Mile Island | ($21.3) | ($60.1) | ($71.6) | ($0.9) | ($39.7) | ($51.2) | $19.5 | ($19.3) | ($30.9) |

## Units At Risk

The definition of units at risk of retirement incorporates judgment. Alternative definitions are included in order to provide more clarity about the significance of the results.

Unit revenues are a combination of energy and ancillary service revenues and capacity market revenues. Units that fail to recover avoidable costs from total market revenues, including capacity market revenues, are at risk of retirement particularly if the results are expected to continue.[56] Units that failed to clear the most recent capacity auction(s) are at increased risk of retirement if this result is outside the control of the plant owner and is expected to continue. The profile of units that have not recovered avoidable costs from total market revenues in two of the last three years or have not cleared either the 2019/2020 or the 2020/2021 capacity auctions is shown in Table 7-36.[57] [58] These units are considered at risk of retirement.[59] The nuclear results are based only on the recovery of avoidable costs and not on capacity market clearing status.

Based on these criteria, 30,785 MW of capacity in PJM are at risk of retirement, in addition to the units that are currently planning to retire, primarily coal and nuclear units. If the coal units at risk are defined to be units receiving less than 90 percent of their avoidable costs, the total coal MW at risk would be 17,302 MW. If nuclear plants at risk are defined to be plants that cover avoidable costs based on forward prices, then the nuclear MW at risk would be 2,939 MW. Based on these criteria, 22,929 MW of capacity in PJM are at risk of retirement, in addition to the units that are currently planning to retire, primarily coal and nuclear units.

56 Units that have either already started the deactivation process or requested deactivation review are excluded from the at risk analysis.
57 Avoidable costs for non-nuclear units are ACR values and exclude APIR.
58 For nuclear units, avoidable costs consist of fuel costs, operating costs, and 50 percent of NEI capital expenditures.
59 Units expected to continue operations for reasons not directly related to market prices are not considered at risk of retirement.

### Table 7-36 Profile of units at risk of retirement

| Technology | No. Units | ICAP (MW) | Avg. 2017 Run Hrs | Avg. Unit Age (Yrs) | Avg. Heat Rate (Btu/MWh) |
|---|---|---|---|---|---|
| CC - Combined Cycle | 5 | 590 | 497 | 33 | 11,302 |
| CT - Aero Derivative | 10 | 254 | 137 | 41 | 13,724 |
| CT - Industrial Frame | 40 | 955 | 94 | 41 | 14,434 |
| Coal Fired (high) | 46 | 21,039 | 3,346 | 46 | 10,428 |
| Coal Fired (low) (90% ACR recovery) | 38 | 17,302 | 3,304 | 46 | 10,390 |
| Diesel or Oil or Gas Steam | 12 | 889 | 968 | 36 | 11,701 |
| Nuclear (high) | 5 | 7,058 | - | 38 | - |
| Nuclear (low) (forward looking) | 3 | 2,939 | - | 38 | - |
| Total (high) | 118 | 30,785 | 1,560 | 42 | 12,312 |
| Total (low) | 108 | 22,929 | 1,404 | 42 | 12,441 |

# 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]
- **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.[2]
- **National Emission Standards for Reciprocating Internal Combustion Engines.** Provisions exempting 100 hours of run time for certain stationary reciprocating internal combustion engines (RICE) participating in emergency demand response programs have been eliminated. As a result, the national emissions standards uniformly apply to all RICE.[3] All RICE are allowed to operate during emergencies, including declared Energy Emergency Alert Level 2 or five percent voltage/frequency deviations.[4]
- **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).[5] 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.[6] On October 10, 2017, the EPA proposed to repeal the Clean Power Plan based a determination that the Plan exceeds the EPA's authority under Section 111 of the EPAs Act.[7]
- **Cooling Water Intakes.** An EPA rule implementing Section 316(b) of the Clean Water Act (CWA) requires that cooling water intake structures reflect the

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

2 CAA § 110(a)(2)(D)(i)(I).

3 EPA, Memorandum, Peter Tsirigotis Guidance on Vacatur of RICE NESHAP and NSPS Provisions for Emergency Engines (April 15, 2016).

4 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).

5 *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."

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

7 *See Repeal of Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units*, Proposed Rule, EPA Docket No. EPA-HQ-OAR-2017-0355, 82 Fed. Reg. 48035 (October 16, 2017).

best technology available for minimizing adverse environmental impacts.[8]

## State Environmental Regulation

- **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 December 8, 2017, auction for the 2015–2017 compliance period was $3.80 per ton. The clearing price is equivalent to a price of $4.19 per metric tonne, the unit used in other carbon markets. The price decreased by $0.55 per ton, 12.6 percent, from $4.35 per ton from September 8, 2017, to $3.80 per ton for December 8, 2017.
- **Carbon Price.** If the price of carbon were $50.00 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).

## 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 December 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.[9]

## 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 December 31, 2017, 93.0 percent of coal steam MW had some type of flue-gas desulfurization (FGD) technology to reduce $SO_2$ emissions, while 99.5 percent of coal steam MW had some type of particulate control, and 93.7 percent of fossil fuel fired capacity in PJM had $NO_X$ emission control technology.

## Renewable Generation

Total wind and solar generation was 2.7 percent of total generation in PJM for 2017, total renewable generation was 4.8 percent of total generation in PJM and was 6.7 percent if coal and solid waste resources in the Tier II RECs programs are included.

## 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. 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.[10]

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

8 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).

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

10 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.").

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.

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 efficient markets 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.[11] [12]

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.

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

11 42 U.S.C. § 7401 et seq. (2000).

12 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.

Standards rule (MATS), which applies the Clean Air Act (CAA) maximum achievable control technology (MACT) requirement to new or modified sources of emissions of mercury and arsenic, acid gas, nickel, selenium and cyanide.[13] The rule 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).[14]

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.[15] The U.S. Supreme Court ruled in 2015 that "the EPA acted unreasonably when it deemed cost irrelevant to the decision to regulate power plants."[16] The remand did 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.[17] 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."[18] 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.[19] On April 28, 2017, the Court granted the 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."[20]

## 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).[21] 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.[22] 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.[23] 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.[24] The CSAPR covers 28

13 *National Emission Standards for Hazardous Air Pollutants From Coal and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil Fuel Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units*, EPA Docket No. EPA-HQ-OAR-2009-0234, 77 Fed. Reg. 9304 (February 16, 2012); *aff'd*, White Stallion Energy Center, LLC v EPA, No. 12-1100 (D.C. Cir. April 15, 2014).

14 NSPS are promulgated under CAA § 111.

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

16 135 S. Ct. 2699, 2712 (2015).

17 *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).

18 *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).

19 *See* Case No. 16-1127, et al.

20 Respondent EPA's Motion to Continue Oral Argument, Case No. 16-1127, et al. (April 18, 2017) at 1.

21 Nitric Oxides ($NO_X$), Sulfur Dioxide ($SO_2$), Ozone ($O_3$), Particulate Matter (PM), Carbon Monoxide (CO) and Lead (Pb).

22 *Rulemaking to Amend Dates in Federal Implementation Plans Addressing Interstate Transport of Ozone and Fine Particulate Matter*, EPA-HQ-OAR-2009-0491.

23 CAA § 110(a)(2)(D)(i)(I).

24 *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).

states, including all of the PJM states except Delaware, and also excluding the District of Columbia.[25]

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.[26] Group 2 does not include any states in the PJM region.[27] 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[28] 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, 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).[29] 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.[30] 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.[31] 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.[32] The EPA has removed North Carolina from the ozone season $NO_X$ trading program.[33] 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.

25 *Id.*
26 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.
27 Group 2 states include: Minnesota, Nebraska, Kansas, Texas, Alabama, Georgia and South Carolina.
28 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.
29 *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").
30 *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).
31 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.*
32 *Id.* at 74554.
33 *Id.* at 74507 n.13.

**Table 8-1 Current and proposed CSAPR ozone season $NO_X$ budgets for electric generating units (before accounting for variability)[34]**

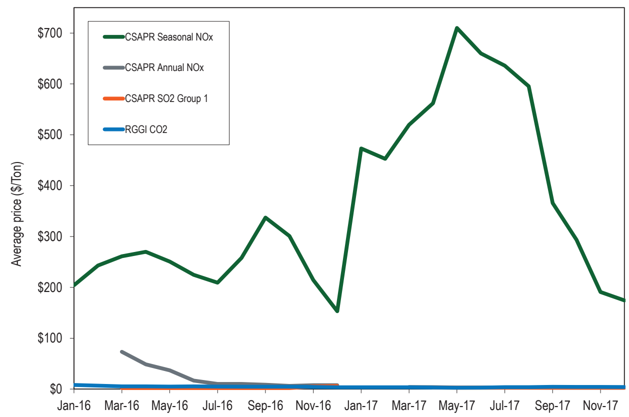
| State | 2017 CSAPR Ozone Season $NO_X$ Budget for Electric Generating Units (before accounting for variability) (Tons) | Assurance Level (Tons) |
|---|---|---|
| Illinois | 14,601 | 17,667 |
| Indiana | 23,303 | 28,197 |
| Kentucky | 21,115 | 25,549 |
| Maryland | 3,828 | 4,632 |
| Michigan | 17,023 | 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."[35] 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 ozone seasons."[36] Accordingly, the EPA established a formulaic limit on the use of transitioned vintage 2015 and 2016 banked allowances.[37]

Figure 8-1 shows average, monthly settled prices for $NO_X$, $CO_2$ and $SO_2$ emissions allowances including CSAPR related allowances for January 1, 2016 through December 31, 2017. Figure 8-1 also shows the average, monthly settled price for the Regional Greenhouse Gas Initiative (RGGI) $CO_2$ allowances.

In 2017, CSAPR annual $NO_X$ prices were 86.8 percent lower than in 2016. The CSAPR annual $NO_X$ price was $73.18 in March 2016, and has decreased steadily since then. There were not any reported CSAPR Annual $NO_X$ cleared purchases for January or February 2016. The CSAPR Seasonal $NO_X$ price hit a peak of $710.12 in May 2017. The CSAPR Update resulted in fewer CSAPR Seasonal $NO_X$ allowances.[38]

**Figure 8-1 Spot monthly average emission price comparison: 2016 and 2017[39]**




## 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).[40] 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 Engines; and Standards of Performance for Stationary Compression Ignition Internal Combustion Engines (collectively RICE Rules).[41]

The RICE Rules apply to emissions such as formaldehyde, acrolein, acetaldehyde, methanol, CO, $NO_X$, volatile organic compounds (VOCs) and PM. The regulatory

34 CSAPR Update at 74567.
35 *Id.* at 74588.
36 *Id.*
37 *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.*

38 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 $SO_2$.
39 Spot monthly average emission price information obtained through Evomarkets, <http://www.evomarkets.com> (Accessed January 23, 2018).
40 *National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines; New Source Performance Standards for Stationary Internal Combustion Engines*, Final Rule, EPA Docket No. EPA-HQ-OAR-2008-0708, 78 Fed. Reg. 6674 (January 30, 2013) ("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").
41 *Id.*

regime for RICE is complicated, and the applicable requirements turn on whether the engine is an "area source" or "major source," and the starter mechanism for the engine (compression ignition or spark ignition).[42]

On May 22, 2012, the EPA proposed amendments to the 2010 RICE NESHAP Rule.[43] 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.[44] As a result, the national emissions standards uniformly apply to all RICE.[45] 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."[46] 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.[47]

On April 15, 2016, the EPA issued a letter explaining how it would implement the vacatur order.[48] 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."[49] The EPA explained that such engines could, however, continue to operate for specified emergency and nonemergency reasons.[50]

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.[51] [52]

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."[53] The Court rejected claims raised by petitioners that raised concerns that the Social Cost of Carbon estimates were arbitrary, were not developed through transparent processes, and were based on inputs that were not peer-reviewed.[54] 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.

42 CAA § 112(a) defines "major source" to mean "any stationary source or group of stationary sources located within a contiguous area and under common control that emits or has the potential to emit considering controls, in the aggregate, 10 tons per year or more of any hazardous air pollutant or 25 tons per year or more of any combination of hazardous air pollutants," and "area source" to mean, "any stationary source of hazardous air pollutants that is not a major source."

43 *National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines; New Source Performance Standards for Stationary Internal Combustion Engines*, Proposed Rule, EPA Docket No. EPA-HQ-OAR-2008-0708.

44 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).

45 *Id.*

46 DENREC v. EPA at 3, 20–21.

47 *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.

48 EPA, Memorandum, Peter Tsirigotis Guidance on Vacatur of RICE NESHAP and NSPS Provisions for Emergency Engines (April 15, 2016).

49 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).

50 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).

51 See CAA § 111.

52 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.

53 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).

54 *Id.*

On September 20, 2013, the EPA proposed national limits on the amount of $CO_2$ that new power plants would be allowed to emit.[55] [56] The 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).[57] 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.[58]

The future of the Clean Power Plan is currently uncertain. On October 10, 2017, the EPA proposed to repeal the Clean Power Plan based on its determination that the Plan exceeds the EPA's authority under Section 111 of the EPA Act.[59] On August 8, 2017, the U.S. Court of Appeals for the District of Columbia Circuit issued an order continuing for 60 days to hold in abeyance court proceedings challenging the Clean Power Plan.[60]

55 *Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units*, Proposed Rule, EPA-HQ-OAR-2013-0495, 79 Fed. Reg. 1430 (January 8, 2014); The President's Climate Action Plan, Executive Office of the President (June 2013) (Climate Action Plan); Presidential Memorandum–Power Sector Carbon Pollution Standards, Environmental Protection Agency (June 25, 2013); Presidential Memorandum–Power Section Carbon Pollution Standards (June 25, 2013) ("June 25th Presidential Memorandum"). The Climate Action Plan can be accessed at: <http://www.whitehouse.gov/sites/default/files/image/president27sclimateactionplan.pdf>.

56 79 Fed. Reg. 1352 (January 8, 2014).

57 *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units*, EPA-HQ-OAR-2013-0602, Final Rule *mimeo* (August 3, 2015), also known as the "Clean Power Plan."

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

59 *See Repeal of Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units*, Proposed Rule, EPA Docket No. EPA-HQ-OAR-2017-0355, 82 Fed. Reg. 48035 (October 16, 2017).

60 See West Virginia v. EPA, No. 15-1363 (D.C. Cir.); North Dakota v. EPA, No. 15-1381 (D.C. Cir.).

## 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).

The CWA applies to the waters of the United States (WOTUS). The CWA defines WOTUS as "navigable waters."[61] On June 17, 2017, the EPA issued a rulemaking to rescind the definition of WOTUS proposed in the 2015 Clean Water Rule.[62] The rule would avoid the potential implementation of a broader definition of WOTUS included in the 2015 rule that was never implemented as the result of a stay issued by a reviewing Court.[63] The proposed rule would restore the pre 2015 rule to the code and the interpreting precedent applicable to the pre 2015 rule. As a result of the stay, the pre 2015 rule is now in effect. The pre 2015 rule includes all navigable waters and waters with a "significant nexus" to such waters.[64]

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.[65] 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

61 33 U.S.C. § 1362(7).

62 80 Fed. Reg. 37054 (June 29, 2015).

63 The stay was issued by the U.S. Court of Appeals for the Sixth Circuit on October 9, 2015.

64 Rapanos v. U.S., 547 U.S. 715 (2006).

65 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 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).

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.

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 WOTUS and has a design intake flow of greater than two million gallons per day (mgd).[66]

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.[67]

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.[68] 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.

66 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).

67 42 U.S.C. §§ 6901 *et seq.*

68 *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.[69] 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.[70] $NO_X$ emissions limits for coal units became effective December 15, 2012.[71] $NO_X$ emissions limits for other unit types became effective May 1, 2015.[72] As of December 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.[73] 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.

Table 8-3 HEDD maximum $NO_X$ emission rates[74]

| Fuel and Unit Type | $NO_x$ Emission Limit (lbs/MWh) |
|---|---|
| Coal Steam Unit | 1.50 |
| Heavier than No. 2 Fuel Oil Steam Unit | 2.00 |
| Simple Cycle Gas CT | 1.00 |
| Simple Cycle Oil CT | 1.60 |
| Combined Cycle Gas CT | 0.75 |
| Combined Cycle Oil CT | 1.20 |
| Regenerative Cycle Gas CT | 0.75 |
| Regenerative Cycle Oil CT | 1.20 |

69 N.J.A.C. § 7:27-19.
70 CTs must have either water injection or selective catalytic reduction (SCR) controls; steam units must have either an SCR or selective noncatalytic reduction (SNCR).
71 N.J.A.C. § 7:27-19.4.
72 N.J.A.C. § 7:27-19.5.
73 See Current New Jersey Turbines that are HEDD Units, <http://www.nj.gov/dep/workgroups/docs/apcrule_20110909turbinelist.pdf>.
74 Regenerative cycle CTs are combustion turbines that recover heat from their exhaust gases and use that heat to preheat the inlet combustion air which is fed into the combustion turbine.

## Illinois Air Quality Standards ($NO_X$, $SO_2$ and Hg)

The State of Illinois has promulgated its own standards for $NO_X$, $SO_2$ and Hg (mercury) known as Multi-Pollutant Standards (MPS) and Combined Pollutants Standards (CPS).[75] 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.[76] 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.[77]

## 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.[78] RGGI generates revenues for the participating states which have spent approximately 64 percent of revenues on energy efficiency, 16 percent on clean and renewable energy, 4 percent on greenhouse gas abatements and 10 percent on direct bill assistance.[79]

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 December 31, 2017, in short tons and metric tonnes.[80] Prices for auctions held December 8, 2017, for the 2015–2017 compliance period were at $3.80 per allowance (equal to one ton of $CO_2$), above the current price floor of $2.05 for RGGI auctions.[81] 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 clearing price of $4.35 in September 2017.

75 35 Ill. Admin. Code §§ 225.233 (Multi-Pollutant Standard (MPS)), 224.295 (Combined Pollutant Standard: Emissions Standards for $NO_X$ and $SO_2$ (CPS)).

76 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).

77 See *Id.*

78 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>.

79 *Investment of RGGI Proceeds Through 2015*, The Regional Greenhouse Gas Initiative, <https://www.rggi.org/docs/ProceedsReport/RGGI_Proceeds_Report_2015.pdf>.

80 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 auctions to use CRRs.

81 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[82]

| | 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 |
| June 7, 2017 | $2.53 | 14,597,470 | 14,597,470 | $2.79 | 13,242,606 | 13,242,606 |
| September 8, 2017 | $4.35 | 14,371,585 | 14,371,585 | $4.80 | 13,037,686 | 13,037,686 |
| December 8, 2017 | $3.80 | 14,687,989 | 14,687,989 | $4.19 | 13,324,723 | 13,324,723 |

## 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.[83] The ZEC program provides that starting June 1, 2017, the Illinois Power Agency (IPA) must procure ZECs under 10 year contracts with select Illinois nuclear power plants.[84]

IPA must procure ZECs equal to 16 percent of 2014 Illinois retail load.[85] The initial base ZEC price equals $16.50/MWh and increases $1.00/MWh annually commencing with the 2023/2024 Delivery Year.[86] 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."[87]

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.[88]

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.[89] 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. The District Court granted the motion to dismiss on July 14, 2017. EPSA appealed to the U.S. Court of Appeals for the Seventh Circuit. On September 6, 2017, the MMU filed a brief of amicus curiae supporting the appeal. The appeal is pending.

82 See Regional Greenhouse Gas Initiative, "Auction Results," <http://www.rggi.org/market/co2_auctions/results> (Accessed January 23, 2018).
83 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>.
84 See IPAA § 1-75(d-5)(1).
85 See *id.*
86 See IPAA § 1-75(d-5)(1)(B).
87 See *id.*
88 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), <http://www.exeloncorp.com/newsroom/clinton-and-quad-cities-retirement>; Thomas Overton, Power, "Byron, Three Mile Island Nuclear Plants at Risk, Exelon Says" (June 7, 2016) (reporting Exelon statement that Byron is "economically challenged"), <http://www.powermag.com/byron-three-mile-island-nuclear-plants-at-risk-exelon-says/?printmode=1>.
89 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.[90] The MMU has supported modification of the Minimum Offer Price (MOPR) Rules to apply to existing units receiving subsidies.[91] 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.[92] 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.[93] In a decision issued July 25, 2017, the District Court dismissed the case. The Coalition for Competitive Electricity appealed to the U.S. Court of Appeals for the Second Circuit. On October 23, 2017, the MMU filed a brief of amicus curiae supporting the appeal. The appeal is pending.

## 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 fulfill 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 December 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 December 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.[94]

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.[95]

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

90 OATT Attachment DD § 5.14(h).

91 See, e.g., Comments of the Independent Market Monitor for PJM, FERC Docket No. EL16-49-000 (April 11, 2016).

92 Coalition for Competitive Electricity, et al., v. Audrey Zibelman, et al., Case No. 1:16-cv-08164-VEC (USDC SDNY).

93 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).

94 See the Indiana Utility Regulatory Commission's "2017 Annual Report" at 37 (Oct. 2017) <http://www.in.gov/iurc/files/IURC%20annual%20report%20web.pdf>.

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

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 2032.[96] 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.[97] 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.

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 8-5 Renewable standards of PJM jurisdictions: 2017 to 2028[98]

| 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

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.

Figure 8-2 shows the number of RECs created monthly by state for January 1, 2005, through December 31, 2017.[99] The figure includes Tier I or the equivalent REC type available in each state. Washington DC, Maryland, and Pennsylvania classify these RECs as Tier I, New Jersey classifies the RECs as Class I and Delaware, Illinois, Ohio, Virginia and Wester Virginia classify these RECs as renewable or eligible. West Virginia

96 See Council of the District of Columbia. B21-0650–Renewable Portfolio Standard Expansion Amendment Act of 2016. <http://lims.dccouncil.us/Legislation/B21-0650> (Accessed February 28, 2018).

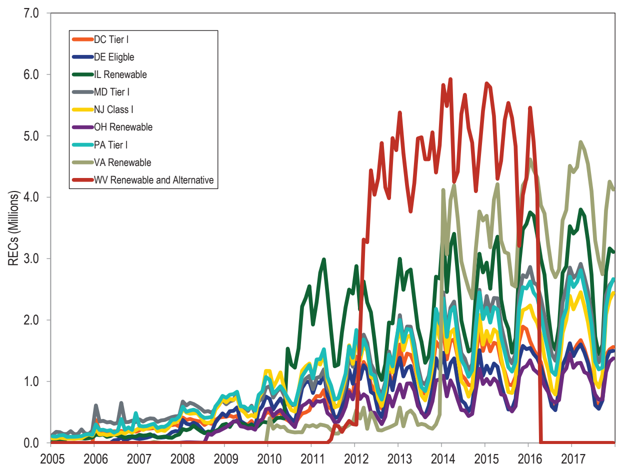
97 See Michigan Legislature. Senate Bill 0438 (2015) <http://legislature.mi.gov/doc.aspx?2015-SB-0438> (Accessed February 28, 2018).

98 This shows the total standard of renewable resources in all PJM jurisdictions, including Tier I, Tier II and Tier III resources.

99 Tier I REC volume obtained through PJM Environmental Information Services <https://www.pjm-eis.com/reports-and-events/public-reports.aspx> (Accessed March 5, 2018).

repealed its renewable portfolio standard, and Virginia has a voluntary renewable portfolio standard. Illinois has the most RECs generated in 2017 with a mandatory renewable portfolio standard.

### Figure 8-2 Number of RECs created monthly by state: 2005 through 2017




The REC prices are 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 8-3 shows the average Tier I REC price by jurisdiction from 2009 through 2017. Tier I REC prices are lower than SREC prices.

### Figure 8-3 Average Tier I REC price by jurisdiction: 2009 through 2017

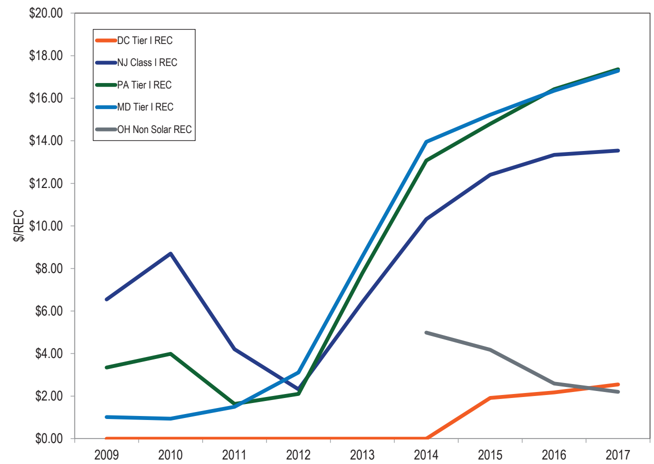


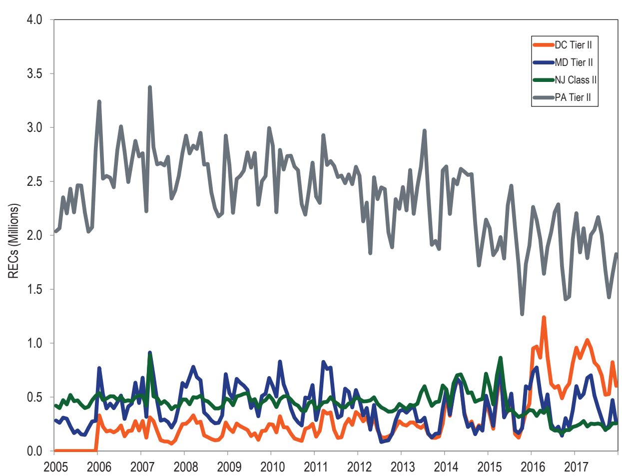

Table 8-6 shows the percent of retail electric load that must be served by Tier II resources under each PJM jurisdictions' RPS by year. Table 8-6 also shows specific technology requirements that PJM jurisdictions have added to their renewable portfolio standards. The standards shown in Table 8-6 are 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.

### 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% |

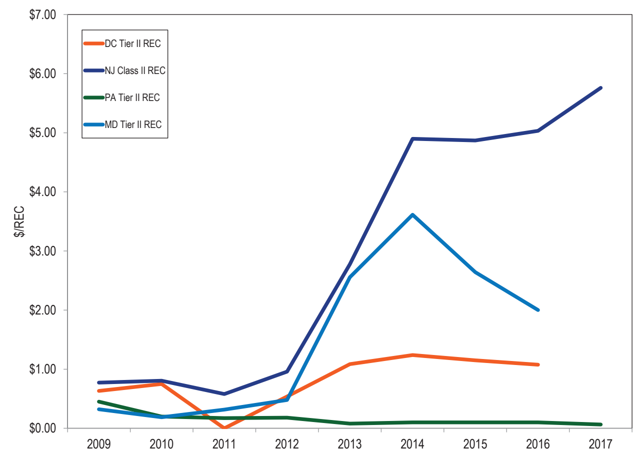
Figure 8-4 shows the number of Tier II RECs created monthly by state for January 1, 2005 through December 31, 2017.[100] The figure includes Tier II or the equivalent REC type available in each state. Washington DC, Maryland, and Pennsylvania classify these RECs as Tier II and New Jersey classifies the RECs as Class II. Pennsylvania has the most Tier II RECs generated in 2017.

### Figure 8-4 Number of Tier II RECs created monthly by state: 2005 through 2017




Tier II prices are lower than SREC and Tier I REC prices. Figure 8-5 shows the average Tier II REC price by jurisdiction for 2009 through 2017. Pennsylvania had the lowest Tier II REC prices at $0.06 per REC while New Jersey had the highest Tier II REC prices at $5.76 per REC.[101]

### Figure 8-5 Average Tier II REC price by jurisdiction: 2009 through 2017[102]




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

100 Tier II REC volume obtained through PJM Environmental Information Services <https://www.pjm-eis.com/reports-and-events/public-reports.aspx> (Accessed March 5, 2018).

101 Tier II REC price information obtained through Evomarkets <http://www.evomarkets.com> (Accessed January 23, 2018). There were not any reported cleared purchases for January 1, through December 31, 2017, for DC Tier II REC or MD Tier II RECs.

102 Tier II REC price information obtained through Evomarkets <http://www.evomarkets.com> (Accessed January 23, 2018). 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.

have the most stringent standard, requiring that at least 4.10 percent of load be served by solar.

### 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 | | | | | | | | | | | |

Figure 8-6 shows the number of SRECs created monthly by state for January 1, 2005 through December 31, 2017.[103] Illinois has the most Tier II RECs generated in 2017.

### Figure 8-6 Number of SRECs created monthly by state: 2005 through 2017

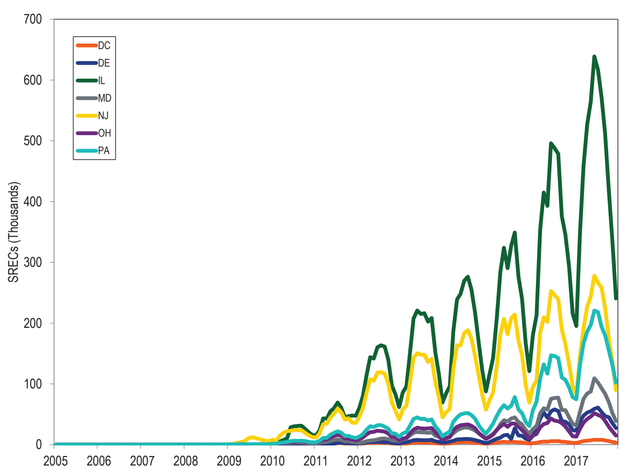
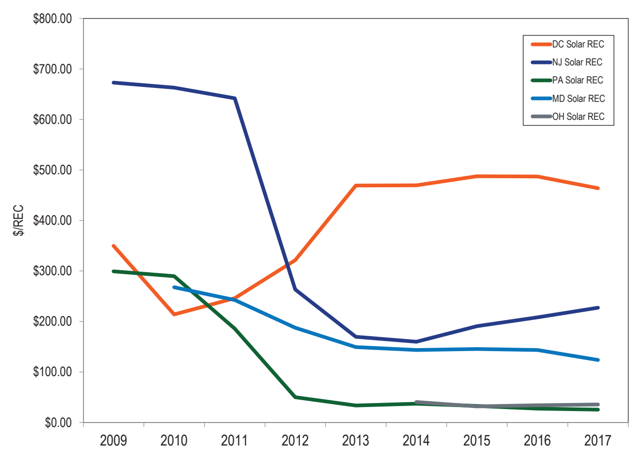



Figure 8-7 shows the average solar REC (SREC) price by jurisdiction for 2009 through December 31, 2017. New solar generating units built in New Jersey to satisfy its RPS requirement lowered the SREC price. The average NJ SREC prices dropped from $673 per SREC in 2009 to $227 per SREC in 2017. The limited 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 $464 per SREC in 2017.[104]

### Figure 8-7 Average SREC price by jurisdiction: 2009 through 2017




103 SREC volume obtained through PJM Environmental Information Services <https://www.pjm-eis.com/reports-and-events/public-reports.aspx> (Accessed March 5, 2018).

104 Solar REC average price information obtained through Evomarkets, <http://www.evomarkets.com> (Accessed January 23, 2018).

Figure 8-8 and Figure 8-9 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 8-8 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 8-8. Figure 8-9 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 8-9 overstates the percent of retail electric load in Pennsylvania that must be served by renewable energy resources.

**Figure 8-8 Map of retail electric load shares under RPS - Tier I resources only: 2017**

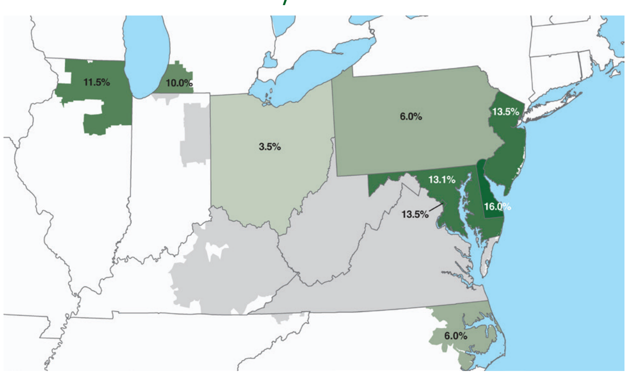
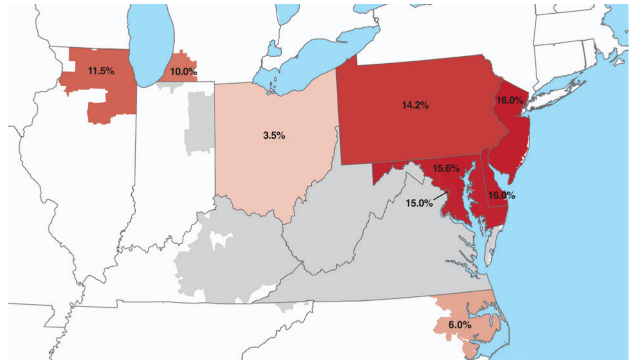



**Figure 8-9 Map of retail electric load shares under RPS – Tier I and Tier II resources: 2017**




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, 14.8 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, 12.6 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 2017. Wind output was 20,294.6 GWh of 32,256.8 Tier I GWh, or 62.9 percent, in the PJM footprint. As shown in Table 8-8, 53,815.5 GWh were generated by renewable resources, including both Tier II and Tier I renewable credits, of which, Tier I resources accounted for 59.9 percent. Total wind and solar generation was 2.7 percent of total generation in PJM for 2017, total renewable generation was 4.8 percent of total generation in PJM and was 6.7 percent if coal and solid waste resources in the Tier II RECs programs are included. Landfill gas, solid waste and waste coal were 17,495.1 GWh of renewable resource generation or 32.5 percent of the total Tier I and Tier II.

## Table 8-8 Renewable resource generation by jurisdiction and renewable resource type (GWh): 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 | 37.1 | 0.0 | 0.0 | 0.0 | 37.1 | 0.0 | 0.0 | 0.0 | 0.0 | 37.1 |
| Illinois | 173.6 | 0.0 | 14.4 | 8,265.7 | 8,453.7 | 0.0 | 0.0 | 0.0 | 0.0 | 8,453.7 |
| Indiana | 48.7 | 42.2 | 16.5 | 4,295.8 | 4,403.2 | 0.0 | 0.0 | 0.0 | 0.0 | 4,403.2 |
| Kentucky | 0.0 | 549.9 | 0.0 | 0.0 | 549.9 | 0.0 | 0.0 | 0.0 | 0.0 | 549.9 |
| Maryland | 81.5 | 1,960.0 | 132.2 | 554.7 | 2,728.4 | 0.0 | 659.6 | 0.0 | 659.6 | 3,388.0 |
| Michigan | 32.1 | 64.4 | 7.7 | 0.0 | 104.2 | 0.0 | 0.0 | 0.0 | 0.0 | 104.2 |
| New Jersey | 282.4 | 14.6 | 583.9 | 11.1 | 892.1 | 412.8 | 1,351.3 | 0.0 | 1,764.0 | 2,656.1 |
| North Carolina | 0.0 | 548.4 | 444.9 | 465.9 | 1,459.2 | 0.0 | 0.0 | 0.0 | 0.0 | 1,459.2 |
| Ohio | 333.0 | 255.5 | 1.3 | 1,489.4 | 2,079.1 | 0.0 | 0.0 | 0.0 | 0.0 | 2,079.1 |
| Pennsylvania | 822.7 | 2,994.1 | 25.5 | 3,440.3 | 7,282.6 | 1,928.8 | 1,382.7 | 7,027.1 | 10,338.6 | 17,621.2 |
| Tennessee | 0.0 | 66.9 | 0.0 | 0.0 | 66.9 | 0.0 | 0.0 | 0.0 | 0.0 | 66.9 |
| Virginia | 583.9 | 356.5 | 203.4 | 0.0 | 1,143.8 | 4,124.1 | 310.5 | 3,295.9 | 7,730.5 | 8,874.4 |
| 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 | 7.1 | 1,278.1 | 0.0 | 1,771.6 | 3,056.7 | 0.0 | 0.0 | 1,065.9 | 1,065.9 | 4,122.6 |
| Total | 2,402.0 | 8,130.6 | 1,429.6 | 20,294.6 | 32,256.8 | 6,465.7 | 3,704.1 | 11,389.0 | 21,558.7 | 53,815.5 |
| Percent of Renewable Generation | 4.5% | 15.1% | 2.7% | 37.7% | 59.9% | 12.0% | 6.9% | 21.2% | 40.1% | 100.0% |
| Percent of Total Generation | 0.3% | 1.0% | 0.2% | 2.5% | 4.0% | 0.8% | 0.5% | 1.4% | 2.7% | 6.7% |

Figure 8-10 shows the average hourly output by fuel type for January 1 through December 31 of 2014 through 2017. Tier I includes landfill gas, run-of-river hydro, solar and wind resources, as defined by the relevant states. Tier II includes pumped storage, solid waste and waste coal resources, as defined by the relevant states. Other includes biomass, miscellaneous, heavy oil, light oil, coal gas, propane, diesel, distributed generation, other biogas, kerosene and batteries.[105]

## Figure 8-10 Average hourly output by fuel type: 2014 through 2017

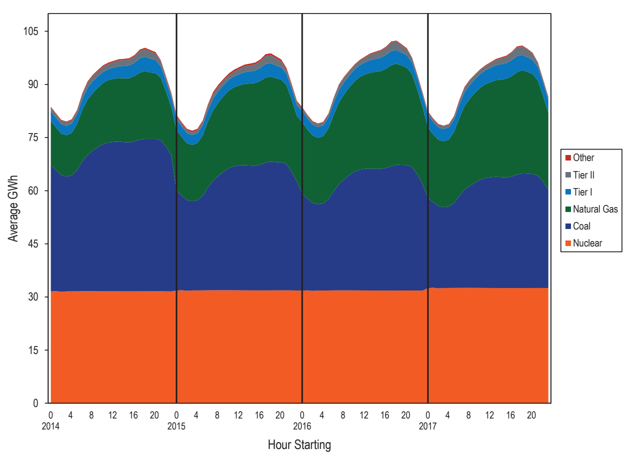



Table 8-9 shows the capacity of renewable resources in PJM by jurisdiction, as defined by primary fuel type. This capacity includes coal and natural gas units that have a renewable fuel as an alternative fuel, and thus are able to earn renewable energy credits based on the fuel used to generate energy. 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, 483.6 MW, or 36.0 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 4,548.8 MW, or 58.0 percent of the total wind capacity.

105 *2017 State of the Market Report for PJM*, Section 3: Energy Market, Table 3-9.

### Table 8-9 PJM renewable capacity by jurisdiction (MW): December 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 | 74.3 | 360.0 | 0.0 | 0.0 | 0.0 | 9.0 | 0.0 | 0.0 | 2,846.4 | 3,289.7 |
| Indiana | 0.0 | 8.0 | 0.0 | 0.0 | 0.0 | 8.2 | 10.1 | 0.0 | 0.0 | 1,702.4 | 1,728.7 |
| 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 | 204.3 | 128.2 | 0.0 | 190.0 | 1,111.0 |
| 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 | 483.6 | 162.0 | 0.0 | 4.5 | 1,192.2 |
| North Carolina | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 465.0 | 291.2 | 0.0 | 0.0 | 208.0 | 964.2 |
| 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 | 261.8 | 1,611.0 | 1,367.2 | 7,969.6 |
| Tennessee | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 156.6 | 0.0 | 0.0 | 0.0 | 0.0 | 156.6 |
| Virginia | 0.0 | 134.1 | 0.0 | 17.0 | 5,166.2 | 350.5 | 321.5 | 123.0 | 585.0 | 0.0 | 6,697.3 |
| West Virginia | 0.0 | 5.4 | 0.0 | 0.0 | 0.0 | 257.9 | 0.0 | 0.0 | 165.0 | 686.3 | 1,114.6 |
| PJM Total | 11,080.0 | 605.8 | 4,503.0 | 255.0 | 6,888.2 | 2,936.3 | 1,345.0 | 675.0 | 2,361.0 | 7,839.5 | 38,488.8 |

Table 8-10 shows renewable capacity registered in the PJM generation attribute tracking system (GATS). This includes solar capacity of 3,959.8 MW of which 1,733.2 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 December 31, 2017[106]

| 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** | **141.5** | **0.0** | **141.5** |
| 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 | 97.2 | 0.0 | 2.1 | 101.5 |
| Georgia | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 61.7 | 258.9 | 0.0 | 320.6 |
| Illinois | 0.0 | 21.4 | 76.9 | 0.0 | 4.5 | 0.0 | 59.3 | 0.0 | 302.8 | 464.9 |
| Indiana | 0.0 | 0.0 | 49.6 | 0.0 | 5.2 | 94.6 | 66.1 | 0.0 | 180.0 | 395.5 |
| Iowa | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 3.2 | 0.0 | 258.0 | 261.1 |
| Kentucky | 600.0 | 162.2 | 18.6 | 0.0 | 0.4 | 0.0 | 27.6 | 93.0 | 0.0 | 901.8 |
| Louisiana | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 129.2 | 0.0 | 129.2 |
| Maryland | 65.0 | 0.0 | 12.7 | 129.0 | 0.0 | 0.0 | 760.5 | 15.0 | 0.3 | 982.5 |
| Michigan | 55.0 | 1.3 | 6.4 | 0.0 | 0.0 | 0.0 | 3.2 | 31.0 | 0.0 | 96.9 |
| Missouri | 0.0 | 0.0 | 5.6 | 0.0 | 0.0 | 0.0 | 19.6 | 0.0 | 451.0 | 476.2 |
| New Jersey | 0.0 | 0.0 | 53.1 | 0.0 | 14.7 | 0.0 | 1,733.2 | 0.0 | 5.0 | 1,806.0 |
| New York | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.4 | 0.0 | 0.0 | 0.4 |
| North Carolina | 0.0 | 430.4 | 0.0 | 0.0 | 0.0 | 0.0 | 494.6 | 151.5 | 0.0 | 1,076.5 |
| North Dakota | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 360.0 | 360.0 |
| Ohio | 0.0 | 1.0 | 33.6 | 92.6 | 16.4 | 32.4 | 171.0 | 92.8 | 35.1 | 474.9 |
| Pennsylvania | 109.7 | 31.7 | 45.2 | 91.0 | 15.2 | 5.0 | 302.3 | 68.6 | 3.3 | 671.8 |
| Tennessee | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Texas | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 57.7 | 0.0 | 57.7 |
| Virginia | 0.0 | 18.7 | 12.1 | 0.0 | 0.9 | 0.0 | 110.8 | 287.6 | 0.0 | 430.0 |
| West Virginia | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 3.8 | 0.0 | 0.0 | 3.8 |
| Wisconsin | 0.0 | 9.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.4 | 44.6 | 0.0 | 54.0 |
| District of Columbia | 0.0 | 0.0 | 0.0 | 0.0 | 10.0 | 0.0 | 44.9 | 0.0 | 0.0 | 54.9 |
| Total | 829.7 | 810.6 | 316.0 | 312.6 | 85.1 | 132.0 | 3,959.8 | 1,371.4 | 1,597.7 | 9,414.8 |

106 See PJM – EIS (Environmental Information Services), Generation Attribute Tracking System, "Renewable Generators Registered in GATS," <https://gats.pjm-eis.com/gats2/PublicReports/RenewableGeneratorsRegisteredinGATS> (Accessed January 8, 2018).

Renewable energy credits are related to the production and purchase of wholesale power, but have not, when they constitute a transaction separate from a wholesale sale of power, been found subject to FERC regulation.[107] 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. FERC has found that such revenues can be appropriately considered in the rates established through the operation of wholesale organized markets.[108] 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.[109] 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.[110]

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.

### 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 added a provision in 2017 that requires SRECs used to comply with Pennsylvania's solar photovoltaics carve out standard, be sourced from resources located within the PJM system.

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 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.

107 See *WSPP, Inc.*, 139 FERC ¶ 61,051 at P 18 (2012) ("we 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"); citing *American Ref-Fuel Company, et al.*, 105 FERC ¶ 61,004 at PP 23-24 (2003) ("American Ref-Fuel, 105 FERC ¶ 61,004 at PP 23-24 ("RECs are created by the States. They exist outside the confines of PURPA... And the contracts for sales of QF capacity and energy, entered into pursuant to PURPA, ... do not control the ownership of RECs."); see also *Williams Solar LLC and Allco Finance Limited*, 156 FERC ¶ 61,042 (2016).

108 See *ISO New England, Inc.*, 146 FERC ¶ 61,084 (2014) 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.").

109 See DSIRE, NC Clean Energy Technology Center. Delaware Renewable Portfolio Standard, <http://programs.dsireusa.org/system/program/detail/1231> (Accessed March 6, 2018).

110 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 8-12 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 from resources located outside of PJM for which the energy associated with the REC is delivered to PJM via dynamic scheduling. |
| 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 located in the state of Ohio or have the capability to deliver power directly into Ohio. Any renewable facility located in a state contiguous to Ohio has been deemed deliverable into the state of Ohio. For renewable resources in noncontiguous states, deliverabilty must be demonstarted to the Public Utilities Commission of Ohio. |
| Pennsylvania | Yes | RECs must be purchased from resources located within PJM. Additionally, all SRECs used for compliance with the Solar PV standard must source from solar PV resources within the state of Pennsylvania. |
| 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. |

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.[111] [112] For example, if the price of carbon were $50.00 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 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 |

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 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 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 approximately $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 $50.00 per ton, assuming that a MWh from a CT is avoided, is $27.60 per MWh. Applying this method to the SREC price history for jurisdictions with solar carve outs yields the implied carbon prices in Table 8-14.

111 Heat rates from: *2016 State of the Market Report for PJM*, Volume 2, Section 7: Net Revenue, p 283, Table 7-4.

112 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 January 23, 2018).

### Table 8-14 Implied carbon price based on SREC prices: 2009 through 2017[113]

| | Solar REC Implied Carbon Price ($/Ton) | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Jurisdiction with Solar REC | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 |
| Delaware | | | | | | $104.16 | $75.87 | $77.75 | $38.51 |
| Maryland | | $485.13 | $439.32 | $339.85 | $270.53 | $260.02 | $263.50 | $259.97 | $224.39 |
| New Jersey | $1,219.13 | $1,201.17 | $1,162.84 | $477.11 | $307.31 | $289.79 | $345.33 | $376.91 | $411.70 |
| Ohio | | | | | | $73.12 | $57.62 | $61.77 | $64.31 |
| Pennsylvania | $541.93 | $524.63 | $336.39 | $90.44 | $60.71 | $67.43 | $59.42 | $49.52 | $46.09 |
| Washington, D.C. | $633.37 | $387.56 | $445.61 | $582.33 | $849.75 | $850.55 | $883.06 | $882.55 | $840.27 |
| Regional Greenhouse Gas Initiative | $CO_2$ Allowance Price ($/Ton) | | | | | | | | |
| RGGI clearing price | $2.77 | $1.91 | $1.89 | $1.93 | $2.92 | $4.72 | $6.10 | $4.47 | $3.42 |

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 $308.00 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 8-15 shows the alternative compliance standards for RPS in PJM jurisdictions.

### Table 8-15 Renewable alternative compliance payments in PJM jurisdictions: December 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 | | $308.00 |
| North Carolina | No specific penalties: At the discretion of the NC Utility Commission | | |
| Ohio | $50.24 | | $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.

113 The Delaware 2017 SREC price used in the derivation of the implied carbon price is the weighted average procurement price reported by the SRECDelaware Program <http://www.srecdelaware.com/documentation/>. All other SREC prices used in the derivation of the implied carbon price are average annual prices obtained through Evomarkets, <http://www.evomarkets.com> (Accessed January 23, 2018).

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 March 5, 2018).

115 See PJM – EIS (Environmental Management System). "Program Information," <http://www.pjm-eis.com/> (Accessed February 7, 2018).

116 See DSIRE, "Database of State Incentives for Renewables & Efficiency, "Policies & Incentives by State," <http://www.dsireusa.org/> (Accessed February 7, 2018).

It is therefore impossible to know the current level of RPS compliance in PJM jurisdictions. As of December 31, 2017, Delaware, New Jersey and the District of Columbia have published a compliance report for 2016 and compliance reports for the year 2015 are available for Illinois, Maryland, Michigan, North Carolina, Ohio and Pennsylvania.[117 118 119]

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 a high of $19.9 million in 2015.[120] Compliance payments for 2016 were $15.2 million. The amount of solar RECs retired in 2016 was 62,173, an increase of 62.9 percent over the amount of solar RECs retired in 2015.[121]

## Distributed Energy Resources

Distributed Energy Resources (DER) in PJM do not have written rules on participating in the wholesale market. A generator could be considered in front or behind the meter based on the wiring or load placement. Resources that are connected behind the meter, are able to avoid requirements faced by resources in front of the meter. The Distributed Energy Resources Subcommittee (DERSC) is currently discussing how to treat the participation of DER resources in the energy market, ancillary service markets and capacity market.[122] Aggregating resources across PJM nodes should not be permitted under any DER proposed rules. The rules for DER should promote competition and not give any resource preferential treatment.

# Emissions Controlled Capacity and Renewables in PJM Markets

## Emission Controlled Capacity in the PJM Region

Environmental regulations affect decisions about emission control investments in existing units, investment in new units and decisions to retire units lacking emission controls.[123] Many PJM units burning fossil fuels have installed emission control technology.

Coal has the highest $SO_2$ emission rate, while natural gas and diesel oil have lower $SO_2$ emission rates.[124] Of the current 62,918.1 MW of coal capacity in PJM, 58,512.0 MW of capacity, 93.0 percent, has some form of FGD (flue-gas desulfurization) technology to reduce $SO_2$ emissions. Table 8-16 shows $SO_2$ emission controls by fossil fuel fired units in PJM.[125 126 127]

### Table 8-16 $SO_2$ emission controls by fuel type (MW): December 31, 2017[128]

| | $SO_2$ Controlled | No $SO_2$ Controls | Total | Percent Controlled |
|---|---|---|---|---|
| Coal | 58,512.0 | 4,406.1 | 62,918.1 | 93.0% |
| Diesel Oil | 0.0 | 5,949.6 | 5,949.6 | 0.0% |
| Natural Gas | 0.0 | 55,412.3 | 55,412.3 | 0.0% |
| Other | 325.0 | 4,920.7 | 5,245.7 | 6.2% |
| Total | 58,837.0 | 70,688.7 | 129,525.7 | 45.4% |

$NO_X$ emission control technology is used by all fossil fuel fired unit types. Of current fossil fuel fired units in PJM, 121,340.0 MW, 93.7 percent, of 129,525.7 MW of capacity in PJM, have emission controls for $NO_X$. Table 8-17 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

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 February 7, 2018).

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 February 7, 2018).

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> May 2, 2016

121 See the Public Service Commission of the District of Columbia's "Report on the Renewable Energy Portfolio Standard for Compliance Year 2016," (May 1, 2017) <http://www.dcpsc.org/getmedia/1806a06a-51de-4d4d-aa5a-e0cdd0517ecb/ReportREPS2017_050117.aspx>.

122 *Distributed Energy Resources Subcommittee*, PJM, <http://www.pjm.com/committees-and-groups/subcommittees/ders.aspx> (Accessed January 26, 2018).

123 See EPA. "National Ambient Air Quality Standards (NAAQS)," <https://www.epa.gov/criteria-air-pollutants/naaqs-table> (Accessed March 5, 2018).

124 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&mc=true&node=se40.18.72_12&rgn=div8> (Accessed October 1, 2016).

125 See EPA. "Air Market Programs Data," <http://ampd.epa.gov/ampd/> (Accessed March 5, 2018).

126 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.

127 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 March 5, 2018).

128 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.

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.[129]

### Table 8-17 $NO_X$ emission controls by fuel type (MW): As of December 31, 2017

| | $NO_X$ Controlled | No $NO_X$ Controls | Total | Percent Controlled |
|---|---|---|---|---|
| Coal | 61,976.8 | 941.3 | 62,918.1 | 98.5% |
| Diesel Oil | 2,207.6 | 3,742.0 | 5,949.6 | 37.1% |
| Natural Gas | 54,355.9 | 1,056.4 | 55,412.3 | 98.1% |
| Other | 2,799.7 | 2,446.0 | 5,245.7 | 53.4% |
| Total | 121,340.0 | 8,185.7 | 129,525.7 | 93.7% |

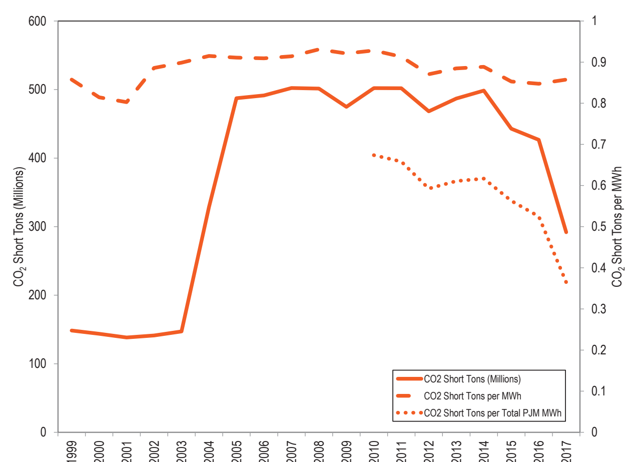
Most coal units in PJM have particulate controls. Typically, technologies such as electrostatic precipitators (ESP) or fabric filters (baghouses) are used to reduce particulate matter from coal steam units.[130] Fabric filters work by allowing the flue gas to pass through a tightly woven fabric which filters out the particulates. Table 8-18 shows particulate emission controls by unit type in PJM. In PJM, 62,584.1 MW, 99.5 percent, of all coal steam unit MW, have some type of particulate emissions control technology, as of December 31, 2017. 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.[131] Currently, 143 of the 160 coal steam units have baghouse or FGD technology installed, representing 56,297 MW out of the 62,918.1 MW total coal capacity, or 89.5 percent.

### Table 8-18 Particulate emission controls by fuel type (MW): As of December 31, 2017

| | Particulate Controlled | No Particulate Controls | Total | Percent Controlled |
|---|---|---|---|---|
| Coal | 62,584.1 | 334.0 | 62,918.1 | 99.5% |
| Diesel Oil | 0.0 | 5,949.6 | 5,949.6 | 0.0% |
| Natural Gas | 2,786.0 | 52,626.3 | 55,412.3 | 5.0% |
| Other | 3,102.0 | 2,143.7 | 5,245.7 | 59.1% |
| Total | 68,472.1 | 61,053.6 | 129,525.7 | 52.9% |

Figure 8-11 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 each year from 1999 to 2017, as well as the $CO_2$ short ton emissions per MWh of total generation within PJM for 2010 to 2017.[132] Since 1999 the amount of $CO_2$ produced per MWh was at a minimum of 0.80 short tons per MWh in 2001, and a maximum of 0.93 short tons per MWh in 2008. In 2017, $CO_2$ emissions were 0.86 short tons per MWh. Total PJM generation decreased from 812,536.3 GWh in 2016 to 800,192.4 GWh in 2017, while $CO_2$ produced decreased from 426.6 million tons in 2016 to 291.9 million tons in 2017.[133] The reduction in $CO_2$ emissions was primarily the result of a decrease in the use of coal for generation. Figure 8-12 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 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 0.80 short tons per MWh in 2001, and a maximum of 0.95 short tons per MWh in 2008. Since 1999 the amount of $CO_2$ produced per MWh during on peak hours was at a minimum of 0.80 short tons per MWh in 2001, and a maximum of 0.92 short tons per MWh in 2008. In 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 8-11 $CO_2$ emissions by year (millions of short tons), by PJM units: 1999 through 2017[134]




129 See EPA. "Mercury and Air Toxics Standards, Cleaner Power Plants," <https://www.epa.gov/mats/cleaner-power-plants#controls> (Accessed March 5, 2018).
130 See EPA, "Air Pollution Control Technology Fact Sheet," <https://www3.epa.gov/ttn/catc/dir1/ff-pulse.pdf> (Accessed March 5, 2018).
131 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 March 5, 2018).
132 Unless otherwise noted, emissions are measured in short tons. A short ton is 2,000 pounds.
133 See *State of the Market Report for PJM*, Volume 2, Section 3: Energy Market, Table 3-9.
134 The emissions are calculated from the continuous emission monitoring system (CEMS) data from generators located within the PJM footprint.

Figure 8-12 $CO_2$ emissions during on and off peak hours by year (millions of short tons), by PJM units: 1999 through 2017[135]

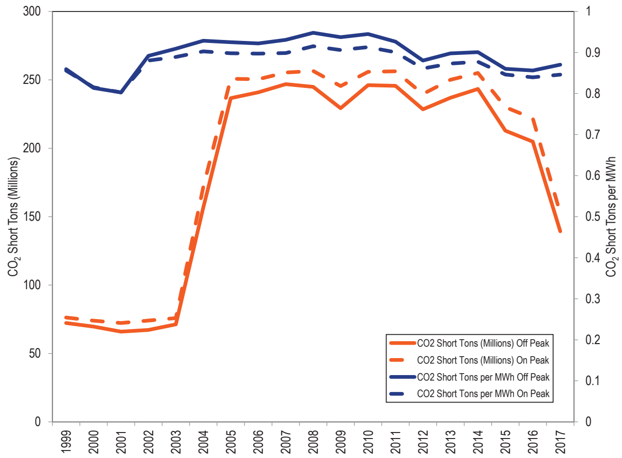
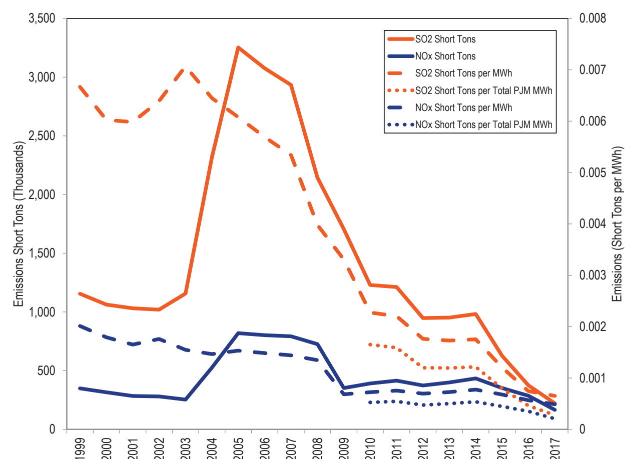



Figure 8-13 shows the total $SO_2$ and $NO_X$ short ton emissions (in thousands) and the short ton emissions per MWh from emitting resources within PJM, for all $SO_2$ and $NO_X$ emitting units, for each year from 1999 to 2017, as well as the $SO_2$ and $NO_X$ short ton emissions per MWh of total generation within PJM for 2010 to 2017. Since 1999 the amount of $SO_2$ produced per MWh was at a minimum of 0.000651 short tons per MWh in 2017, and a maximum of 0.007069 short tons per MWh in 2003. Since 1999, the amount of $NO_X$ produced per MWh was at a minimum of 0.000487 short tons per MWh in 2017, and a maximum of 0.002013 short tons per MWh in 1999. In 2017, $SO_2$ emissions were 0.000651 short tons per MWh and $NO_X$ emissions were 0.000487 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 8-14 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 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 0.000630 short tons per MWh in 2017, and a maximum of 0.007271 short tons per MWh in 2003. Since 1999 the amount of $SO_2$ produced per MWh during on peak hours was at a minimum of 0.000669 short tons per MWh in 2017, and a maximum of 0.006884 short tons per MWh in 2003. Since 1999, the amount of $NO_X$ produced per MWh during off peak hours was at a minimum of 0.000498 short tons per MWh in 2017, and a maximum of 0.001987 short tons per MWh in 1999. Since 1999, the amount of $NO_X$ produced per MWh during on peak hours was at a minimum of 0.000478 short tons per MWh in 2017, and a maximum of 0.002037 short tons per MWh in 1999. In 2017, $SO_2$ emissions were 0.000630 short tons per MWh and 0.000669 short tons per MWh for off and on peak hours. In 2017, $NO_X$ emissions were 0.000498 short tons per MWh and 0.000478 short tons per MWh for off and on peak hours.

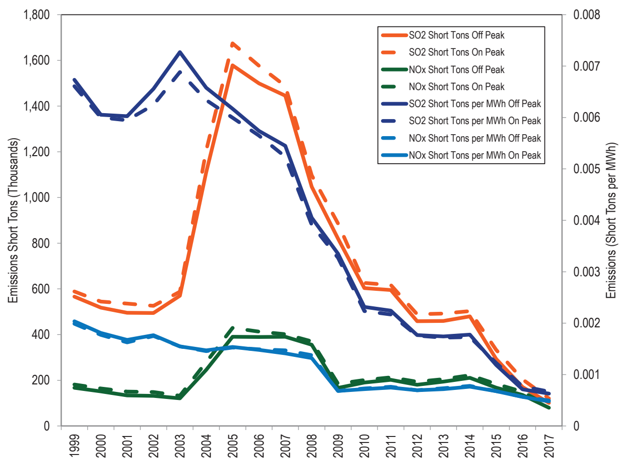
Figure 8-13 $SO_2$ and $NO_X$ emissions by year (thousands of short tons), by PJM units: 1999 through 2017[136]




135 The emissions are calculated from the continuous emission monitoring system (CEMS) data from generators located within the PJM footprint.

136 The emissions are calculated from the continuous emission monitoring system (CEMS) data from generators located within the PJM footprint.

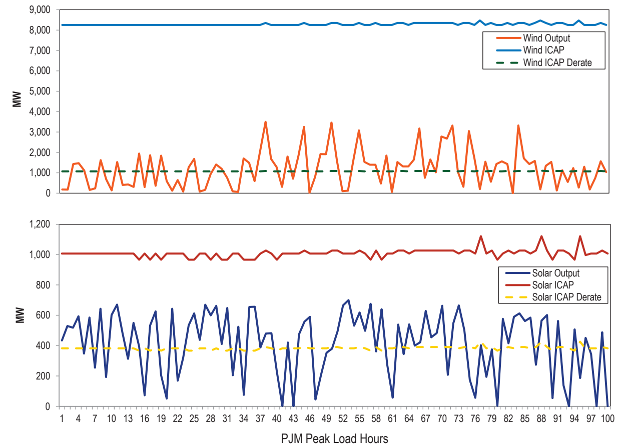
### Figure 8-14 $SO_2$ and $NO_X$ emissions during on and off peak hours by year (thousands of short tons), by PJM units: 1999 through 2017[137]




## 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 8-15 shows the wind and solar output during the top 100 load hours in PJM for 2017. The top 100 load hours in PJM during 2017 are within PJM defined peak load 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 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 56 hours and below the derated ICAP for 44 hours of the top 100 peak load hours of 2017. Wind output was above the derated ICAP 6,534 hours and below the derated ICAP for 2,226 hours for 2017. The wind capacity factor for the top 100 peak load hours of 2017 is 14.5 percent. Solar output was above the derated ICAP for 63 hours and below the derated ICAP for 37 hours of the top 100 peak load hours of 2017. Solar output was above the derated ICAP 1,845 hours and below the derated ICAP for 6,915 hours for 2017. The solar capacity factor for the top 100 peak load hours of 2017 is 41.3 percent.

### Figure 8-15 Wind and solar output during the top 100 peak load hours in PJM: 2017




## Wind Units

Table 8-19 shows the capacity factor of wind units in PJM. In 2017, the capacity factor of wind units in PJM was 33.4 percent. Wind units that were capacity resources had a capacity factor of 33.4 percent and an installed capacity of 7,449 MW. Wind units that were classified as energy only had a capacity factor of 33.5 percent and an installed capacity of 1,015 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.[138]

### Table 8-19 Capacity factor of wind units in PJM: 2017[139]

| Type of Resource | Capacity Factor | Installed Capacity (MW) |
|---|---|---|
| Energy-Only Resource | 33.5% | 1,015 |
| Capacity Resource | 33.4% | 7,449 |
| All Units | 33.4% | 8,463 |

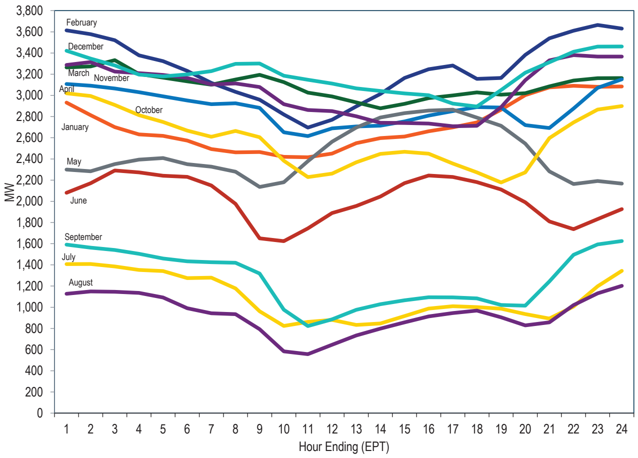
Figure 8-16 shows the average hourly real-time generation of wind units in PJM, by month for 2017. The hour with the highest average output, 3,664.6 MW, occurred in February, and the hour with the lowest average output, 563.6 MW, occurred in August. Wind output in PJM is generally higher in off-peak hours and lower in on-peak hours.

137 The emissions are calculated from the continuous emission monitoring system (CEMS) data from generators located within the PJM footprint.

138 Wind resources are derated to 13 percent unless demonstrating higher availability during peak periods.

139 Capacity factor is calculated based on online date of the resource.

### Figure 8-16 Average hourly real-time generation of wind units in PJM: 2017




### Figure 8-17 Average hourly day-ahead generation of wind units in PJM: 2017

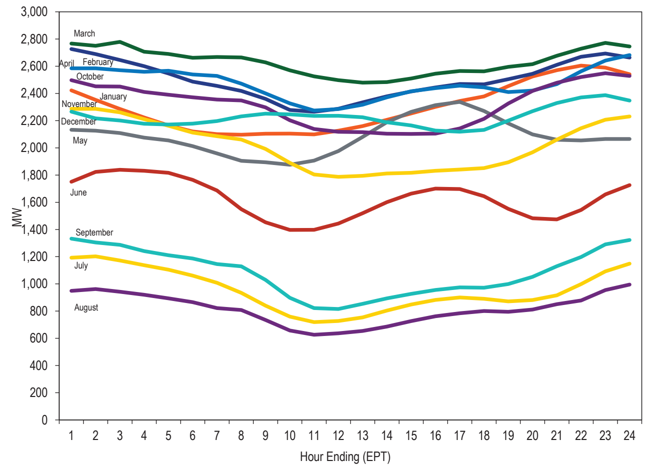



Table 8-20 shows the generation and capacity factor of wind units in each month of January 1, 2016 through December 31, 2017.

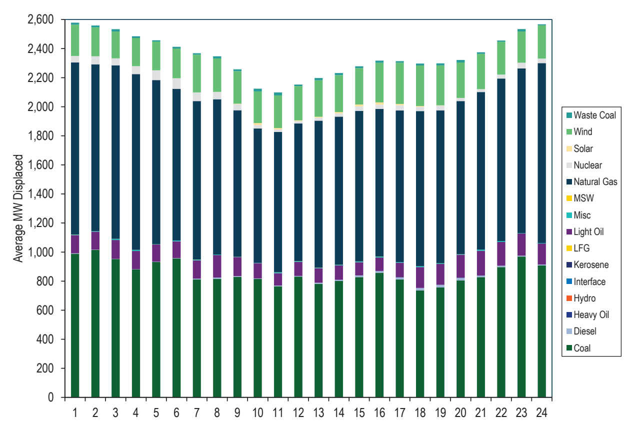
### Table 8-20 Capacity factor of wind units in PJM by month: 2016 and 2017

| | 2016 | | 2017 | |
|---|---|---|---|---|
| Month | Generation (MWh) | Capacity Factor | Generation (MWh) | Capacity Factor |
| January | 2,095,618.0 | 40.5% | 2,016,120.9 | 37.8% |
| February | 1,925,470.3 | 39.8% | 2,178,159.8 | 44.4% |
| March | 1,781,561.4 | 34.5% | 2,299,037.1 | 42.5% |
| April | 1,587,976.6 | 31.7% | 2,071,212.0 | 39.8% |
| May | 1,230,631.9 | 23.6% | 1,824,269.0 | 34.7% |
| June | 1,029,071.2 | 19.7% | 1,456,609.5 | 28.6% |
| July | 691,689.6 | 12.8% | 809,478.9 | 16.9% |
| August | 603,498.4 | 11.2% | 689,983.0 | 15.0% |
| September | 1,017,658.6 | 19.5% | 908,311.6 | 19.0% |
| October | 1,647,392.1 | 30.5% | 1,916,644.9 | 35.6% |
| November | 1,851,353.3 | 34.7% | 2,197,021.1 | 40.2% |
| December | 2,254,119.4 | 39.4% | 2,149,119.8 | 42.0% |
| Annual | 17,716,040.8 | 28.1% | 20,515,967.5 | 33.4% |

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 8-17 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.

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 8-18 shows the hourly average proportion of marginal units by fuel type mapped to the hourly average MW of real-time wind generation in 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.

### Figure 8-18 Marginal fuel at time of wind generation in PJM: 2017



## 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 3,959.8 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 8-21 shows the capacity factor of solar units in PJM. In 2017, the capacity factor of solar units in PJM was 22.4 percent. Solar units that were capacity resources had a capacity factor of 22.5 percent and an installed capacity of 965 MW. Solar units that were classified as energy only had a capacity factor of 21.0 percent and an installed capacity of 348 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.[140]

### Table 8-21 Capacity factor of solar units in PJM: 2017

| Type of Resource | Capacity Factor | Installed Capacity (MW) |
|---|---|---|
| Energy-Only Resource | 21.0% | 348 |
| Capacity Resource | 22.5% | 965 |
| All Units | 22.4% | 1,313 |

Solar output differs from month to month, based on seasonal variation and daylight hours during the month. Figure 8-19 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 8-19 Average hourly real-time generation of solar units in PJM: 2017

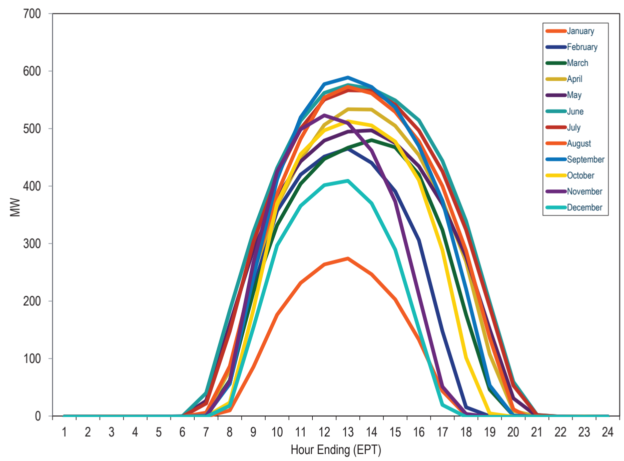



Table 8-22 shows the generation and capacity factor of solar units in each month of January 1, 2016 through December 31, 2017.

### Table 8-22 Capacity factor of solar units in PJM by month: 2016 through 2017

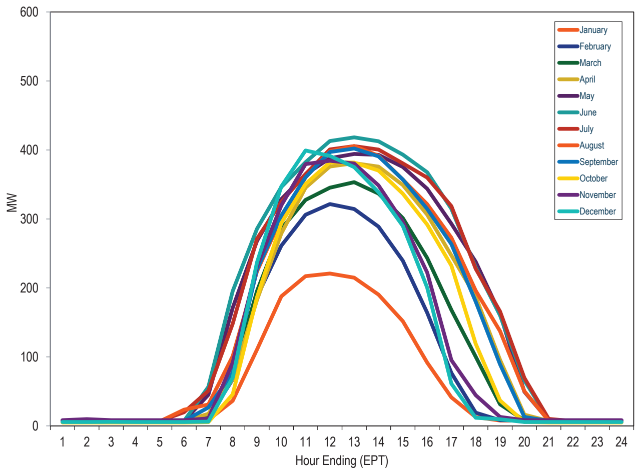
| | 2016 | | 2017 | |
|---|---|---|---|---|
| Month | Generation (MWh) | Capacity Factor | Generation (MWh) | Capacity Factor |
| January | 38,858.7 | 10.8% | 47,456.3 | 11.6% |
| February | 43,770.8 | 12.6% | 84,111.1 | 21.7% |
| March | 73,745.6 | 19.1% | 109,498.1 | 25.0% |
| April | 85,867.1 | 22.8% | 121,835.3 | 27.5% |
| May | 77,453.7 | 19.8% | 127,944.3 | 26.9% |
| June | 101,147.1 | 26.0% | 146,226.0 | 30.5% |
| July | 101,146.3 | 25.1% | 144,300.0 | 28.6% |
| August | 99,167.5 | 24.5% | 133,780.1 | 26.3% |
| September | 74,093.9 | 18.7% | 125,731.7 | 25.4% |
| October | 67,357.0 | 16.4% | 104,658.9 | 19.1% |
| November | 57,259.6 | 14.4% | 90,442.5 | 16.3% |
| December | 38,424.5 | 9.4% | 61,707.8 | 12.0% |
| Annual | 858,291.9 | 18.4% | 1,297,692.0 | 22.5% |

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 noncapacity related solar energy at their discretion. Figure 8-20 shows the average hourly day-ahead generation offers of solar units in PJM, by month.[141]

140 Solar resources are derated to 38 percent unless demonstrating higher availability during peak periods.

141 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.

Figure 8-20 Average hourly day-ahead generation of solar units in PJM: 2017



# 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 2017, PJM was a monthly net exporter of energy in the Real-Time Energy Market in all months.[1] In 2017, the real-time net interchange of -22,958.1 GWh was lower than the net interchange of -9,153.6 GWh in 2016.
- **Aggregate Imports and Exports in the Day-Ahead Energy Market.** In 2017, PJM was a monthly net exporter of energy in the Day-Ahead Energy Market in all months. In 2017, the total day-ahead net interchange of -19,550.1 GWh was lower than net interchange of -9,182.4 GWh in 2016.
- **Aggregate Imports and Exports in the Day-Ahead and the Real-Time Energy Market.** In 2017, gross imports in the Day-Ahead Energy Market were 184.9 percent of gross imports in the Real-Time Energy Market (135.4 percent in 2016). In 2017, gross exports in the Day-Ahead Energy Market were 125.4 percent of the gross exports in the Real-Time Energy Market (127.8 percent in 2016).
- **Interface Imports and Exports in the Real-Time Energy Market.** In 2017, there were net scheduled exports at 11 of PJM's 20 interfaces in the Real-Time Energy Market.
- **Interface Pricing Point Imports and Exports in the Real-Time Energy Market.** In 2017, there were net scheduled exports at 11 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 2017, there were net scheduled exports at 12 of PJM's 20 interfaces in the Day-Ahead Energy Market.
- **Interface Pricing Point Imports and Exports in the Day-Ahead Energy Market.** In 2017, there were net scheduled exports at 12 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 2017, up to congestion transactions were net exports at four of PJM's 19 interface pricing points eligible for day-ahead transactions in the Day-Ahead Energy Market.
- **Inadvertent Interchange.** In 2017, net scheduled interchange was -22,958 GWh and net actual interchange was -23,147 GWh, a difference of 189 GWh. In 2016, the difference was 1,186 GWh. This difference is inadvertent interchange.
- **Loop Flows.** In 2017, the Wisconsin Energy Corporation (WEC) Interface had the largest loop flows of any interface with -1,934 GWh of net scheduled interchange and 9,387 GWh of net actual interchange, a difference of 11,321 GWh. In 2017, the SouthIMP interface pricing point had the largest loop flows of any interface pricing point with 8,015 GWh of net scheduled interchange and 24,457 GWh of net actual interchange, a difference of 16,442 GWh.

### Interactions with Bordering Areas

#### PJM Interface Pricing with Organized Markets

- **PJM and MISO Interface Prices.** In 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 56.9 percent of the hours.
- **PJM and New York ISO Interface Prices.** In 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 52.2 percent of the hours.
- **Neptune Underwater Transmission Line to Long Island, New York.** In 2017, the hourly flow (PJM to NYISO) was consistent with the real-time hourly price differences between the PJM Neptune Interface

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).

and the NYISO Neptune bus in 59.7 percent of the hours.

- **Linden Variable Frequency Transformer (VFT) Facility.** In 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 53.5 percent of the hours.
- **Hudson DC Line.** In 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 9.0 percent of the hours.[3]

## Interchange Transaction Issues

- **PJM Transmission Loading Relief Procedures (TLRs).** PJM issued six TLRs of level 3a or higher in 2017, compared to nine such TLRs issued in 2016.
- **Up to congestion.** The average number of up to congestion bids submitted in the Day-Ahead Energy Market decreased by 11.2 percent, from 156,021 bids per day in 2016 to 138,489 bids per day in 2017. The average cleared volume of up to congestion bids submitted in the Day-Ahead Energy Market increased by 1.2 percent, from 824,885 MWh per day in 2016, to 838,258 MWh per day in 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.[4] [5] 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.[6]

## 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 authority to the MISO interface pricing point. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM monitor, and adjust as necessary, the weights applied to the components of the interfaces to ensure that the interface prices reflect ongoing changes in system conditions. The MMU also recommends that PJM review the mappings of external balancing authorities to individual interface pricing points to reflect changes to the impact of the external power source on PJM tie lines as a result of system topology changes. The MMU recommends that this review occur at least annually. (Priority: Low. First reported 2009. Status: Not adopted.)
- The MMU recommends that, in order to permit a complete analysis of loop flow, FERC and NERC ensure that the identified data are made available

3 The Hudson line was out of service for all hours in the first nine months of 2017. In the first nine months of 2017, there were five hours with less than 1 MW of unscheduled flow across the Hudson line.

4 *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).

5 *See* Letter Order, Docket No. ER14-381-000 (June 30, 2014).

6 *See* joint statement of PJM and the MMU re Interchange Scheduling issued July 29, 2014, at: <http://www.monitoringanalytics.com/reports/Market_Messages/Messages/PJM_IMM_Statement_on_Interchange_Scheduling_20140729.pdf>.

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: Partially adopted, 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 2017.)

## 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.[7]

### 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 2017, PJM was a monthly net exporter of energy in the Real-Time Energy Market in all months (Figure 9-1).[8] In 2017, the total real-time net interchange of -22,958.1 GWh was lower than the net interchange of -9,153.6 GWh in 2016. The large difference in net interchange volumes from 2016 to 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 in the import volume resulting from the switch from treatment as imports to internal generation based on pseudo tie status contributed to the shift from importing to exporting interchange. In 2017, the peak month for net exporting interchange was July, -2,559.2 GWh; in 2016 it was September, -2,758.6 GWh. Gross monthly export volumes in 2017 averaged 3,209.9 GWh compared to 3,507.3 GWh in 2016, while gross monthly imports in 2017 averaged 1,296.7 GWh compared to 2,744.5 GWh in 2016.

In 2017, PJM was a monthly net exporter of energy in the Day-Ahead Energy Market in all months (Figure 9-1). In 2017, the total day-ahead net interchange of -19,550.1 GWh was lower than the net interchange of -9,182.4 GWh in 2016. The implementation of the pseudo tied units on June 1, 2016, also affected 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 in the form of import transactions. When those external units became pseudo tied units in PJM, they were

7 For an explanation and current rate for each billing line item, see "*Customer Guide to PJM Billing*," (August 1, 2017) <http://www.pjm.com/~/media/markets-ops/settlements/custgd.ashx>.

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

required to offer into the Day-Ahead Energy Market. The removal of these day-ahead import transactions accounted for 96.1 percent of the difference in the day-ahead net interchange totals in 2017 compared to 2016. In 2017, the peak month for net exporting interchange was August, -2,236.3 GWh; in 2016 it was August, -2,418.0 GWh. Gross monthly export volumes in 2017 averaged 4,026.6 GWh compared to 4,481.7 GWh in 2016, while gross monthly imports in 2017 averaged 2,397.4 GWh compared to 3,716.5 GWh in 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 2017, gross imports in the Day-Ahead Energy Market were 184.9 percent of gross imports in the Real-Time Energy Market (135.4 percent in 2016). In 2017, gross exports in the Day-Ahead Energy Market were 125.4 percent of gross exports in the Real-Time Energy Market (127.8 percent in 2016). In 2017, net interchange was -19,550.1 GWh in the Day-Ahead Energy Market and -22,958.1 GWh in the Real-Time Energy Market compared to -9,182.4 GWh in the Day-Ahead Energy Market and -9,153.6 GWh in the Real-Time Energy Market in 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 MWh in the Day-Ahead and Real-Time Energy Markets times the applicable operating reserve rates.[9] In 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.

9 Up to congestion transactions create financial obligations to deliver in real time, but do not pay operating reserve charges.

Figure 9-1 PJM real-time and day-ahead scheduled imports and exports: 2017

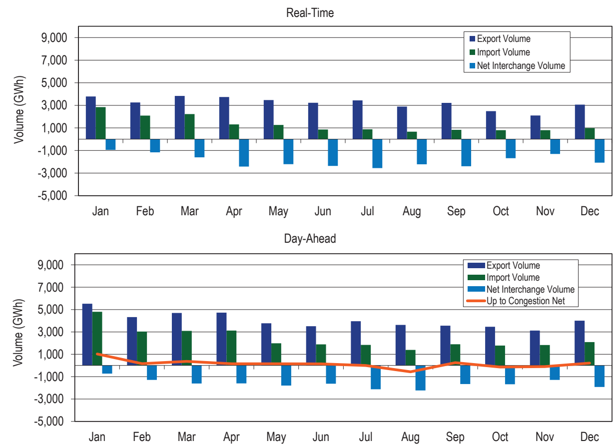
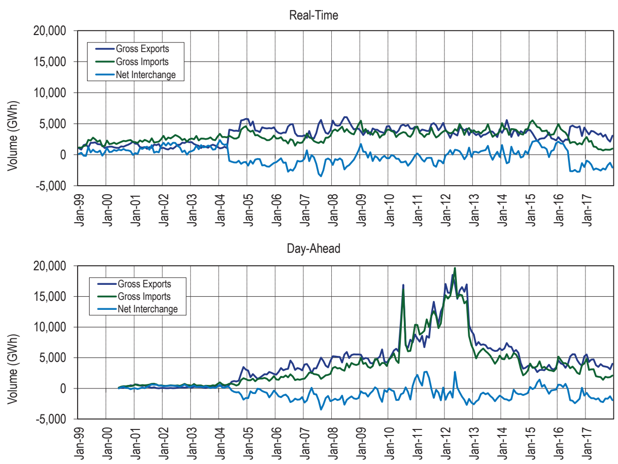



Figure 9-2 shows the real-time and day-ahead import and export volume for PJM from 1999 through December 31, 2017. PJM shifted from a consistent net importer of energy to relatively consistent net exporter of energy in 2004 in both the Real-Time and Day-Ahead Energy Markets, coincident with the expansion 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 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: 1999 through 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 2017. Figure 9-3 shows the approximate geographic location of the interfaces. In 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 10 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 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 2017, there were net scheduled exports at 11 of PJM's 20 interfaces. The top three net exporting interfaces in the Real-Time Energy Market accounted for 59.2 percent of the total net scheduled exports: PJM/Cinergy (CIN) with 25.9 percent, PJM/Eastern Alliant Energy (ALTE) with 17.0 percent and PJM/Neptune (NEPT) with 16.2 percent of the net scheduled export volume. The four separate interfaces that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT, PJM/HUDS and PJM/Linden (LIND)) together represented 30.5 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 six of the 10 separate interfaces that connect PJM to MISO. Those six exporting interfaces represented 68.8 percent of the total net PJM scheduled exports in the Real-Time Energy Market.

In the Real-Time Energy Market, in 2017, there were net scheduled imports at eight of PJM's 20 interfaces. The top three importing interfaces in the Real-Time Energy Market accounted for 82.9 percent of the total net scheduled imports: PJM/LG&E Energy, L.L.C. (LGEE) with 29.8 percent, PJM/Duke Energy Corp. (DUK) with 28.2 percent and PJM/Ameren-Illinois (AMIL) with 25.0 percent of the net scheduled import volume.[10] 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. There were net scheduled imports in the Real-Time Energy Market at three of the 10 separate interfaces that connect PJM to MISO. Those three interfaces represented 25.1 percent of the total net PJM scheduled imports in the Real-Time Energy Market.

10 In the Real-Time Energy Market, one PJM interface had a net interchange of zero (PJM/City Water Light & Power (CWLP)).

## Table 9-2 Real-time scheduled net interchange volume by interface (GWh): 2017

| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| CPLE | (15.7) | 27.0 | (8.6) | (3.5) | 42.3 | 33.6 | 46.3 | 17.2 | 74.7 | 73.8 | 124.3 | (4.4) | 407.0 |
| CPLW | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.1 | 0.0 | 0.5 | 0.3 | 1.0 |
| DUK | 453.7 | 315.0 | 373.3 | 133.3 | 134.2 | 104.0 | 69.4 | (95.7) | 91.1 | 115.5 | 2.4 | (33.5) | 1,662.6 |
| LGEE | 225.2 | 95.7 | 169.3 | 172.9 | 172.0 | 125.6 | 171.0 | 142.7 | 100.9 | 111.0 | 111.6 | 158.3 | 1,756.0 |
| MISO | (522.8) | (806.3) | (1,370.5) | (2,217.0) | (2,525.1) | (1,982.3) | (2,110.0) | (1,729.2) | (2,227.1) | (1,390.6) | (981.0) | (519.2) | (18,381.1) |
| ALTE | (39.0) | (349.6) | (429.9) | (388.1) | (522.3) | (434.6) | (710.2) | (553.9) | (635.2) | (336.4) | (269.7) | (233.3) | (4,902.1) |
| ALTW | 0.4 | 0.5 | 0.0 | 0.0 | 0.1 | 0.1 | (0.9) | 0.0 | 0.6 | 0.2 | 0.0 | 0.0 | 1.0 |
| AMIL | 376.2 | 223.5 | 212.9 | 114.2 | 138.9 | 60.8 | 50.7 | 27.0 | 90.6 | 27.4 | 44.4 | 106.9 | 1,473.4 |
| CIN | (319.6) | (282.3) | (560.3) | (1,189.0) | (1,112.7) | (948.6) | (787.7) | (530.2) | (803.5) | (472.2) | (383.2) | (97.3) | (7,486.6) |
| CWLP | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| IPL | (18.4) | (35.9) | (34.8) | (103.3) | (151.2) | (105.6) | (114.4) | (115.8) | (157.1) | (91.3) | (30.5) | (1.7) | (960.0) |
| MEC | (472.9) | (402.7) | (410.5) | (375.1) | (488.6) | (311.5) | (316.1) | (247.4) | (291.3) | (358.1) | (339.2) | (331.5) | (4,345.0) |
| MECS | 100.4 | (20.8) | 56.0 | 43.5 | (162.3) | (52.1) | (52.2) | (42.6) | (147.3) | (40.3) | 9.3 | 73.3 | (235.2) |
| NIPS | 0.0 | 8.6 | 0.0 | 0.0 | (1.6) | 0.0 | 0.1 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 7.1 |
| WEC | (149.9) | 52.5 | (203.8) | (319.1) | (225.3) | (190.8) | (179.4) | (266.2) | (283.9) | (119.8) | (12.2) | (35.7) | (1,933.8) |
| NYISO | (1,336.9) | (1,045.2) | (823.5) | (486.9) | (69.1) | (575.2) | (608.2) | (534.7) | (461.9) | (601.6) | (567.3) | (1,702.1) | (8,812.5) |
| HUDS | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | (0.0) | (44.9) | (229.2) | (274.2) |
| LIND | (222.2) | (157.9) | (147.5) | (106.6) | (79.5) | (58.8) | (47.6) | (57.1) | (71.3) | (106.3) | (91.1) | (202.7) | (1,348.4) |
| NEPT | (484.9) | (419.9) | (444.6) | (349.7) | (122.5) | (388.9) | (427.2) | (441.0) | (336.6) | (414.2) | (371.3) | (480.6) | (4,681.3) |
| NYIS | (629.8) | (467.4) | (231.5) | (30.6) | 132.9 | (127.5) | (133.3) | (36.7) | (54.0) | (81.1) | (60.0) | (789.6) | (2,508.5) |
| OVEC | (20.8) | (17.5) | (18.3) | (12.5) | (13.2) | (12.2) | (13.4) | (13.4) | (12.3) | (12.6) | (16.7) | (19.6) | (182.7) |
| TVA | 273.9 | 268.0 | 70.2 | (12.2) | 45.3 | (60.4) | (114.3) | (7.7) | 44.7 | 20.0 | 22.1 | 41.9 | 591.6 |
| Total | (943.5) | (1,163.3) | (1,608.2) | (2,425.9) | (2,213.6) | (2,366.9) | (2,559.2) | (2,220.7) | (2,389.9) | (1,684.5) | (1,304.1) | (2,078.3) | (22,958.1) |

## Table 9-3 Real-time scheduled gross import volume by interface (GWh): 2017

| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| CPLE | 7.2 | 39.3 | 5.9 | 28.6 | 109.0 | 83.0 | 85.6 | 71.7 | 120.4 | 113.3 | 178.2 | 129.1 | 971.4 |
| CPLW | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.1 | 0.0 | 0.5 | 0.3 | 1.0 |
| DUK | 519.8 | 382.9 | 428.6 | 187.8 | 157.6 | 174.4 | 165.9 | 93.7 | 157.2 | 162.8 | 75.1 | 32.7 | 2,538.4 |
| LGEE | 225.2 | 99.6 | 171.7 | 172.9 | 191.9 | 125.8 | 171.0 | 143.1 | 128.6 | 116.7 | 115.0 | 158.3 | 1,819.8 |
| MISO | 992.0 | 562.9 | 793.9 | 345.6 | 383.2 | 225.7 | 214.9 | 138.3 | 193.6 | 136.5 | 184.4 | 399.9 | 4,570.9 |
| ALTE | 267.9 | 0.0 | 25.0 | 13.7 | 35.0 | 8.0 | 54.7 | 39.6 | 6.6 | 9.2 | 19.7 | 61.9 | 541.4 |
| ALTW | 0.4 | 0.5 | 0.0 | 0.0 | 0.1 | 0.1 | 0.4 | 0.0 | 0.6 | 0.2 | 0.0 | 0.0 | 2.4 |
| AMIL | 377.8 | 224.6 | 219.5 | 114.3 | 139.2 | 61.1 | 50.7 | 28.3 | 100.9 | 27.4 | 49.9 | 129.8 | 1,523.4 |
| CIN | 115.5 | 100.8 | 328.5 | 78.1 | 118.1 | 31.3 | 8.5 | 3.7 | 6.1 | 9.5 | 7.4 | 40.6 | 848.2 |
| CWLP | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| IPL | 30.7 | 13.0 | 39.0 | 8.1 | 1.5 | 5.3 | 2.2 | 0.2 | 0.6 | 2.2 | 29.0 | 26.6 | 158.3 |
| MEC | 26.7 | 31.5 | 40.4 | 36.1 | 31.7 | 41.0 | 32.0 | 35.6 | 43.8 | 47.6 | 43.7 | 49.2 | 459.4 |
| MECS | 173.0 | 27.8 | 141.5 | 95.4 | 45.4 | 76.0 | 63.5 | 29.5 | 32.7 | 37.5 | 29.3 | 91.5 | 843.1 |
| NIPS | 0.0 | 8.6 | 0.0 | 0.0 | 0.0 | 0.0 | 0.1 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 8.7 |
| WEC | 0.0 | 156.1 | 0.0 | 0.0 | 12.2 | 2.9 | 2.6 | 1.3 | 2.3 | 2.9 | 5.5 | 0.3 | 186.1 |
| NYISO | 788.6 | 694.5 | 674.5 | 424.5 | 249.2 | 192.1 | 194.0 | 183.0 | 158.0 | 182.2 | 164.1 | 169.5 | 4,074.1 |
| HUDS | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| LIND | 0.3 | 1.3 | 6.0 | 1.8 | 16.2 | 10.9 | 9.9 | 12.5 | 8.3 | 20.5 | 13.9 | 1.3 | 102.7 |
| NEPT | 0.0 | 0.0 | 0.0 | 0.0 | 0.1 | 0.0 | 0.1 | 0.0 | 0.1 | 0.0 | 0.0 | 0.0 | 0.4 |
| NYIS | 788.4 | 693.2 | 668.4 | 422.8 | 232.9 | 181.2 | 184.0 | 170.5 | 149.6 | 161.7 | 150.1 | 168.1 | 3,971.0 |
| OVEC | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| TVA | 305.5 | 311.7 | 150.9 | 155.2 | 168.4 | 63.4 | 45.5 | 42.0 | 74.0 | 90.9 | 82.9 | 94.2 | 1,584.7 |
| Total | 2,838.3 | 2,090.8 | 2,225.4 | 1,314.7 | 1,259.4 | 864.3 | 876.9 | 671.9 | 831.9 | 802.3 | 800.3 | 984.0 | 15,560.2 |

Table 9-4 Real-time scheduled gross export volume by interface (GWh): 2017

| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| CPLE | 22.9 | 12.2 | 14.5 | 32.1 | 66.8 | 49.4 | 39.3 | 54.5 | 45.7 | 39.5 | 54.0 | 133.5 | 564.4 |
| CPLW | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| DUK | 66.2 | 67.9 | 55.3 | 54.5 | 23.4 | 70.4 | 96.4 | 189.4 | 66.1 | 47.3 | 72.7 | 66.2 | 875.8 |
| LGEE | 0.0 | 3.9 | 2.4 | 0.1 | 19.9 | 0.2 | 0.1 | 0.4 | 27.7 | 5.7 | 3.4 | 0.0 | 63.7 |
| MISO | 1,514.8 | 1,369.2 | 2,164.4 | 2,562.7 | 2,908.3 | 2,208.0 | 2,324.9 | 1,867.5 | 2,420.7 | 1,527.1 | 1,165.4 | 919.1 | 22,952.0 |
| ALTE | 306.9 | 349.6 | 454.9 | 401.8 | 557.4 | 442.6 | 764.9 | 593.6 | 641.7 | 345.6 | 289.4 | 295.2 | 5,443.5 |
| ALTW | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 1.4 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 1.4 |
| AMIL | 1.6 | 1.1 | 6.6 | 0.1 | 0.3 | 0.3 | 0.0 | 1.3 | 10.3 | 0.0 | 5.5 | 22.9 | 50.0 |
| CIN | 435.1 | 383.1 | 888.8 | 1,267.1 | 1,230.8 | 979.9 | 796.2 | 533.9 | 809.6 | 481.7 | 390.6 | 137.9 | 8,334.7 |
| CWLP | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| IPL | 49.1 | 48.9 | 73.8 | 111.4 | 152.7 | 110.9 | 116.7 | 116.0 | 157.7 | 93.5 | 59.4 | 28.2 | 1,118.2 |
| MEC | 499.6 | 434.2 | 450.9 | 411.3 | 520.3 | 352.5 | 348.1 | 283.0 | 335.1 | 405.7 | 382.9 | 380.7 | 4,804.3 |
| MECS | 72.6 | 48.6 | 85.5 | 51.9 | 207.7 | 128.1 | 115.7 | 72.1 | 180.0 | 77.8 | 20.0 | 18.3 | 1,078.3 |
| NIPS | 0.0 | 0.0 | 0.0 | 0.0 | 1.6 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 1.6 |
| WEC | 149.9 | 103.6 | 203.8 | 319.1 | 237.5 | 193.7 | 182.0 | 267.6 | 286.2 | 122.8 | 17.7 | 35.9 | 2,119.9 |
| NYISO | 2,125.5 | 1,739.7 | 1,498.0 | 911.4 | 318.3 | 767.2 | 802.2 | 717.7 | 619.9 | 783.7 | 731.4 | 1,871.5 | 12,886.6 |
| HUDS | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 44.9 | 229.2 | 274.2 |
| LIND | 222.4 | 159.2 | 153.5 | 108.3 | 95.7 | 69.7 | 57.5 | 69.6 | 79.5 | 126.7 | 105.0 | 204.0 | 1,451.2 |
| NEPT | 484.9 | 419.9 | 444.6 | 349.7 | 122.6 | 388.9 | 427.4 | 441.0 | 336.7 | 414.2 | 371.3 | 480.6 | 4,681.7 |
| NYIS | 1,418.2 | 1,160.6 | 899.9 | 453.4 | 100.0 | 308.7 | 317.3 | 207.1 | 203.7 | 242.8 | 210.1 | 957.7 | 6,479.5 |
| OVEC | 20.8 | 17.5 | 18.3 | 12.5 | 13.2 | 12.2 | 13.4 | 13.4 | 12.3 | 12.6 | 16.7 | 19.6 | 182.7 |
| TVA | 31.5 | 43.7 | 80.8 | 167.4 | 123.1 | 123.8 | 159.8 | 49.7 | 29.3 | 70.9 | 60.9 | 52.2 | 993.1 |
| Total | 3,781.8 | 3,254.1 | 3,833.6 | 3,740.6 | 3,473.0 | 3,231.2 | 3,436.1 | 2,892.6 | 3,221.7 | 2,486.9 | 2,104.4 | 3,062.2 | 38,518.3 |

## 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.[11] 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 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.[12]

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.[13] 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

11 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.

12 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.

13 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.

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 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.[14] 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.[15]

In the Real-Time Energy Market, in 2017, there were net scheduled exports at 11 of PJM's 18 interface pricing points eligible for real-time transactions.[16] The top three net exporting interface pricing points in the Real-Time Energy Market accounted for 87.1 percent of the total net scheduled exports: PJM/MISO with 65.6 percent, PJM/NEPTUNE with 14.0 percent and PJM/NYIS with 7.5 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 26.3 percent of the total net PJM scheduled exports in the Real-Time Energy Market.

In the Real-Time Energy Market, in 2017, there were net scheduled imports at five of PJM's 18 interface pricing points eligible for real-time transactions. The top two net importing interface pricing points in the Real-Time Energy Market accounted for 88.1 percent of the total net scheduled imports: PJM/SouthIMP with 75.8 percent and PJM/ North Carolina Municipal Power Authority (NCMPAIMP) with 12.3 percent of the net scheduled import volume. The four separate interface pricing points that connect PJM to the NYISO (PJM/NYIS, PJM/NEPTUNE, PJM/HUDSONTP and PJM/LINDENVFT) had net scheduled exports in the Real-Time Energy Market.[17]

14 On June 1, 2015, PJM began using a dynamic weighting factor in the calculation for the Ontario Interface Pricing Point.

15 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.

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

17 In the Real-Time Energy Market, two PJM interface pricing points had a net interchange of zero (Southeast and Southwest).

## Table 9-5 Real-time scheduled net interchange volume by interface pricing point (GWh): 2017

| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| IMO | 222.1 | 127.6 | 231.4 | 21.6 | 97.7 | 34.7 | 64.6 | 47.1 | (3.4) | 13.8 | 52.0 | 154.9 | 1,064.2 |
| MISO | (1,466.3) | (1,322.5) | (2,082.4) | (2,463.0) | (2,813.6) | (2,116.8) | (2,266.7) | (1,818.1) | (2,359.1) | (1,467.6) | (1,044.5) | (782.5) | (22,003.1) |
| NORTHWEST | 0.1 | (0.2) | (0.1) | 0.0 | (0.1) | 0.0 | 0.0 | 0.0 | (0.5) | 0.0 | 0.0 | (0.0) | (0.8) |
| NYISO | (1,336.9) | (1,045.2) | (825.9) | (486.9) | (69.5) | (584.0) | (612.4) | (535.3) | (459.1) | (601.7) | (567.9) | (1,702.4) | (8,827.1) |
| HUDSONTP | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | (0.0) | (44.9) | (229.2) | (274.2) |
| LINDENVFT | (222.2) | (157.9) | (147.5) | (106.6) | (79.5) | (58.8) | (47.6) | (57.1) | (71.3) | (106.3) | (91.1) | (202.7) | (1,348.4) |
| NEPTUNE | (484.9) | (419.9) | (444.6) | (349.7) | (122.5) | (388.9) | (427.2) | (441.0) | (336.6) | (414.2) | (371.3) | (480.6) | (4,681.3) |
| NYIS | (629.8) | (467.4) | (233.8) | (30.6) | 132.5 | (136.3) | (137.5) | (37.2) | (51.3) | (81.3) | (60.6) | (789.9) | (2,523.2) |
| OVEC | (20.8) | (17.5) | (18.3) | (12.5) | (13.2) | (12.2) | (13.4) | (13.4) | (12.3) | (12.6) | (16.7) | (19.6) | (182.7) |
| Southern Imports | 1,780.5 | 1,222.6 | 1,240.1 | 769.6 | 819.6 | 557.6 | 568.7 | 392.9 | 616.3 | 548.7 | 467.0 | 528.5 | 9,512.1 |
| CPLEIMP | 5.9 | 2.0 | 4.4 | 0.1 | 10.5 | 2.8 | 12.3 | 3.2 | 31.2 | 1.5 | 0.0 | 0.5 | 74.4 |
| DUKIMP | 11.1 | 6.0 | 35.2 | 38.4 | 10.4 | 5.9 | 1.0 | 0.8 | 3.0 | 4.6 | 0.9 | 2.5 | 119.9 |
| NCMPAIMP | 173.4 | 151.6 | 118.1 | 58.1 | 55.7 | 100.6 | 74.4 | 73.3 | 90.6 | 106.5 | 172.5 | 128.0 | 1,302.7 |
| SOUTHEAST | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| SOUTHWEST | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| SOUTHIMP | 1,590.2 | 1,063.0 | 1,082.4 | 673.0 | 743.1 | 448.3 | 480.9 | 315.6 | 491.6 | 436.1 | 293.5 | 397.5 | 8,015.1 |
| Southern Exports | (122.1) | (128.0) | (153.0) | (254.8) | (234.5) | (246.1) | (300.0) | (294.0) | (171.8) | (165.1) | (194.1) | (257.2) | (2,520.7) |
| CPLEEXP | (14.0) | (1.9) | (9.0) | (18.0) | (20.6) | (18.1) | (7.2) | (8.4) | (5.7) | (2.7) | (1.2) | (3.0) | (109.9) |
| DUKEXP | (28.3) | (40.7) | (7.4) | (12.3) | (1.6) | (18.3) | (43.9) | (71.8) | (19.2) | (28.5) | (17.7) | (119.1) | (408.9) |
| NCMPAEXP | 0.0 | 0.0 | 0.0 | 0.0 | (0.1) | 0.0 | 0.0 | 0.0 | (0.4) | (0.3) | 0.0 | 0.0 | (0.8) |
| SOUTHEAST | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| SOUTHWEST | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| SOUTHEXP | (79.8) | (85.4) | (136.6) | (224.5) | (212.2) | (209.7) | (248.8) | (213.8) | (146.5) | (133.6) | (175.3) | (135.0) | (2,001.2) |
| Total | (943.5) | (1,163.3) | (1,608.2) | (2,425.9) | (2,213.6) | (2,366.9) | (2,559.2) | (2,220.7) | (2,389.9) | (1,684.5) | (1,304.1) | (2,078.3) | (22,958.1) |

## Table 9-6 Real-time scheduled gross import volume by interface pricing point (GWh): 2017

| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| IMO | 222.3 | 127.6 | 231.6 | 25.7 | 97.8 | 34.7 | 64.7 | 47.1 | 3.2 | 13.8 | 52.0 | 155.2 | 1,075.8 |
| MISO | 46.7 | 46.1 | 81.7 | 94.8 | 93.3 | 88.8 | 53.7 | 49.4 | 54.8 | 57.9 | 117.8 | 131.1 | 916.0 |
| NORTHWEST | 0.1 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.1 |
| NYISO | 788.6 | 694.5 | 672.0 | 424.5 | 248.7 | 183.3 | 189.8 | 182.4 | 157.6 | 182.0 | 163.5 | 169.2 | 4,056.2 |
| HUDSONTP | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| LINDENVFT | 0.3 | 1.3 | 6.0 | 1.8 | 16.2 | 10.9 | 9.9 | 12.5 | 8.3 | 20.5 | 13.9 | 1.3 | 102.7 |
| NEPTUNE | 0.0 | 0.0 | 0.0 | 0.0 | 0.1 | 0.0 | 0.1 | 0.0 | 0.1 | 0.0 | 0.0 | 0.0 | 0.4 |
| NYIS | 788.4 | 693.2 | 666.0 | 422.8 | 232.4 | 172.4 | 179.8 | 169.9 | 149.3 | 161.5 | 149.5 | 167.8 | 3,953.0 |
| OVEC | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Southern Imports | 1,780.5 | 1,222.6 | 1,240.1 | 769.6 | 819.6 | 557.6 | 568.7 | 392.9 | 616.3 | 548.7 | 467.0 | 528.5 | 9,512.1 |
| CPLEIMP | 5.9 | 2.0 | 4.4 | 0.1 | 10.5 | 2.8 | 12.3 | 3.2 | 31.2 | 1.5 | 0.0 | 0.5 | 74.4 |
| DUKIMP | 11.1 | 6.0 | 35.2 | 38.4 | 10.4 | 5.9 | 1.0 | 0.8 | 3.0 | 4.6 | 0.9 | 2.5 | 119.9 |
| NCMPAIMP | 173.4 | 151.6 | 118.1 | 58.1 | 55.7 | 100.6 | 74.4 | 73.3 | 90.6 | 106.5 | 172.5 | 128.0 | 1,302.7 |
| SOUTHEAST | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| SOUTHWEST | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| SOUTHIMP | 1,590.2 | 1,063.0 | 1,082.4 | 673.0 | 743.1 | 448.3 | 480.9 | 315.6 | 491.6 | 436.1 | 293.5 | 397.5 | 8,015.1 |
| Southern Exports | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| CPLEEXP | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| DUKEXP | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| NCMPAEXP | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| SOUTHEAST | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| SOUTHWEST | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| SOUTHEXP | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Total | 2,838.3 | 2,090.8 | 2,225.4 | 1,314.7 | 1,259.4 | 864.3 | 876.9 | 671.9 | 831.9 | 802.3 | 800.3 | 984.0 | 15,560.2 |

Table 9-7 Real-time scheduled gross export volume by interface pricing point (GWh): 2017

| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| IMO | 0.3 | 0.1 | 0.1 | 4.0 | 0.1 | 0.0 | 0.1 | 0.0 | 6.6 | 0.0 | 0.0 | 0.3 | 11.6 |
| MISO | 1,513.0 | 1,368.6 | 2,164.2 | 2,557.8 | 2,906.9 | 2,205.6 | 2,320.4 | 1,867.5 | 2,413.8 | 1,525.5 | 1,162.3 | 913.5 | 22,919.1 |
| NORTHWEST | 0.0 | 0.2 | 0.1 | 0.0 | 0.1 | 0.0 | 0.0 | 0.0 | 0.5 | 0.0 | 0.0 | 0.0 | 0.9 |
| NYISO | 2,125.5 | 1,739.7 | 1,497.9 | 911.4 | 318.2 | 767.2 | 802.2 | 717.7 | 616.8 | 783.7 | 731.4 | 1,871.5 | 12,883.3 |
| HUDSONTP | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 44.9 | 229.2 | 274.2 |
| LINDENVFT | 222.4 | 159.2 | 153.5 | 108.3 | 95.7 | 69.7 | 57.5 | 69.6 | 79.5 | 126.7 | 105.0 | 204.0 | 1,451.2 |
| NEPTUNE | 484.9 | 419.9 | 444.6 | 349.7 | 122.6 | 388.9 | 427.4 | 441.0 | 336.7 | 414.2 | 371.3 | 480.6 | 4,681.7 |
| NYIS | 1,418.2 | 1,160.6 | 899.8 | 453.4 | 99.9 | 308.7 | 317.3 | 207.1 | 200.6 | 242.8 | 210.1 | 957.7 | 6,476.2 |
| OVEC | 20.8 | 17.5 | 18.3 | 12.5 | 13.2 | 12.2 | 13.4 | 13.4 | 12.3 | 12.6 | 16.7 | 19.6 | 182.7 |
| Southern Imports | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| CPLEIMP | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| DUKIMP | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| NCMPAIMP | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| SOUTHEAST | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| SOUTHWEST | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| SOUTHIMP | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Southern Exports | 122.1 | 128.0 | 153.0 | 254.8 | 234.5 | 246.1 | 300.0 | 294.0 | 171.8 | 165.1 | 194.1 | 257.2 | 2,520.7 |
| CPLEEXP | 14.0 | 1.9 | 9.0 | 18.0 | 20.6 | 18.1 | 7.2 | 8.4 | 5.7 | 2.7 | 1.2 | 3.0 | 109.9 |
| DUKEXP | 28.3 | 40.7 | 7.4 | 12.3 | 1.6 | 18.3 | 43.9 | 71.8 | 19.2 | 28.5 | 17.7 | 119.1 | 408.9 |
| NCMPAEXP | 0.0 | 0.0 | 0.0 | 0.0 | 0.1 | 0.0 | 0.0 | 0.0 | 0.4 | 0.3 | 0.0 | 0.0 | 0.8 |
| SOUTHEAST | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| SOUTHWEST | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| SOUTHEXP | 79.8 | 85.4 | 136.6 | 224.5 | 212.2 | 209.7 | 248.8 | 213.8 | 146.5 | 133.6 | 175.3 | 135.0 | 2,001.2 |
| Total | 3,781.8 | 3,254.1 | 3,833.6 | 3,740.6 | 3,473.0 | 3,231.2 | 3,436.1 | 2,892.6 | 3,221.7 | 2,486.9 | 2,104.4 | 3,062.2 | 38,518.3 |

## 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.[18] 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.[19]

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

18 Effective September 17, 2010, up to congestion transactions no longer required a willing to pay congestion transmission reservation.

19 See the *2010 State of the Market Report for PJM*, Volume 2, Section 4, "Interchange Transactions," for details.

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 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 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 2017, there were net scheduled exports at 12 of PJM's 20 interfaces. The top three net exporting interfaces in the Day-Ahead Energy Market accounted for 59.5 percent of the total net scheduled exports: PJM/Neptune (NEPT) with 20.4 percent, PJM/MidAmerican Energy Company (MEC) with 20.0 percent, and PJM/Eastern Alliant Energy (ALTE) with 18.8 percent of the net scheduled export volume. The four separate interfaces that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT, PJM/HUDS and PJM/Linden (LIND)) together represented 35.5 percent of the total net PJM scheduled exports in the Day-Ahead Energy Market. In 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 63.1 percent of the total net PJM exports in the Day-Ahead Energy Market.

In the Day-Ahead Energy Market, in 2017, there were net scheduled imports at four of PJM's 20 interfaces. The top two net importing interfaces in the Day-Ahead Energy Market accounted for 98.7 percent of the total net scheduled imports: PJM/Duke Energy Corp. (DUK) with 57.7 percent and PJM/CPLE[20] with 41.1 percent of the net scheduled import volume. The four separate interfaces that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT, PJM/HUDS and PJM/Linden (LIND)) had net scheduled exports in the Real-Time Energy Market. In 2017, there were net imports in the Day-Ahead Energy Market at zero of the 10 separate interfaces that connect PJM to MISO.[21]

20 The Progress Energy Carolinas (PEC) LMP is defined as the Carolina Power and Light (East) (CPLE) pricing point.

21 In the Day-Ahead Energy Market, four PJM interfaces had a net interchange of zero (PJM/Western Alliant Energy (ALTW), PJM/City Water Light & Power (CWLP), PJM/Northern Indiana Public Service Company (NIPS) and PJM/Ohio Valley Electric Cooperative (OVEC)).

## Table 9-8 Day-ahead scheduled net interchange volume by interface (GWh): 2017

| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| CPLE | (11.2) | 7.5 | (3.2) | 0.7 | 41.3 | 77.4 | 77.5 | 76.6 | 121.0 | 131.0 | 202.0 | 124.7 | 845.4 |
| CPLW | 0.0 | 0.0 | 0.0 | 0.1 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.1 |
| DUK | 330.8 | 281.6 | 312.4 | 81.2 | 12.4 | 56.1 | 70.0 | 10.2 | 14.3 | 3.4 | 0.6 | 14.3 | 1,187.4 |
| LGEE | 0.0 | 0.3 | 0.0 | 11.1 | 14.6 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 26.0 |
| MISO | (934.0) | (867.5) | (1,469.1) | (1,395.5) | (1,781.1) | (1,232.6) | (1,517.0) | (1,118.0) | (1,586.8) | (1,105.7) | (911.0) | (769.2) | (14,687.4) |
| ALTE | (225.7) | (280.7) | (378.9) | (268.1) | (461.2) | (351.6) | (693.8) | (453.4) | (508.5) | (261.5) | (212.9) | (273.2) | (4,369.6) |
| ALTW | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| AMIL | 0.0 | 0.0 | (5.8) | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 1.5 | 0.0 | (3.3) | (17.6) | (25.3) |
| CIN | (129.5) | (93.6) | (459.9) | (537.0) | (518.7) | (335.0) | (283.1) | (183.8) | (419.7) | (351.6) | (293.5) | (69.1) | (3,674.5) |
| CWLP | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| IPL | 0.0 | (2.3) | (13.0) | (5.8) | (15.1) | (25.7) | 0.0 | (0.8) | 0.0 | 0.0 | 0.0 | 0.0 | (62.5) |
| MEC | (496.4) | (433.1) | (428.2) | (408.3) | (509.6) | (345.3) | (340.3) | (290.9) | (333.1) | (393.1) | (380.7) | (378.3) | (4,737.1) |
| MECS | 8.1 | (18.7) | (66.9) | (41.3) | (150.7) | (81.1) | (110.0) | (70.5) | (159.8) | (75.3) | (8.8) | 3.6 | (771.4) |
| NIPS | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| WEC | (90.5) | (39.2) | (116.4) | (135.0) | (125.8) | (93.9) | (89.8) | (118.7) | (167.3) | (24.1) | (11.8) | (34.5) | (1,047.1) |
| NYISO | (1,181.0) | (894.0) | (768.1) | (389.8) | (161.0) | (599.9) | (665.4) | (614.7) | (446.8) | (531.4) | (499.8) | (1,523.7) | (8,275.7) |
| HUDS | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | (30.8) | (175.6) | (206.3) |
| LIND | (33.1) | (21.7) | (20.1) | (14.6) | (17.4) | (11.1) | (17.8) | (12.8) | (10.5) | (17.3) | (11.4) | (29.7) | (217.6) |
| NEPT | (489.6) | (412.1) | (445.4) | (351.7) | (131.4) | (393.1) | (441.9) | (464.2) | (348.3) | (415.8) | (373.2) | (484.6) | (4,751.1) |
| NYIS | (658.3) | (460.2) | (302.6) | (23.5) | (12.2) | (195.7) | (205.7) | (137.7) | (88.0) | (98.4) | (84.5) | (833.8) | (3,100.7) |
| OVEC | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| TVA | 38.4 | 19.7 | (48.6) | (61.5) | (73.7) | (70.4) | (86.9) | (21.5) | (10.1) | (46.1) | 10.3 | 20.3 | (330.1) |
| Total without Up To Congestion | (1,757.1) | (1,452.4) | (1,976.5) | (1,753.7) | (1,947.6) | (1,769.4) | (2,121.8) | (1,667.3) | (1,908.4) | (1,548.8) | (1,197.9) | (2,133.5) | (21,234.4) |
| Up To Congestion | 1,032.7 | 160.6 | 369.8 | 155.9 | 151.8 | 144.1 | (0.0) | (569.1) | 252.4 | (133.9) | (93.9) | 213.7 | 1,684.2 |
| Total | (724.4) | (1,291.8) | (1,606.7) | (1,597.8) | (1,795.8) | (1,625.3) | (2,121.8) | (2,236.3) | (1,655.9) | (1,682.7) | (1,291.8) | (1,919.8) | (19,550.1) |

## Table 9-9 Day-ahead scheduled gross import volume by interface (GWh): 2017

| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| CPLE | 5.4 | 17.8 | 5.2 | 23.5 | 95.1 | 111.1 | 104.9 | 103.4 | 135.1 | 143.0 | 210.4 | 152.0 | 1,106.9 |
| CPLW | 0.0 | 0.0 | 0.0 | 0.1 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.1 |
| DUK | 342.3 | 281.6 | 322.6 | 88.6 | 12.4 | 56.5 | 71.5 | 11.5 | 14.7 | 3.9 | 0.6 | 15.8 | 1,222.0 |
| LGEE | 0.0 | 0.3 | 0.0 | 11.1 | 14.6 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 26.0 |
| MISO | 54.3 | 11.3 | 15.2 | 1.3 | 1.4 | 3.7 | 1.3 | 1.9 | 1.5 | 2.3 | 10.5 | 31.2 | 135.8 |
| ALTE | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 2.0 | 0.8 | 0.7 | 0.0 | 1.0 | 0.0 | 0.0 | 4.5 |
| ALTW | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| AMIL | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 1.5 | 0.0 | 0.0 | 0.0 | 1.5 |
| CIN | 2.6 | 0.0 | 0.0 | 0.0 | 0.0 | 0.2 | 0.0 | 0.4 | 0.0 | 0.0 | 0.0 | 9.6 | 12.8 |
| CWLP | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| IPL | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| MEC | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| MECS | 51.6 | 11.3 | 15.2 | 1.3 | 1.4 | 1.5 | 0.5 | 0.8 | 0.0 | 1.3 | 10.5 | 21.6 | 117.0 |
| NIPS | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| WEC | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| NYISO | 645.8 | 571.7 | 496.6 | 295.4 | 15.5 | 7.2 | 0.7 | 0.8 | 16.6 | 8.0 | 4.2 | 3.0 | 2,065.5 |
| HUDS | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| LIND | 0.0 | 0.2 | 0.5 | 0.2 | 0.9 | 1.2 | 0.4 | 0.1 | 1.4 | 1.9 | 0.9 | 0.1 | 7.9 |
| NEPT | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| NYIS | 645.8 | 571.5 | 496.1 | 295.2 | 14.6 | 6.0 | 0.3 | 0.6 | 15.2 | 6.1 | 3.3 | 2.9 | 2,057.6 |
| OVEC | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| TVA | 41.9 | 43.8 | 0.9 | 22.1 | 0.8 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 16.8 | 39.3 | 165.6 |
| Total without Up To Congestion | 1,089.7 | 926.4 | 840.6 | 442.0 | 139.7 | 178.5 | 178.4 | 117.5 | 167.9 | 157.2 | 242.6 | 241.3 | 4,721.8 |
| Up To Congestion | 3,714.6 | 2,109.4 | 2,253.9 | 2,684.1 | 1,843.1 | 1,708.3 | 1,659.4 | 1,277.7 | 1,734.8 | 1,622.3 | 1,591.4 | 1,847.8 | 24,046.7 |
| Total | 4,804.3 | 3,035.8 | 3,094.4 | 3,126.1 | 1,982.7 | 1,886.8 | 1,837.8 | 1,395.1 | 1,902.7 | 1,779.5 | 1,834.1 | 2,089.1 | 28,768.6 |

Table 9-10 Day-ahead scheduled gross export volume by interface (GWh): 2017

| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| CPLE | 16.6 | 10.3 | 8.3 | 22.8 | 53.8 | 33.8 | 27.4 | 26.7 | 14.1 | 12.0 | 8.5 | 27.3 | 261.5 |
| CPLW | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| DUK | 11.5 | 0.0 | 10.2 | 7.3 | 0.0 | 0.4 | 1.6 | 1.2 | 0.4 | 0.6 | 0.0 | 1.5 | 34.6 |
| LGEE | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| MISO | 988.3 | 878.8 | 1,484.3 | 1,396.8 | 1,782.5 | 1,236.2 | 1,518.3 | 1,119.9 | 1,588.3 | 1,108.0 | 921.5 | 800.4 | 14,823.3 |
| ALTE | 225.7 | 280.7 | 378.9 | 268.1 | 461.2 | 353.6 | 694.6 | 454.1 | 508.5 | 262.5 | 212.9 | 273.2 | 4,374.1 |
| ALTW | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| AMIL | 0.0 | 0.0 | 5.8 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 3.3 | 17.6 | 26.8 |
| CIN | 132.1 | 93.6 | 459.9 | 537.0 | 518.7 | 335.2 | 283.1 | 184.2 | 419.7 | 351.6 | 293.5 | 78.7 | 3,687.3 |
| CWLP | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| IPL | 0.0 | 2.3 | 13.0 | 5.8 | 15.1 | 25.7 | 0.0 | 0.8 | 0.0 | 0.0 | 0.0 | 0.0 | 62.5 |
| MEC | 496.4 | 433.1 | 428.2 | 408.3 | 509.6 | 345.3 | 340.3 | 290.9 | 333.1 | 393.1 | 380.7 | 378.3 | 4,737.1 |
| MECS | 43.6 | 29.9 | 82.1 | 42.6 | 152.1 | 82.6 | 110.5 | 71.3 | 159.8 | 76.6 | 19.3 | 18.1 | 888.4 |
| NIPS | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| WEC | 90.5 | 39.2 | 116.4 | 135.0 | 125.8 | 93.9 | 89.8 | 118.7 | 167.3 | 24.1 | 11.8 | 34.5 | 1,047.1 |
| NYISO | 1,826.9 | 1,465.7 | 1,264.7 | 685.2 | 176.5 | 607.1 | 666.0 | 615.5 | 463.4 | 539.4 | 504.0 | 1,526.7 | 10,341.2 |
| HUDS | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 30.8 | 175.6 | 206.3 |
| LIND | 33.1 | 21.9 | 20.6 | 14.8 | 18.4 | 12.3 | 18.2 | 13.0 | 11.9 | 19.2 | 12.3 | 29.9 | 225.5 |
| NEPT | 489.6 | 412.1 | 445.4 | 351.7 | 131.4 | 393.1 | 441.9 | 464.2 | 348.3 | 415.8 | 373.2 | 484.6 | 4,751.1 |
| NYIS | 1,304.2 | 1,031.7 | 798.7 | 318.7 | 26.8 | 201.7 | 206.0 | 138.3 | 103.2 | 104.5 | 87.8 | 836.7 | 5,158.3 |
| OVEC | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| TVA | 3.5 | 24.1 | 49.5 | 83.6 | 74.5 | 70.4 | 86.9 | 21.5 | 10.1 | 46.1 | 6.5 | 19.0 | 495.7 |
| Total without Up To Congestion | 2,846.8 | 2,378.9 | 2,817.0 | 2,195.8 | 2,087.3 | 1,947.9 | 2,300.2 | 1,784.7 | 2,076.3 | 1,706.0 | 1,440.5 | 2,374.9 | 25,956.2 |
| Up To Congestion | 2,681.9 | 1,948.8 | 1,884.1 | 2,528.2 | 1,691.3 | 1,564.3 | 1,659.4 | 1,846.7 | 1,482.3 | 1,756.2 | 1,685.3 | 1,634.1 | 22,362.5 |
| Total | 5,528.6 | 4,327.6 | 4,701.1 | 4,723.9 | 3,778.6 | 3,512.2 | 3,959.6 | 3,631.4 | 3,558.6 | 3,462.2 | 3,125.8 | 4,009.0 | 48,318.7 |

## 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 2017, up to congestion transactions accounted for 83.6 percent of all scheduled import MW transactions and 46.3 percent of all scheduled export MW transactions in the Day-Ahead Energy Market. The day-ahead net scheduled interchange in 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 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 2017, the day-ahead net scheduled interchange at the NIPSCO interface pricing point was -6,038.0 GWh

(Table 9-11). Table 9-12 shows that all -6,038.0 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 2017, there were net scheduled exports at 12 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 59.8 percent of the total net scheduled exports: PJM/MISO with 26.1 percent, PJM/NIPSCO with 19.5 percent and PJM/NEPTUNE with 14.2 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 21.4 percent of the total net PJM scheduled exports in the Day-Ahead Energy Market (the PJM/HUDSONTP interface pricing point had net scheduled imports).

In the Day-Ahead Energy Market, in 2017, there were net scheduled imports at seven of PJM's 19 interface pricing points eligible for day-ahead transactions. The top three net importing interface pricing points in the Day-Ahead Energy Market accounted for 82.8 percent of the total net scheduled imports: PJM/Ohio Valley Electric Corporation (OVEC) with 34.1 percent, PJM/Southeast with 33.0 percent and PJM/SOUTHIMP with 15.8 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 represented 1.6 percent of the total net PJM scheduled imports in the Day-Ahead Energy Market (the PJM/NYIS, PJM/NEPTUNE and PJM/LINDENVFT interface pricing points had net scheduled exports).

In the Day-Ahead Energy Market, in 2017, up to congestion transactions had net scheduled exports at four of PJM's 19 interface pricing points eligible for day-ahead transactions. The top two net exporting interface pricing points eligible for up to congestion transactions accounted for 83.8 percent of the total net up to congestion scheduled exports: PJM/NIPSCO with 52.4 percent and PJM/Southwest with 31.4 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.

In the Day-Ahead Energy Market, in 2017, up to congestion transactions had net scheduled imports at nine of PJM's 19 interface pricing points eligible for day-ahead transactions. The top three net importing interface pricing points eligible for up to congestion transactions accounted for 74.6 percent of the total net up to congestion scheduled imports: PJM/OVEC with 29.4 percent, PJM/Southeast with 28.5 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 14.0 percent of the total net scheduled up to congestion exports in the Day-Ahead Energy Market.[22]

## Table 9-11 Day-ahead scheduled net interchange volume by interface pricing point (GWh): 2017

| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| IMO | 134.8 | (25.0) | (202.5) | (168.7) | 16.5 | 85.6 | (26.9) | (38.9) | (33.5) | (64.4) | (17.2) | 8.9 | (331.3) |
| MISO | (100.3) | (259.5) | (931.6) | (465.3) | (1,129.3) | (814.2) | (1,146.5) | (789.3) | (1,095.6) | (553.9) | (458.2) | (332.0) | (8,075.8) |
| NIPSCO | (950.4) | (289.9) | (344.8) | (769.6) | (455.1) | (328.1) | (565.2) | (557.6) | (305.3) | (431.5) | (511.3) | (529.3) | (6,038.0) |
| NORTHWEST | (370.1) | (455.6) | (326.7) | (204.6) | (452.9) | (270.5) | (323.6) | (248.2) | (240.4) | (489.2) | (430.0) | (256.5) | (4,068.2) |
| NYISO | (838.4) | (756.8) | (759.1) | (316.6) | (46.1) | (293.9) | (446.4) | (512.9) | (307.2) | (437.9) | (384.9) | (1,329.4) | (6,429.7) |
| HUDSONTP | 191.8 | 24.8 | (57.5) | (10.6) | (22.9) | 53.8 | 48.1 | 3.9 | (7.0) | 11.5 | (16.7) | (33.6) | 185.6 |
| LINDENVFT | (58.5) | (43.6) | (28.0) | (14.5) | 11.0 | 28.3 | 4.1 | (5.5) | 17.6 | (0.9) | 5.2 | 10.4 | (74.4) |
| NEPTUNE | (482.9) | (387.4) | (386.8) | (291.1) | (126.5) | (347.3) | (403.4) | (416.3) | (340.4) | (419.6) | (329.7) | (469.3) | (4,400.8) |
| NYIS | (488.9) | (350.5) | (286.8) | (0.4) | 92.4 | (28.7) | (95.2) | (95.0) | 22.6 | (28.9) | (43.7) | (837.0) | (2,140.1) |
| OVEC | 742.4 | 64.9 | 497.4 | 390.0 | 445.9 | 157.3 | 443.1 | 262.0 | 248.9 | 257.1 | 168.3 | 210.6 | 3,888.0 |
| Southern Imports | 1,418.8 | 988.4 | 996.3 | 786.4 | 552.3 | 542.6 | 600.9 | 423.0 | 704.3 | 708.6 | 783.9 | 797.7 | 9,303.1 |
| CPLEIMP | 5.4 | 3.2 | 5.2 | 0.0 | 5.7 | 2.5 | 0.1 | 1.5 | 0.0 | 2.6 | 0.6 | 0.0 | 26.7 |
| DUKIMP | 8.2 | 26.9 | 19.6 | 8.5 | 4.6 | 0.5 | 1.2 | 2.4 | 24.0 | 1.4 | 1.0 | 1.2 | 99.5 |
| NCMPAIMP | 175.1 | 152.1 | 149.9 | 93.2 | 90.6 | 134.1 | 108.0 | 108.9 | 126.1 | 139.5 | 208.9 | 159.4 | 1,645.8 |
| SOUTHEAST | 424.7 | 377.5 | 439.6 | 347.8 | 235.7 | 255.8 | 283.4 | 204.9 | 312.9 | 416.1 | 314.6 | 291.8 | 3,904.8 |
| SOUTHWEST | 376.6 | 125.7 | 164.6 | 186.6 | 87.4 | 74.0 | 81.7 | 66.3 | 177.8 | 103.3 | 175.9 | 207.5 | 1,827.1 |
| SOUTHIMP | 428.8 | 303.1 | 217.5 | 150.3 | 128.3 | 75.8 | 126.6 | 38.9 | 63.5 | 45.6 | 82.9 | 137.9 | 1,799.2 |
| Southern Exports | (761.1) | (558.4) | (535.7) | (849.5) | (727.2) | (704.2) | (657.0) | (774.5) | (627.2) | (671.6) | (442.2) | (489.7) | (7,798.2) |
| CPLEEXP | (15.8) | (9.8) | (7.7) | (21.7) | (50.8) | (32.5) | (27.0) | (26.3) | (13.7) | (11.7) | (8.3) | (21.7) | (247.0) |
| DUKEXP | 0.0 | 0.0 | 0.0 | (2.2) | 0.0 | (0.4) | (1.6) | 0.0 | 0.0 | 0.0 | 0.0 | (5.2) | (9.3) |
| NCMPAEXP | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | (0.4) | (0.6) | 0.0 | 0.0 | (0.9) |
| SOUTHEAST | (13.3) | (21.9) | (9.7) | (7.2) | (15.2) | (5.3) | (7.3) | (8.3) | (7.4) | (12.1) | (16.0) | (18.7) | (142.4) |
| SOUTHWEST | (576.6) | (401.3) | (332.9) | (631.8) | (447.8) | (516.1) | (427.0) | (579.1) | (487.0) | (392.6) | (306.3) | (341.5) | (5,439.9) |
| SOUTHEXP | (155.4) | (125.4) | (185.4) | (186.6) | (213.4) | (149.9) | (194.2) | (160.8) | (118.8) | (254.6) | (111.7) | (102.6) | (1,958.7) |
| Total | (724.4) | (1,291.8) | (1,606.7) | (1,597.8) | (1,795.8) | (1,625.3) | (2,121.8) | (2,236.3) | (1,655.9) | (1,682.7) | (1,291.8) | (1,919.8) | (19,550.1) |

## Table 9-12 Up to congestion scheduled net interchange volume by interface pricing point (GWh): 2017

| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| IMO | 83.2 | (36.3) | (217.7) | (170.0) | 15.1 | 84.2 | (27.4) | (39.7) | (32.6) | (65.7) | (27.7) | (12.8) | (447.5) |
| MISO | 404.5 | 198.9 | 127.9 | 544.6 | 171.1 | 88.1 | 30.7 | 38.6 | 160.3 | 206.2 | 125.3 | 107.8 | 2,203.9 |
| NIPSCO | (950.4) | (289.9) | (344.8) | (769.6) | (455.1) | (328.1) | (565.2) | (557.6) | (305.3) | (431.5) | (511.3) | (529.3) | (6,038.0) |
| NORTHWEST | 110.7 | (35.1) | 98.1 | 182.3 | 29.2 | 61.2 | 16.7 | 42.7 | 92.0 | (142.3) | (92.0) | 93.1 | 456.7 |
| NYISO | 342.6 | 137.2 | 9.0 | 73.2 | 114.9 | 306.0 | 218.9 | 101.8 | 142.4 | 93.5 | 114.9 | 195.6 | 1,850.2 |
| HUDSONTP | 191.8 | 24.8 | (57.5) | (10.6) | (22.9) | 53.8 | 48.1 | 3.9 | (7.0) | 11.5 | 14.0 | 142.0 | 391.9 |
| LINDENVFT | (25.4) | (22.0) | (7.9) | 0.1 | 28.4 | 39.4 | 21.9 | 7.4 | 28.2 | 16.4 | 16.6 | 41.5 | 144.6 |
| NEPTUNE | 6.8 | 24.7 | 58.6 | 60.7 | 4.8 | 45.8 | 38.4 | 47.9 | 7.8 | (3.8) | 43.4 | 15.3 | 350.3 |
| NYIS | 169.4 | 109.7 | 15.8 | 23.1 | 104.6 | 167.0 | 110.5 | 42.7 | 113.4 | 69.5 | 40.8 | (3.1) | 963.4 |
| OVEC | 742.4 | 64.9 | 497.4 | 390.0 | 445.9 | 157.3 | 443.1 | 262.0 | 248.9 | 257.1 | 168.3 | 210.6 | 3,888.0 |
| Southern Imports | 1,029.2 | 645.0 | 667.6 | 641.1 | 429.4 | 374.9 | 424.4 | 308.2 | 549.3 | 561.7 | 556.0 | 590.6 | 6,777.4 |
| CPLEIMP | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| DUKIMP | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| NCMPAIMP | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| SOUTHEAST | 424.7 | 377.5 | 439.6 | 347.8 | 235.7 | 255.8 | 283.4 | 204.9 | 312.9 | 416.1 | 314.6 | 291.8 | 3,904.8 |
| SOUTHWEST | 376.6 | 125.7 | 164.6 | 186.6 | 87.4 | 74.0 | 81.7 | 66.3 | 177.8 | 103.3 | 175.9 | 207.5 | 1,827.1 |
| SOUTHIMP | 227.9 | 141.8 | 63.4 | 106.7 | 106.3 | 45.2 | 59.4 | 37.0 | 58.6 | 42.2 | 65.5 | 91.4 | 1,045.4 |
| Southern Exports | (729.5) | (524.0) | (467.7) | (735.7) | (598.9) | (599.6) | (541.1) | (725.1) | (602.7) | (612.9) | (427.3) | (442.0) | (7,006.4) |
| CPLEEXP | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| DUKEXP | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| NCMPAEXP | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| SOUTHEAST | (13.3) | (21.9) | (9.7) | (7.2) | (15.2) | (5.3) | (7.1) | (8.3) | (7.4) | (12.1) | (16.0) | (18.7) | (142.2) |
| SOUTHWEST | (576.6) | (401.3) | (332.9) | (631.8) | (447.8) | (516.1) | (427.0) | (579.1) | (487.0) | (392.6) | (306.3) | (341.5) | (5,439.9) |
| SOUTHEXP | (139.5) | (100.8) | (125.0) | (96.7) | (136.0) | (78.2) | (107.1) | (137.7) | (108.3) | (208.2) | (105.0) | (81.8) | (1,424.3) |
| Total Interfaces | 1,032.7 | 160.6 | 369.8 | 155.9 | 151.8 | 144.1 | (0.0) | (569.1) | 252.4 | (133.9) | (93.9) | 213.7 | 1,684.2 |
| INTERNAL | 28,699.9 | 24,147.9 | 24,822.8 | 25,401.8 | 22,243.3 | 18,460.3 | 20,816.1 | 20,420.0 | 18,835.2 | 18,871.5 | 18,205.6 | 20,282.7 | 261,207.1 |
| Total | 29,732.6 | 24,308.5 | 25,192.6 | 25,557.7 | 22,395.1 | 18,604.3 | 20,816.0 | 19,851.0 | 19,087.7 | 18,737.6 | 18,111.7 | 20,496.5 | 262,891.4 |

22 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 9-13 Day-ahead scheduled gross import volume by interface pricing point (GWh): 2017

| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| IMO | 213.7 | 67.9 | 56.5 | 26.6 | 54.0 | 172.1 | 82.4 | 37.9 | 44.5 | 54.9 | 75.3 | 121.1 | 1,006.9 |
| MISO | 753.3 | 402.1 | 343.1 | 762.1 | 329.3 | 234.9 | 187.1 | 205.8 | 313.6 | 321.9 | 256.7 | 227.9 | 4,337.8 |
| NIPSCO | 60.1 | 158.5 | 137.7 | 127.2 | 108.1 | 66.6 | 10.3 | 21.9 | 62.2 | 37.2 | 11.7 | 8.5 | 809.8 |
| NORTHWEST | 398.3 | 184.1 | 261.1 | 340.7 | 190.8 | 256.9 | 190.0 | 221.0 | 223.0 | 109.5 | 125.0 | 248.6 | 2,749.1 |
| NYISO | 1,156.1 | 863.3 | 651.2 | 541.3 | 215.3 | 391.8 | 261.2 | 147.2 | 228.0 | 190.5 | 259.6 | 351.8 | 5,257.1 |
| HUDSONTP | 231.3 | 106.6 | 12.7 | 11.4 | 17.4 | 86.2 | 53.0 | 7.4 | 17.9 | 29.1 | 84.5 | 208.2 | 865.7 |
| LINDENVFT | 17.4 | 13.7 | 21.7 | 108.6 | 55.3 | 50.0 | 34.7 | 14.7 | 50.0 | 38.6 | 35.8 | 66.3 | 506.7 |
| NEPTUNE | 36.2 | 39.1 | 64.9 | 81.6 | 14.9 | 56.7 | 41.0 | 50.5 | 19.7 | 33.8 | 70.2 | 24.1 | 532.8 |
| NYIS | 871.2 | 703.8 | 551.8 | 339.6 | 127.6 | 199.0 | 132.6 | 74.5 | 140.4 | 89.0 | 69.1 | 53.3 | 3,351.9 |
| OVEC | 804.0 | 371.6 | 648.6 | 541.9 | 533.0 | 221.8 | 506.0 | 338.4 | 327.1 | 356.9 | 321.9 | 333.5 | 5,304.7 |
| Southern Imports | 1,418.8 | 988.4 | 996.3 | 786.4 | 552.3 | 542.6 | 600.9 | 423.0 | 704.3 | 708.6 | 783.9 | 797.7 | 9,303.1 |
| CPLEIMP | 5.4 | 3.2 | 5.2 | 0.0 | 5.7 | 2.5 | 0.1 | 1.5 | 0.0 | 2.6 | 0.6 | 0.0 | 26.7 |
| DUKIMP | 8.2 | 26.9 | 19.6 | 8.5 | 4.6 | 0.5 | 1.2 | 2.4 | 24.0 | 1.4 | 1.0 | 1.2 | 99.5 |
| NCMPAIMP | 175.1 | 152.1 | 149.9 | 93.2 | 90.6 | 134.1 | 108.0 | 108.9 | 126.1 | 139.5 | 208.9 | 159.4 | 1,645.8 |
| SOUTHEAST | 424.7 | 377.5 | 439.6 | 347.8 | 235.7 | 255.8 | 283.4 | 204.9 | 312.9 | 416.1 | 314.6 | 291.8 | 3,904.8 |
| SOUTHWEST | 376.6 | 125.7 | 164.6 | 186.6 | 87.4 | 74.0 | 81.7 | 66.3 | 177.8 | 103.3 | 175.9 | 207.5 | 1,827.1 |
| SOUTHIMP | 428.8 | 303.1 | 217.5 | 150.3 | 128.3 | 75.8 | 126.6 | 38.9 | 63.5 | 45.6 | 82.9 | 137.9 | 1,799.2 |
| Southern Exports | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| CPLEEXP | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| DUKEXP | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| NCMPAEXP | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| SOUTHEAST | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| SOUTHWEST | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| SOUTHEXP | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Total | 4,804.3 | 3,035.8 | 3,094.4 | 3,126.1 | 1,982.7 | 1,886.8 | 1,837.8 | 1,395.1 | 1,902.7 | 1,779.5 | 1,834.1 | 2,089.1 | 28,768.6 |

## Table 9-14 Up to congestion scheduled gross import volume by interface pricing point (GWh): 2017

| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| IMO | 162.1 | 56.6 | 41.2 | 25.3 | 52.6 | 170.7 | 81.9 | 37.1 | 44.5 | 53.6 | 64.8 | 99.5 | 889.8 |
| MISO | 750.7 | 402.1 | 343.1 | 762.1 | 329.3 | 232.7 | 186.3 | 204.7 | 313.6 | 320.9 | 256.7 | 218.3 | 4,320.5 |
| NIPSCO | 60.1 | 158.5 | 137.7 | 127.2 | 108.1 | 66.6 | 10.3 | 21.9 | 62.2 | 37.2 | 11.7 | 8.5 | 809.8 |
| NORTHWEST | 398.3 | 184.1 | 261.1 | 340.7 | 190.8 | 256.9 | 190.0 | 221.0 | 223.0 | 109.5 | 125.0 | 248.6 | 2,749.1 |
| NYISO | 510.2 | 291.6 | 154.5 | 245.9 | 199.8 | 384.6 | 260.5 | 146.4 | 215.1 | 182.5 | 255.4 | 348.9 | 3,195.4 |
| HUDSONTP | 231.3 | 106.6 | 12.7 | 11.4 | 17.4 | 86.2 | 53.0 | 7.4 | 17.9 | 29.1 | 84.5 | 208.2 | 865.7 |
| LINDENVFT | 17.4 | 13.5 | 21.2 | 108.4 | 54.4 | 48.8 | 34.3 | 14.6 | 48.7 | 36.6 | 34.9 | 66.1 | 498.8 |
| NEPTUNE | 36.2 | 39.1 | 64.9 | 81.6 | 14.9 | 56.7 | 41.0 | 50.5 | 19.7 | 33.8 | 70.2 | 24.1 | 532.8 |
| NYIS | 225.4 | 132.3 | 55.7 | 44.4 | 113.1 | 193.0 | 132.3 | 73.8 | 128.9 | 82.9 | 65.8 | 50.4 | 1,298.1 |
| OVEC | 804.0 | 371.6 | 648.6 | 541.9 | 533.0 | 221.8 | 506.0 | 338.4 | 327.1 | 356.9 | 321.9 | 333.5 | 5,304.7 |
| Southern Imports | 1,029.2 | 645.0 | 667.6 | 641.1 | 429.4 | 374.9 | 424.4 | 308.2 | 549.3 | 561.7 | 556.0 | 590.6 | 6,777.4 |
| CPLEIMP | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| DUKIMP | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| NCMPAIMP | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| SOUTHEAST | 424.7 | 377.5 | 439.6 | 347.8 | 235.7 | 255.8 | 283.4 | 204.9 | 312.9 | 416.1 | 314.6 | 291.8 | 3,904.8 |
| SOUTHWEST | 376.6 | 125.7 | 164.6 | 186.6 | 87.4 | 74.0 | 81.7 | 66.3 | 177.8 | 103.3 | 175.9 | 207.5 | 1,827.1 |
| SOUTHIMP | 227.9 | 141.8 | 63.4 | 106.7 | 106.3 | 45.2 | 59.4 | 37.0 | 58.6 | 42.2 | 65.5 | 91.4 | 1,045.4 |
| Southern Exports | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| CPLEEXP | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| DUKEXP | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| NCMPAEXP | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| SOUTHEAST | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| SOUTHWEST | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| SOUTHEXP | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Total Interfaces | 3,714.6 | 2,109.4 | 2,253.9 | 2,684.1 | 1,843.1 | 1,708.3 | 1,659.4 | 1,277.7 | 1,734.8 | 1,622.3 | 1,591.4 | 1,847.8 | 24,046.7 |

## Table 9-15 Day-ahead scheduled gross export volume by interface pricing point (GWh): 2017

| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| IMO | 78.9 | 92.8 | 259.0 | 195.3 | 37.5 | 86.5 | 109.4 | 76.7 | 78.0 | 119.3 | 92.5 | 112.2 | 1,338.2 |
| MISO | 853.6 | 661.6 | 1,274.7 | 1,227.4 | 1,458.7 | 1,049.2 | 1,333.6 | 995.1 | 1,409.1 | 875.7 | 714.9 | 559.9 | 12,413.6 |
| NIPSCO | 1,010.4 | 448.4 | 482.5 | 896.7 | 563.2 | 394.8 | 575.5 | 579.5 | 367.4 | 468.7 | 522.9 | 537.8 | 6,847.8 |
| NORTHWEST | 768.5 | 639.7 | 587.9 | 545.4 | 643.7 | 527.4 | 513.6 | 469.1 | 463.4 | 598.7 | 555.0 | 505.1 | 6,817.4 |
| NYISO | 1,994.5 | 1,620.1 | 1,410.3 | 857.9 | 261.3 | 685.7 | 707.6 | 660.0 | 535.2 | 628.4 | 644.5 | 1,681.3 | 11,686.8 |
| HUDSONTP | 39.5 | 81.8 | 70.2 | 22.0 | 40.3 | 32.4 | 4.9 | 3.5 | 24.9 | 17.6 | 101.2 | 241.8 | 680.1 |
| LINDENVFT | 75.9 | 57.3 | 49.7 | 123.1 | 44.3 | 21.6 | 30.6 | 20.2 | 32.4 | 39.4 | 30.6 | 55.9 | 581.0 |
| NEPTUNE | 519.0 | 426.6 | 451.7 | 372.7 | 141.5 | 403.9 | 444.4 | 466.8 | 360.1 | 453.4 | 400.0 | 493.4 | 4,933.6 |
| NYIS | 1,360.1 | 1,054.4 | 838.6 | 340.0 | 35.3 | 227.7 | 227.8 | 169.5 | 117.8 | 117.9 | 112.7 | 890.2 | 5,492.1 |
| OVEC | 61.6 | 306.7 | 151.2 | 151.9 | 87.1 | 64.5 | 62.9 | 76.4 | 78.2 | 99.8 | 153.7 | 122.9 | 1,416.7 |
| Southern Imports | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| CPLEIMP | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| DUKIMP | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| NCMPAIMP | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| SOUTHEAST | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| SOUTHWEST | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| SOUTHIMP | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Southern Exports | 761.1 | 558.4 | 535.7 | 849.5 | 727.2 | 704.2 | 657.0 | 774.5 | 627.2 | 671.6 | 442.2 | 489.7 | 7,798.2 |
| CPLEEXP | 15.8 | 9.8 | 7.7 | 21.7 | 50.8 | 32.5 | 27.0 | 26.3 | 13.7 | 11.7 | 8.3 | 21.7 | 247.0 |
| DUKEXP | 0.0 | 0.0 | 0.0 | 2.2 | 0.0 | 0.4 | 1.6 | 0.0 | 0.0 | 0.0 | 0.0 | 5.2 | 9.3 |
| NCMPAEXP | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.4 | 0.6 | 0.0 | 0.0 | 0.9 |
| SOUTHEAST | 13.3 | 21.9 | 9.7 | 7.2 | 15.2 | 5.3 | 7.3 | 8.3 | 7.4 | 12.1 | 16.0 | 18.7 | 142.4 |
| SOUTHWEST | 576.6 | 401.3 | 332.9 | 631.8 | 447.8 | 516.1 | 427.0 | 579.1 | 487.0 | 392.6 | 306.3 | 341.5 | 5,439.9 |
| SOUTHEXP | 155.4 | 125.4 | 185.4 | 186.6 | 213.4 | 149.9 | 194.2 | 160.8 | 118.8 | 254.6 | 111.7 | 102.6 | 1,958.7 |
| Total | 5,528.6 | 4,327.6 | 4,701.1 | 4,723.9 | 3,778.6 | 3,512.2 | 3,959.6 | 3,631.4 | 3,558.6 | 3,462.2 | 3,125.8 | 4,009.0 | 48,318.7 |

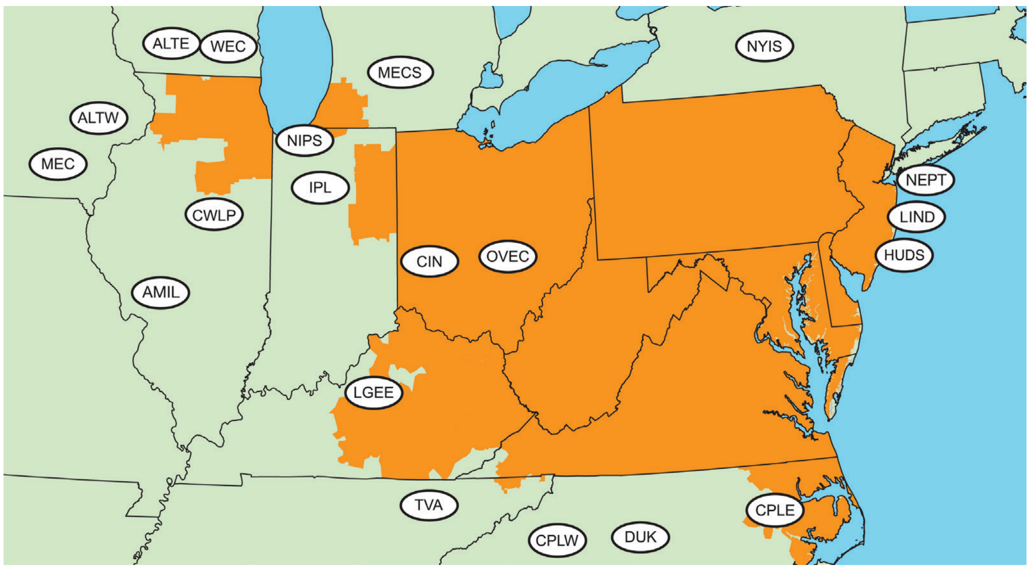
## Table 9-16 Up to congestion scheduled gross export volume by interface pricing point (GWh): 2017

| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| IMO | 78.9 | 92.8 | 259.0 | 195.3 | 37.5 | 86.5 | 109.4 | 76.7 | 77.1 | 119.3 | 92.5 | 112.2 | 1,337.3 |
| MISO | 346.2 | 203.3 | 215.2 | 217.5 | 158.2 | 144.6 | 155.6 | 166.1 | 153.3 | 114.7 | 131.4 | 110.5 | 2,116.5 |
| NIPSCO | 1,010.4 | 448.4 | 482.5 | 896.7 | 563.2 | 394.8 | 575.5 | 579.5 | 367.4 | 468.7 | 522.9 | 537.8 | 6,847.8 |
| NORTHWEST | 287.6 | 219.2 | 163.1 | 158.5 | 161.6 | 195.7 | 173.4 | 178.3 | 130.9 | 251.7 | 217.0 | 155.4 | 2,292.5 |
| NYISO | 167.6 | 154.4 | 145.5 | 172.7 | 84.8 | 78.6 | 41.6 | 44.6 | 72.7 | 88.9 | 140.5 | 153.2 | 1,345.2 |
| HUDSONTP | 39.5 | 81.8 | 70.2 | 22.0 | 40.3 | 32.4 | 4.9 | 3.5 | 24.9 | 17.6 | 70.5 | 66.2 | 473.8 |
| LINDENVFT | 42.8 | 35.5 | 29.1 | 108.3 | 26.0 | 9.4 | 12.4 | 7.2 | 20.5 | 20.3 | 18.2 | 24.7 | 354.2 |
| NEPTUNE | 29.4 | 14.5 | 6.4 | 21.0 | 10.1 | 10.9 | 2.6 | 2.6 | 11.8 | 37.6 | 26.8 | 8.9 | 182.5 |
| NYIS | 56.0 | 22.6 | 39.9 | 21.3 | 8.5 | 26.0 | 21.8 | 31.2 | 15.5 | 13.4 | 25.0 | 53.6 | 334.7 |
| OVEC | 61.6 | 306.7 | 151.2 | 151.9 | 87.1 | 64.5 | 62.9 | 76.4 | 78.2 | 99.8 | 153.7 | 122.9 | 1,416.7 |
| Southern Imports | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| CPLEIMP | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| DUKIMP | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| NCMPAIMP | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| SOUTHEAST | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| SOUTHWEST | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| SOUTHIMP | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Southern Exports | 729.5 | 524.0 | 467.7 | 735.7 | 598.9 | 599.6 | 541.1 | 725.1 | 602.7 | 612.9 | 427.3 | 442.0 | 7,006.4 |
| CPLEEXP | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| DUKEXP | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| NCMPAEXP | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| SOUTHEAST | 13.3 | 21.9 | 9.7 | 7.2 | 15.2 | 5.3 | 7.1 | 8.3 | 7.4 | 12.1 | 16.0 | 18.7 | 142.2 |
| SOUTHWEST | 576.6 | 401.3 | 332.9 | 631.8 | 447.8 | 516.1 | 427.0 | 579.1 | 487.0 | 392.6 | 306.3 | 341.5 | 5,439.9 |
| SOUTHEXP | 139.5 | 100.8 | 125.0 | 96.7 | 136.0 | 78.2 | 107.1 | 137.7 | 108.3 | 208.2 | 105.0 | 81.8 | 1,424.3 |
| Total Interfaces | 2,681.9 | 1,948.8 | 1,884.1 | 2,528.2 | 1,691.3 | 1,564.3 | 1,659.4 | 1,846.7 | 1,482.3 | 1,756.2 | 1,685.3 | 1,634.1 | 22,362.5 |

## Table 9-17 Active real-time and day-ahead scheduling interfaces: 2017[23]

| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ALTE | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active |
| ALTW | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active |
| AMIL | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active |
| CIN | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active |
| CPLE | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active |
| CPLW | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active |
| CWLP | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active |
| DUK | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active |
| HUDS | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active |
| IPL | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active |
| LGEE | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active |
| LIND | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active |
| MEC | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active |
| MECS | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active |
| NEPT | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active |
| NIPS | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active |
| NYIS | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active |
| OVEC | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active |
| TVA | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active |
| WEC | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active |

## Figure 9-3 PJM's footprint and its external day-ahead and real-time scheduling interfaces




23 On July 2, 2012, Duke Energy Corp. (DUK) completed a merger with Progress Energy Inc. (CPLE and CPLW). As of December 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.

Table 9-18 Active day-ahead and real-time scheduled interface pricing points: 2017[24]

| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| CPLEEXP | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active |
| CPLEIMP | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active |
| DUKEXP | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active |
| DUKIMP | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active |
| HUDSONTP | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active |
| LINDENVFT | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active |
| MISO | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active |
| NCMPAEXP | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active |
| NCMPAIMP | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active |
| NEPTUNE | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active |
| NIPSCO | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active |
| Northwest | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active |
| NYIS | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active |
| Ontario IESO | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active |
| OVEC | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active |
| Southeast | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active |
| SOUTHEXP | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active |
| SOUTHIMP | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active |
| Southwest | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active | Active |

## Loop Flows

Actual energy flows are the real-time metered power flows at an interface for a defined period. The comparable scheduled flows are the real-time power flows scheduled at an interface for a defined period. Inadvertent interchange is the difference between the total actual flows for the PJM system (net actual interchange) and the total scheduled flows for the PJM system (net scheduled interchange) for a defined period. Loop flows are the difference between actual and scheduled power flows at a specific interface. Loop flows can exist at the same time that inadvertent interchange is zero. For example, actual imports could exceed scheduled imports at one interface and actual exports could exceed scheduled exports at another interface by the same amount. The result is loop flow, despite the fact that system actual and scheduled power flow net to a zero difference.[25]

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 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 2017, there were net scheduled

24 The NIPSCO interface pricing point is valid only in the Day-Ahead Energy Market.

25 See the *2012 State of the Market Report for PJM*, Volume 2, Section 8, "Interchange Transactions," for a more detailed discussion.

flows of 2,573 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 2017, net scheduled interchange was -22,958 GWh and net actual interchange was -23,147 GWh, a difference of 189 GWh. In 2016, net scheduled interchange was -9,154 GWh and net actual interchange was -7,967 GWh, a difference of 1,186 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.[26]

Table 9-19 shows that in 2017, the Wisconsin Energy Corporation (WEC) Interface had the largest loop flows of any interface with 1,934 GWh of net scheduled interchange and 9,387 GWh of net actual interchange, a difference of 11,321 GWh.

### Table 9-19 Net scheduled and actual PJM flows by interface (GWh): 2017

| | Actual | Net Scheduled | Difference (GWh) |
|---|---|---|---|
| CPLE | 4,188 | 407 | 3,781 |
| CPLW | (1,310) | 1 | (1,311) |
| DUK | 750 | 1,663 | (912) |
| LGEE | 3,461 | 1,756 | 1,705 |
| MISO | (29,248) | (18,381) | (10,867) |
| ALTE | (4,514) | (4,902) | 389 |
| ALTW | (1,909) | 1 | (1,910) |
| AMIL | (1,112) | 1,473 | (2,585) |
| CIN | (9,628) | (7,487) | (2,142) |
| CWLP | (216) | 0 | (216) |
| IPL | (787) | (960) | 173 |
| MEC | (3,865) | (4,345) | 480 |
| MECS | (8,174) | (235) | (7,939) |
| NIPS | (8,432) | 7 | (8,439) |
| WEC | 9,387 | (1,934) | 11,321 |
| NYISO | (9,419) | (8,812) | (606) |
| HUDS | (274) | (274) | 0 |
| LIND | (1,348) | (1,348) | 0 |
| NEPT | (4,681) | (4,681) | 0 |
| NYIS | (3,115) | (2,509) | (606) |
| OVEC | 2,392 | (183) | 2,575 |
| TVA | 6,039 | 592 | 5,447 |
| Total | (23,147) | (22,958) | (189) |

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.[27] For example, the MWh for a transaction whose transmission path is SPP through MISO and into PJM would be reflected in the SouthIMP interface pricing point net schedule totals because SPP is mapped to the SouthIMP interface pricing point. The actual flow on an interface pricing point is defined as the metered flow across the transmission lines that are included in the interface pricing point.

The differences between the scheduled MWh mapped to a specific interface pricing point and actual power flows at the interface pricing points provide a better measure of loop flows than differences at the interfaces. The scheduled transactions are mapped to interface pricing points based on the expected flow from the generation balancing authority and load balancing authority, whereas scheduled transactions are assigned to interfaces based solely on the OASIS path that the market participants reflect the transmission path into or out of PJM to one neighboring balancing authority. Power flows at the interface pricing points provide a more accurate reflection of where scheduled power flows actually enter or leave the PJM footprint based on the complete transaction path.

Table 9-20 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

26 See PJM. "Manual 12: Balancing Operations," Rev. 37 (November 16, 2017).

27 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).

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 (24,457 GWh) and the total southern export actual flows (-11,330 GWh) for 13,127 GWh of net imports. The net scheduled flows from the southern region are determined by summing the total southern import scheduled flows (9,512 GWh) and the total southern export scheduled flows (-2,521 GWh) for 6,991 GWh of net imports. In 2017, the loop flows at the southern region were the difference between the southern region net scheduled flows (6,991 GW) and the southern region net actual flows (13,127 GWh) for a total of 6,136 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): 2017

| | Actual | Net Scheduled | Difference (GWh) |
|---|---|---|---|
| IMO | 0 | 1,064 | (1,064) |
| MISO | (29,248) | (22,003) | (7,245) |
| NORTHWEST | 0 | (1) | 1 |
| NYISO | (9,419) | (8,827) | (591) |
| HUDSONTP | (274) | (274) | 0 |
| LINDENVFT | (1,348) | (1,348) | 0 |
| NEPTUNE | (4,681) | (4,681) | 0 |
| NYIS | (3,115) | (2,523) | (591) |
| OVEC | 2,392 | (183) | 2,575 |
| Southern Imports | 24,457 | 9,512 | 14,945 |
| CPLEIMP | 0 | 74 | (74) |
| DUKIMP | 0 | 120 | (120) |
| NCMPAIMP | 0 | 1,303 | (1,303) |
| SOUTHEAST | 0 | 0 | 0 |
| SOUTHWEST | 0 | 0 | 0 |
| SOUTHIMP | 24,457 | 8,015 | 16,442 |
| Southern Exports | (11,330) | (2,521) | (8,809) |
| CPLEEXP | 0 | (110) | 110 |
| DUKEXP | 0 | (409) | 409 |
| NCMPAEXP | 0 | (1) | 1 |
| SOUTHEAST | 0 | 0 | 0 |
| SOUTHWEST | 0 | 0 | 0 |
| SOUTHEXP | (11,330) | (2,001) | (9,329) |
| Total | (23,147) | (22,958) | (189) |

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 1,049 of the 1,064 GWh (98.7 percent) of gross scheduled transactions that were mapped to the IMO interface pricing point were scheduled as imports through MISO, and 15 of the 1,064 GWh (1.3 percent) were scheduled as imports through the NYISO.

Table 9-21 shows that in 2017, the SouthIMP interface pricing point had the largest loop flows of any interface pricing point with 8,015 GWh of net scheduled interchange and 24,457 GWh of net actual interchange, a difference of 16,442 GWh.

Table 9-21 Net scheduled and actual PJM flows by interface pricing point (GWh) (Adjusted for IMO Scheduled Interfaces): 2017

| | Actual | Net Scheduled | Difference (GWh) |
|---|---|---|---|
| MISO | (29,248) | (20,954) | (8,294) |
| NORTHWEST | 0 | (1) | 1 |
| NYISO | (9,419) | (8,812) | (606) |
| HUDSONTP | (274) | (274) | 0 |
| LINDENVFT | (1,348) | (1,348) | 0 |
| NEPTUNE | (4,681) | (4,681) | 0 |
| NYIS | (3,115) | (2,509) | (606) |
| OVEC | 2,392 | (183) | 2,575 |
| Southern Imports | 24,457 | 9,512 | 14,945 |
| CPLEIMP | 0 | 74 | (74) |
| DUKIMP | 0 | 120 | (120) |
| NCMPAIMP | 0 | 1,303 | (1,303) |
| SOUTHEAST | 0 | 0 | 0 |
| SOUTHWEST | 0 | 0 | 0 |
| SOUTHIMP | 24,457 | 8,015 | 16,442 |
| Southern Exports | (11,330) | (2,521) | (8,809) |
| CPLEEXP | 0 | (110) | 110 |
| DUKEXP | 0 | (409) | 409 |
| NCMPAEXP | 0 | (1) | 1 |
| SOUTHEAST | 0 | 0 | 0 |
| SOUTHWEST | 0 | 0 | 0 |
| SOUTHEXP | (11,330) | (2,001) | (9,329) |
| Total | (23,147) | (22,958) | (189) |

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 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 (347 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 (-8,064 GWh).

Table 9-22 Net scheduled and actual PJM flows by interface and interface pricing point (GWh): 2017

| Interface | Interface Pricing Point | Actual | Net Scheduled | Difference (GWh) | Interface | Interface Pricing Point | Actual | Net Scheduled | Difference (GWh) |
|---|---|---|---|---|---|---|---|---|---|
| ALTE | | (4,514) | (4,902) | 389 | IPL | | (787) | (960) | 173 |
| | IMO | 0 | 223 | (223) | | IMO | 0 | 90 | (90) |
| | MISO | (4,514) | (5,408) | 895 | | MISO | (787) | (1,061) | 274 |
| | SOUTHIMP | 0 | 283 | (283) | | SOUTHEXP | 0 | (0) | 0 |
| ALTW | | (1,909) | 1 | (1,910) | | SOUTHIMP | 0 | 11 | (11) |
| | IMO | 0 | 1 | (1) | LGEE | | 3,461 | 1,756 | 1,705 |
| | MISO | (1,909) | (0) | (1,908) | | SOUTHEXP | (6,113) | (64) | (6,050) |
| AMIL | | (1,112) | 1,473 | (2,585) | | SOUTHIMP | 9,574 | 1,820 | 7,754 |
| | MISO | (1,112) | 26 | (1,137) | LIND | | (1,348) | (1,348) | 0 |
| | SOUTHIMP | 0 | 1,448 | (1,448) | | LINDENVFT | (1,348) | (1,348) | 0 |
| CIN | | (9,628) | (7,487) | (2,142) | MEC | | (3,865) | (4,345) | 480 |
| | IMO | 0 | 347 | (347) | | IMO | 0 | 1 | (1) |
| | MISO | (9,628) | (8,064) | (1,564) | | MISO | (3,865) | (4,349) | 484 |
| | NORTHWEST | 0 | (1) | 1 | | SOUTHEXP | 0 | (5) | 5 |
| | SOUTHEXP | 0 | (12) | 12 | | SOUTHIMP | 0 | 9 | (9) |
| | SOUTHIMP | 0 | 244 | (244) | MECS | | (8,174) | (235) | (7,939) |
| CPLE | | 4,188 | 407 | 3,781 | | IMO | 0 | 388 | (388) |
| | CPLEEXP | 0 | (110) | 110 | | MISO | (8,174) | (1,049) | (7,125) |
| | CPLEIMP | 0 | 74 | (74) | | SOUTHEXP | 0 | (4) | 4 |
| | DUKEXP | 0 | (99) | 99 | | SOUTHIMP | 0 | 430 | (430) |
| | DUKIMP | 0 | 12 | (12) | NEPT | | (4,681) | (4,681) | 0 |
| | NCMPAIMP | 0 | 719 | (719) | | NEPTUNE | (4,681) | (4,681) | 0 |
| | SOUTHEXP | (1,706) | (355) | (1,350) | NIPS | | (8,432) | 7 | (8,439) |
| | SOUTHIMP | 5,894 | 166 | 5,728 | | MISO | (8,432) | 7 | (8,439) |
| CPLW | | (1,310) | 1 | (1,311) | | SOUTHIMP | 0 | 0 | (0) |
| | NCMPAIMP | 0 | 0 | (0) | NYIS | | (3,115) | (2,509) | (606) |
| | SOUTHEXP | (1,369) | 0 | (1,369) | | IMO | 0 | 15 | (15) |
| | SOUTHIMP | 58 | 1 | 58 | | NYIS | (3,115) | (2,523) | (591) |
| CWLP | | (216) | 0 | (216) | OVEC | | 2,392 | (183) | 2,575 |
| | MISO | (216) | 0 | (216) | | OVEC | 2,392 | (183) | 2,575 |
| DUK | | 750 | 1,663 | (912) | TVA | | 6,039 | 592 | 5,447 |
| | DUKEXP | 0 | (310) | 310 | | SOUTHEXP | (1,416) | (993) | (422) |
| | DUKIMP | 0 | 108 | (108) | | SOUTHIMP | 7,454 | 1,585 | 5,869 |
| | NCMPAEXP | 0 | (1) | 1 | WEC | | 9,387 | (1,934) | 11,321 |
| | NCMPAIMP | 0 | 583 | (583) | | IMO | 0 | 0 | (0) |
| | SOUTHEXP | (727) | (565) | (161) | | MISO | 9,387 | (2,104) | 11,491 |
| | SOUTHIMP | 1,477 | 1,847 | (371) | | SOUTHEXP | 0 | (2) | 2 |
| HUDS | | (274) | (274) | 0 | | SOUTHIMP | 0 | 172 | (172) |
| | HUDSONTP | (274) | (274) | 0 | Grand Total | | (23,147) | (22,958) | (189) |

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 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 AMIL Interface (26 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 (-8,064 GWh).

### Table 9-23 Net scheduled and actual PJM flows by interface pricing point and interface (GWh): 2017

| Interface Pricing Point | Interface | Actual | Net Scheduled | Difference (GWh) | Interface Pricing Point | Interface | Actual | Net Scheduled | Difference (GWh) |
|---|---|---|---|---|---|---|---|---|---|
| CPLEEXP | | 0 | (110) | 110 | NCMPAIMP | | 0 | 1,303 | (1,303) |
| | CPLE | 0 | (110) | 110 | | CPLE | 0 | 719 | (719) |
| CPLEIMP | | 0 | 74 | (74) | | CPLW | 0 | 0 | (0) |
| | CPLE | 0 | 74 | (74) | | DUK | 0 | 583 | (583) |
| DUKEXP | | 0 | (409) | 409 | NEPTUNE | | (4,681) | (4,681) | 0 |
| | CPLE | 0 | (99) | 99 | | NEPT | (4,681) | (4,681) | 0 |
| | DUK | 0 | (310) | 310 | NORTHWEST | | 0 | (1) | 1 |
| DUKIMP | | 0 | 120 | (120) | | CIN | 0 | (1) | 1 |
| | CPLE | 0 | 12 | (12) | NYIS | | (3,115) | (2,523) | (591) |
| | DUK | 0 | 108 | (108) | | NYIS | (3,115) | (2,523) | (591) |
| HUDSONTP | | (274) | (274) | 0 | OVEC | | 2,392 | (183) | 2,575 |
| | HUDS | (274) | (274) | 0 | | OVEC | 2,392 | (183) | 2,575 |
| IMO | | 0 | 1,064 | (1,064) | SOUTHEXP | | (11,330) | (2,001) | (9,329) |
| | ALTE | 0 | 223 | (223) | | CIN | 0 | (12) | 12 |
| | ALTW | 0 | 1 | (1) | | CPLE | (1,706) | (355) | (1,350) |
| | CIN | 0 | 347 | (347) | | CPLW | (1,369) | 0 | (1,369) |
| | IPL | 0 | 90 | (90) | | DUK | (727) | (565) | (161) |
| | MEC | 0 | 1 | (1) | | IPL | 0 | (0) | 0 |
| | MECS | 0 | 388 | (388) | | LGEE | (6,113) | (64) | (6,050) |
| | NYIS | 0 | 15 | (15) | | MEC | 0 | (5) | 5 |
| | WEC | 0 | 0 | (0) | | MECS | 0 | (4) | 4 |
| LINDENVFT | | (1,348) | (1,348) | 0 | | TVA | (1,416) | (993) | (422) |
| | LIND | (1,348) | (1,348) | 0 | | WEC | 0 | (2) | 2 |
| MISO | | (29,248) | (22,003) | (7,245) | SOUTHIMP | | 24,457 | 8,015 | 16,442 |
| | ALTE | (4,514) | (5,408) | 895 | | ALTE | 0 | 283 | (283) |
| | ALTW | (1,909) | (0) | (1,908) | | AMIL | 0 | 1,448 | (1,448) |
| | AMIL | (1,112) | 26 | (1,137) | | CIN | 0 | 244 | (244) |
| | CIN | (9,628) | (8,064) | (1,564) | | CPLE | 5,894 | 166 | 5,728 |
| | CWLP | (216) | 0 | (216) | | CPLW | 58 | 1 | 58 |
| | IPL | (787) | (1,061) | 274 | | DUK | 1,477 | 1,847 | (371) |
| | MEC | (3,865) | (4,349) | 484 | | IPL | 0 | 11 | (11) |
| | MECS | (8,174) | (1,049) | (7,125) | | LGEE | 9,574 | 1,820 | 7,754 |
| | NIPS | (8,432) | 7 | (8,439) | | MEC | 0 | 9 | (9) |
| | WEC | 9,387 | (2,104) | 11,491 | | MECS | 0 | 430 | (430) |
| NCMPAEXP | | 0 | (1) | 1 | | NIPS | 0 | 0 | (0) |
| | DUK | 0 | (1) | 1 | | TVA | 7,454 | 1,585 | 5,869 |
| | | | | | | WEC | 0 | 172 | (172) |
| | | | | | Grand Total | | (23,147) | (22,958) | (189) |

## 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.[28]

## 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.[29]

## Actual Tie Line Flow Data

An analysis of loop flow requires knowledge of the actual path of energy transactions. Currently, a very limited set of tie line data is made available via the NERC IDC and the Central Repository for Curtailments (CRC) website. Additionally, the available tie line data, and the data within the IDC, are presented as information on a screen, which does not permit analysis of the underlying data.

## Dynamic Schedule and Pseudo-Tie Data

Dynamic schedule and pseudo ties represent another type of interchange transaction between balancing authorities. While dynamic schedules are required to be tagged, the tagged profile is only an estimate of what energy is expected to flow. Dynamic schedules are implemented within each balancing authority's Energy Management System (EMS), with the current values shared over Inter-Control Center Protocol (ICCP) links. By definition, the dynamic schedule scheduled and actual values will always be identical from a balancing authority standpoint, and the tagged profile should be removed from the calculation of loop flows to eliminate double counting of the energy profile. Dynamic schedule data from all balancing authorities are required in order to account for all scheduled and actual flows.

Pseudo-ties are similar to dynamic schedules in that they represent a transaction between balancing authorities and are handled within the EMS systems and data are shared over the ICCP. Pseudo ties only differ from dynamic schedules in how the generating resource is modeled within the balancing authorities' ACE equations. Dynamic schedules are modeled as resources located in one area serving load in another, while pseudo ties are modeled as resources in one area moved to another area. Unlike dynamic schedules, pseudo tie transactions are not required to be tagged. Pseudo tie data from all balancing authorities are required in order to account for all scheduled and actual flows.

## Area Control Error (ACE) Data

Area Control Error (ACE) data provides information about how well each balancing authority is matching their generation with their load. This information, combined with the scheduled and actual interchange values will show whether an individual balancing authority is pushing on or leaning on the interconnection, contributing to loop flows.

NERC makes real-time ACE graphs available on their Reliability Coordinator Information System (RCIS) website. This information is presented only in graphical form, and the underlying data is not available for analysis.

28 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.

29 141 FERC ¶ 61,235 (2012). *Availability of E-Tag Information to Commission Staff.*

### Market Flow Impact Data

In addition to interchange transactions, internal dispatch can also affect flows on balancing authorities' tie lines. The impact of internal dispatch on tie lines is called market flow. Market flow data are imported in the IDC, but there is only limited historical data, as only market flow data related to TLR levels 3 or higher are required to be made available via a Congestion Management Report (CMR). The remaining data are deleted.

There is currently a project in development through the NERC Operating Reliability Subcommittee (ORS) called the Market Flow Impact Tool. The purpose of this tool is to make visible the impacts of dispatch on loop flows. The MMU supports the development of this tool, and requests that FERC and NERC ensure that the underlying data are provided to market monitors and other approved entities.

### Generation and Load Data

Generation data (both real-time scheduled generation and actual output) and load data would permit analysis of the extent to which balancing authorities are meeting their commitments to serve load. If a balancing authority is not meeting its load commitment with adequate generation, the result is unscheduled flows across the interconnections to establish power balance.

Market areas are transparent in providing real-time load while 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 recommends, 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.[30]

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

30 See "LMP Aggregate Definitions," (December 20, 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>.

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. On June 1, 2017, MISO modified their MISO/PJM interface definition to match PJM's PJM/MISO interface definition.

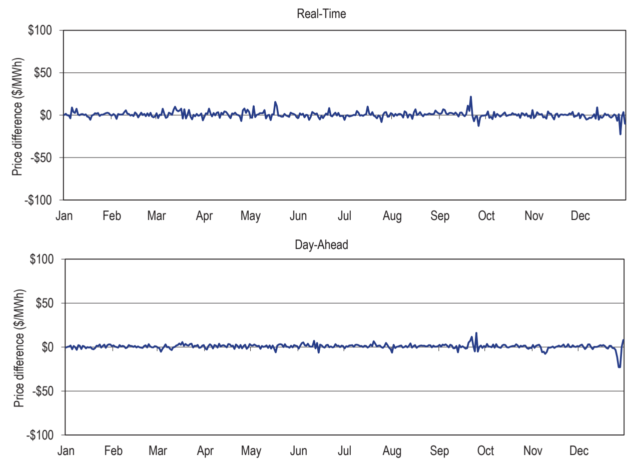
## Real-Time and Day-Ahead PJM/MISO Interface Prices

In 2017, the direction of flow was consistent with price differentials in 56.9 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 9-30).

Table 9-24 PJM and MISO flow based hours and average hourly price differences: 2017

| LMP Difference | Flow Direction | Number of Hours | Average Hourly Price Difference |
|---|---|---|---|
| MISO/PJM LMP > PJM/MISO LMP | Total Hours | 4,987 | $4.91 |
| | Consistent Flow (PJM to MISO) | 4,983 | $4.90 |
| | Inconsistent Flow (MISO to PJM) | 4 | $9.76 |
| | No Flow | 0 | $0.00 |
| PJM/MISO LMP > MISO/PJM LMP | Total Hours | 3,773 | $5.25 |
| | Consistent Flow (MISO to PJM) | 2 | $0.65 |
| | Inconsistent Flow (PJM to MISO) | 3,771 | $5.25 |
| | 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): 2017



## Distribution and Prices of Hourly Flows at the PJM/MISO Interface

In 2017, the direction of hourly energy flows was consistent with PJM and MISO interface price differentials in 4,985 hours (56.9 percent of all hours), and was inconsistent with price differentials in 3,772 hours (43.1 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 3,772 hours where flows were in a direction inconsistent with price differences, 2,755 of those hours (73.0 percent) had a price difference greater than or equal to $1.00 and 1,045 of those hours (27.7 percent) had a price difference greater than or equal to $5.00. The largest price difference with such flows was $210.03. Of the 4,985 hours where flows were consistent with price differences, 3,787 of those hours (76.0 percent) had a price difference greater than or equal to $1.00 and 1,097 of all such hours (22.0 percent) had a price difference greater than or equal to $5.00. The largest price difference with such flows was $298.16.

### Table 9-25 Distribution of hourly flows that are consistent and inconsistent with price differences between PJM and MISO: 2017

| Price Difference Range (Greater Than or Equal To) | Inconsistent Hours | Percent of Inconsistent Hours | Consistent Hours | Percent of Consistent Hours |
|---|---|---|---|---|
| $0.00 | 3,772 | 100.0% | 4,985 | 100.0% |
| $1.00 | 2,755 | 73.0% | 3,787 | 76.0% |
| $5.00 | 1,045 | 27.7% | 1,097 | 22.0% |
| $10.00 | 512 | 13.6% | 496 | 9.9% |
| $15.00 | 297 | 7.9% | 281 | 5.6% |
| $20.00 | 190 | 5.0% | 193 | 3.9% |
| $25.00 | 136 | 3.6% | 137 | 2.7% |
| $50.00 | 27 | 0.7% | 47 | 0.9% |
| $75.00 | 10 | 0.3% | 28 | 0.6% |
| $100.00 | 4 | 0.1% | 14 | 0.3% |
| $200.00 | 2 | 0.1% | 2 | 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% |

## Distribution and Prices of Hourly Flows at the PJM/MISO Interface After June 1, 2017, MISO/PJM Interface Pricing Point Modification

MISO modified the definition of the MISO/PJM Interface, to match the existing PJM/MISO Interface, effective June 1, 2017. The new interface definition includes ten equally weighted buses that are close to the PJM/MISO border. In the seven months of operation under the new interface pricing definition, the direction of hourly energy flows was consistent with PJM and MISO interface price differentials in 2,769 of the 5,134 hours (53.9 percent of all hours), and was inconsistent with price differentials in 2,365 of the 5,134 hours (46.1 percent of all hours). Table 9-26 shows the distribution of hourly energy flows between PJM and MISO based on the price differences between the PJM/MISO and MISO/PJM prices from June 1, 2017, through December 31, 2017. Of the 2,365 hours where flows were in a direction inconsistent with price differences, 1,742 of those hours (73.7 percent) had a price difference greater than or equal to $1.00 and 675 of those hours (28.5 percent) had a price difference greater than or equal to $5.00. The largest price difference with such flows was $210.03. Of the 2,769 hours where flows were consistent with price differences, 2,075 of those hours (74.9 percent) had a price difference greater than or equal to $1.00 and 585 of all such hours (21.1 percent) had a price difference greater than or equal to $5.00. The largest price difference with such flows was $298.16.

### Table 9-26 Distribution of hourly flows that are consistent and inconsistent with price differences between PJM and MISO: June 1 through December 31, 2017

| Price Difference Range (Greater Than or Equal To) | Inconsistent Hours | Percent of Inconsistent Hours | Consistent Hours | Percent of Consistent Hours |
|---|---|---|---|---|
| $0.00 | 2,365 | 100.0% | 2,769 | 100.0% |
| $1.00 | 1,742 | 73.7% | 2,075 | 74.9% |
| $5.00 | 675 | 28.5% | 585 | 21.1% |
| $10.00 | 338 | 14.3% | 263 | 9.5% |
| $15.00 | 184 | 7.8% | 142 | 5.1% |
| $20.00 | 119 | 5.0% | 101 | 3.6% |
| $25.00 | 88 | 3.7% | 74 | 2.7% |
| $50.00 | 19 | 0.8% | 29 | 1.0% |
| $75.00 | 10 | 0.4% | 19 | 0.7% |
| $100.00 | 4 | 0.2% | 10 | 0.4% |
| $200.00 | 2 | 0.1% | 2 | 0.1% |
| $300.00 | 0 | 0.0% | 0 | 0.0% |
| $400.00 | 0 | 0.0% | 0 | 0.0% |
| $500.00 | 0 | 0.0% | 0 | 0.0% |

## PJM and NYISO Interface Prices

If interface prices were defined in a comparable manner by PJM and the NYISO, if identical rules governed external transactions in PJM and the NYISO, if time lags were not built into the rules governing such transactions and if no risks were associated with such transactions, then prices at the interfaces would be expected to be very close and the level of transactions would be expected to be related to any price differentials. The fact that none of these conditions exists is important in explaining the observed relationship between interface prices and inter-RTO/ISO power flows, and those price differentials.[31]

PJM and NYISO each calculate an interface LMP using network models including distribution factor impacts. Prior to May 1, 2017, PJM used two buses within NYISO to calculate the PJM/NYIS interface pricing point LMP. The NYISO uses proxy buses to calculate interface prices with neighboring balancing authorities. A proxy bus is a single bus, located outside the NYISO footprint, which represents generation and load in a neighboring balancing authority area. The NYISO models imports from PJM as generation at the Keystone proxy bus, delivered to the NYISO reference bus with the assumption that 32 percent of the flow will enter the NYISO across the free flowing A/C ties, 32 percent will enter the NYISO across the Ramapo PARs, 21 percent will enter the NYISO across the ABC PARs and 15 percent will enter the NYISO across the J/K PARs. The NYISO models exports to PJM as being delivered to load at the Keystone proxy bus, sourced from the NYISO reference bus with the assumption that 32 percent of the flow will enter PJM across the free flowing A/C ties, 32 percent will enter PJM across the Ramapo PARs, 21 percent will enter PJM across the ABC PARs and 15 percent will enter PJM across the J/K PARs.

The PJM/NYIS interface definition using two buses was created to include the impact of the ConEd wheeling agreement. The ConEd wheeling agreement ended on May 1, 2017. The end of the wheeling agreement meant that the expected actual power flows would change and therefore the definition of the interface price needed to change. Effective May 1, 2017, PJM replaced the old PJM/NYIS interface price definition. The new PJM/NYIS interface price is based on four buses within NYISO. The four buses were chosen based on a power flow analysis of transfers between PJM and the NYISO and the resultant distribution of flows across the free flowing A/C ties.

### Real-Time and Day-Ahead PJM/NYISO Interface Prices

In 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 52.2 percent of the hours in 2017. Table 9-27 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 9-30).

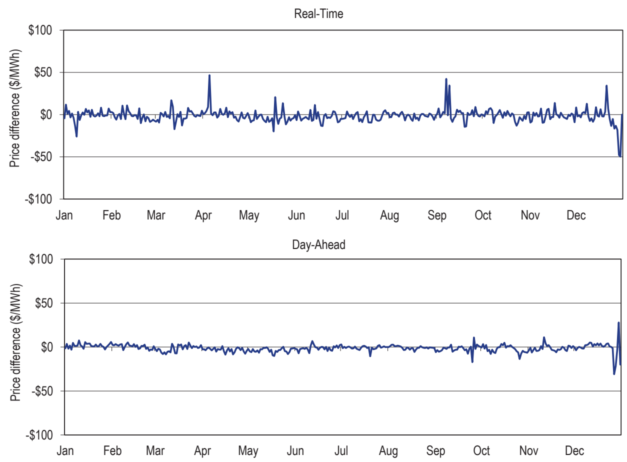
31 See the *2012 State of the Market Report for PJM*, Volume2, Section 8, "Interchange Transactions," for a more detailed discussion.

Table 9-27 PJM and NYISO flow based hours and average hourly price differences: 2017[32]

| LMP Difference | Flow Direction | Number of Hours | Average Hourly Price Difference |
|---|---|---|---|
| NYIS/PJM proxy bus LBMP > PJM/NYIS LMP | Total Hours | 3,424 | $10.62 |
| | Consistent Flow (PJM to NYIS) | 2,743 | $10.80 |
| | Inconsistent Flow (NYIS to PJM) | 681 | $9.92 |
| | No Flow | 0 | $0.00 |
| PJM/NYIS LMP > NYIS/PJM proxy bus LBMP | Total Hours | 5,336 | $9.11 |
| | Consistent Flow (NYIS to PJM) | 1,829 | $8.33 |
| | Inconsistent Flow (PJM to NYIS) | 3,507 | $9.51 |
| | No Flow | 0 | $0.00 |

Figure 9-5 Real-time and day-ahead daily hourly average price difference (NY/PJM proxy - PJM/NYIS Interface): 2017




## Distribution and Prices of Hourly Flows at the PJM/NYISO Interface

In 2017, the direction of hourly energy flows was consistent with PJM/NYISO and NYISO/PJM price differences in 4,572 hours (52.2 percent of all hours), and was inconsistent with price differences in 4,185 hours (47.8 percent of all hours). Table 9-28 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 4,185 hours where flows were in a direction inconsistent with price differences, 3,662 of those hours (87.5 percent) had a price difference greater than or equal to $1.00 and 2,022 of all those hours (48.3 percent) had a price difference greater than or equal to $5.00. The largest price difference with such flows was $332.18. Of the 4,572 hours where flows were consistent with price differences, 4,004 of those hours (87.6 percent) had a price difference greater than or equal to $1.00 and 2,146 of all such hours (46.9 percent) had a price difference greater than or equal to $5.00. The largest price difference with such flows was $970.61.

Table 9-28 Distribution of hourly flows that are consistent and inconsistent with price differences between PJM and NYISO: 2017

| Price Difference Range (Greater Than or Equal To) | Inconsistent Hours | Percent of Inconsistent Hours | Consistent Hours | Percent of Consistent Hours |
|---|---|---|---|---|
| $0.00 | 4,185 | 100.0% | 4,572 | 100.0% |
| $1.00 | 3,662 | 87.5% | 4,004 | 87.6% |
| $5.00 | 2,022 | 48.3% | 2,146 | 46.9% |
| $10.00 | 1,010 | 24.1% | 1,078 | 23.6% |
| $15.00 | 617 | 14.7% | 586 | 12.8% |
| $20.00 | 411 | 9.8% | 405 | 8.9% |
| $25.00 | 319 | 7.6% | 301 | 6.6% |
| $50.00 | 113 | 2.7% | 123 | 2.7% |
| $75.00 | 55 | 1.3% | 58 | 1.3% |
| $100.00 | 31 | 0.7% | 41 | 0.9% |
| $200.00 | 6 | 0.1% | 14 | 0.3% |
| $300.00 | 2 | 0.0% | 6 | 0.1% |
| $400.00 | 0 | 0.0% | 4 | 0.1% |
| $500.00 | 0 | 0.0% | 2 | 0.0% |

## Distribution and Prices of Hourly Flows at the PJM/NYIS Interface After May 1, 2017, PJM/NYIS Interface Pricing Point Modification

PJM modified the definition of the PJM/NYIS Interface effective May 1, 2017. In the first eight months of operation under the new interface pricing definition, the direction of hourly energy flows was consistent with PJM and NYIS interface price differentials in 3,121 of the 5,878 hours (53.1 percent of all hours), and was inconsistent with price differentials in 2,757 of the 5,878 hours (46.9 percent of all hours). Table 9-29 shows the distribution of hourly energy flows between PJM and NYIS based on the price differences between the PJM/

32 The NYISO Locational Based Marginal Price (LBMP) is the equivalent term to PJM's Locational Marginal Price (LMP).

NYIS and NYIS/PJM prices from May 1, 2017 through December 31, 2017. Of the 2,757 hours where flows were in a direction inconsistent with price differences, 2,403 of those hours (87.2 percent) had a price difference greater than or equal to $1.00 and 1,301 of those hours (47.2 percent) had a price difference greater than or equal to $5.00. The largest price difference with such flows was $332.18. Of the 3,121 hours where flows were consistent with price differences, 2,754 of those hours (88.2 percent) had a price difference greater than or equal to $1.00 and 1,507 of all such hours (48.3 percent) had a price difference greater than or equal to $5.00. The largest price difference with such flows was $968.99.

#### Table 9-29 Distribution of hourly flows that are consistent and inconsistent with price differences between PJM and NYIS: May 1 through December 31, 2017

| Price Difference Range (Greater Than or Equal To) | Inconsistent Hours | Percent of Inconsistent Hours | Consistent Hours | Percent of Consistent Hours |
|---|---|---|---|---|
| $0.00 | 2,757 | 100.0% | 3,121 | 100.0% |
| $1.00 | 2,403 | 87.2% | 2,754 | 88.2% |
| $5.00 | 1,301 | 47.2% | 1,507 | 48.3% |
| $10.00 | 664 | 24.1% | 760 | 24.4% |
| $15.00 | 414 | 15.0% | 410 | 13.1% |
| $20.00 | 278 | 10.1% | 277 | 8.9% |
| $25.00 | 218 | 7.9% | 198 | 6.3% |
| $50.00 | 89 | 3.2% | 83 | 2.7% |
| $75.00 | 47 | 1.7% | 40 | 1.3% |
| $100.00 | 28 | 1.0% | 28 | 0.9% |
| $200.00 | 6 | 0.2% | 11 | 0.4% |
| $300.00 | 2 | 0.1% | 5 | 0.2% |
| $400.00 | 0 | 0.0% | 3 | 0.1% |
| $500.00 | 0 | 0.0% | 1 | 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 9-30, including average prices and measures of variability.

#### Table 9-30 PJM, NYISO and MISO real-time and day-ahead border price averages: 2017

| | | Real-Time | | Day-Ahead | |
|---|---|---|---|---|---|
| | Description | NYISO | MISO | NYISO | MISO |
| Average Hourly Price | PJM Price at ISO Border | $28.80 | $26.80 | $28.78 | $27.05 |
| | ISO Price at PJM Border | $27.40 | $27.34 | $27.51 | $27.72 |
| | Difference at Border (PJM-ISO) | $1.40 | ($0.54) | $1.27 | ($0.67) |
| | Average Absolute Value of Hourly Difference at Border | $9.70 | $5.05 | $3.72 | $2.56 |
| | Sign Changes per Day | 6.2 | 7 | 3.4 | 3.8 |
| Standard Deviation | PJM Price at ISO Border | $21.89 | $13.97 | $13.65 | $8.90 |
| | ISO Price at PJM Border | $26.85 | $15.65 | $12.93 | $8.33 |
| | Difference at Border (PJM-ISO) | $26.16 | $12.14 | $5.97 | $4.26 |

## 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 59.7 percent of the hours in 2017. Table 9-31 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 9-31 PJM and NYISO flow based hours and average hourly price differences (Neptune): 2017

| LMP Difference | Flow Direction | Number of Hours | Average Hourly Price Difference |
|---|---|---|---|
| NYIS/Neptune Bus LBMP > PJM/NEPT LMP | Total Hours | 5,278 | $14.83 |
| | Consistent Flow (PJM to NYIS) | 5,226 | $14.84 |
| | Inconsistent Flow (NYIS to PJM) | 0 | $0.00 |
| | No Flow | 52 | $14.11 |
| PJM/NEPT LMP > NYIS/Neptune Bus LBMP | Total Hours | 3,482 | $8.76 |
| | Consistent Flow (NYIS to PJM) | 0 | $0.00 |
| | Inconsistent Flow (PJM to NYIS) | 3,428 | $8.76 |
| | No Flow | 54 | $9.00 |

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").[33] The PJM Out Service is covered by normal PJM OASIS business operations.[34] The Neptune Service falls under the provisions for controllable merchant facilities, Schedule 14 of the PJM Tariff. The Neptune Service is also acquired on the PJM OASIS.

Neptune Service is owned by a primary rights holder, and any 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 December 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.

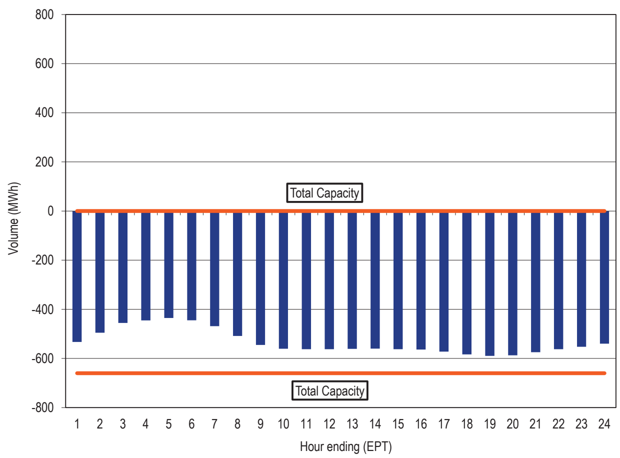
Table 9-32 shows the percent of scheduled interchange across the Neptune Line by the primary rights holder since commercial operations began in July, 2007. Table 9-32 shows that in 2017, the primary rights holder was responsible for 100 percent of the scheduled interchange across the Neptune Line in all months. Figure 9-6 shows the hourly average flow across the Neptune Line for 2017.

33 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>.
34 See OASIS "Regional Transmission and Energy Scheduling Practices," (October 3, 2017) <http://www.pjm.com/~/media/etools/oasis/regional-practices-clean-pdf.ashx>.

Table 9-32 Percent of scheduled interchange across the Neptune line by primary rights holder: July 1, 2007 through December 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% | 100.00% |
| May | NA | 100.00% | 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% | 100.00% |
| July | 100.00% | 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% | 100.00% |
| September | 100.00% | 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% | 100.00% |
| November | 100.00% | 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% | 100.00% |

Figure 9-6 Neptune hourly average flow: 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 53.5 percent of the hours in 2017. Table 9-33 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 9-33 PJM and NYISO flow based hours and average hourly price differences (Linden): 2017

| LMP Difference | Flow Direction | Number of Hours | Average Hourly Price Difference |
|---|---|---|---|
| NYIS/Linden Bus LBMP > PJM/LIND LMP | Total Hours | 4,849 | $11.16 |
| | Consistent Flow (PJM to NYIS) | 4,683 | $10.96 |
| | Inconsistent Flow (NYIS to PJM) | 0 | $0.00 |
| | No Flow | 166 | $16.86 |
| PJM/LIND LMP > NYIS/Linden Bus LBMP | Total Hours | 3,911 | $10.47 |
| | Consistent Flow (NYIS to PJM) | 0 | $0.00 |
| | Inconsistent Flow (PJM to NYIS) | 3,874 | $10.46 |
| | No Flow | 37 | $12.03 |

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").[35] The PJM Out Service is covered by normal PJM OASIS business operations.[36] 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.

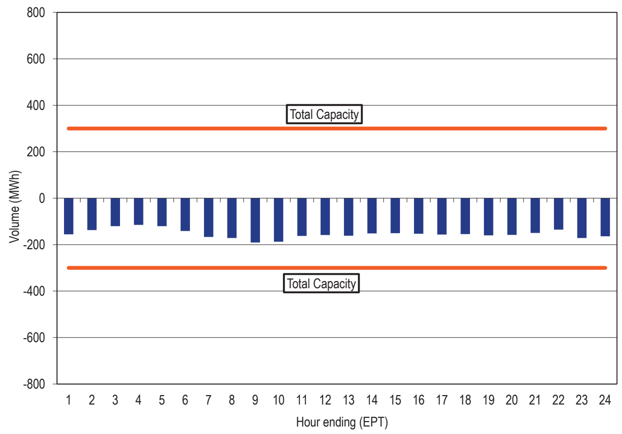
Linden VFT Service is owned by a primary rights holder, and any nonfirm service that is not used (as defined by a schedule on a NERC Tag) may be released either voluntarily by the primary rights holder or by default by PJM. The primary rights holder may elect to voluntarily release monthly, weekly, daily 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 December 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 released service unless a second transmission customer acquires the released service.

### Table 9-34 Percent of scheduled interchange across the Linden VFT Line by primary rights holder: November 1, 2009 through December 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% | 100.00% |
| May | NA | 100.00% | 100.00% | 100.00% | 100.00% | 100.00% | 100.00% | 100.00% | 100.00% |
| June | NA | 100.00% | 100.00% | 100.00% | 100.00% | 27.27% | 100.00% | 100.00% | 100.00% |
| July | NA | 100.00% | 100.00% | 100.00% | 100.00% | 29.56% | 100.00% | 100.00% | 100.00% |
| August | NA | 100.00% | 100.00% | 100.00% | 100.00% | 82.46% | 100.00% | 100.00% | 100.00% |
| September | NA | 100.00% | 100.00% | 100.00% | 100.00% | 81.68% | 100.00% | 100.00% | 100.00% |
| October | NA | 100.00% | 100.00% | 100.00% | 100.00% | 100.00% | 35.05% | 100.00% | 100.00% |
| November | 100.00% | 100.00% | 100.00% | 100.00% | 99.86% | 100.00% | 61.45% | 100.00% | 100.00% |
| December | 100.00% | 100.00% | 100.00% | 98.22% | 100.00% | 100.00% | 84.57% | 100.00% | 100.00% |

Table 9-34 shows the percent of scheduled interchange across the Linden VFT Line by the primary rights holder since commercial operations began in November, 2009. Table 9-34 shows that in 2017, the primary rights holder was responsible for 100 percent of the scheduled interchange across the Linden VFT Line in all months. Figure 9-7 shows the hourly average flow across the Linden VFT Line for 2017.

### Figure 9-7 Linden hourly average flow: 2017[37]




35 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>.

36 See OASIS "Regional Transmission and Energy Scheduling Practices," (October 3, 2017) <http://www.pjm.com/~/media/etools/oasis/regional-practices-clean-doc.ashx>.

37 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.

## 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 (Con Ed) 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 9.0 percent of the hours in 2017. Table 9-35 shows the number of hours and average hourly price differences between the PJM/HUDS Interface and the NYIS/Hudson bus based on LMP differences and flow direction.

### Table 9-35 PJM and NYISO flow based hours and average hourly price differences (Hudson): 2017[38]

| LMP Difference | Flow Direction | Number of Hours | Average Hourly Price Difference |
|---|---|---|---|
| NYIS/Hudson Bus LBMP > PJM/HUDS LMP | Total Hours | 4,721 | $11.24 |
| | Consistent Flow (PJM to NYIS) | 792 | $15.25 |
| | Inconsistent Flow (NYIS to PJM) | 0 | $0.00 |
| | No Flow | 3,929 | $10.43 |
| PJM/HUDS LMP > NYIS/Hudson Bus LBMP | Total Hours | 4,039 | $10.69 |
| | Consistent Flow (NYIS to PJM) | 0 | $0.00 |
| | Inconsistent Flow (PJM to NYIS) | 513 | $25.74 |
| | No Flow | 3,523 | $8.50 |

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").[39] The PJM Out Service is covered by normal PJM OASIS business operations.[40] 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 December 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 9-36 shows the percent of scheduled interchange across the Hudson Line by the primary rights holder since commercial operations began in May, 2013. Table 9-36 shows that in 2017, the primary rights holder was responsible for 80.12 percent and 21.93 percent of the scheduled interchange across the Hudson line in November and December. There was no scheduled interchange across the Hudson Line in the remaining months of 2017. Figure 9-8 shows the hourly average flow across the Hudson Line for 2017.

### Table 9-36 Percent of scheduled interchange across the Hudson Line by primary rights holder: May 1, 2013 through December 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 | NA |
| May | 100.00% | 26.87% | 100.00% | 100.00% | NA |
| June | 100.00% | 5.89% | 59.72% | 100.00% | NA |
| July | 100.00% | 18.51% | 84.34% | NA | NA |
| August | 100.00% | 75.17% | 65.48% | NA | NA |
| September | 100.00% | 75.31% | 78.73% | NA | NA |
| October | 100.00% | 99.71% | 18.65% | 100.00% | NA |
| November | 85.57% | 99.60% | 24.67% | 100.00% | 80.12% |
| December | 28.32% | 1.68% | 100.00% | NA | 21.93% |

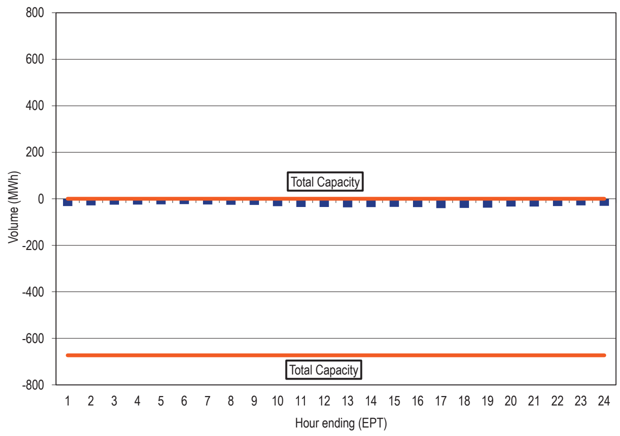
38 The Hudson line was out of service for all hours in the first nine months of 2017. In the first nine months of 2017, there were five hours with less than 1 MW of unscheduled flow across the Hudson line.

39 See OASIS "PJM Business Practices for Hudson Transmission Service,"<http://www.pjm.com/~/media/etools/oasis/merch-trans-facilities/htp-Business-practices.ashx>.

40 See OASIS "Regional Transmission and Energy Scheduling Practices," (October 3, 2017) <http://www.pjm.com/~/media/etools/oasis/regional-practices-clean-doc.ashx>.

Figure 9-8 Hudson hourly average flow: 2017




## Interchange Activity During High Load Hours

The PJM metered system peak load during 2017 was 142,387 MW in the HE 1700 on July 19, 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 July 2017, PJM was a net scheduled exporter of energy in all hours. During July, 2017, the average hourly scheduled exports were 3,440 MW (representing 3.4 percent of the average hourly load of 99,787 MW in July 2017). PJM was a net exporter of energy in all hours on July 19, 2017, with average hourly scheduled exports of -3,781 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 9-37 shows a summary of the elements included in each of the operating agreements PJM has with its bordering areas.

Table 9-37 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[41]

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.[42]

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. Prior to June 1, 2017, MISO used all of the PJM generator buses in its model of the PJM system in its calculation of the MISO/PJM interface pricing point.[43] On June 1, 2017, MISO modified their MISO/PJM interface definition to match PJM's PJM/MISO interface definition.[44]

An operating entity is an entity that operates and controls a portion of the bulk transmission system with the goal of ensuring reliable energy interchange between generators, loads and other operating entities.[45] Coordinated flowgates are identified to determine which flowgates an operating entity impacts significantly. This set of flowgates may then be used in the congestion management process. An operating entity will conduct sensitivity studies to determine which flowgates are significantly impacted by the flows of the operating

41 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>.

42 See "PJM/MISO Joint and Common Market Initiative," <http://www.pjm.com/committees-and-groups/stakeholder-meetings/pjm-miso-joint-common.aspx>.

43 See the *2012 State of the Market Report for PJM*, Volume 2, Section 8, "Interchange Transactions," for a more detailed discussion.

44 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>.

45 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>.

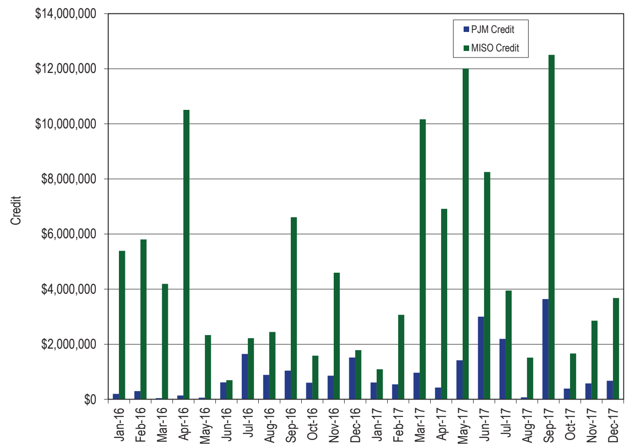
entity's control zones (historic control areas that existed in the IDC). An operating entity identifies these flowgates by performing five studies to determine which flowgates the operating entity will monitor and help control. These studies include generation to load distribution factor studies, transfer distribution factor analysis and an external asynchronous resource study. An operating entity may also specify additional flowgates that have not passed any of the five studies to be coordinated flowgates where the operating entity expects to use the TLR process to manage congestion.[46] 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 2017, PJM added 23 flowgates and deleted 33 flowgates, leaving 140 flowgates eligible for M2M coordination as of December 31, 2017. As of January 1, 2017, MISO had 261 flowgates eligible for M2M coordination. In 2017, MISO added 122 flowgates and deleted 149 flowgates, leaving 234 flowgates eligible for M2M coordination as of December 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 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.

46 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>.

### Figure 9-9 Credits for coordinated congestion management: 2016 and 2017[47]




## PJM and New York Independent System Operator Joint Operating Agreement (JOA)[48]

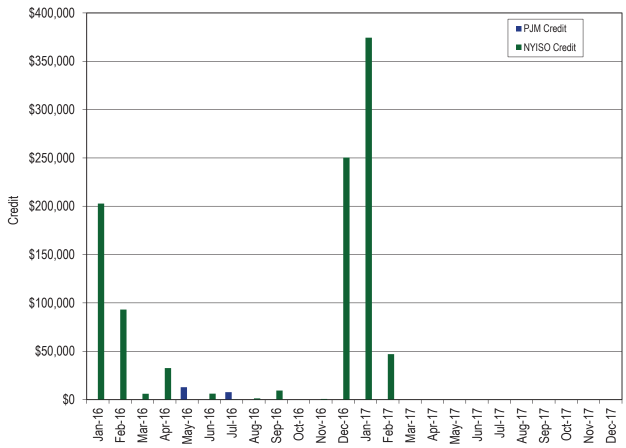
The Joint Operating Agreement between NYISO and PJM Interconnection, L.L.C. became effective on January 15, 2013. Under the market to market rules, the organizations coordinate pricing at their borders.

In 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.

47 The totals represented in this figure represent the settlements as of the time of this report and may not include adjustments or resettlements.

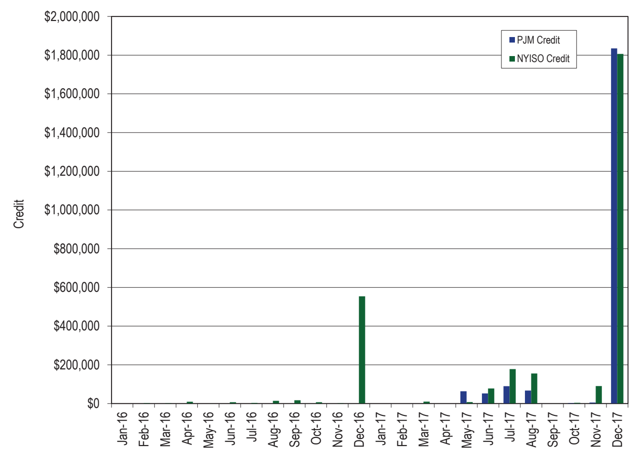
48 See "New York Independent System Operator, Inc., Joint Operating Agreement with PJM Interconnection, L.L.C.," (June 21, 2017) <http://www.pjm.com/~/media/documents/agreements/nyiso-joa.ashx>.

**Figure 9-10 Credits for coordinated congestion management (flowgates): 2016 and 2017[49]**




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 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 PAR settlement will occur for each interval during coordinated operations. The PAR settlements are determined based on whether the measured real-time flow on each of the 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. Effective May 1, 2017, coincident with the termination of the ConEd wheel, PJM and NYISO began M2M coordination at all of the PARs along the PJM/NYISO seam. Prior to May 1, 2017, only the Ramapo PARs were included in the M2M process. In 2017, PAR settlements resulted in monthly payments from PJM to NYISO. Figure 9-11 shows the PAR credits for coordinated congestion management between PJM and NYISO. The large increase in PAR credits in December was due to system operations coordination during the extreme temperatures in the final week of 2017. While there were significant coordination credits in December, the net result was a credit to PJM from the NYISO of only $28,514.

**Figure 9-11 Credits for coordinated congestion management (PARs): 2016 and 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

49 The totals represented in this figure represent the settlements as of the time of this report and may not include adjustments or resettlements.

50 See "New York Independent System Operator, Inc., Joint Operating Agreement with PJM Interconnection, L.L.C.," (June 21, 2017) <http://www.pjm.com/~/media/documents/agreements/nyiso-joa.ashx>.

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>.

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 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 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.

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

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).

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.

output of the modeled units are often insufficient to cover the reported real-time load, and therefore no units are considered marginal. When this occurs, the MMU believes that the CPLEIMP and CPLEEXP pricing points should revert to the SOUTHIMP and SOUTHEXP interface prices, but this has not happened. When this occurs, PJM uses the high-low interface pricing method as described in Section 2.6A (1) of the PJM Tariff. The MMU does not believe that this is appropriate, and does not see the basis for this approach in either the PJM Tariff or the PJM/DEP JOA.

On July 2, 2012, Duke Energy and Progress Energy Inc. completed a merger. While the individual companies planned to operate separately for a period of time, they have a joint dispatch agreement, and a joint open access transmission tariff.[56] On October 3, 2014, Duke Energy Progress (DEP) and PJM submitted revisions to the JOA to include a new Appendix B, update references to DEP's current legal name, and incorporate other revisions.[57] The MMU submitted a protest to this filing noting that the existing JOA depends on the specific characteristics of PEC as a standalone company, and the assumptions reflected in the current JOA no longer apply under the DEP joint dispatch agreement.[58] As noted in the 2010 filing, "the terms and conditions of the bilateral agreement among PEC and PJM are grounded in an appreciation of their systems as they exist at the time of the effective date of the JOA, but they fully expect that evolving circumstances, protocols and requirements will require that they negotiate, in good faith, a response to such changes."[59] The joint dispatch agreement changed the unique operational relationship that existed when the congestion management protocol was established. However, the merged company has not engaged in discussions with PJM as to whether the congestion management protocol that was "tailored to their [PJM and PEC] unique operational relationship" is still appropriate, or whether the congestion management protocol needs to be revised. The existing JOA does not apply to the merged company and should be terminated.

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.

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 2017, DEP acquired the required transmission service in only 997 of the 8,760 hours (11.4 percent of all hours), with an average capacity of approximately 145 MW. At most, DEP could have increased their generation to help manage constraints via a sale of power to PJM 11.4 percent of the time in 2017, and the maximum redispatch would have been only 145 MW, on average.

A CMA that can only be used in 11.4 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), DEP, 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 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 2017.

## 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 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 CPLEIMP and CPLEEXP 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 9-38 shows the real-time LMP calculated per the PJM/DEP JOA and the high/low pricing method used by Duke and NCMPA for 2017. The values shown in Table 9-38 are the average LMP over only the hours in 2017, where interchange transactions settled at those pricing points. The difference between the LMP under these agreements and PJM's SouthIMP LMP ranged from -$0.41 with NCMPA to -$0.14 with PEC.[64] This means that under the specific interface pricing agreements NCMPA would receive, on average, $0.41 less for importing energy into PJM than if they were to receive the SouthIMP pricing point. In 2017, market participants received $455,271 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 $0.23 with Duke to $5.78 with NCMPA. This means that under the specific interface pricing agreements NCMPA would pay, on average, $5.78 more for exporting energy from PJM than they would have if they were to pay the SouthEXP pricing point. In 2017, market participants paid $413,775 more for exporting energy using these pricing points than they would have if they were to have paid the SouthEXP pricing point.

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>.

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.

Table 9-38 Real-time average hourly LMP comparison for Duke, PEC and NCMPA: 2017

| | Import LMP | Export LMP | SOUTHIMP | SOUTHEXP | Difference IMP LMP - SOUTHIMP | Difference EXP LMP - SOUTHEXP |
|---|---|---|---|---|---|---|
| Duke | $32.34 | $25.38 | $32.66 | $25.14 | ($0.31) | $0.23 |
| PEC | $32.65 | $31.89 | $32.79 | $30.25 | ($0.14) | $1.63 |
| NCMPA | $25.82 | $36.97 | $26.22 | $31.19 | ($0.41) | $5.78 |

Table 9-39 shows the day-ahead LMP calculated per the PJM/DEP JOA and the high/low pricing method used by Duke and NCMPA for 2017. The values shown in Table 9-39 are the average LMP over only the hours in 2017, where interchange transactions settled at those pricing points. The difference between the LMP under these agreements and PJM's SouthIMP LMP ranged from -$0.01 with Duke to $0.52 with PEC. This means that under the specific interface pricing agreements PEC would receive, on average, $0.52 more for importing energy into PJM than if they were to receive the SouthIMP pricing point. In 2017, market participants received $69,048 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 $0.86 with NCMPA to $1.23 with Duke. This means that under the specific interface pricing agreements Duke would pay, on average, $1.23 more for exporting energy from PJM than if they were to pay the SouthEXP pricing point. In 2017, market participants paid $253,154 more for exporting energy using these pricing points than they would have if they were to have paid the SouthEXP pricing point.

Table 9-39 Day-ahead average hourly LMP comparison for Duke, PEC and NCMPA: 2017

| | Import LMP | Export LMP | SOUTHIMP | SOUTHEXP | Difference IMP LMP - SOUTHIMP | Difference EXP LMP - SOUTHEXP |
|---|---|---|---|---|---|---|
| Duke | $35.06 | $35.81 | $35.07 | $34.58 | ($0.01) | $1.23 |
| PEC | $29.23 | $31.72 | $28.71 | $30.86 | $0.52 | $0.86 |
| NCMPA | $27.83 | $33.79 | $27.81 | $32.64 | $0.01 | $1.15 |

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 OATT.[67] By order issued September 16, 2010, the Commission approved this settlement, which extended Con Edison's special protocol indefinitely.[68] The Commission approved transmission service agreements that provided for Con Edison to take firm point-to-point service going forward under the 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

65 See the *2017 State of the Market Report for PJM*, 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 2, 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).

was 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 modeled 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).

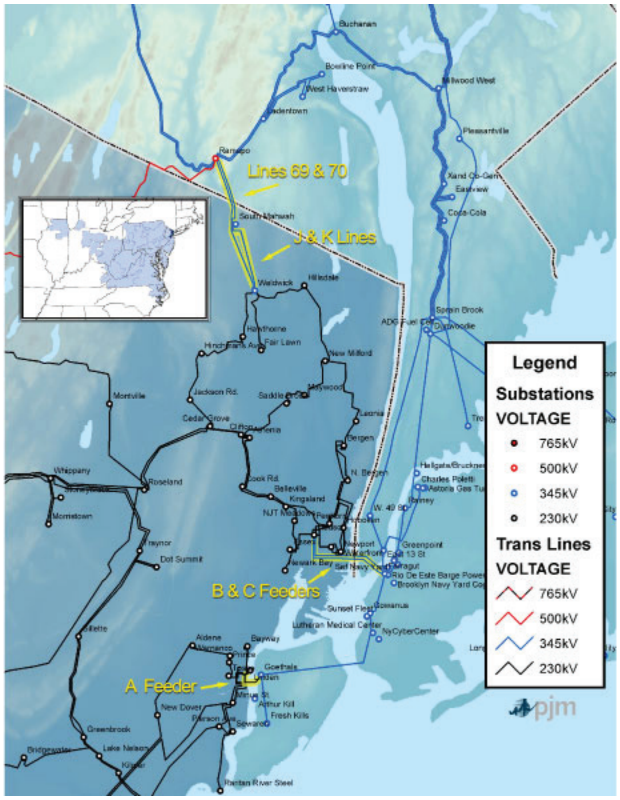
On April 28, 2016, Con Edison announced its intent to terminate its 1,000 MW long-term firm point-to-point transmission service, effective May 1, 2017. Upon termination of the transmission reservation, the Con Edison protocol would also be terminated. On October 4, 2016, the NYISO and PJM issued a draft 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 included 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 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. On May 1, 2017, the Con Edison protocol was terminated and the new protocol, as described in the December 19, 2016, "Con Ed/PSEG Wheel Replacement Proposal" was implemented.[72]

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>.

72 *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>.

Figure 9-12 Con Edison Protocol




## Interchange Transaction Issues

### Hudson Transmission Partners (HTP) and Linden VFT Requests to Convert Firm Transmission Withdrawal Rights (FTWR) to Non Firm Transmission Withdrawal Rights (NFTWR)

In 2014, cost allocations for RTEP projects included the Bergen-Linden Corridor (BLC) project. PSEG explained:

> [The BLC project] is designed to replace the existing 138kV transmission system from Bergen to Linden with a double circuit 345kV transmission system. PJM determined that this new transmission system is necessary to ensure reliable electric service, eliminate anticipated transmission constraints, and respond to PJM/Federal Energy Regulatory Commission (FERC)-mandated infrastructure expansion. The project will eliminate electric system capacity issues in Northern New Jersey, providing better power quality in the region.

Using the solution-based DFAX cost allocation method, PJM initially allocated BLC's estimated costs: $720 million to Con Edison; $103 million to HTP; $10 million to Linden VFT; no costs to Neptune; and $88 million to PSEG. To avoid its share of the cost allocation, Con Edison elected to terminate its 1,000 MW of long-term firm transmission service (the Con Ed Wheel) effective April 30, 2017. PJM reallocated the costs: $634 million to HTP; $132 million to Linden VFT; and the remaining $128 million to PSEG. The Commission denied complaints about the cost allocation, ruling that PJM applied the Commission accepted regional cost allocation method.

In June 2017, HTP and Linden separately initiated the process to amend their interconnection service agreements to reflect the conversion of FTWRs to NFTWRs in an apparent effort to avoid paying their allocated share of the RTEP cost allocations. On June 2, 2017, HTP sent a letter to PJM and PSEG requesting that their original Interconnection Service Agreement (ISA) be amended to reflect the conversion of their 320 MW of FTWRs to NFTWRs. On June 22, 2017, PSEG notified PJM and HTP that it did not agree to the ISA amendment. Because PSEG did not agree to the amendment to the ISA, HTP requested that PJM file an unexecuted amended interconnection service agreement with the Commission to convert their FTWRs to NFTWRs. Similarly, at the request of Linden VFT, PJM also filed an unexecuted amended ISA to convert their FTWRs to NFTWRs.[73] On September 8, 2017, the Commission rejected the amended ISA and instituted a proceeding "to examine the justness and reasonableness of HTP being unable to convert its Firm Transmission Withdrawal Rights to Non-Firm Transmission Withdrawal Rights." On December 15, 2017, the Commission found that the exiting HTP and Linden ISA's are unjust and unreasonable insofar as they do not permit HTP and Linden to convert their FTWRs to NFTWRs and ordered PJM to amend the existing ISA's to reflect the conversion of FTWRs to NFTWRs.[74] [75] On January 19, 2018, PJM filed amended Schedule 12 Appendix and Appendix A revisions reflecting the Commissions orders eliminating the Linden and HTP cost responsibility assignments for RTEP projects with an effective date of January 1, 2018.[76]

Linden has requested PJM long-term firm transmission through the long-term firm queue. PJM's Initial Study Long-Term Firm Transmission Service notes:

> … For the purpose of this study, and as requested by the Customer, PJM assumed FERC approval to amend the pre-existing Linden VFT Interconnection Service Agreements (Queue # U2-077 and W1-001) and resulting termination of the associated firm rights.

Linden has requested that PJM provide an initial study with the assumption that FERC approves the termination of their FTWRs. Linden VFT apparently expects to maintain the ability to export capacity to NYISO from PJM with the same level of transmission service level they currently have under the FTWR construct while avoiding payment of their RTEP cost allocations. Linden VFT has obtained assurance from NYISO that NFTWRs in conjunction with firm point to point transmission service from PJM to the Linden VFT point of delivery, will allow Linden VFT to continue to export capacity from PJM to NYISO exactly as they did with FTWRs.

HTP has, to date, only requested conversion of its FTWRs to NFTWRs. Neptune was not allocated any RTEP costs and has not requested a change in service.

The claim that Linden and/or HTP could use NFTWRs in conjunction with firm point-to-point transmission to continue to export capacity from PJM to NYISO while avoiding RTEP costs is not correct.

Section 232.2 of the OATT states: (emphasis added):

> … A Transmission Interconnection Customer that is granted Firm Transmission Withdrawal Rights <u>and/or transmission customers that have a Point of Delivery at the Border of PJM where the Transmission System interconnects with the Merchant D.C.</u> Transmission Facilities may be responsible for a reasonable allocation of transmission upgrade costs added to the Regional Transmission Expansion Plan after such Transmission Interconnection Customer's

73 See *PJM Interconnection, L.L.C*, Docket No. ER17-2267-000 (August 9, 2017).

74 161 FERC ¶ 62,242 (2017). *Order requiring PJM to permit conversion of firm to non-firm transmission withdrawal rights under interconnection service agreement.*

75 161 FERC ¶ 62,264 (2017). *Order granting complaint, in part.*

76 See *PJM Interconnection, L.L.C* Docket No. ER18-680-000 (January 19, 2018).

> Queue Position is established, in accordance with Section 3E and Schedule 12 of the Tariff…

Section 232.2 of the OATT explicitly requires the same RTEP cost allocation when a transmission customer has FTWRs and when a transmission customer has "a Point of Delivery at the Border of PJM where the Transmission System interconnects with the Merchant D.C. Transmission Facilities." That is the situation here. Linden is structured as a controllable AC line which is functionally the same as a DC tie line. Identical treatment of RTEP costs is appropriate because the service is the same. Linden, if it relinquishes it's FTWRs and instead uses firm point-to-point transmission service from PJM to the Linden VFT point of delivery and NFTWRs across the Linden VFT Line, would have the same service before and after the change. These two methods would be appropriately treated the same under Section 232.2, and HTP, if it follows Linden VFT's approach also would be treated the same.

With the conversion of HTP's and Linden's FTWRs to NFTWRs, any acquisition of long-term firm point-to-point transmission service from PJM to the point of interconnection with their DC tie line, HTP and/or Linden should continue to be assigned a portion of the RTEP cost responsibilities. But such assignment requires modification to Schedule 12 of the OATT to include the options defined in Section 232.2. Once Schedule 12 is modified, HTP and/or Linden would become eligible to export capacity from PJM to the NYISO over their DC tie lines. Section 232.2 of the PJM Tariff combined with the NYISO deliverability requirements for capacity imports makes this explicit.

It would not be reasonable or consistent with economic logic to permit HTP and/or Linden to retain the same capacity export service with a different name and avoid an allocation of RTEP costs.

## 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 nine in 2016 to six in 2017.[77] The number of different flowgates for which PJM declared a TLR 3a or higher increased from one in 2016 to three in 2017. The total MWh of transactions curtailed decreased by 87.8 percent from 107,291 MWh in 2016 to 13,059 MWh in 2017.

The number of MISO issued TLRs of level 3a or higher decreased from 77 in 2016 to 75 in 2017. The number of different flowgates for which MISO declared a TLR 3a or higher increased from 22 in 2016 to 25 in 2017. The total MWh of transaction curtailments decreased by 43.6 percent from 127,785 MWh in 2016 to 72,069 MWh in 2017.

The number of NYISO issued TLRs of level 3a or higher was one in 2016 and one in 2017. The number of different flowgates for which NYISO declared a TLR 3a or higher was one in 2016 and one in 2017. The total MWh of transaction curtailments decreased by 100.0 percent from 217 MWh in 2016 to 0 MWh in 2017.

77 TLR Level 3a is the first level of TLR that results in the curtailment of transactions. See the *2017 State of the Market Report for PJM*, Volume II, Appendix E, "Interchange Transactions," for a more complete discussion of TLR levels.

## Table 9-40 PJM MISO, and NYISO TLR procedures: 2014 through 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 |
| Apr-17 | 0 | 10 | 0 | 0 | 7 | 0 | 0 | 16,422 | 0 |
| May-17 | 0 | 11 | 0 | 0 | 8 | 0 | 0 | 7,292 | 0 |
| Jun-17 | 0 | 13 | 0 | 0 | 6 | 0 | 0 | 8,576 | 0 |
| Jul-17 | 0 | 0 | 1 | 0 | 0 | 1 | 0 | 0 | 0 |
| Aug-17 | 0 | 3 | 0 | 0 | 2 | 0 | 0 | 2,449 | 0 |
| Sep-17 | 0 | 4 | 0 | 0 | 3 | 0 | 0 | 6,439 | 0 |
| Oct-17 | 1 | 12 | 0 | 1 | 7 | 0 | 763 | 9,089 | 0 |
| Nov-17 | 0 | 2 | 0 | 0 | 2 | 0 | 0 | 806 | 0 |
| Dec-17 | 2 | 2 | 0 | 2 | 2 | 0 | 6,156 | 2,221 | 0 |

Table 9-41 Number of TLRs by TLR level by reliability coordinator: 2017[78]

| Year | Reliability Coordinator | 3a | 3b | 4 | 5a | 5b | 6 | Total |
|---|---|---|---|---|---|---|---|---|
| 2017 | MISO | 42 | 16 | 0 | 10 | 7 | 0 | 75 |
| | NYIS | 1 | 0 | 0 | 0 | 0 | 0 | 1 |
| | ONT | 6 | 0 | 0 | 0 | 0 | 0 | 6 |
| | PJM | 4 | 2 | 0 | 0 | 0 | 0 | 6 |
| | SOCO | 1 | 4 | 0 | 0 | 0 | 0 | 5 |
| | SWPP | 34 | 4 | 0 | 54 | 19 | 0 | 111 |
| | TVA | 13 | 11 | 0 | 2 | 5 | 0 | 31 |
| | VACS | 3 | 3 | 0 | 0 | 0 | 0 | 6 |
| Total | | 104 | 40 | 0 | 66 | 31 | 0 | 241 |

## 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.[79]

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.

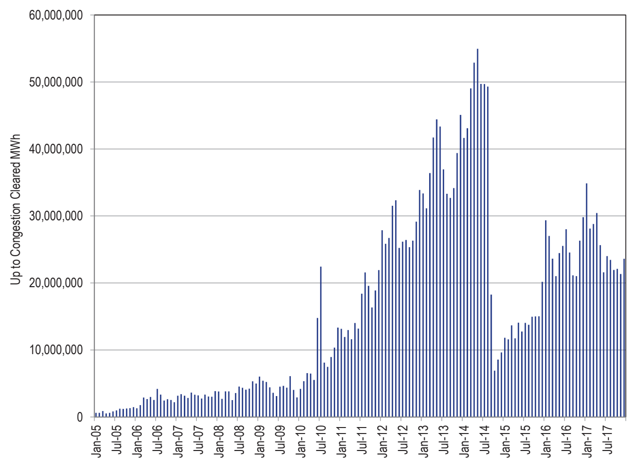
Up to congestion transactions impact the day-ahead dispatch and unit commitment. Despite that, up to congestion transactions do not pay operating reserves charges. Up to congestion transactions also negatively affect FTR funding.[80]

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.[81]

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..."[82]

The average number of up to congestion bids submitted in the Day-Ahead Energy Market decreased by 11.2 percent, from 156,021 bids per day in 2016 to 138,489 bids per day in 2017. The average cleared volume of up to congestion bids submitted in the Day-Ahead Energy Market increased by 1.2 percent, from 824,885 MWh per day in 2016, to 838,258 MWh per day in 2017.

Figure 9-13 Monthly up to congestion cleared bids in MWh: 2005 through 2017




78 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.

79 See the *2012 State of the Market Report for PJM*, Volume II, Section 8, "Interchange Transactions," for a more detailed discussion.

80 See the *2017 State of the Market Report for PJM*, Section 13: FTRs and ARRs, "FTR Forfeitures" for more information on up to congestion transaction impacts on FTRs.

81 148 FERC ¶ 61,144 (2014).

82 16 U.S.C. § 824e.

Table 9-42 Monthly volume of cleared and submitted up to congestion bids: 2016 and 2017[83]

| | 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 |
| Apr-17 | 8,427,340 | 9,544,151 | 576,134 | 91,517,521 | 110,065,146 | 243,246 | 286,654 | 28,526 | 3,777,591 | 4,336,017 |
| May-17 | 6,914,185 | 5,793,561 | 532,000 | 73,575,991 | 86,815,737 | 210,223 | 210,292 | 21,746 | 3,246,035 | 3,688,296 |
| Jun-17 | 5,490,865 | 6,038,899 | 632,947 | 68,528,243 | 80,690,953 | 194,713 | 191,222 | 20,606 | 3,077,217 | 3,483,758 |
| Jul-17 | 6,613,969 | 6,050,326 | 639,026 | 74,941,744 | 88,245,065 | 203,947 | 198,230 | 19,463 | 3,378,819 | 3,800,459 |
| Aug-17 | 6,749,590 | 6,674,135 | 718,858 | 77,129,276 | 91,271,858 | 191,589 | 188,708 | 11,951 | 3,374,088 | 3,766,336 |
| Sep-17 | 6,762,933 | 6,905,161 | 652,672 | 72,767,743 | 87,088,509 | 172,092 | 169,393 | 11,818 | 2,831,072 | 3,184,375 |
| Oct-17 | 6,477,119 | 7,030,028 | 638,955 | 73,263,143 | 87,409,245 | 182,695 | 210,191 | 11,980 | 3,125,553 | 3,530,419 |
| Nov-17 | 6,961,973 | 6,561,240 | 642,567 | 65,378,670 | 79,544,452 | 217,415 | 195,059 | 13,324 | 2,947,507 | 3,373,305 |
| Dec-17 | 7,586,123 | 6,516,890 | 711,886 | 69,995,034 | 84,809,933 | 231,328 | 175,164 | 15,744 | 3,110,890 | 3,533,126 |
| TOTAL | 1,437,661,645 | 1,357,080,960 | 93,236,624 | 5,116,127,145 | 8,004,106,374 | 38,008,497 | 32,042,928 | 2,496,645 | 202,398,503 | 274,946,573 |

In 2017, the cleared MW volume of up to congestion transactions was comprised of 7.3 percent imports, 6.8 percent exports, 0.5 percent wheeling transactions and 85.4 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.[84] As of September 30, 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 (NOPR) was issued to address UTC uplift for all RTOs/ISOs.[85] The outcome of the investigation in PJM will be held in abeyance pending the outcome of the NOPR proceeding.[86]

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 9-43 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.

83 See the *2017 State of the Market Report for PJM*, Volume 2, Appendix E, "Interchange Transactions," for the monthly volume of cleared and submitted up to congestion bids: 2009 through 2017.
84 148 FERC ¶ 61,144 (2014).
85 158 FERC ¶ 61,047.
86 158 FERC ¶ 61,038 at P 3 (2017).

### Table 9-42 Monthly volume of cleared and submitted up to congestion bids: 2016 and 2017 (continued)

| | 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 |
| Apr-17 | 2,507,486 | 2,351,550 | 176,621 | 25,401,805 | 30,437,462 | 81,365 | 93,895 | 6,981 | 1,435,787 | 1,618,028 |
| May-17 | 1,716,363 | 1,564,608 | 126,693 | 22,243,327 | 25,650,992 | 70,481 | 70,024 | 5,163 | 1,314,020 | 1,459,688 |
| Jun-17 | 1,572,832 | 1,428,776 | 135,513 | 18,460,280 | 21,597,400 | 62,478 | 61,569 | 3,893 | 1,168,823 | 1,296,763 |
| Jul-17 | 1,546,229 | 1,546,263 | 113,165 | 20,816,061 | 24,021,719 | 60,457 | 68,847 | 3,371 | 1,262,370 | 1,395,045 |
| Aug-17 | 1,177,158 | 1,746,210 | 100,492 | 20,420,033 | 23,443,893 | 58,192 | 75,898 | 3,032 | 1,299,202 | 1,436,324 |
| Sep-17 | 1,632,026 | 1,379,580 | 102,737 | 18,835,214 | 21,949,558 | 66,178 | 54,143 | 3,205 | 1,129,589 | 1,253,115 |
| Oct-17 | 1,482,374 | 1,616,248 | 139,924 | 18,871,489 | 22,110,035 | 65,586 | 85,126 | 4,400 | 1,286,807 | 1,441,919 |
| Nov-17 | 1,455,401 | 1,549,254 | 136,025 | 18,205,565 | 21,346,245 | 65,423 | 76,099 | 5,231 | 1,187,848 | 1,334,601 |
| Dec-17 | 1,698,478 | 1,484,766 | 149,340 | 20,282,749 | 23,615,331 | 61,703 | 66,518 | 5,843 | 1,187,420 | 1,321,484 |
| TOTAL | 470,434,477 | 446,217,497 | 29,636,209 | 1,414,314,529 | 2,360,602,712 | 14,246,339 | 12,071,565 | 833,471 | 75,069,409 | 102,220,784 |

### Table 9-43 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.[87]

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.[88]

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.

## Sham Scheduling

Sham scheduling refers to a scheduling method under which a market participant breaks a single transaction, from generation balancing authority (source) to load balancing authority (sink), into multiple segments. Sham scheduling hides the actual source of generation from the load balancing authority. When unable to identify the source of the energy, the load balancing authority 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).

Sham scheduling can also be achieved by submitting a transaction that is in the opposite direction of a portion of a larger transaction schedule.

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

87 16 U.S.C. § 824e.
88 See OATT Attachment Q § I.A.4.

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.[89]

The MMU believes that the new PJM/IMO interface price method is a step in the right direction towards pricing energy that sources or sinks in Ontario based on the path of the actual, physical transfer of energy. The MMU remains concerned about the assumption of PAR operations, and will continue to evaluate the impact of PARs on the scheduled and actual flows and the impacts on the PJM/IMO interface price. The MMU remains concerned about the potential for market participants to continue to engage in sham scheduling activities after the new method is implemented.

The MMU recommends that if the PJM/IMO interface price remains and with PJM's new method in place, that PJM implement additional business rules to remove the incentive to engage in sham scheduling activities using the PJM/IMO interface price. Such rules would prohibit the same market participant from scheduling an export

89 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>.

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 2017, of the 1,064 GWh of the gross scheduled transactions between PJM and IESO, 1,050 GWh (98.7 percent) wheeled through MISO (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.[90]

## 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.[91] The evaluation is based on the forward-looking prices as determined by PJM's intermediate term security constrained economic dispatch tool (ITSCED) and the NYISO's real-time commitment (RTC) tool. PJM shares its PJM/NYISO interface price ITSCED results with the NYISO. The NYISO compares the PJM/NYISO interface price with its RTC calculated NYISO/PJM interface price. If the PJM and NYISO interface price spread is greater than the market participant's CTS bid, the transaction is approved. If the PJM and NYISO interface price spread is less than the CTS bid, the transaction is denied.

The ITSCED application runs approximately every five minutes and each run produces forecast LMPs for the intervals approximately 30 minutes, 45 minutes, 90 minutes and 135 minutes ahead. Therefore, for each 15 minute interval, the various ITSCED solutions will produce 12 forecasted PJM/NYIS interface prices. To evaluate the accuracy of ITSCED forecasts, the forecasted PJM/NYIS interface price for each 15 minute interval from ITSCED was compared to the actual real-time interface LMP for 2017. Table 9-44 shows that over all 12 forecast ranges, ITSCED predicted the real-time PJM/NYIS interface LMP within the range of $0.00 to $5.00 in 36.7 percent of the intervals. In those intervals, the average price difference between the ITSCED forecasted LMP and the actual real-time LMP was $1.63 per MWh. In 6.5 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 $72.87 when the price difference was greater than $20.00, and $74.64 when the price difference was greater than -$20.00.

### Table 9-44 Differences between forecast and actual PJM/NYIS interface prices: 2017

| Range of Price Differences | Percent of All Intervals | Average Price Difference |
|---|---|---|
| > $20 | 2.6% | $72.87 |
| $10 to $20 | 3.8% | $13.71 |
| $5 to $10 | 7.0% | $7.05 |
| $0 to $5 | 36.7% | $1.63 |
| $0 to -$5 | 37.6% | $1.57 |
| -$5 to -$10 | 5.4% | $6.98 |
| -$10 to -$20 | 2.9% | $14.04 |
| < -$20 | 3.9% | $74.64 |

Table 9-45 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 74.0 percent of all intervals, the average price difference between the ITSCED forecasted LMP and the actual real-time interface LMP fell within +/- $5.00 of the actual PJM/NYIS interface real-time LMP, compared to 73.7 percent in the 135 minute ahead ITSCED results.

90 On October 1, 2013, a sub-group of PJM's Market Implementation Committee started stakeholder discussions to address this inconsistency in market pricing.
91 PJM and the NYISO implemented CTS on November 4, 2014. 146 FERC ¶ 61,096 (2014).

### Table 9-45 Differences between forecast and actual PJM/NYIS interface prices: 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 | 1.8% | $52.45 | 1.7% | $54.30 | 1.8% | $63.58 | 4.4% | $69.55 |
| $10 to $20 | 3.5% | $13.64 | 3.6% | $13.57 | 3.6% | $13.68 | 4.3% | $13.82 |
| $5 to $10 | 6.4% | $7.08 | 7.3% | $7.03 | 6.8% | $7.03 | 7.5% | $7.06 |
| $0 to $5 | 30.8% | $1.70 | 39.1% | $1.67 | 40.5% | $1.57 | 39.8% | $1.57 |
| $0 to -$5 | 42.9% | $1.74 | 36.2% | $1.54 | 36.0% | $1.45 | 34.2% | $1.45 |
| -$5 to -$10 | 6.9% | $7.00 | 5.5% | $6.94 | 4.9% | $6.99 | 4.2% | $6.99 |
| -$10 to -$20 | 3.5% | $13.94 | 2.8% | $14.09 | 2.6% | $14.16 | 2.3% | $14.04 |
| < -$20 | 4.2% | $83.75 | 4.0% | $66.85 | 3.8% | $66.75 | 3.3% | $68.10 |

In 7.7 percent of the intervals in the 30 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 $69.55 when the price difference was greater than $20.00, and $68.10 when the price difference was greater than -$20.00.

Table 9-46 and Table 9-47 show the monthly differences between forecasted and actual PJM/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 9-46 Monthly Differences between forecast and actual PJM/NYIS interface prices (percent of intervals): 2017

| Interval | Range of Price Differences | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | YTD Avg |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ~ 30 Minutes Prior to Real-Time | > $20 | 4.8% | 1.3% | 4.6% | 4.8% | 4.3% | 4.0% | 3.0% | 3.8% | 7.1% | 6.3% | 5.3% | 2.9% | 4.4% |
| | $10 to $20 | 3.6% | 1.2% | 5.4% | 3.9% | 4.9% | 4.0% | 4.9% | 4.7% | 7.1% | 5.8% | 4.5% | 1.4% | 4.3% |
| | $5 to $10 | 5.5% | 4.1% | 8.6% | 9.0% | 8.3% | 5.5% | 9.2% | 9.5% | 12.1% | 9.9% | 5.8% | 1.9% | 7.5% |
| | $0 to $5 | 47.8% | 50.6% | 41.1% | 44.0% | 40.6% | 45.1% | 43.1% | 46.8% | 42.0% | 37.0% | 28.8% | 11.4% | 39.8% |
| | $0 to -$5 | 31.0% | 37.2% | 31.2% | 31.3% | 32.6% | 33.2% | 32.2% | 29.7% | 23.7% | 31.4% | 44.8% | 52.5% | 34.2% |
| | -$5 to -$10 | 3.1% | 2.9% | 2.7% | 3.5% | 5.2% | 4.2% | 2.6% | 2.2% | 3.8% | 4.4% | 4.8% | 11.2% | 4.2% |
| | -$10 to -$20 | 1.3% | 1.5% | 2.8% | 1.9% | 1.6% | 2.2% | 2.1% | 1.5% | 1.4% | 2.6% | 2.9% | 5.9% | 2.3% |
| | < -$20 | 3.1% | 1.2% | 3.5% | 1.6% | 2.4% | 1.7% | 2.9% | 1.8% | 2.8% | 2.6% | 3.0% | 12.8% | 3.3% |
| Interval | Range of Price Differences | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | YTD Avg |
| ~ 45 Minutes Prior to Real-Time | > $20 | 1.4% | 0.1% | 1.1% | 1.4% | 1.1% | 1.7% | 0.7% | 1.3% | 4.0% | 3.1% | 3.1% | 2.3% | 1.8% |
| | $10 to $20 | 2.9% | 0.7% | 2.8% | 3.1% | 4.3% | 3.0% | 3.5% | 3.8% | 7.0% | 5.4% | 4.9% | 1.5% | 3.6% |
| | $5 to $10 | 4.6% | 2.7% | 7.5% | 7.7% | 8.2% | 6.0% | 7.8% | 8.7% | 11.2% | 9.9% | 5.5% | 1.9% | 6.8% |
| | $0 to $5 | 44.7% | 48.3% | 42.3% | 45.9% | 43.0% | 44.4% | 45.2% | 48.4% | 41.9% | 38.6% | 30.9% | 13.3% | 40.5% |
| | $0 to -$5 | 36.8% | 41.4% | 33.4% | 32.8% | 33.5% | 35.4% | 34.0% | 30.9% | 26.5% | 31.7% | 43.0% | 53.1% | 36.0% |
| | -$5 to -$10 | 4.3% | 3.5% | 5.3% | 4.6% | 5.5% | 4.6% | 2.9% | 3.2% | 3.6% | 5.3% | 5.8% | 9.5% | 4.9% |
| | -$10 to -$20 | 1.6% | 1.7% | 3.2% | 2.4% | 1.7% | 2.3% | 2.3% | 1.8% | 2.4% | 3.1% | 2.9% | 5.5% | 2.6% |
| | < -$20 | 3.7% | 1.6% | 4.5% | 2.1% | 2.7% | 2.6% | 3.6% | 1.9% | 3.4% | 2.9% | 3.8% | 13.0% | 3.8% |
| Interval | Range of Price Differences | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | YTD Avg |
| ~ 90 Minutes Prior to Real-Time | > $20 | 1.1% | 0.0% | 0.8% | 1.1% | 1.4% | 1.4% | 1.0% | 1.3% | 3.1% | 3.4% | 3.0% | 2.3% | 1.7% |
| | $10 to $20 | 2.2% | 0.8% | 3.0% | 3.1% | 5.2% | 3.2% | 3.5% | 3.6% | 7.2% | 5.7% | 4.3% | 1.4% | 3.6% |
| | $5 to $10 | 3.2% | 3.1% | 7.7% | 8.7% | 8.9% | 6.8% | 8.1% | 9.0% | 13.6% | 9.4% | 6.3% | 2.1% | 7.3% |
| | $0 to $5 | 37.8% | 43.7% | 39.7% | 46.5% | 42.8% | 43.8% | 43.8% | 44.8% | 39.1% | 39.5% | 31.0% | 16.7% | 39.1% |
| | $0 to -$5 | 44.1% | 43.8% | 34.5% | 31.2% | 31.0% | 34.4% | 34.8% | 33.5% | 26.3% | 29.7% | 41.6% | 50.0% | 36.2% |
| | -$5 to -$10 | 4.9% | 4.8% | 6.4% | 5.0% | 6.2% | 5.0% | 2.8% | 3.6% | 4.5% | 6.0% | 6.9% | 9.4% | 5.5% |
| | -$10 to -$20 | 2.8% | 2.2% | 3.3% | 2.2% | 1.7% | 2.7% | 2.3% | 2.1% | 2.4% | 3.0% | 3.2% | 5.2% | 2.8% |
| | < -$20 | 3.9% | 1.6% | 4.7% | 2.2% | 2.7% | 2.8% | 3.6% | 2.0% | 3.9% | 3.2% | 3.8% | 12.8% | 4.0% |
| Interval | Range of Price Differences | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | YTD Avg |
| ~ 135 Minutes Prior to Real-Time | > $20 | 1.5% | 0.2% | 2.0% | 0.8% | 1.1% | 1.3% | 1.6% | 1.7% | 2.5% | 3.3% | 2.6% | 3.2% | 1.8% |
| | $10 to $20 | 1.6% | 1.3% | 4.2% | 1.7% | 2.9% | 3.7% | 3.7% | 5.1% | 6.2% | 5.1% | 4.8% | 1.3% | 3.5% |
| | $5 to $10 | 4.4% | 3.9% | 6.9% | 5.0% | 5.9% | 5.4% | 8.9% | 8.9% | 11.5% | 8.0% | 5.7% | 2.4% | 6.4% |
| | $0 to $5 | 33.3% | 40.6% | 32.8% | 29.2% | 28.2% | 29.6% | 29.2% | 37.3% | 33.3% | 34.3% | 26.5% | 16.3% | 30.8% |
| | $0 to -$5 | 46.9% | 45.3% | 37.4% | 48.6% | 45.6% | 45.0% | 45.6% | 37.0% | 31.9% | 35.9% | 45.5% | 49.7% | 42.9% |
| | -$5 to -$10 | 5.2% | 4.6% | 8.1% | 8.0% | 9.7% | 7.6% | 4.6% | 5.4% | 6.3% | 6.4% | 7.6% | 9.0% | 6.9% |
| | -$10 to -$20 | 3.2% | 2.3% | 3.8% | 4.2% | 3.4% | 4.1% | 2.6% | 2.6% | 3.4% | 3.5% | 3.2% | 5.2% | 3.5% |
| | < -$20 | 3.9% | 1.7% | 4.7% | 2.6% | 3.2% | 3.3% | 3.7% | 2.0% | 5.0% | 3.5% | 4.1% | 12.9% | 4.2% |

### Table 9-47 Monthly differences between forecast and actual PJM/NYIS interface prices (average price difference): 2017

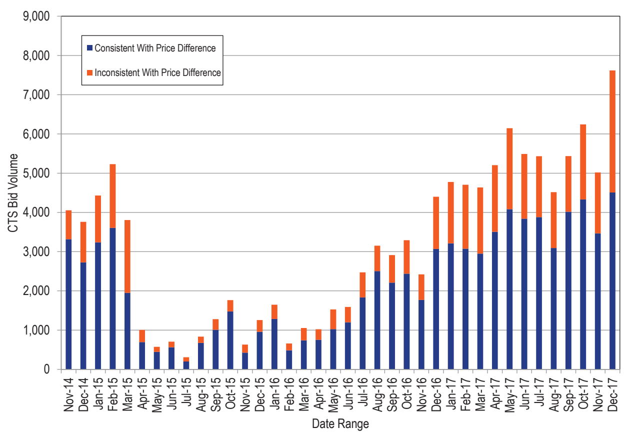
| Interval | Range of Price Differences | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | YTD Avg |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ~ 30 Minutes Prior to Real-Time | > $20 | $63.36 | $38.03 | $70.05 | $69.83 | $53.05 | $41.12 | $57.35 | $47.21 | $140.30 | $55.03 | $59.67 | $77.00 | $69.55 |
| | $10 to $20 | $13.96 | $12.85 | $13.90 | $14.17 | $13.91 | $13.49 | $13.96 | $13.43 | $13.93 | $13.70 | $13.79 | $14.59 | $13.82 |
| | $5 to $10 | $6.99 | $7.03 | $7.01 | $7.05 | $7.13 | $7.00 | $7.12 | $7.11 | $7.19 | $7.03 | $6.81 | $7.07 | $7.06 |
| | $0 to $5 | $1.20 | $1.24 | $1.58 | $1.66 | $1.69 | $1.65 | $1.57 | $1.61 | $1.89 | $1.87 | $1.43 | $1.51 | $1.57 |
| | $0 to -$5 | $1.07 | $1.12 | $1.48 | $1.39 | $1.48 | $1.38 | $1.26 | $1.37 | $1.45 | $1.54 | $1.45 | $2.03 | $1.45 |
| | -$5 to -$10 | $6.92 | $7.14 | $6.72 | $7.30 | $6.95 | $6.60 | $6.89 | $7.06 | $7.02 | $7.04 | $7.04 | $7.05 | $6.99 |
| | -$10 to -$20 | $13.76 | $13.84 | $14.60 | $14.17 | $13.92 | $14.33 | $14.62 | $13.44 | $14.10 | $13.77 | $13.99 | $13.85 | $14.04 |
| | < -$20 | $48.79 | $61.42 | $61.04 | $49.11 | $60.04 | $45.27 | $49.75 | $36.99 | $94.25 | $65.23 | $67.71 | $85.60 | $68.10 |
| Interval | Range of Price Differences | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | YTD Avg |
| ~ 45 Minutes Prior to Real-Time | > $20 | $129.62 | $27.09 | $39.66 | $51.24 | $37.14 | $45.77 | $50.51 | $36.92 | $114.48 | $49.31 | $38.73 | $53.14 | $63.58 |
| | $10 to $20 | $13.93 | $13.48 | $13.42 | $13.01 | $13.53 | $13.54 | $13.84 | $13.47 | $13.45 | $13.97 | $14.32 | $14.02 | $13.68 |
| | $5 to $10 | $6.94 | $6.85 | $7.11 | $7.03 | $7.04 | $6.94 | $7.00 | $7.01 | $6.97 | $7.04 | $7.20 | $7.33 | $7.03 |
| | $0 to $5 | $1.16 | $1.22 | $1.54 | $1.61 | $1.67 | $1.66 | $1.59 | $1.69 | $1.90 | $1.84 | $1.48 | $1.42 | $1.57 |
| | $0 to -$5 | $1.09 | $1.21 | $1.49 | $1.40 | $1.56 | $1.44 | $1.39 | $1.41 | $1.54 | $1.52 | $1.46 | $1.80 | $1.45 |
| | -$5 to -$10 | $7.05 | $7.01 | $6.87 | $7.21 | $6.84 | $6.82 | $6.90 | $6.98 | $7.16 | $7.01 | $7.02 | $7.04 | $6.99 |
| | -$10 to -$20 | $13.89 | $13.71 | $14.01 | $14.15 | $14.49 | $14.94 | $14.66 | $14.78 | $13.10 | $14.31 | $13.54 | $14.34 | $14.16 |
| | < -$20 | $55.02 | $54.95 | $61.58 | $51.42 | $52.98 | $43.12 | $46.48 | $39.67 | $95.92 | $66.93 | $63.88 | $86.05 | $66.75 |
| Interval | Range of Price Differences | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | YTD Avg |
| ~ 90 Minutes Prior to Real-Time | > $20 | $119.08 | $33.83 | $42.81 | $35.65 | $36.34 | $45.91 | $53.87 | $29.38 | $101.99 | $36.85 | $36.99 | $51.48 | $54.30 |
| | $10 to $20 | $12.58 | $13.63 | $13.59 | $13.23 | $13.94 | $13.39 | $13.35 | $13.37 | $13.60 | $13.60 | $14.10 | $14.12 | $13.57 |
| | $5 to $10 | $7.00 | $6.54 | $7.03 | $6.92 | $7.11 | $7.03 | $7.03 | $6.90 | $7.04 | $7.07 | $7.37 | $7.39 | $7.03 |
| | $0 to $5 | $1.26 | $1.35 | $1.61 | $1.73 | $1.74 | $1.77 | $1.71 | $1.79 | $2.04 | $1.85 | $1.54 | $1.39 | $1.67 |
| | $0 to -$5 | $1.30 | $1.39 | $1.61 | $1.53 | $1.70 | $1.63 | $1.53 | $1.49 | $1.69 | $1.51 | $1.51 | $1.71 | $1.54 |
| | -$5 to -$10 | $6.98 | $7.01 | $6.99 | $6.99 | $6.83 | $6.80 | $6.80 | $6.80 | $7.03 | $7.06 | $6.93 | $6.98 | $6.94 |
| | -$10 to -$20 | $14.12 | $13.90 | $13.95 | $13.58 | $13.52 | $14.47 | $14.84 | $14.25 | $13.99 | $14.02 | $14.12 | $14.11 | $14.09 |
| | < -$20 | $56.42 | $59.93 | $60.23 | $50.61 | $56.61 | $45.65 | $47.14 | $37.02 | $79.87 | $69.08 | $67.22 | $88.21 | $66.85 |
| Interval | Range of Price Differences | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | YTD Avg |
| ~ 135 Minutes Prior to Real-Time | > $20 | $106.59 | $28.28 | $34.69 | $38.20 | $44.90 | $40.68 | $43.69 | $32.89 | $96.92 | $38.97 | $36.97 | $57.15 | $52.45 |
| | $10 to $20 | $14.50 | $12.23 | $13.70 | $13.19 | $12.97 | $13.45 | $13.11 | $14.11 | $13.66 | $13.80 | $14.14 | $13.32 | $13.64 |
| | $5 to $10 | $7.33 | $7.14 | $7.12 | $6.83 | $7.15 | $6.99 | $6.98 | $7.09 | $7.15 | $6.88 | $7.24 | $7.23 | $7.08 |
| | $0 to $5 | $1.31 | $1.47 | $1.75 | $1.65 | $1.78 | $1.77 | $1.75 | $1.75 | $2.13 | $1.90 | $1.61 | $1.41 | $1.70 |
| | $0 to -$5 | $1.45 | $1.56 | $1.72 | $1.84 | $1.99 | $1.86 | $1.76 | $1.73 | $1.76 | $1.68 | $1.71 | $1.81 | $1.74 |
| | -$5 to -$10 | $7.06 | $7.18 | $7.08 | $6.92 | $6.95 | $7.05 | $6.62 | $6.75 | $7.20 | $7.10 | $6.92 | $7.10 | $7.00 |
| | -$10 to -$20 | $14.00 | $13.85 | $13.79 | $13.64 | $13.94 | $14.70 | $14.44 | $13.60 | $13.76 | $13.69 | $13.99 | $13.89 | $13.94 |
| | < -$20 | $56.09 | $54.70 | $58.99 | $47.95 | $143.53 | $246.97 | $47.26 | $37.10 | $79.39 | $68.10 | $64.32 | $86.53 | $83.75 |

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 NYISO has a 75 minute bid submission deadline. While market participants have the option to specify bid data on 15 minute intervals, market participants must submit their bids 75 minutes prior to the requested transaction start time. The 75 minute bid submission deadline associated with scheduling energy transactions in the NYISO should be shortened. Reducing this deadline could significantly improve pricing efficiency at the PJM/NYISO border for non-CTS transactions and for CTS transactions as market participants would be able to adjust their bids in response to real-time price signals.

CTS transactions were evaluated for each 15 minute interval. From November 4, 2014, through December 31, 2017, 121,006 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 36,466 (30.1 percent) of the intervals was inconsistent with the differences in real-time PJM/NYISO and NYISO/PJM prices. For example, if a market participant submits a CTS transaction from NYISO to PJM with a spread bid of $5.00, and NYISO's forecasted PJM interface price was at least $5.00 lower than PJM's forecasted NYISO interface price, the transaction would be approved. For 30.1 percent of the approved transactions, the actual, real-time price differentials were in the opposite direction of the forecast differential. The actual, real-time price differentials meant that the transactions would have been economic in the opposite direction. For 69.9 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 December 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. The coordinated transaction scheduling (CTS) proposal will 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.

On February 3, 2017, as amended on February 28, 2017, PJM filed a request to revise the CTS implementation date from March 1, 2017 to October 3, 2017.[92] PJM requested the delay to accommodate the timing of other PJM market system enhancements with the enhancements needed to implement CTS. On March 30, 2017, the Commission approved the new implementation date of October 3, 2017.[93] On October 3, 2017, PJM and MISO implemented the CTS process.

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 2017. Table 9-48 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 35.6 percent of all intervals. In those intervals, the average price difference between the ITSCED forecasted LMP and the actual real-time LMP was $1.54. In 5.5 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 $64.74 when the price difference was greater than $20.00, and $62.59 when the price difference was greater than -$20.00.

### Table 9-48 Differences between forecast and actual PJM/MISO interface prices: 2017

| Range of Price Differences | Percent of All Intervals | Average Price Difference |
|---|---|---|
| > $20 | 2.2% | $65.74 |
| $10 to $20 | 4.5% | $13.78 |
| $5 to $10 | 7.5% | $7.09 |
| $0 to $5 | 35.6% | $1.54 |
| $0 to -$5 | 38.5% | $1.50 |
| -$5 to -$10 | 5.2% | $7.01 |
| -$10 to -$20 | 3.1% | $14.22 |
| < -$20 | 3.3% | $62.59 |

Table 9-49 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 73.6 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 73.4 percent in the 135 minute ahead ITSCED results.

92 See *PJM Interconnection, L.L.C*, Docket No. ER17-934-000 (February 3, 2017).
93 *See* Letter Order, Docket No. ER17-934-001 (March 30, 2017).

### Table 9-49 Differences between forecast and actual PJM/MISO interface prices: 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 | 1.4% | $35.74 | 1.4% | $39.43 | 1.3% | $52.21 | 4.0% | $63.78 |
| $10 to $20 | 4.0% | $13.74 | 4.8% | $13.73 | 4.1% | $13.54 | 5.0% | $13.96 |
| $5 to $10 | 6.1% | $7.11 | 8.0% | $7.09 | 7.7% | $7.05 | 7.9% | $7.09 |
| $0 to $5 | 27.4% | $1.56 | 39.3% | $1.54 | 40.7% | $1.52 | 38.9% | $1.52 |
| $0 to -$5 | 46.0% | $1.67 | 35.8% | $1.43 | 35.9% | $1.37 | 34.7% | $1.38 |
| -$5 to -$10 | 7.1% | $7.02 | 4.7% | $6.92 | 4.5% | $7.03 | 4.3% | $7.00 |
| -$10 to -$20 | 4.1% | $14.16 | 2.7% | $14.17 | 2.7% | $14.33 | 2.5% | $14.09 |
| < -$20 | 3.9% | $73.41 | 3.2% | $53.18 | 3.2% | $53.11 | 2.7% | $53.52 |

In 6.7 percent of the intervals in the 30 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 $63.78 when the price difference was greater than $20.00, and $53.52 when the price difference was greater than -$20.00.

Table 9-50 and Table 9-51 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 9-50 Monthly Differences between forecast and actual PJM/MISO interface prices (percent of intervals): 2017

| Interval | Range of Price Differences | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | YTD Avg |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ~ 30 Minutes Prior to Real-Time | > $20 | 3.4% | 1.6% | 5.3% | 4.1% | 4.5% | 4.2% | 4.1% | 3.5% | 7.2% | 5.0% | 3.5% | 1.6% | 4.0% |
| | $10 to $20 | 3.4% | 1.1% | 6.2% | 4.1% | 6.5% | 5.3% | 6.1% | 4.9% | 9.1% | 6.1% | 4.8% | 2.0% | 5.0% |
| | $5 to $10 | 5.7% | 3.7% | 10.3% | 8.3% | 10.5% | 7.3% | 7.9% | 9.5% | 12.4% | 9.1% | 6.6% | 2.8% | 7.9% |
| | $0 to $5 | 48.7% | 48.7% | 39.0% | 43.5% | 36.3% | 42.7% | 42.3% | 49.7% | 40.5% | 34.1% | 28.8% | 13.5% | 38.9% |
| | $0 to -$5 | 32.9% | 39.9% | 27.9% | 32.4% | 30.7% | 30.5% | 30.9% | 26.9% | 22.6% | 36.0% | 46.4% | 59.1% | 34.7% |
| | -$5 to -$10 | 2.2% | 2.8% | 5.0% | 4.3% | 5.8% | 3.6% | 2.5% | 2.1% | 3.3% | 4.2% | 5.2% | 10.8% | 4.3% |
| | -$10 to -$20 | 1.5% | 0.9% | 3.0% | 2.1% | 3.0% | 3.2% | 2.3% | 1.7% | 2.1% | 2.7% | 2.8% | 5.0% | 2.5% |
| | < -$20 | 2.1% | 1.3% | 3.3% | 1.2% | 2.6% | 3.1% | 3.9% | 1.8% | 2.7% | 2.7% | 1.9% | 5.1% | 2.7% |
| Interval | Range of Price Differences | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | YTD Avg |
| ~ 45 Minutes Prior to Real-Time | > $20 | 0.7% | 0.2% | 1.7% | 0.9% | 1.3% | 1.3% | 1.2% | 1.1% | 3.9% | 1.4% | 0.9% | 0.7% | 1.3% |
| | $10 to $20 | 2.7% | 0.5% | 4.2% | 3.1% | 5.4% | 3.6% | 4.1% | 4.0% | 7.1% | 6.3% | 5.4% | 2.4% | 4.1% |
| | $5 to $10 | 5.0% | 3.1% | 9.3% | 7.6% | 11.6% | 8.0% | 8.0% | 8.9% | 11.9% | 8.5% | 7.6% | 2.7% | 7.7% |
| | $0 to $5 | 47.0% | 48.0% | 41.9% | 46.5% | 38.6% | 43.0% | 45.2% | 49.9% | 41.7% | 37.8% | 32.3% | 16.9% | 40.7% |
| | $0 to -$5 | 37.3% | 42.6% | 31.4% | 33.8% | 29.7% | 32.2% | 30.6% | 29.6% | 25.4% | 36.1% | 43.1% | 58.7% | 35.9% |
| | -$5 to -$10 | 3.1% | 2.7% | 5.0% | 4.0% | 7.1% | 3.9% | 2.8% | 2.4% | 3.5% | 4.0% | 5.5% | 9.3% | 4.5% |
| | -$10 to -$20 | 1.5% | 1.2% | 2.8% | 2.3% | 3.3% | 3.8% | 3.0% | 2.0% | 2.7% | 2.6% | 2.9% | 4.2% | 2.7% |
| | < -$20 | 2.7% | 1.7% | 3.7% | 1.7% | 2.9% | 4.1% | 4.9% | 2.2% | 3.8% | 3.2% | 2.3% | 5.2% | 3.2% |
| Interval | Range of Price Differences | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | YTD Avg |
| ~ 90 Minutes Prior to Real-Time | > $20 | 1.1% | 0.2% | 2.2% | 0.5% | 1.8% | 1.7% | 1.9% | 0.8% | 3.8% | 1.4% | 0.9% | 0.9% | 1.4% |
| | $10 to $20 | 2.4% | 1.0% | 4.8% | 3.8% | 7.7% | 4.9% | 5.0% | 5.0% | 7.7% | 7.6% | 5.5% | 2.4% | 4.8% |
| | $5 to $10 | 3.9% | 3.4% | 9.6% | 8.3% | 13.1% | 8.1% | 7.8% | 7.3% | 12.7% | 10.2% | 7.9% | 3.5% | 8.0% |
| | $0 to $5 | 40.5% | 45.7% | 39.6% | 46.0% | 36.7% | 43.9% | 43.7% | 48.6% | 39.1% | 36.1% | 33.2% | 19.7% | 39.3% |
| | $0 to -$5 | 42.9% | 43.3% | 31.6% | 33.0% | 28.6% | 29.8% | 31.0% | 31.2% | 25.6% | 35.0% | 42.3% | 55.3% | 35.8% |
| | -$5 to -$10 | 4.3% | 3.4% | 5.5% | 4.5% | 5.7% | 3.9% | 3.1% | 3.0% | 4.5% | 4.1% | 4.9% | 8.8% | 4.7% |
| | -$10 to -$20 | 2.0% | 1.3% | 2.7% | 2.3% | 3.4% | 3.6% | 2.9% | 1.8% | 2.8% | 2.6% | 3.0% | 4.3% | 2.7% |
| | < -$20 | 3.0% | 1.7% | 3.9% | 1.6% | 2.8% | 4.2% | 4.7% | 2.3% | 3.8% | 3.1% | 2.3% | 5.0% | 3.2% |
| Interval | Range of Price Differences | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | YTD Avg |
| ~ 135 Minutes Prior to Real-Time | > $20 | 1.6% | 0.3% | 2.5% | 0.1% | 1.0% | 1.0% | 1.8% | 1.4% | 1.4% | 1.5% | 1.7% | 1.9% | 1.4% |
| | $10 to $20 | 3.6% | 1.5% | 5.5% | 1.5% | 4.1% | 3.0% | 4.1% | 6.6% | 4.1% | 5.7% | 5.5% | 2.8% | 4.0% |
| | $5 to $10 | 4.9% | 3.8% | 8.5% | 4.2% | 6.9% | 5.3% | 6.9% | 5.9% | 7.9% | 8.1% | 6.8% | 4.2% | 6.1% |
| | $0 to $5 | 31.9% | 36.0% | 29.6% | 24.0% | 20.5% | 25.6% | 25.8% | 34.3% | 28.1% | 27.5% | 26.8% | 19.1% | 27.4% |
| | $0 to -$5 | 48.2% | 51.6% | 39.2% | 54.0% | 44.6% | 46.3% | 46.7% | 41.2% | 37.5% | 43.0% | 46.5% | 54.3% | 46.0% |
| | -$5 to -$10 | 4.6% | 4.1% | 7.2% | 9.2% | 11.7% | 6.5% | 5.1% | 5.6% | 8.3% | 6.6% | 7.4% | 8.7% | 7.1% |
| | -$10 to -$20 | 2.3% | 1.1% | 3.2% | 4.7% | 6.9% | 6.3% | 3.6% | 2.4% | 6.5% | 4.4% | 3.1% | 4.6% | 4.1% |
| | < -$20 | 2.9% | 1.7% | 4.2% | 2.2% | 4.2% | 6.1% | 6.1% | 2.7% | 6.1% | 3.2% | 2.3% | 4.5% | 3.9% |

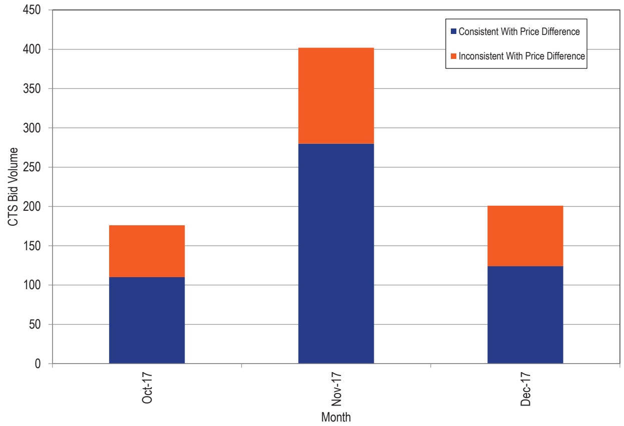
**Table 9-51 Monthly differences between forecast and actual PJM/MISO interface prices (average price difference): 2017**

| Interval | Range of Price Differences | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | YTD Avg |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ~ 30 Minutes Prior to Real-Time | > $20 | $43.86 | $42.30 | $57.15 | $73.06 | $54.49 | $45.18 | $49.58 | $51.17 | $127.67 | $47.59 | $60.47 | $43.33 | $63.78 |
| | $10 to $20 | $13.89 | $13.95 | $14.25 | $14.33 | $13.56 | $14.22 | $13.84 | $13.91 | $13.81 | $14.17 | $13.74 | $14.03 | $13.96 |
| | $5 to $10 | $7.11 | $6.92 | $7.06 | $7.04 | $7.18 | $7.02 | $7.04 | $7.00 | $7.27 | $7.10 | $7.05 | $7.07 | $7.09 |
| | $0 to $5 | $1.17 | $1.10 | $1.67 | $1.65 | $1.63 | $1.55 | $1.52 | $1.50 | $1.72 | $1.81 | $1.51 | $1.70 | $1.52 |
| | $0 to -$5 | $0.99 | $1.03 | $1.48 | $1.32 | $1.52 | $1.21 | $1.13 | $1.11 | $1.35 | $1.54 | $1.41 | $1.99 | $1.38 |
| | -$5 to -$10 | $7.19 | $6.96 | $7.12 | $6.98 | $7.30 | $7.08 | $7.08 | $7.20 | $7.02 | $6.77 | $6.96 | $6.77 | $7.00 |
| | -$10 to -$20 | $14.04 | $14.32 | $14.02 | $13.99 | $14.02 | $13.82 | $14.84 | $13.94 | $14.02 | $14.31 | $14.06 | $13.99 | $14.09 |
| | < -$20 | $60.49 | $50.06 | $54.83 | $44.68 | $55.11 | $39.63 | $63.84 | $48.03 | $61.84 | $48.19 | $50.29 | $53.69 | $53.52 |
| Interval | Range of Price Differences | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | YTD Avg |
| ~ 45 Minutes Prior to Real-Time | > $20 | $42.79 | $34.22 | $40.06 | $47.21 | $44.00 | $46.22 | $36.06 | $35.72 | $94.99 | $27.62 | $27.14 | $31.20 | $52.21 |
| | $10 to $20 | $13.11 | $14.62 | $13.86 | $13.63 | $13.76 | $13.45 | $13.33 | $13.32 | $13.27 | $13.60 | $13.48 | $14.37 | $13.54 |
| | $5 to $10 | $6.98 | $6.60 | $7.02 | $6.99 | $7.01 | $6.92 | $7.25 | $7.04 | $7.13 | $7.09 | $7.23 | $6.78 | $7.05 |
| | $0 to $5 | $1.05 | $1.07 | $1.70 | $1.57 | $1.71 | $1.53 | $1.52 | $1.57 | $1.76 | $1.85 | $1.39 | $1.60 | $1.52 |
| | $0 to -$5 | $1.01 | $1.11 | $1.44 | $1.35 | $1.51 | $1.27 | $1.20 | $1.15 | $1.39 | $1.50 | $1.38 | $1.80 | $1.37 |
| | -$5 to -$10 | $7.09 | $6.91 | $6.83 | $7.17 | $7.07 | $7.31 | $7.07 | $7.13 | $7.21 | $6.90 | $7.01 | $6.89 | $7.03 |
| | -$10 to -$20 | $13.69 | $13.42 | $13.91 | $13.98 | $13.93 | $14.42 | $14.48 | $14.63 | $14.13 | $14.86 | $14.32 | $15.05 | $14.33 |
| | < -$20 | $57.60 | $47.03 | $55.84 | $44.82 | $57.31 | $38.84 | $60.24 | $46.43 | $68.27 | $45.36 | $48.20 | $54.00 | $53.11 |
| Interval | Range of Price Differences | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | YTD Avg |
| ~ 90 Minutes Prior to Real-Time | > $20 | $33.41 | $37.26 | $39.08 | $26.46 | $33.83 | $37.24 | $35.13 | $31.01 | $60.56 | $26.30 | $28.90 | $31.97 | $39.43 |
| | $10 to $20 | $13.60 | $13.14 | $13.55 | $13.86 | $14.00 | $13.75 | $13.67 | $13.58 | $13.41 | $13.71 | $13.95 | $14.24 | $13.73 |
| | $5 to $10 | $6.95 | $6.75 | $6.96 | $6.98 | $7.12 | $7.19 | $7.19 | $7.05 | $7.03 | $7.21 | $7.34 | $6.95 | $7.09 |
| | $0 to $5 | $1.12 | $1.10 | $1.76 | $1.62 | $1.67 | $1.58 | $1.50 | $1.55 | $1.78 | $1.83 | $1.55 | $1.44 | $1.54 |
| | $0 to -$5 | $1.11 | $1.23 | $1.48 | $1.41 | $1.69 | $1.34 | $1.26 | $1.32 | $1.51 | $1.57 | $1.45 | $1.72 | $1.43 |
| | -$5 to -$10 | $7.00 | $6.84 | $6.79 | $6.95 | $7.18 | $7.17 | $7.15 | $6.92 | $7.09 | $6.59 | $6.91 | $6.70 | $6.92 |
| | -$10 to -$20 | $14.11 | $13.10 | $13.80 | $13.69 | $13.55 | $14.45 | $14.85 | $14.13 | $13.91 | $14.49 | $14.37 | $14.61 | $14.17 |
| | < -$20 | $55.41 | $47.69 | $52.80 | $46.60 | $57.07 | $39.14 | $63.01 | $45.80 | $65.01 | $47.44 | $52.00 | $54.63 | $53.18 |
| Interval | Range of Price Differences | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | YTD Avg |
| ~ 135 Minutes Prior to Real-Time | > $20 | $32.31 | $38.91 | $35.10 | $26.62 | $48.56 | $41.40 | $37.06 | $30.88 | $42.19 | $41.00 | $23.90 | $33.37 | $35.74 |
| | $10 to $20 | $14.39 | $12.96 | $13.54 | $14.02 | $13.36 | $13.24 | $13.25 | $13.86 | $13.35 | $14.41 | $13.84 | $13.93 | $13.74 |
| | $5 to $10 | $7.07 | $7.28 | $7.21 | $6.88 | $7.09 | $7.04 | $7.13 | $7.23 | $6.91 | $7.33 | $7.11 | $6.94 | $7.11 |
| | $0 to $5 | $1.15 | $1.16 | $1.84 | $1.55 | $1.76 | $1.73 | $1.56 | $1.43 | $1.82 | $1.84 | $1.61 | $1.47 | $1.56 |
| | $0 to -$5 | $1.26 | $1.39 | $1.65 | $1.81 | $1.97 | $1.74 | $1.59 | $1.56 | $1.73 | $1.87 | $1.63 | $1.81 | $1.67 |
| | -$5 to -$10 | $6.90 | $6.82 | $6.86 | $7.04 | $7.15 | $7.16 | $7.05 | $7.06 | $7.23 | $6.76 | $7.09 | $6.90 | $7.02 |
| | -$10 to -$20 | $13.64 | $12.97 | $14.00 | $14.19 | $13.46 | $14.70 | $14.52 | $13.82 | $13.96 | $14.80 | $14.21 | $14.59 | $14.16 |
| | < -$20 | $56.50 | $46.86 | $52.01 | $42.91 | $126.92 | $147.79 | $58.06 | $43.87 | $65.61 | $48.90 | $51.88 | $56.17 | $73.41 |

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.

CTS transactions were evaluated for each interval. From October 3, 2017, through December 31, 2017, 779 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 265 (34.0 percent) of the intervals was inconsistent with the differences in real-time PJM/MISO and MISO/PJM prices. For example, if a market participant submits a CTS transaction from MISO to PJM with a spread bid of $5.00, and MISO's forecasted PJM interface price was at least $5.00 lower than PJM's forecasted MISO interface price, the transaction would be approved. For 34.0 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 66.0 percent of the intervals, the forecast price differentials were consistent with real-time PJM/MISO and MISO/PJM price differences. Figure 9-15 shows the monthly volume of cleared PJM/MISO CTS bids. Figure 9-15 also shows the percent of cleared bids that resulted in flows consistent and inconsistent with price differences.

Figure 9-15 Monthly cleared PJM/MISO CTS bid volume: October 3, 2017 through December 31, 2017




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 9-52 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 9-52 Monthly uncollected congestion charges: 2010 through 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 | $0 |
| May | $41,025 | $0 | ($27) | $0 | $0 | $0 | $0 | $0 |
| Jun | $169,197 | $1,354 | $78 | $0 | $0 | $0 | $0 | $0 |
| Jul | $827,617 | $1,115 | $0 | $0 | $0 | $0 | $0 | $0 |
| Aug | $731,539 | $37 | $0 | $0 | $0 | $0 | $0 | $0 |
| Sep | $119,162 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Oct | $257,448 | ($31,443) | ($6,870) | $0 | $0 | $0 | $0 | $0 |
| Nov | $30,843 | ($795) | ($4,678) | $0 | $0 | $0 | $0 | $0 |
| Dec | $127,176 | ($659) | ($209) | $0 | $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.

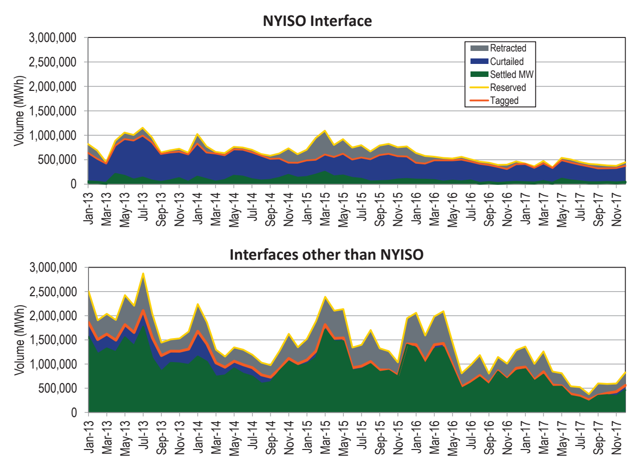
However, PJM has interpreted its JOA with MISO to require restrictions on spot imports and exports although MISO has not implemented a corresponding restriction.[94] The result is that the availability of spot import service is limited by ATC and not all spot transactions are approved. Spot import service (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.[95] 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 9-16 shows the spot import service use for the NYISO Interface, and for all other interfaces, from 2013 through 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 9-16 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 9-16 Spot import service use: 2013 through 2017




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.

94 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>.

95 See OASIS "Regional Transmission and Energy Scheduling Practices," (October 3, 2017) <http://www.pjm.com/~/media/etools/oasis/regional-practices-clean-pdf.ashx>.

## 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.[96] 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.

96 The minimum duration for a real-time dispatchable transaction was modified to 15 minutes as per FERC Order No. 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.[97] [98] On April 17, 2014, FERC issued its order which found that PJM's 45 minute duration rule was inconsistent with Order No. 764.[99]

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.[100]

## 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.[101] On July 15, 2010, MISO submitted revisions to the MISO Tariff to implement criteria for identifying and allocating the costs of MVPs.[102] On December 16, 2010, the Commission accepted the proposed MVP charge for export and wheel-through transactions, except for transactions that sink in PJM.[103] 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.

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.[104] The Court ordered the

97 *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).
98 Order No. 764 at P 51.
99 *See Id.* at P 12.
100 *See* joint statement of PJM and the MMU re Interchange Scheduling issued July 29, 2014 <http://www.monitoringanalytics.com/reports/Market_Messages/Messages/PJM_IMM_Statement_on_Interchange_Scheduling_20140729.pdf>.
101 See MISO. MTEP "Multi Value Project Portfolio Analysis," <https://www.misoenergy.org/Planning/TransmissionExpansionPlanning/Pages/MVPAnalysis.aspx>.
102 See Midwest Independent Transmission Operator Inc. filing, Docket No. ER10-1791-000 (July 15, 2010).
103 133 FERC ¶ 61,221 (2010); *order on reh'g*, 137 FERC ¶ 61,074 (2011).
104 Illinois Commerce Commission, et al. v. FERC, 721 F.3d 764, 778–780 (7th Cir. 2013).

Commission to consider on remand whether, in light of current conditions, what if any limitations on export pricing to PJM by MISO are justified.[105] 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.[106]

On July 13, 2016, FERC issued an Order permitting MISO to collect charges associated with MVPs for all transactions sinking in PJM, effective immediately.[107] 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."[108] Table 9-53 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.[109] It is not clear whether the MUR charge has affected interchange volumes from MISO into PJM.

**Table 9-53 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 |

105 *Id.* at 780.
106 *Id.* at 779.
107 156 FERC ¶ 61,034 (2016).
108 *Id.* at P 55.
109 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 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 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 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 15.4 percent of all cleared hours in 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 2,373 hours (27.1 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 |

- The regulation market structure was evaluated as not competitive for 2017 because the PJM Regulation Market failed the three pivotal supplier (TPS) test in 85.7 percent of the hours in 2017.
- Participant behavior in the PJM Regulation Market was evaluated as competitive for 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.

1 75 FERC ¶ 61,080 (1996).
2 Energy imbalance service refers to the Real-Time Energy Market.

- 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. For 2017, the average primary reserve requirement was 2,211.6 MW in the RTO Zone and 2,027.4 MW in the MAD Subzone.

## 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 2017 there was an average hourly supply of 1,172.1 MW of tier 1 available in the RTO Zone. In 2017, there was an average hourly supply of 493.9 MW of tier 1 synchronized reserve available within the MAD Subzone and an additional 727.4 MW of tier 1 available to the MAD Subzone from the RTO Zone.
- **Demand.** The synchronized reserve requirement is calculated hourly as the largest contingency within both the RTO Zone and the MAD 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 per MW. This is the Synchronized Energy Premium Price.

  Of the Degree of Generator Performance (DGP) adjusted tier 1 synchronized reserve MW estimated at market clearing, 50.5 percent actually responded during the six synchronized reserve events with duration of 10 minutes or longer in 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. The tariff requires payment of the tier 2 synchronized reserve market clearing price to tier 1 resources whenever the nonsynchronized reserve market clearing price rises above zero. This requirement was unnecessary and inconsistent with efficient markets. This change 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 $2,197,514 in 2017.

3 See PJM. "Manual 10: Pre-Scheduling Operations," Rev. 36 (Dec. 22, 2017), p. 24.

## Tier 2 Synchronized Reserve Market

Tier 2 synchronized reserve is part of primary reserve and is comprised of resources that are synchronized to the grid, that incur costs to be synchronized, that have an obligation to respond, that have penalties for failure to respond, 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 uses 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 2017, the supply of offered and eligible tier 2 synchronized reserve was 24,231.3 MW in the RTO Zone of which 6,561.8 MW (including 1,520.9 MW of DSR) was located in the MAD Subzone.
- **Demand.** The average hourly required synchronized reserve requirement was 1,504.8 MW in the RTO Reserve Zone and 1,493.3 MW for the Mid-Atlantic Dominion Reserve Subzone. The hourly average required tier 2 synchronized reserve was 323.0 MW in the MAD Subzone and 688.8 MW in the RTO.
- **Market Concentration.** 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 2017.

  In 2017, the weighted average HHI for tier 2 synchronized reserve in the Mid-Atlantic Dominion Subzone was 5927, which is classified as highly concentrated. The MMU calculates that the three pivotal supplier test in the Mid-Atlantic Dominion Subzone would have been failed in 66.7 percent of hours.

  In 2017, the weighted average HHI for cleared tier 2 synchronized reserve in the RTO Synchronized Reserve Zone was 6543, which is classified as highly concentrated. The MMU calculates that the three pivotal supplier test in the RTO Synchronized Reserve Zone would have been failed in 58.9 percent of hours.

### 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, unless the unit type is exempt. 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 $3.28 per MW in 2017, a decrease of $0.90 from 2016.

  The weighted average price for tier 2 synchronized reserve for all cleared hours in the RTO Synchronized Reserve Zone was $3.73 per MW in 2017, a decrease of $1.15 from 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. Generation owners do not submit supply offers. 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 (based on offer parameters), and on the resource opportunity costs calculated by PJM.

### Market Structure

- **Supply.** In 2017, the average hourly supply of eligible nonsynchronized reserve was 2,171.5 MW in the RTO Zone.
- **Demand.** Demand for nonsynchronized reserve equals the primary reserve requirement minus the tier 1 synchronized reserve estimate and minus

the scheduled tier 2 synchronized reserve.[4] In the RTO Zone, the market cleared an hourly average of 1,053.2 MW of nonsynchronized reserve in 2017.

- **Market Concentration.** In 2017, the weighted average HHI for cleared nonsynchronized reserve in the RTO Zone was 4242, which is highly concentrated. The MMU calculates that the three pivotal supplier test would have been failed in 55.6 percent of hours.

### Market Conduct

- **Offers.** Generation owners do not submit supply offers. 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 hours in the RTO Reserve Zone $0.13 per MW in 2017. The price cleared above $0.00 only 1.7 percent of hours.

## 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. The Day-Ahead Scheduling Reserve Market (DASR) has no performance obligations except that a unit which clears the DASR market may not be on an outage in real time.[5] If DASR units are on an outage in real time or cleared DASR MW are not available, the DASR payment is not made.

4 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Rev. 92 (Nov. 1, 2017), p. 81. "Because Synchronized Reserve may be utilized to meet the Primary Reserve requirement, there is no explicit requirement for non-synchronized reserves."

5 See PJM, "Manual 11: Energy & Ancillary Services Market Operations," Rev. 92 (Nov. 1, 2017), p. 155 §11.2.7.

### 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 30 minute energy ramp rate or the economic maximum MW minus the day-ahead dispatch point for all online units. In 2017, the average available hourly DASR was 36,547.8 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 5,608.8 MW per hour in 2017, compared to 6,072.5 MW per hour in 2016.
- **Concentration.** In 2017, the MMU estimates that the DASR Market would have failed the three pivotal supplier test in 15.9 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 2017, a daily average of 39.2 percent of units offered above $0.00. A daily average of 14.8 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 2017.

### Market Performance

- **Price.** In 2017, the weighted average DASR price for all hours when the DASRMCP was above $0.00 was $2.11.

## 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 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 fast ramp rates. In the Regulation Market RegD MW are converted to effective MW using a marginal rate of substitution (MRTS), called a marginal benefit function (MBF). Correctly implemented, the MBF would be 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 2017, the average hourly eligible supply of regulation for nonramp hours was 1,136.1 performance adjusted MW (869.0 effective MW).[6] This was a decrease of 90.7 performance adjusted MW (an increase of 7.8 effective MW) from 2016, when the average hourly eligible supply of regulation for nonramp hours was 1,226.8 performance adjusted MW (861.2 effective MW). In 2017, the average hourly eligible supply of regulation for ramp hours was 1,427.2 performance adjusted MW (1,183.4 effective MW). This was an increase of 230.9 performance adjusted MW (233.4 effective MW) from 2016, when the average hourly eligible supply of regulation was 1,196.3 performance adjusted MW (950.0 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.
- **Supply and Demand.** The nonramp regulation requirement of 525.0 effective MW was provided by a combination of RegA and RegD resources equal to 488.1 hourly average MW in 2017. This is a decrease of 28.1 MW from 2016, when the average hourly total regulation cleared MW for nonramp hours were 516.2 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 720.2 hourly average MW in 2017. This is an increase of 84.2 MW from 2016, where the average hourly regulation cleared MW for ramp hours were 636.0 MW.

  The ratio of the average hourly eligible supply of regulation to average hourly regulation demand for ramp hours was 1.98 in 2017. This is an increase of 5.4 percent from 2016, when the ratio was 1.88. The ratio of the average hourly eligible supply of regulation to average hourly regulation demand required for nonramp hours was 2.33 in 2017. This is a decrease of 2.0 percent from 2016, when the ratio was 2.38.
- **Market Concentration.** In 2017, the three pivotal supplier test was failed in 85.7 percent of hours. In 2017, the weighted average HHI of RegA resources was 2677, which is highly concentrated and the weighted average HHI of RegD resources was 1604, which is also highly concentrated. The weighted average HHI of all resources was 1136, 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.[7] In 2017, there were 221 resources following the RegA signal and 61 resources following the RegD signal.

## Market Performance

- **Price and Cost.** The weighted average clearing price for regulation was $16.78 per effective MW of regulation in 2017. This is an increase of $1.05 per MW, or 6.7 percent, from the weighted average clearing price of $15.73 per MW in 2016. The weighted average cost of regulation in 2017 was

6 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>.

7 See the *2016 State of the Market Report for PJM*, Volume 2, Appendix F "Ancillary Services Markets."

$23.03 per effective MW of regulation. This is an increase of $4.89 per MW, or 27.0 percent, from the weighted average cost of $18.14 per MW in 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 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 1.0, 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 average MBF is less than 1.0, resulting in persistent overpayment of RegD resources that creates an artificial incentive for inefficient entry of RegD resources. The MBF averaged less than 1.0 in six months of 2017, resulting in RegD resources being paid an average of $17.4 million (288.3 percent) more than they should have in 2017. In each month of 2016, the average MBF was less than 1.0, resulting in RegD resources being paid an average of $14.6 million (1,565.7 percent) more than they should have been.
- **Marginal Benefit Factor Function.** The marginal benefit factor (MBF) is intended to measure the operational substitutability of RegD resources for RegA resources. The marginal benefit factor function is incorrectly defined and applied in the PJM market clearing. 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.[8]
- **Changes to the Regulation Market.** 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. PJM made additional changes which went into effect on January 9, 2017. These include changing the definition of 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. The January 9 changes did not resolve the underlying issues. Effective July 31, 2017, PJM ended the use of excursion hours (hours ending 7:00, 8:00, 18:00-21:00), in which PJM had decided that more RegA was needed and PJM did not clear any RegD with an MBF less than 1.0.

## 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 2017, total black start charges were $69.5 million, including $69.3 million in revenue requirement charges and $0.257 million in operating reserve charges. Black start revenue requirements 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 2017 ranged from $0.06 per MW-day in the DLCO Zone

8 The issues associated with over procurement were brought before the PJM Operating Committee in May of 2015. Regulation Performance Impacts, PJM Operating Committee, (May 26, 2015), which can be accessed at: <http://www.pjm.com/committees-and-groups/committees/oc.aspx>.

9 OATT Schedule 1 § 1.3BB.

(total charges were $51,114) to $4.28 per MW-day in the PENELEC Zone (total charges were $4,543,929).

## 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.[10] 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 2017, total reactive charges were $334.3 million, an 11.9 percent increase from $298.7 million in 2016. Reactive capability revenue requirement charges increased from $296.2 million in 2016 to $313.9 million in 2017 and reactive service charges increased from $2.4 million in 2016 to $20.4 million in 2017. Total reactive service charges in 2017 ranged from $1,239 in the RECO Zone to $47.5 million in the ComEd Zone.

## Frequency Response

In response to a November 17, 2016 FERC NOPR,[11] PJM formed the Primary Frequency Response Senior Task Force (PFRSTF) to review primary frequency response and propose changes to its tariff and operating manuals, including consideration of compensation mechanisms if needed.

## Ancillary Services Costs per MWh of Load: January through September, 1999 through 2017

Table 10-4 shows PJM ancillary services costs for 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: 1999 through 2017[12]

| Year | Regulation | Scheduling, Dispatch and System Control | Reactive | Synchronized Reserve | Total |
|---|---|---|---|---|---|
| 1999 | $0.15 | $0.23 | $0.26 | $0.00 | $0.64 |
| 2000 | $0.39 | $0.26 | $0.29 | $0.00 | $0.94 |
| 2001 | $0.53 | $0.71 | $0.22 | $0.00 | $1.46 |
| 2002 | $0.42 | $0.86 | $0.20 | $0.01 | $1.49 |
| 2003 | $0.50 | $1.05 | $0.24 | $0.15 | $1.94 |
| 2004 | $0.51 | $0.93 | $0.26 | $0.13 | $1.83 |
| 2005 | $0.80 | $0.72 | $0.26 | $0.11 | $1.89 |
| 2006 | $0.53 | $0.74 | $0.29 | $0.08 | $1.64 |
| 2007 | $0.63 | $0.72 | $0.29 | $0.06 | $1.70 |
| 2008 | $0.70 | $0.38 | $0.34 | $0.08 | $1.50 |
| 2009 | $0.34 | $0.29 | $0.36 | $0.05 | $1.04 |
| 2010 | $0.36 | $0.35 | $0.45 | $0.07 | $1.23 |
| 2011 | $0.32 | $0.34 | $0.41 | $0.09 | $1.16 |
| 2012 | $0.26 | $0.40 | $0.46 | $0.04 | $1.16 |
| 2013 | $0.25 | $0.39 | $0.76 | $0.04 | $1.44 |
| 2014 | $0.33 | $0.40 | $0.40 | $0.12 | $1.25 |
| 2015 | $0.23 | $0.41 | $0.37 | $0.11 | $1.12 |
| 2016 | $0.11 | $0.41 | $0.38 | $0.05 | $0.95 |
| 2017 | $0.14 | $0.46 | $0.44 | $0.06 | $1.10 |

## Recommendations

- The MMU recommends that the Regulation Market be modified to incorporate a consistent application of the marginal benefit factor (MBF) throughout the optimization, assignment and settlement process. The MBF should be defined as the Marginal Rate of Technical Substitution (MRTS) between RegA and RegD. (Priority: High. First reported 2012. Status: Not adopted. Pending before FERC.)
- 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. Pending before FERC.)

10 OATT Schedule 2.

11 *Essential Reliability Services and the Evolving Bulk-Power System – Primary Frequency Response*, Notice of Proposed Rulemaking, 157 FERC ¶ 61,122 (Nov. 17, 2016) ("NOPR").

12 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 LOC calculation used in the Regulation Market be based on the resource's dispatched energy offer schedule, not the lower of its price or cost offer schedule. (Priority: Medium. First reported 2010. Status: Pending before FERC.)
- 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, to prevent gaming, 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. (Priority: Medium. First reported 2016. Status: Not adopted. Pending before FERC.)
- The MMU recommends the use of a single five minute clearing price based on actual five minute LMP and lost opportunity cost to improve the performance of the Regulation Market. (Priority: Medium. First reported 2010. Status: Adopted in 2012.)
- The MMU recommends that PJM be required to save data elements necessary for verifying the performance of the Regulation Market. (Priority: Medium. First reported 2010. Status: Not adopted.)
- The MMU recommends enhanced documentation of the implementation of the Regulation Market design. (Priority: Medium. First reported 2010. Status: Pending before FERC.)
- The MMU recommends that the rule requiring that tier 1 synchronized reserve resources are paid the tier 2 price when the nonsynchronized reserve price is above zero be eliminated immediately and that, under the current rule, 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: Partially 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 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, 2016.)
- 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.)
- 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 PJM modify the DASR Market to ensure that all resources cleared incur a real-time performance obligation. (Priority: Low. First reported 2013. 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 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 that for oil tanks which are shared with other resources only a proportionate share of the minimum tank suction level (MTSL) be allocated to black start service. The MMU further recommends that the PJM tariff be updated to clearly state how the MTSL will be calculated for black start

units sharing oil tanks. (Priority: Medium. First reported Q3, 2017. Status: Not adopted.)

- The MMU recommends that capability to operate under the proposed deadband (+/- 0.036 HZ) and droop (5 percent) settings be mandated as a condition of interconnection and that such capability be required of both new and existing resources. The MMU recommends that no additional compensation be provided as the current PJM market design provides adequate compensation. (Priority: Low. New recommendation. Status: Not adopted.)

## Conclusion

The current PJM regulation market design that incorporates two signals using two resource types was a result of Commission Order No. 755 and subsequent orders that required a flawed design.[13]

The current design of the PJM Regulation Market is significantly flawed. The market design has failed to correctly incorporate the marginal rate of technical substitution (MRTS) in market clearing and settlement. The market design uses the marginal benefit factor (MBF) to incorrectly represent the MRTS and uses a mileage ratio instead of the MBF in settlement. This failure to correctly and consistently incorporate the MRTS 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.

To address these flaws, the MMU and PJM developed a joint proposal which was approved by the PJM Members Committee on July 27, 2017 and filed with FERC on October 17, 2017.[14] The PJM/MMU joint proposal addresses issues with the inconsistent application of the marginal benefit factor throughout the optimization and settlement process in the PJM Regulation Market.

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 six spinning events 10 minutes or longer in 2017, the response was 87.6 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. 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 already 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 $2,197,514 million in 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

13 *Frequency Regulation Compensation in the Organized Wholesale Power Markets*, Order No. 755, 137 FERC ¶ 61,064 at PP 197–200 (2011).
14 18 CFR § 385.211 (2017)

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 status must be reported quarterly. PJM implements this contingency reserve requirement using primary reserves.[15] 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

#### Demand

PJM requires that 150 percent of the largest contingency on the system be maintained as primary reserve. PJM can make temporary adjustments to the primary reserve requirement when grid maintenance or outages change the largest contingency or in cases of hot weather alerts or cold weather alerts.

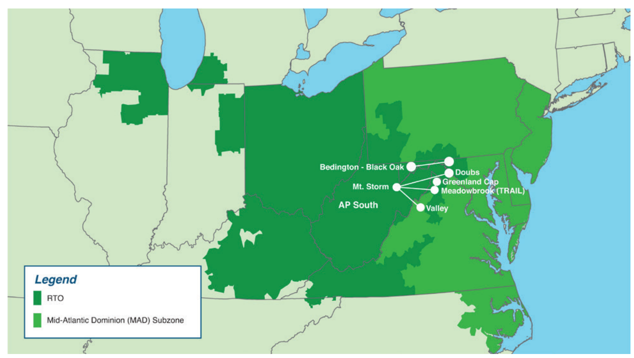
Until July 12, 2017, PJM's default primary reserve requirement was 2,175 MW for the RTO Zone. From January 1 through May 9, 2017, the primary reserve requirement was 1,700 MW for the MAD Subzone. On May 10, 2017, the primary reserve requirement for the MAD Subzone was raised to 2,175 MW. This means that the full 2,175 MW of primary reserve must at all times be deliverable everywhere across the RTO. On July 12, 2017, PJM adopted a dynamic reserve requirement set equal to 150 percent of the largest contingency, determined hourly, based on the forecasted dispatch.

On January 10, 2017, the primary reserve requirement in the RTO Reserve Zone was temporarily raised from 2,175 MW to 3,300 MW for 32 hours. On May 10, 2017, the primary reserve requirement for the RTO Reserve Zone was temporarily raised from 2,175 MW to 2,550 MW for two hours. Beginning October 16, 2017, the primary reserve requirement was raised to 3,997 MW for 41 hours. The hourly average RTO primary reserve requirement from January 1, 2017 through July 11, 2017 was 2,183.3 MW. From July 12, 2017 through December 31, 2017, the average primary reserve requirement in the RTO Zone was 2,243.5 MW.

On October 16, 2017, the primary reserve requirement was temporarily raised to 3,997 MW for 41 hours in the MAD Subzone. From July 12, 2017 through December 31, 2017, the average hourly primary reserve requirement was 2,216.7 MW.

Transmission constraints limit the deliverability of reserves within the RTO, requiring the definition of the Mid-Atlantic Dominion (MAD) Subzone (Figure 10-1).[16]

Figure 10-1 PJM RTO Zone and MAD Subzone geography: 2017




The 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. Between January 1, 2017, and September 30, 2017, Bedington - Black Oak was the most limiting interface in 52.6 percent of hourly market solutions and AP South was the most limiting interface in the other 47.4 percent of hours.

The NERC standard for primary reserves in a control area is equal to 150 percent of the control area's largest contingency. PJM requires that synchronized reserves equal at least 100 percent of the largest contingency. Prior to PJM's introduction of the dynamic, real

15 See PJM "Manual 10: Pre-Scheduling Operations," Rev. 36 (Dec. 22, 2017) at p.22.

16 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, Rev. 92 (Nov. 1, 2017) at 75.

time determination of the largest contingency in every spinning market solution on July 12, 2017, the synchronized reserve requirement was 1,450 MW in every hour for both RTO Reserve Zone and the Mid Atlantic Dominion Reserve Subzone. From July 12, through December 31, 2017, the synchronized reserve requirement averaged 1,541.1 MW per hour in the MAD Subzone and 1,559.8 MW per hour in the RTO Zone.

## Supply

The demand for primary reserve is satisfied by tier 1 synchronized reserves, tier 2 synchronized reserves and nonsynchronized reserves, subject to the requirement that synchronized reserves equal 100 percent of the largest contingency. After the hourly synchronized reserve requirement is satisfied, the 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 as well as PJM's synchronized reserve requirement. In the MAD Subzone an average of 1,226.2 MW of tier 1 was identified by the ASO market solution as available hour ahead in 2017 (Table 10-6).[17] Of that 1,226.2 MW, an average of 731.6 MW was available from outside the MAD Subzone. Tier 1 synchronized reserve fully satisfied the MAD Subzone synchronized reserve requirement in 27.5 percent of hours in 2017. In the RTO Zone, an average of 1,172.1 MW of tier 1 was available (Table 10-6). Tier 1 synchronized reserve fully satisfied the RTO Zone synchronized reserve requirement in 32.4 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). Resources listed as available for tier 2 synchronized reserve without a synchronized reserve offer will have their offer price automatically set to $0.00. Offer MW and other non-cost offer parameters can be changed during the operating day. Prior to November 1, 2017, owners were permitted to make resources unavailable for tier 2 synchronized reserve daily or hourly, but only if they were physically unavailable. After November 1, 2017, owners who opt in for intraday updates may change their offer price up to 65 minutes before the hour. Certain unit types including nuclear, wind, solar, and energy storage resources, are expected to have zero MW tier 2 synchronized reserve offer quantities.[18]

After tier 1 is estimated, the remainder of the synchronized reserve requirement is met by tier 2. In the RTO Zone, there were 24, 208.1 MW of tier 2 synchronized reserve offered daily. Of this, 6,559.8 MW were located in the MAD Subzone (Figure 10-10) and available to meet the average tier 2 hourly demand of 319.6 MW (Table 10-5).

In the MAD Subzone, there was an average of 2,084.4 MW of eligible nonsynchronized reserve supply available to meet the average hourly demand for primary reserve above the synchronized reserve requirement of 1,492.3 MW. (Table 10-6) In the RTO Zone, an hourly average of 2,391.5 MW supply was available to meet the average hourly demand of 564.8 MW (Table 10-5).

Table 10-5 provides the average hourly reserves, by type, uses to satisfy the primary reserve requirement in the MAD Subzone from January 1, 2016, through December 31, 2017.

17 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.

18 See PJM "Manual 11: Energy & Ancillary Services Market Operations," Rev. 92 (Nov. 1, 2017) at 74.

Table 10-5 Average monthly reserves used to satisfy the primary reserve requirement, MAD Subzone: 2016 through 2017

| Year | Month | Tier 1 Total MW | Tier 2 Synchronized Reserve MW | Nonsynchronized 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 | 356.1 | 361.1 | 1,698.9 |
| 2017 | Feb | 1,111.6 | 233.2 | 377.7 | 1,722.5 |
| 2017 | Mar | 767.4 | 453.3 | 399.3 | 1,620.0 |
| 2017 | Apr | 896.9 | 362.4 | 435.4 | 1,694.7 |
| 2017 | May | 1,164.6 | 376.8 | 440.8 | 1,982.2 |
| 2017 | Jun | 1,373.0 | 379.6 | 459.9 | 2,212.5 |
| 2017 | Jul | 1,391.9 | 353.3 | 448.2 | 2,193.4 |
| 2017 | Aug | 1,438.3 | 226.9 | 451.8 | 2,117.0 |
| 2017 | Sep | 1,419.2 | 339.7 | 442.1 | 2,201.0 |
| 2017 | Oct | 1,364.2 | 348.1 | 460.4 | 2,172.7 |
| 2017 | Nov | 1,392.1 | 245.9 | 428.0 | 2,066.0 |
| 2017 | Dec | 1,411.5 | 160.0 | 478.9 | 2,050.4 |
| 2017 | | 1,226.0 | 319.6 | 432.0 | 1,977.6 |

Table 10-6 provides the average monthly reserves, by type, used to satisfy the primary reserve requirement in the RTO Zone for 2016 and 2017.

Table 10-6 Average monthly reserves used to satisfy the primary reserve requirement, RTO Zone: 2016 through 2017

| Year | Month | Tier 1 Total MW | Tier 2 Synchronized Reserve MW | Nonsynchronized 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 | 730.6 | 372.3 | 2,308.2 |
| 2017 | Feb | 1,172.0 | 508.3 | 395.1 | 2,253.2 |
| 2017 | Mar | 654.2 | 693.1 | 420.9 | 2,204.0 |
| 2017 | Apr | 805.1 | 623.0 | 452.2 | 2,216.5 |
| 2017 | May | 924.1 | 560.7 | 454.0 | 2,257.5 |
| 2017 | Jun | 1,413.5 | 568.8 | 474.9 | 2,533.0 |
| 2017 | Jul | 1,540.1 | 667.6 | 459.5 | 2,675.7 |
| 2017 | Aug | 1,512.8 | 517.0 | 466.9 | 2,589.9 |
| 2017 | Sep | 1,368.9 | 496.6 | 453.2 | 2,442.3 |
| 2017 | Oct | 1,104.3 | 528.5 | 477.3 | 2,110.1 |
| 2017 | Nov | 1,173.6 | 465.6 | 447.3 | 2,086.5 |
| 2017 | Dec | 1,308.4 | 417.8 | 497.9 | 2,224.1 |
| 2017 | | 1,166.4 | 564.8 | 447.6 | 2,325.1 |

## Supply and Demand

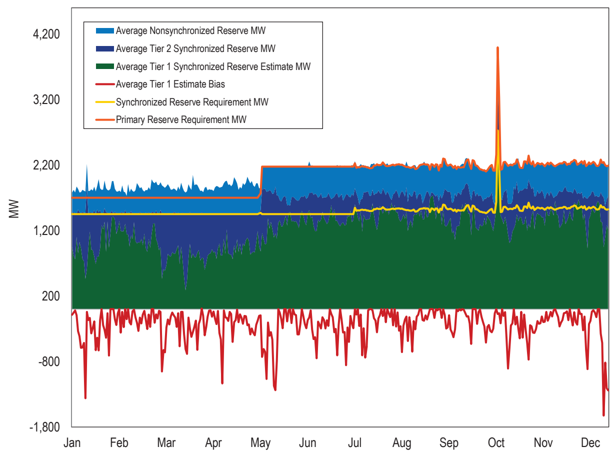
The market solution software relevant to reserves consists of: the Ancillary Services Optimizer (ASO) solving hourly; the intermediate term security constrained economic dispatch market solution (IT-SCED); and the real-time (short term) security constrained economic dispatch market solution (RT-SCED).

The ASO market solution determines the actual primary reserves required each hour as one hundred and fifty percent of the largest contingency based on generation and transmission resources. Of this, synchronized reserves must be one hundred percent of the largest contingency. The ASO first assigns self-scheduled synchronized reserves and then estimates the amount of tier 1 synchronized reserves available. The remainder of the requirement up to the synchronized reserve required is filled by a market solution of tier 2 synchronized reserves. Above that requirement, the ASO jointly optimizes energy, synchronized reserves, and nonsynchronized reserves based on forecast system conditions to determine the most economic set of resources to commit for primary reserve in the upcoming operating hour. Figure 10-2 and Figure 10-3 show the components of primary reserve in the solution.

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 calculated hourly in the MAD Subzone. The ASO first estimates how much tier 1 synchronized reserve (green area) is available. If there is enough tier 1 MW available to satisfy the synchronized reserve requirement, then ASO jointly optimizes synchronized reserve and nonsynchronized reserve to assign the remaining primary reserve up to the primary reserve requirement. If there is not enough tier 1 synchronized reserve then the remaining synchronized reserve requirement up to the synchronized reserve is filled with tier 2 synchronized reserve (dark blue area). After synchronized reserve is assigned, 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 above the synchronized reserve requirement is filled by nonsynchronized reserve.

Figure 10-2 Mid-Atlantic Dominion Subzone primary reserve MW by source (Daily Averages): 2017




The solution method is the same for the RTO Reserve Zone.[19] Figure 10-3 shows how the hour ahead ASO satisfies the primary reserve requirement for the RTO Zone.

Figure 10-3 RTO Reserve Zone primary reserve MW by source (Daily Averages): 2017

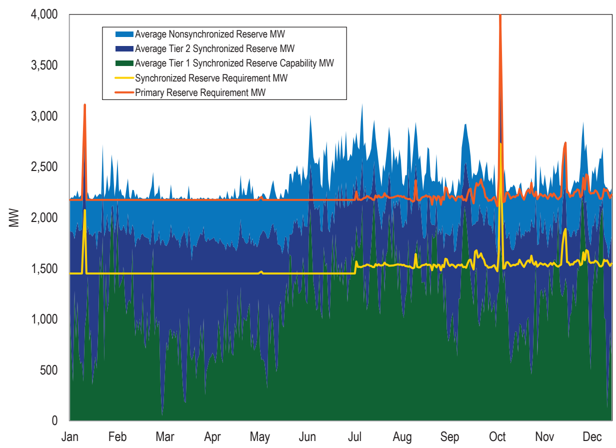


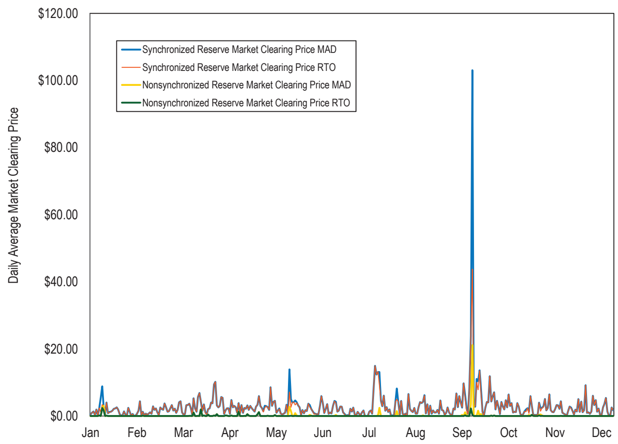

Figure 10-2 and Figure 10-3 show that tier 1 synchronized reserve remains the major contributor to satisfying the synchronized reserve requirements both in the RTO Zone and the Mid-Atlantic Dominion (MAD) Subzone.

19 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 2017.

Figure 10-4 Daily weighted average market clearing prices ($/MW) for synchronized reserve and nonsynchronized reserve: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). The "Cost per MW" column is the total credits divided by the total MW of reserves.

Table 10-7 MW credited, price, cost, and all-in price for primary reserve and components, RTO Reserve Zone: 2017

| Product | MW Share of Primary Reserve Requirement | MW | Credits Paid | Price Per MW Reserve | Cost Per MW Reserve |
|---|---|---|---|---|---|
| Tier 1 Synchronized Reserve Response | NA | 5,000 | $471,132 | NA | $94.23 |
| Tier 1 Synchronized Reserve Estimated | 1.0% | 137,030 | $2,197,809 | $0.00 | $16.04 |
| Tier 2 Synchronized Reserve Scheduled | 31.8% | 4,367,382 | $38,251,656 | $3.71 | $8.88 |
| Non Synchronized Reserve Scheduled | 67.2% | 9,228,856 | $7,023,487 | $0.13 | $0.76 |
| Primary Reserve (total of above) | 100.0% | 13,738,268 | $47,944,084 | $1.27 | $3.49 |

On a combined basis, the ratio of price to cost for all primary reserve during 2017 is low at 36.8 percent. This is partly a result of the unnecessary payment of the tier 2 price to tier 1 resources, and partly a result of the poor price to cost ratio of nonsynchronized reserves. While tier 1 has zero actual incremental cost, estimated tier 1 is paid the tier 2 clearing price in any hour where nonsynchronized reserves clears at a non-zero price. Table 10-7 shows that the cost of tier 1 reserves is $16.04 per MW when the price of nonsynchronized reserve is greater than zero and almost twice the cost of tier 2 reserves which is $8.88 per MW.

## 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. Tier 1 synchronized reserve is the first element of primary reserve identified by the market software and has an incremental cost of zero. Tier 1 reserves are paid to respond to a synchronized reserve event. Tier 1 reserves are paid a clearing price whenever the nonsynchronized reserve market clearing price is above $0, regardless of their actual response.

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.

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.[20] 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 submitted synchronized reserve ramp rate, adjusted by its DGP. 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.[21]

In 2017, PJM estimated tier 1 MW for an average of 147 units as part of the market solution each hour for which the average DGP was 89.2 percent.

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 nuclear, wind, solar, energy storage, and hydro units.[22] 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 2017, in the RTO Reserve Zone, the average hourly estimated tier 1 synchronized reserve was 1,166.4 MW (Table 10-8). In 32.3 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 2017, in the MAD Reserve Subzone, the average hourly estimated tier 1 synchronized reserve was 491.5 MW in the MAD Subzone and 665.1 MW were available from the RTO (Table 10-8). In 27.9 percent of hours, the estimated tier 1 synchronized reserve available in MAD was greater than the synchronized reserve requirement, meaning that the synchronized reserve requirement was met entirely by tier 1 synchronized reserve.

### Table 10-8 Monthly average market solution tier 1 synchronized reserve (MW) identified hourly: 2016 through 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 | Average | 549.3 | 574.3 | 1,123.6 | 1,263.1 |
| | | | | | |
| 2017 | Jan | 529.3 | 452.3 | 981.6 | 1,020.4 |
| 2017 | Feb | 526.1 | 585.5 | 1,111.6 | 1,172.0 |
| 2017 | Mar | 292.6 | 474.8 | 767.4 | 654.2 |
| 2017 | Apr | 288.2 | 608.8 | 896.9 | 805.1 |
| 2017 | May | 386.5 | 778.1 | 1,164.6 | 924.1 |
| 2017 | Jun | 559.5 | 813.5 | 1,373.0 | 1,413.5 |
| 2017 | Jul | 693.8 | 698.1 | 1,391.9 | 1,540.1 |
| 2017 | Aug | 583.1 | 855.2 | 1,438.3 | 1,512.8 |
| 2017 | Sep | 564.7 | 854.5 | 1,419.2 | 1,368.9 |
| 2017 | Oct | 465.7 | 898.4 | 1,364.2 | 1,104.3 |
| 2017 | Nov | 469.7 | 922.4 | 1,392.1 | 1,173.6 |
| 2017 | Dec | 539.8 | 871.7 | 1,411.5 | 1,308.4 |
| 2017 | Average | 491.6 | 734.4 | 1,226.0 | 1,166.4 |

## Demand

There is no required amount of tier 1 synchronized reserve.

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.

20 See PJM "Manual 12: Balancing Operations," Rev. 37 (Nov. 16, 2017) at 78.

21 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).

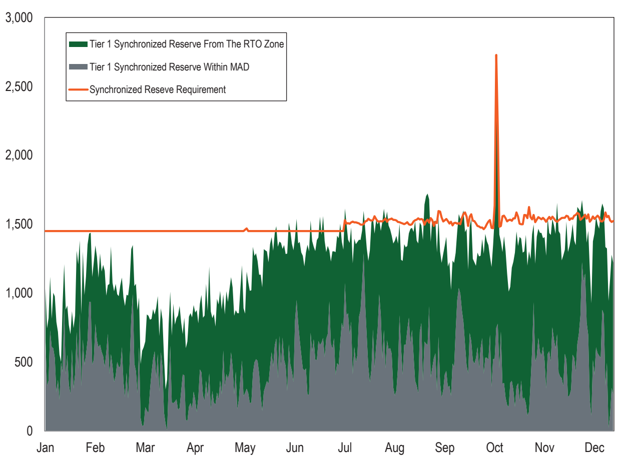
22 See PJM "Manual 11: Energy & Ancillary Services Market Operations," Rev. 92 (Nov. 1, 2017) at 72.

## Supply and Demand

When solving for the synchronized reserve requirement the market solution first subtracts the amount of self scheduled synchronized reserve from the requirement and then estimates the amount of tier 1.

In the MAD Subzone, the market solution takes all tier 1 MW estimated to be available within the MAD Subzone (gray area of Figure 10-5). It then adds the tier 1 MW estimated to be available within the MAD Subzone from the RTO Zone (green area of Figure 10-5) up to the synchronized reserve requirement. If the total tier 1 synchronized reserve is less than the synchronized reserve requirement, the remainder of the synchronized reserve requirement is filled with tier 2 synchronized reserve (white area below the synchronized reserve required line in Figure 10-5).

Figure 10-5 Daily average tier 1 synchronized reserve supply (MW) in the MAD Subzone: 2017




Average demand for synchronized reserve in the RTO Zone in 2017 was 1,504.8 MW. There was a temporary increase in the hourly synchronized reserve requirement to 2,200 MW on January 10 and 11, to 1,658 MW for two hours on May 8, to 1,680 MW for three hours on May 9, and to 2,728 MW for 41 consecutive hours between October 16 and October 18, 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 2017, tier 1 synchronized reserve event response credits of $471,132 were paid for 4,999.8 MWh of tier 1 response at an average cost per MWh of $94.23, for 19 spinning event hours (Table 10-9).

Table 10-9 Tier 1 synchronized reserve event response costs: 2016 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 |
|---|---|---|---|---|---|
| 2016 | Jan | 2 | 731.1 | $70,330 | $96.24 |
| 2016 | Feb | 2 | 675.0 | $40,622 | $60.18 |
| 2016 | Mar | 0 | 0.0 | $0 | $0.00 |
| 2016 | Apr | 1 | 339.0 | $66,199 | $195.27 |
| 2016 | May | 2 | 113.4 | $9,790 | $86.35 |
| 2016 | Jun | 1 | 206.9 | $11,129 | $53.78 |
| 2016 | Jul | 3 | 714.3 | $58,114 | $81.36 |
| 2016 | Aug | 1 | 334.5 | $13,026 | $38.95 |
| 2016 | Sep | 2 | 452.4 | $34,824 | $76.97 |
| 2016 | Oct | 2 | 281.1 | $24,130 | $85.85 |
| 2016 | Nov | 1 | 204.3 | $10,910 | $53.41 |
| 2016 | Dec | 1 | 256.8 | $14,766 | $57.50 |
| 2016 | Total | 18 | 4,308.8 | $353,840 | $76.57 |
| | | | | | |
| 2017 | Jan | 6 | 1,252.0 | $60,319 | $48.18 |
| 2017 | Feb | 3 | 627.4 | $56,103 | $89.42 |
| 2017 | Mar | 2 | 769.2 | $56,352 | $73.26 |
| 2017 | Apr | 2 | 307.8 | $17,559 | $57.05 |
| 2017 | May | 1 | 388.7 | $20,940 | $53.87 |
| 2017 | Jun | 2 | 611.9 | $28,681 | $46.87 |
| 2017 | Jul | 0 | 0.0 | $0 | $0.00 |
| 2017 | Aug | 0 | 0.0 | $0 | $0.00 |
| 2017 | Sep | 3 | 1,042.8 | $231,178 | $221.69 |
| 2017 | Oct | 0 | 0.0 | $0 | $0.00 |
| 2017 | Nov | 0 | 0.0 | $0 | $0.00 |
| 2017 | Dec | 0 | 0.0 | $0 | $0.00 |
| 2017 | Total | 19 | 4,999.8 | $471,132 | $94.23 |

## Paying Tier 1 the Tier 2 Price

Tier 1 synchronized reserve has zero marginal cost and the corresponding price for tier 1 synchronized reserves is also zero. 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 149 hours in 2017. For those 149 hours, tier 1 synchronized reserve resources were paid a weighted average synchronized reserve market clearing price of $13.87 per MW and earned $2,197,809 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: 2016 through 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 | Total | 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 | Apr | 16 | $9.82 | 11,680 | $114,662 | 730.0 |
| 2017 | May | 19 | $10.61 | 20,242 | $214,816 | 1,065.3 |
| 2017 | Jun | 8 | $4.96 | 7,563 | $37,542 | 945.4 |
| 2017 | Jul | 7 | $29.58 | 6,631 | $196,128 | 947.2 |
| 2017 | Aug | 4 | $14.04 | 3,926 | $55,108 | 981.5 |
| 2017 | Sep | 26 | $45.11 | 21,030 | $948,664 | 808.9 |
| 2017 | Oct | 9 | $7.65 | 6,343 | $48,539 | 704.8 |
| 2017 | Nov | 26 | $6.35 | 24,218 | $153,842 | 931.4 |
| 2017 | Dec | 2 | $0.26 | 1,274 | $295 | 637.0 |
| 2017 | Total | 149 | $13.87 | 137,030 | $2,197,809 | 928.7 |

The additional payments to tier 1 synchronized reserves under the shortage pricing rule are 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; all estimated tier 1 receives the higher payment regardless of whether they provide any response during any spinning event. Tier 1 resources are not obligated to respond to synchronized reserve events. In 2017, 60.1 percent of the DGP adjusted market solution's estimated tier 1 resources MW actually responded during synchronized reserve events of 10 minutes or longer. Thus, 39.9 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. Unlike tier 1 resources, 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 2017, tier 1 synchronized reserve was paid $471,132 for responding to synchronized reserve events. During the same time period tier 1 synchronized reserve was paid a windfall of $2,197,514 simply because the NSRMCP was greater than $0.00 in 147 hours (Table 10-11).

### Table 10-11 Excess payments for tier 1 synchronized reserve: 2016 through 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 | Total | 4,629 | $382,585 | 233 | 357,442 | $4,948,084 | 1,285.1 |
| | | | | | | | |
| 2017 | Jan | 1,252 | $60,319 | 208 | 19,441 | $221,157 | 1,143.6 |
| 2017 | Feb | 627 | $56,103 | 209 | 1,293 | $15,971 | 1,293.2 |
| 2017 | Mar | 769 | $56,352 | 385 | 13,389 | $191,084 | 956.4 |
| 2017 | Apr | 308 | $17,559 | 149 | 11,680 | $114,662 | 730.0 |
| 2017 | May | 389 | $20,940 | 406 | 20,242 | $214,816 | 1,065.4 |
| 2017 | Jun | 612 | $28,681 | 312 | 7,563 | $37,542 | 945.4 |
| 2017 | Jul | 0 | $0 | NA | 6,631 | $196,128 | 947.2 |
| 2017 | Aug | 0 | $0 | NA | 3,926 | $55,108 | 981.5 |
| 2017 | Sep | 1,043 | $231,178 | 368 | 21,030 | $948,664 | 808.9 |
| 2017 | Oct | 0 | $0 | NA | 6,343 | $48,539 | 704.8 |
| 2017 | Nov | 0 | $0 | NA | 24,218 | $153,842 | 931.4 |
| 2017 | Dec | 0 | $0 | NA | 1,274 | $295 | 637.0 |
| 2017 | Total | 5,000 | $471,132 | 291 | 137,030 | $2,197,809 | 928.7 |

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.[23] 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.

23 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 tier 2 synchronized reserve solution by forcing the software to assume a different tier 1 MW value than it actually 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 although sometimes the solution is biased positively (Table 10-14).

### Table 10-14 RTO Zone ASO tier 1 estimate biasing: 2016 through 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 | Total | 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 | Apr | 227 | (697.1) | 0 | NA |
| 2017 | May | 301 | (1,000.3) | 13 | 207.7 |
| 2017 | Jun | 253 | (873.5) | 0 | NA |
| 2017 | Jul | 244 | (938.1) | 0 | NA |
| 2017 | Aug | 179 | (805.3) | 2 | 1,250.0 |
| 2017 | Sep | 144 | (682.6) | 0 | NA |
| 2017 | Oct | 234 | (807.7) | 0 | NA |
| 2017 | Nov | 240 | (739.7) | 0 | NA |
| 2017 | Dec | 273 | (920.0) | 0 | NA |
| 2017 | Total | 2,975 | (827.7) | 22 | 256.7 |

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. 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 60 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 the clearing price (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. Demand side resources are also considered to be inflexible.

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 although certain unit types are exempt. 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.[24]

In 2017, the Mid Atlantic Dominion (MAD) Reserve Subzone averaged 6,561.8 MW of tier 2 synchronized reserve offers, and the RTO Reserve Zone averaged 24,231.3 MW of tier 2 synchronized reserve offers (Figure 10-10).

The supply of tier 2 synchronized reserve in 2017 was sufficient to cover the ASO hourly requirement net of tier 1 in both the RTO Reserve Zone and the MAD Reserve Subzone. The supply of tier 2 synchronized reserve was short in two 5 minute intervals in the RTO Zone during a spinning event on September 21.

24 See PJM "Manual 11: Energy & Ancillary Services Market Operations," Rev. 99 (Nov. 1, 2017) at 84.

The largest portion of cleared tier 2 synchronized reserve in 2017 was from CTs, 42.4 percent (Figure 10-6). 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.[25] The DR MW share of the total cleared Tier 2 Synchronized Reserve Market in 2017 was 24.3 percent.

**Figure 10-6 Cleared tier 2 synchronized reserve average hourly MW per hour by unit type, RTO Zone: 2016 through 2017**

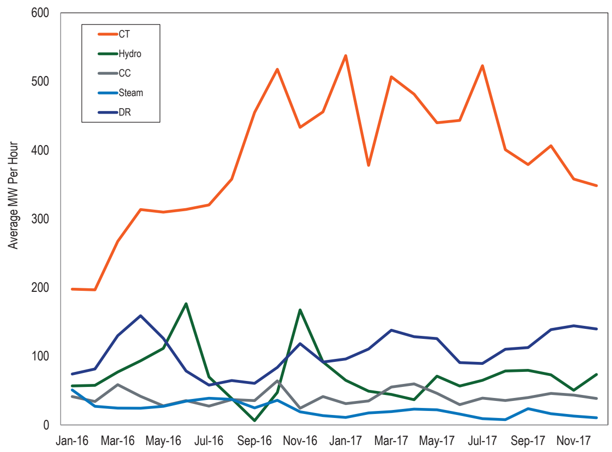
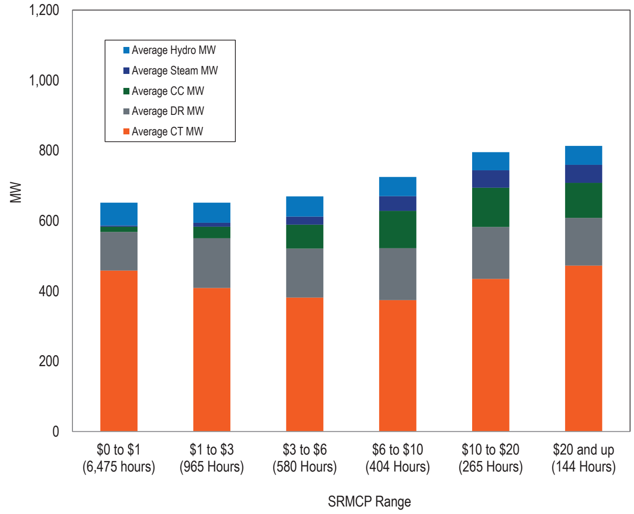



Figure 10-7 provides the average hourly cleared tier 2 MW by unit type by tier 2 clearing price range (SRMCP).

**Figure 10-7 Average hourly tier 2 MW by unit type by SRMCP range: 2017**




## Demand

Until July 12, 2017 the default synchronized reserve requirement was set to 1,450 MW in both the Mid-Atlantic Dominion Subzone and the RTO Zone (Table 10-15). On July 12, 2017, PJM adopted a dynamic reserve requirement set equal to 150 percent of the largest contingency, determined hourly, based on the forecasted dispatch. There are two circumstances in which PJM may alter the synchronized reserve requirement from its 150 percent of the largest contingency 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.[26] 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. The synchronized reserve requirement was increased for a two hour period on May 10, 2017 to 1,680 MW. The synchronized reserve requirement was increased for 23 hours from September 30, through October 1, 2017, for a temporary switching condition. The synchronized reserve requirement was increased to 2,728 MW for 41

25 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.

26 PJM "Manual 11: Energy & Ancillary Services Market Operations," Rev. 92 (Nov. 1, 2017) at 88.

hours from October 16, 2017 through October 18, 2017, for a temporary switching condition. The synchronized reserve requirement was increased to 1,890 MW for 62 hours from November 28, 2017 through November 30, 2017, for a temporary switching condition.

### Table 10-15 Default Tier 2 Synchronized Reserve Markets required MW, RTO Zone and Mid-Atlantic Dominion Subzone

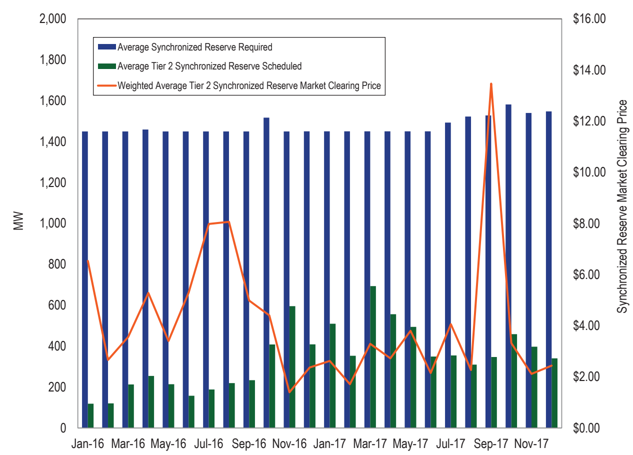
| Mid-Atlantic Dominion Subzone | | | RTO Synchronized Reserve Zone | | |
|---|---|---|---|---|---|
| From Date | To Date | Required MW | From Date | To Date | Required MW |
| May 10, 2008 | May 8, 2010 | 1,150 | May 10, 2008 | Jan 1, 2009 | 1,305 |
| May 8, 2010 | Jul 13, 2010 | 1,200 | Jan 1, 2009 | 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 | Jul 11, 2017 | 1,450 | Jan 8, 2015 | Jul 11, 2017 | 1,450 |
| Jul 12, 2017 | | Calculated Hourly | Jul 12, 2017 | | Calculated Hourly |

In 2017 the average hourly synchronized reserve requirement was 1,504.8 MW. From July 12, 2017 through December 31, 2017 (dynamically determined synchronized reserve requirement) the average requirement was 1,559.8 MW.

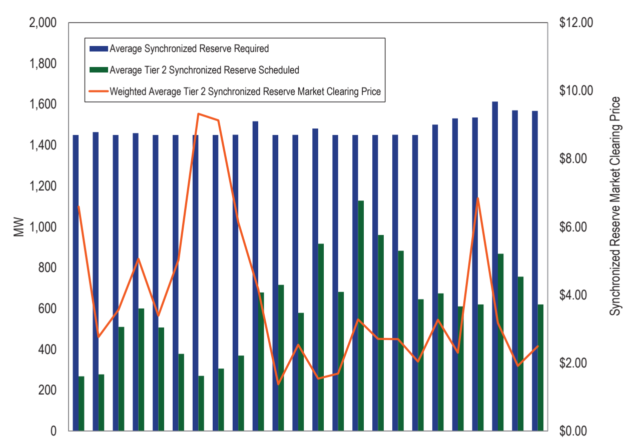
The RTO Reserve Zone purchased an hourly average of 688.8 MW of tier 2 synchronized reserves in 2017. Of this, an average of 323.0 MW cleared within the MAD Subzone.

Figure 10-8 and Figure 10-9 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 December 2017, for the RTO Reserve Zone and MAD Reserve Subzone. The shortage pricing on September 21, 2017, was the result of a nine-hour period of ACE control problems.[27] PJM called a low ACE spinning event during hour 14. There were 11 intervals of step 1 primary reserve shortage (NSRMCP=$300), and two intervals of step 2 synchronized reserve shortage (SRMCP=$300). In three subsequent intervals the SRMCP reached $768.59. The hourly SRMCP for September 21, hour 14 was $465.30.

### Figure 10-8 MAD monthly average tier 2 synchronized reserve scheduled MW: 2016 through, 2017




### Figure 10-9 RTO monthly average tier 2 synchronized reserve scheduled MW: 2016 through 2017




27 See the *2017 State of the Market Report for PJM*, Volume 2: Section 3, Energy Market, Scarcity for a full analysis of the September 21, 2017, scarcity event.

## Market Concentration

The HHI for tier 2 synchronized reserve for cleared hours in the Mid-Atlantic Dominion Subzone Tier 2 Synchronized Reserve Market in 2017 was 5927, which is defined as highly concentrated. The largest hourly market share was 100 percent and 99.9 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 2017 was 6543, which is defined as highly concentrated. The largest hourly market share was 100 percent and 94.1 percent of cleared hours had a maximum market share greater than or equal to 40 percent.

In the MAD Subzone, flexible synchronized reserve was 7.2 percent of all tier 2 synchronized reserve in 2017. In the RTO Zone, flexible synchronized reserve assigned was 12.1 percent of all tier 2 synchronized reserve during the same period.

The MMU calculates that 66.7 percent of hours would have failed the three pivotal supplier test in the MAD Subzone in 2017 for the inflexible Synchronized Reserve Market (excluding self scheduled synchronized reserve) in the hour ahead market (Table 10-16) and 58.9 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: 2016 through, 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 | Average | 87.2% | 45.3% |
| | | | |
| 2017 | Jan | 79.3% | 67.0% |
| 2017 | Feb | 73.8% | 57.6% |
| 2017 | Mar | 72.6% | 38.3% |
| 2017 | Apr | 75.0% | 51.0% |
| 2017 | May | 70.9% | 69.8% |
| 2017 | Jun | 62.6% | 84.9% |
| 2017 | Jul | 57.3% | 69.5% |
| 2017 | Aug | 34.8% | 71.0% |
| 2017 | Sep | 53.7% | 66.4% |
| 2017 | Oct | 72.8% | 38.5% |
| 2017 | Nov | 71.2% | 47.4% |
| 2017 | Dec | 75.9% | 45.1% |
| 2017 | Average | 66.7% | 58.9% |

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

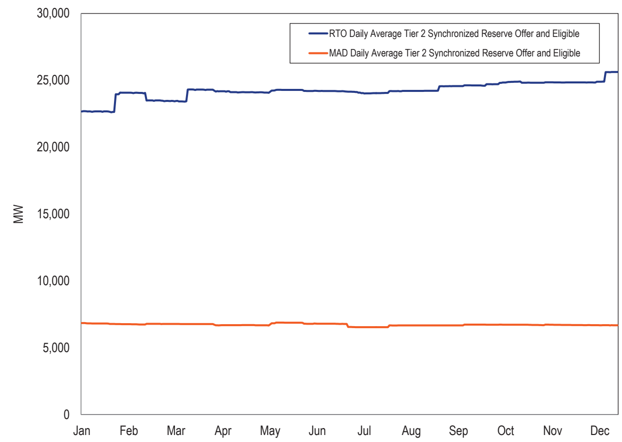
### Offers

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. Certain defined resource types are not required to offer tier 2 because they cannot reliably provide synchronized reserve. These include: nuclear, wind, solar, landfill gas and energy storage resources.[28]

Figure 10-10 shows the daily average of hourly offered tier 2 synchronized reserve MW for both the RTO Synchronized Reserve Zone and the Mid-Atlantic Dominion Synchronized Reserve Subzone. In 2017, the ratio of online and eligible tier 2 synchronized reserve to synchronized reserve required in the Mid-Atlantic Dominion Subzone was 4.66 averaged over all hours. For the RTO Synchronized Reserve Zone the ratio was 4.69.

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 required regardless of online/offline state.[29] 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 10-10). 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.

**Figure 10-10 Tier 2 synchronized reserve hourly offer and eligible volume (MW), averaged daily: 2017**




Of all nonemergency resources capable of reliably producing synchronized reserve and therefore obligated to offer, an average of 3.4 percent of units capable of providing tier 2 synchronized reserve did not enter a daily tier 2 synchronized reserve offer in 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.[30]

Figure 10-11 shows average offer MW volume by market and unit type for the MAD Subzone and Figure 10-12 shows average offer MW volume by market and unit type for the RTO Zone.

28 See PJM "Manual 11: Energy & Ancillary Services Market Operations," Rev. 92 (Nov. 1, 2017) at 72.
29 See *id.* ("Regardless of online/offline state, all non-emergency generation capacity resources must submit a daily offer for Tier 2 Synchronized Reserve in eMKT…").
30 PJM has adopted a new business rule in the third quarter of 2017 to enforce compliance with the tier 2 must-offer requirement. PJM enters a zero dollar offer price for all units with a must offer obligation for tier 2 synchronized reserves.

Figure 10-11 MAD average daily tier 2 synchronized reserve offer by unit type (MW): 2014 through 2017

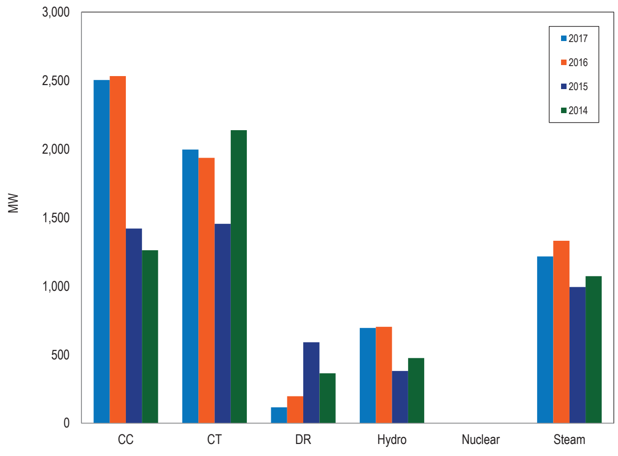
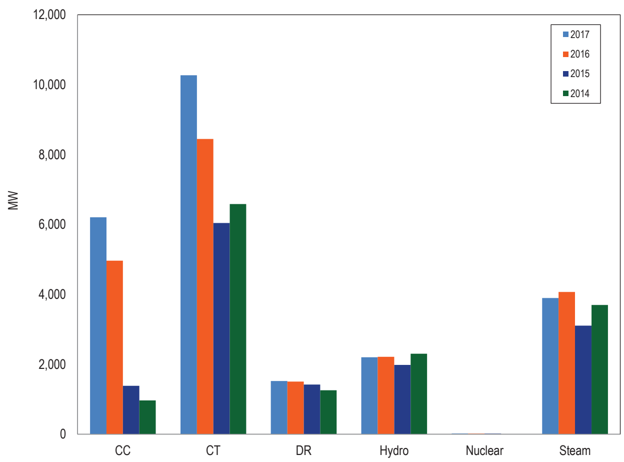



Figure 10-12 RTO Zone average daily tier 2 synchronized reserve offer by unit type (MW): 2014 through 2017




## 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 Synchronized Reserve Market for synchronized reserves.

In 2017, a Tier 2 Synchronized Reserve Market was cleared for the MAD Subzone in 99.3 percent of all hours. In 0.7 percent of hours there was enough tier 1 synchronized reserve or self-scheduled tier 2 reserve to cover the full requirement. The MAD tier 2 market cleared an average of 319.6 MW at a weighted average clearing price of $3.27 compared to $4.15 in 2016.

In 2017, the Tier 2 Synchronized Reserve Market for the RTO Zone cleared an average of 564.8 MW at a weighted average price of $3.71 compared to $4.88 in 2016.

In 97.7 percent of cleared hours, the synchronized reserve market clearing price was the same for both the MAD Subzone and the RTO Zone. In the 2.3 percent of hours when the price diverged, the average clearing price was $20.60 in the MAD Subzone, and $12.63 in the RTO Zone.

Supply, performance, and demand are reflected in the price of synchronized reserve. (Figure 10-8 and Figure 10-9).

### Table 10-17 MAD Subzone, weighted average SRMCP and average scheduled, tier 1 estimated and demand response MW: 2016 through 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 | 1,263.5 | 62.2 |
| 2016 | Feb | $1.99 | 205.3 | 1,230.1 | 63.1 |
| 2016 | Mar | $3.07 | 386.8 | 993.3 | 97.8 |
| 2016 | Apr | $4.62 | 500.9 | 912.4 | 125.7 |
| 2016 | May | $2.88 | 432.0 | 956.5 | 96.6 |
| 2016 | Jun | $4.34 | 311.7 | 1,116.9 | 67.1 |
| 2016 | Jul | $7.98 | 188.0 | 1,254.7 | 46.8 |
| 2016 | Aug | $8.06 | 219.2 | 1,228.4 | 50.5 |
| 2016 | Sep | $4.66 | 230.6 | 1,170.6 | 43.6 |
| 2016 | Oct | $4.00 | 407.9 | 1,086.1 | 58.8 |
| 2016 | Nov | $1.28 | 595.1 | 774.8 | 92.8 |
| 2016 | Dec | $2.21 | 408.7 | 995.0 | 69.5 |
| 2016 | Average | $4.15 | 341.0 | 1,089.7 | 72.9 |
| | | | | | |
| 2017 | Jan | $2.25 | 356.1 | 981.6 | 96.0 |
| 2017 | Feb | $1.75 | 233.2 | 1,111.6 | 110.5 |
| 2017 | Mar | $2.87 | 453.3 | 767.4 | 140.5 |
| 2017 | Apr | $2.80 | 362.4 | 896.9 | 128.4 |
| 2017 | May | $3.26 | 376.8 | 1,164.6 | 126.2 |
| 2017 | Jun | $2.12 | 379.6 | 1,373.0 | 91.3 |
| 2017 | Jul | $3.24 | 353.3 | 1,391.9 | 89.4 |
| 2017 | Aug | $2.05 | 226.9 | 1,438.3 | 110.2 |
| 2017 | Sep | $11.56 | 339.7 | 1,419.2 | 113.1 |
| 2017 | Oct | $2.98 | 348.1 | 1,364.2 | 138.8 |
| 2017 | Nov | $2.08 | 245.9 | 1,392.1 | 144.3 |
| 2017 | Dec | $2.38 | 160.0 | 1,411.5 | 139.8 |
| 2017 | Average | $3.28 | 319.6 | 1,226.0 | 119.0 |

### Table 10-18 RTO zone weighted average SRMCP and average scheduled, tier 1 estimated and demand response MW: 2016 through2017

| 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 | Average | $4.88 | 455.1 | 1,399.0 | 94.0 |
| | | | | | |
| 2017 | Jan | $2.16 | 730.6 | 1,020.4 | 96.0 |
| 2017 | Feb | $1.89 | 508.3 | 1,172.0 | 110.5 |
| 2017 | Mar | $3.81 | 693.1 | 654.2 | 140.5 |
| 2017 | Apr | $2.89 | 623.0 | 805.1 | 128.4 |
| 2017 | May | $3.48 | 560.7 | 924.1 | 126.2 |
| 2017 | Jun | $2.24 | 568.8 | 1,413.5 | 91.3 |
| 2017 | Jul | $4.15 | 667.6 | 1,540.1 | 89.4 |
| 2017 | Aug | $2.72 | 517.0 | 1,512.8 | 110.2 |
| 2017 | Sep | $12.60 | 496.6 | 1,368.9 | 113.1 |
| 2017 | Oct | $3.55 | 528.5 | 1,104.3 | 138.8 |
| 2017 | Nov | $2.30 | 465.6 | 1,173.6 | 144.3 |
| 2017 | Dec | $3.00 | 417.8 | 1,308.4 | 139.8 |
| 2017 | Average | $3.73 | 564.8 | 1,166.5 | 119.0 |

## 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 2017, the price to cost (including self scheduled) ratio of the RTO Zone Tier 2 Synchronized Reserve Market averaged 41.8 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): 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 | 242,160 | $1,821,697 | $2.25 | $7.52 | 29.9% |
| MAD Subzone | 2017 | Feb | 137,103 | $1,354,202 | $1.75 | $9.88 | 17.7% |
| MAD Subzone | 2017 | Mar | 328,192 | $2,611,457 | $2.87 | $7.96 | 36.1% |
| MAD Subzone | 2017 | Apr | 229,057 | $1,780,751 | $2.80 | $7.77 | 36.0% |
| MAD Subzone | 2017 | May | 231,704 | $1,960,763 | $3.26 | $8.46 | 38.5% |
| MAD Subzone | 2017 | Jun | 170,078 | $1,586,215 | $2.12 | $9.33 | 22.7% |
| MAD Subzone | 2017 | Jul | 193,231 | $2,367,906 | $3.24 | $12.25 | 26.4% |
| MAD Subzone | 2017 | Aug | 157,259 | $1,269,006 | $2.05 | $8.07 | 25.4% |
| MAD Subzone | 2017 | Sep | 172,568 | $3,631,598 | $11.56 | $21.04 | 54.9% |
| MAD Subzone | 2017 | Oct | 217,186 | $2,703,322 | $2.98 | $12.45 | 23.9% |
| MAD Subzone | 2017 | Nov | 157,391 | $1,350,024 | $2.08 | $8.58 | 24.3% |
| MAD Subzone | 2017 | Dec | 138,151 | $1,296,784 | $2.25 | $9.39 | 24.0% |
| MAD Subzone | 2017 | | 2,374,080 | $23,733,724 | $3.27 | $10.23 | 32.0% |
| | | | | | | | |
| RTO Zone | 2017 | Jan | 464,500 | $3,282,394 | $2.16 | $7.07 | 30.5% |
| RTO Zone | 2017 | Feb | 316,299 | $2,014,318 | $1.89 | $6.37 | 29.7% |
| RTO Zone | 2017 | Mar | 488,009 | $4,297,595 | $3.81 | $8.81 | 43.2% |
| RTO Zone | 2017 | Apr | 438,444 | $3,567,451 | $2.89 | $8.14 | 35.6% |
| RTO Zone | 2017 | May | 418,051 | $3,302,941 | $3.48 | $7.90 | 44.1% |
| RTO Zone | 2017 | Jun | 284,845 | $2,233,462 | $2.24 | $7.84 | 28.6% |
| RTO Zone | 2017 | Jul | 306,615 | $3,518,497 | $4.15 | $11.48 | 36.1% |
| RTO Zone | 2017 | Aug | 268,260 | $1,935,732 | $2.72 | $7.22 | 37.7% |
| RTO Zone | 2017 | Sep | 296,111 | $4,972,581 | $12.60 | $16.79 | 75.0% |
| RTO Zone | 2017 | Oct | 401,595 | $3,878,155 | $3.55 | $9.66 | 36.8% |
| RTO Zone | 2017 | Nov | 343,474 | $2,389,690 | $2.30 | $6.96 | 33.1% |
| RTO Zone | 2017 | Dec | 341,179 | $2,858,839 | $2.77 | $8.39 | 33.1% |
| RTO Zone | 2017 | | 4,367,382 | $38,251,656 | $3.71 | $8.88 | 41.8% |

## 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.[31] 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.[32] Tier 2 resources are obligated to sustain their final output for the 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 2017, there have been 16 spinning events, six of which were 10 minutes or longer.

Tier 1 resource owners are paid for the actual amount of synchronized reserve they provide in response to a

31 See *2011 State of the Market Report for PJM*, Vol. 2, Section 9, "Ancillary Services," at 250.

32 See PJM "Manual 11: Energy & Ancillary Services Market Operations," Rev. 92 (Nov. 1, 2017) § 4.2.11 Verification at 97.

synchronized reserve event.[33] 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.[34] The penalty period is calculated as the average number of days between spinning events. For 2017, PJM used the average number of days between spinning events from November 2015 through October 2016 which is 13 days.[35] 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 were six synchronized reserve events of 10 minutes or longer in 2017. For those six events, 12.4 percent of all scheduled tier 2 synchronized reserve MW were not delivered and were penalized (Table 10-20).

### Table 10-20 Synchronized reserve events 10 minutes or longer, tier 2 response compliance, RTO Reserve Zone: 2017

| Spin Event (Day, Time) | Duration (Minutes) | Tier 1 Estimate (MW Adj by DGP) | Tier 1 Response (MW) | Tier 2 Scheduled (MW) | Tier 2 Response (MW) | Tier 2 Penalty (MW) | Tier 1 Response Percent | Tier 2 Response Percent |
|---|---|---|---|---|---|---|---|---|
| Mar 23, 2017 06:48 | 24 | 926.8 | 549.6 | 742.8 | 559.1 | 183.7 | 59.3% | 75.3% |
| Apr 8, 2017 11:53 | 10 | 1,222.6 | 827.2 | 879.3 | 828.7 | 50.6 | 67.7% | 94.2% |
| May 8, 2017 04:18 | 10 | 1,325.6 | 976.3 | 335.1 | 298.5 | 36.6 | 73.6% | 89.1% |
| Jun 8, 2017 03:39 | 10 | 974.4 | 726.7 | 575.7 | 522.4 | 53.3 | 74.6% | 90.7% |
| Sep 4, 2017 20:03 | 15 | 476.3 | 68.1 | 601.0 | 563.8 | 37.2 | 14.3% | 93.8% |
| Sep 21, 2017 14:15 | 16 | 305.8 | 217.4 | 1,253.9 | 1,037.3 | 216.6 | 71.1% | 82.7% |
| 2017 Average | 14.2 | 871.9 | 560.9 | 731.3 | 635.0 | 96.3 | 60.1% | 87.6% |

## History of Synchronized Reserve Events

Synchronized reserve is designed to provide relief for disturbances.[36] [37] A disturbance is defined as loss of 1,000 MW of generation and/or transmission resources within 60 seconds. 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 five low ACE events in 2017, on January 12, 2017 for 8 minutes, February 13, 2017 for 7 minutes, March 23, 2017 for 24 minutes, June 20, 2017 for 9 minutes, and September 21, 2017 for 16 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 30 minutes. When the need is for reserve extending past 30 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.

33 See *id.* at 98.

34 See PJM. "Manual 28: Operating Agreement Accounting," Rev. 76 (June 1, 2017) p. 47. *See also* PJM "Manual 11: Energy & Ancillary Services Market Operations," Rev. 92 (Nov. 1, 2017) § 4.2.12 Non-Performance, p. 99.

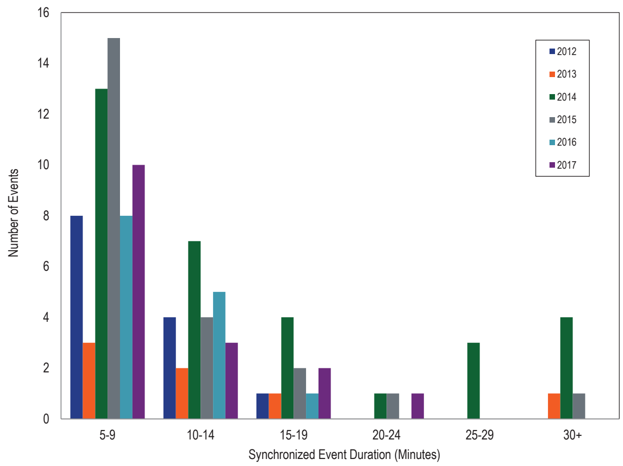
35 "2016 Third Quarter Synchronized Reserve Performance & 2017 Synchronized Reserve Penalty Days," presentation to the Operating Committee, December 13, 2016. <http://www.pjm.com/~/media/committees-groups/committees/oc/20161213/20161213-item-16-2016-third-quarter-synchronized-reserve-performance-with-2017-penalty-days.ashx>.

36 *2013 State of the Market Report for PJM*, Appendix F – PJM's DCS Performance, at 451-452.

37 See PJM "Manual 12: Balancing Operations," Rev. 37 (Nov. 16, 2017) § 4.1.2 Loading Reserves at 40.

From January 1, 2010 through December 31, 2017, PJM experienced 207 synchronized reserve events (Table 10-21), approximately 2.1 events per month. During this period, synchronized reserve events had an average duration of 12.2 minutes.

Figure 10-13 Synchronized reserve events duration distribution curve: 2012 through 2017



## Table 10-21 Synchronized reserve events: 2010 through 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 | | | | | | |

| 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 | APR-08-2017 11:53 | RTO | 10 |
| JAN-26-2014 17:11 | RTO | 6 | APR-25-2015 03:21 | RTO | 9 | SEP-11-2016 19:30 | RTO | 9 | MAY-08-2017 04:18 | RTO | 10 |
| JAN-31-2014 15:05 | RTO | 13 | JUL-30-2015 14:04 | RTO | 10 | OCT-12-2016 08:21 | RTO | 5 | JUN-08-2017 03:39 | RTO | 10 |
| FEB-02-2014 14:03 | Dominion | 8 | AUG-05-2015 19:47 | RTO | 7 | OCT-12-2016 14:40 | RTO | 7 | JUN-20-2017 05:38 | RTO | 9 |
| FEB-08-2014 06:05 | Dominion | 18 | AUG-19-2015 16:47 | RTO | 9 | NOV-04-2016 17:13 | RTO | 11 | SEP-04-2017 20:18 | MAD | 15 |
| FEB-22-2014 23:05 | RTO | 7 | SEP-05-2015 01:16 | RTO | 7 | DEC-03-2016 00:11 | RTO | 7 | SEP-07-2017 09:16 | RTO | 9 |
| MAR-01-2014 05:18 | RTO | 26 | SEP-10-2015 10:12 | RTO | 8 | DEC-31-2016 05:10 | RTO | 12 | SEP-21-2017 14:15 | RTO | 16 |
| 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 | | | | | | | | | |

## 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 and is based on parameters in offers submitted by resource owners. 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

Prior to July 12, 2017, PJM specified that 2,175 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). As of July 12, 2017, the largest contingency is calculated dynamically in every synchronized and nonsynchronized reserve market solution and the primary requirement is set equal to 150 percent of the largest expected contingency within the upcoming hour. 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. On May 10, 2017 the default primary reserve requirement for the RTO Reserve Zone was raised from 2,175 MW to 2,550 MW for three hours.

The RTO Zone demand for nonsynchronized reserve increased significantly on May 10, 2017, as a result of the PJM rule change that increased the primary reserve requirement in the MAD Subzone from 1,700 MW to 2,175 MW. In addition, this increase changed the mix of scheduled MW from mostly hydro to mostly CT resources.

On July 12, 2017, PJM adopted a dynamic hourly calculation of the largest contingency. On September 30, 2017, the primary reserve requirement was fixed at 2,365 MW for 24 consecutive hours. Between October 16 and October 18, 2017, the primary reserve requirement was set to 3,997 MW for 41 hours. On November 29, 2017, the primary reserve requirement was set to 2,740 MW for 42 hours.

The average hourly demand for primary reserve from July 12, 2017 through December 31, 2017 was 2,243.5 MW.

#### 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 nonsynchronized 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 times 10 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 that can start in 10 minutes or less, combined cycles and diesels.[38] In 2017, an average of 1,053.2 MW of nonsynchronized reserve was scheduled hourly out of 2,171.5 eligible MW as part of the primary reserve requirement in the RTO Zone.

In 2017, CTs provided 52.2 percent of scheduled nonsynchronized reserve and hydro provided 46.8 percent. The remaining 1.1 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 2017.

### Table 10-22 Nonsynchronized reserve market HHIs: 2017

| Year | Month | MAD HHI | RTO HHI |
|---|---|---|---|
| 2017 | Jan | 5538 | 5525 |
| 2017 | Feb | 5404 | 5402 |
| 2017 | Mar | 5679 | 5653 |
| 2017 | Apr | 4858 | 4847 |
| 2017 | May | 4213 | 4209 |
| 2017 | Jun | 3922 | 3922 |
| 2017 | Jul | 4106 | 4105 |
| 2017 | Aug | 4084 | 4084 |
| 2017 | Sep | 3806 | 3802 |
| 2017 | Oct | 3391 | 3391 |
| 2017 | Nov | 3125 | 3123 |
| 2017 | Dec | 2841 | 2841 |
| 2017 | Average | 4247 | 4242 |

### Table 10-23 Nonsynchronized reserve market pivotal supply test: 2017

| Year | Month | RTO Three Pivotal Supplier Hours |
|---|---|---|
| 2017 | Jan | 32.2% |
| 2017 | Feb | 31.1% |
| 2017 | Mar | 38.1% |
| 2017 | Apr | 38.1% |
| 2017 | May | 52.3% |
| 2017 | Jun | 60.4% |
| 2017 | Jul | 55.9% |
| 2017 | Aug | 57.1% |
| 2017 | Sep | 70.8% |
| 2017 | Oct | 82.1% |
| 2017 | Nov | 57.1% |
| 2017 | Dec | 92.5% |
| 2017 | Average | 55.6% |

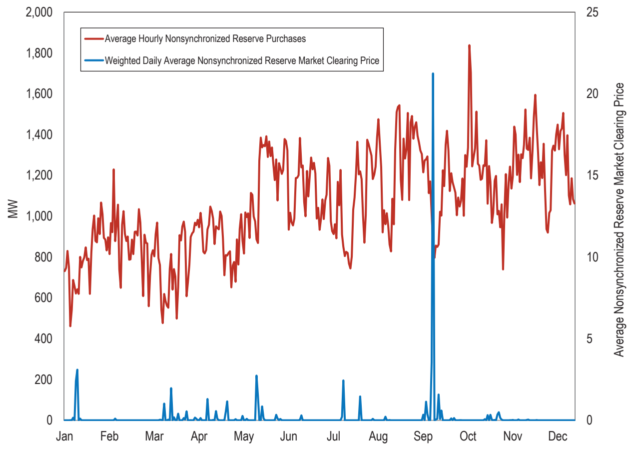
## Price

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 10-14 shows the daily average nonsynchronized reserve market clearing price and average scheduled MW for the RTO Zone. In 2017, the average nonsynchronized market clearing price was $0.13 per MW. The hourly average nonsynchronized reserve assigned was 1,053.2 MW. The market cleared at a price greater than $0 in 152 hours. The maximum hourly clearing price was $388.72 per MW on September 21, 2017 during the course of a low ACE spinning event.

38 See PJM "Manual 11: Energy & Ancillary Services Market Operations," Rev. 92 (Nov. 1, 2017) at 101.

**Figure 10-14 Daily average RTO Zone nonsynchronized reserve market clearing price and MW purchased: 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.[39]

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 nonsynchronized reserve.

In 2017, the price to cost ratio for the RTO Zone was 17.2 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 1.7 percent of hours. The nonsynchronized reserve market clearing price was the same in the RTO zone and MAD Subzone in all but 53 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.

39 See PJM "Manual 11: Energy & Ancillary Services Market Operations," Rev. 92 (Nov. 1, 2017) at 103.

Table 10-24 RTO Zone nonsynchronized reserve MW, charges, price, and cost: 2016 through 2017

| Market | Year | Month | Total Nonsynchronized Reserve MW | Total Nonsynchronized Reserve Charges | Weighted Nonsynchronized Reserve Market Price | Nonsynchronized Reserve Cost | Price/Cost Ratio |
|---|---|---|---|---|---|---|---|
| RTO Zone | 2016 | Jan | 688,475 | $1,334,376 | $0.30 | $1.94 | 15.6% |
| RTO Zone | 2016 | Feb | 638,024 | $672,413 | $0.11 | $1.05 | 10.0% |
| RTO Zone | 2016 | Mar | 657,739 | $405,829 | $0.31 | $0.62 | 49.6% |
| RTO Zone | 2016 | Apr | 644,913 | $786,978 | $0.35 | $1.22 | 28.5% |
| RTO Zone | 2016 | May | 636,927 | $274,583 | $0.05 | $0.43 | 10.9% |
| RTO Zone | 2016 | Jun | 579,356 | $613,656 | $0.04 | $1.06 | 3.6% |
| RTO Zone | 2016 | Jul | 604,267 | $407,660 | $0.07 | $0.67 | 9.6% |
| RTO Zone | 2016 | Aug | 585,751 | $782,948 | $0.25 | $1.34 | 18.6% |
| RTO Zone | 2016 | Sep | 616,146 | $666,839 | $0.15 | $1.08 | 13.9% |
| RTO Zone | 2016 | Oct | 722,690 | $650,190 | $0.42 | $0.90 | 46.8% |
| RTO Zone | 2016 | Nov | 554,057 | $308,101 | $0.03 | $0.56 | 4.7% |
| RTO Zone | 2016 | Dec | 525,505 | $289,433 | $0.00 | $0.55 | 0.1% |
| RTO Zone | 2016 | Total | 7,453,849 | $7,193,007 | $0.17 | $0.95 | 18.0% |
| | | | | | | | |
| RTO Zone | 2017 | Jan | 585,294 | $384,707 | $0.15 | $0.66 | 23.0% |
| RTO Zone | 2017 | Feb | 599,301 | $171,893 | $0.00 | $0.29 | 1.2% |
| RTO Zone | 2017 | Mar | 548,021 | $382,743 | $0.14 | $0.70 | 20.2% |
| RTO Zone | 2017 | Apr | 653,581 | $357,047 | $0.13 | $0.55 | 24.4% |
| RTO Zone | 2017 | May | 796,190 | $508,149 | $0.16 | $0.64 | 25.4% |
| RTO Zone | 2017 | Jun | 841,672 | $351,251 | $0.03 | $0.42 | 7.4% |
| RTO Zone | 2017 | Jul | 745,694 | $876,884 | $0.13 | $1.18 | 11.1% |
| RTO Zone | 2017 | Aug | 874,602 | $548,271 | $0.01 | $0.63 | 1.4% |
| RTO Zone | 2017 | Sep | 867,103 | $1,229,492 | $0.73 | $1.42 | 51.6% |
| RTO Zone | 2017 | Oct | 929,944 | $713,508 | $0.02 | $0.77 | 2.5% |
| RTO Zone | 2017 | Nov | 850,863 | $727,515 | $0.05 | $0.86 | 5.5% |
| RTO Zone | 2017 | Dec | 936,590 | $772,028 | $0.00 | $0.82 | 0.1% |
| RTO Zone | 2017 | Total | 9,228,856 | $7,023,487 | $0.13 | $0.76 | 17.1% |

## 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. The Day-Ahead Scheduling Reserve 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.[40]

## 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 30 minutes, or the economic maximum MW minus the day-ahead dispatch point. For offline resources capable of being online in 30 minutes, the DASR quantity is the economic maximum. In 2017, the average available hourly DASR was 36,547.8 MW, a 5.1 percent increase from 2016. The DASR hourly MW purchased averaged 5,608.8 MW, a decrease from 6,072.5 MW in 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.[41] 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.

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 outages in real time.[42] The recovery was for hours cleared from April 2015 through March 2016. This recovery is completed for a total of $404,000.

40 See PJM "Manual 11: Energy & Ancillary Services Market Operations," Rev. 92 (Nov. 1, 2017) at 155 §11.2.7.

41 See PJM "Manual 11: Energy & Ancillary Services Market Operations," Rev. 92 (Nov. 1, 2017) at 152 §11.2.2 Day-Ahead Scheduling Reserve Market Eligibility.

42 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>.

Of the 5,608.8 MW average hourly DASR cleared in 2017, 66.5 percent was from CTs, 9.0 percent was from steam, 18.0 percent was from hydro, and 6.0 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 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.[43] 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."[44] The amount of additional DASR MW that may be required is the Adjusted Fixed Demand (AFD) determined by a Seasonal Conditional Demand (SCD) factor.[45] The SCD factor is calculated separately for the winter (November through March) and summer (April through October) seasons. The SCD factor is calculated every year based on the top 10 peak load days from the prior year. For November 2016 through October 2017, the SCD values are 4.72 percent for winter and 2.77 percent for summer. For November 2017 through March of 2018 the value is 3.89 percent. PJM Dispatch may also schedule additional Day-Ahead Scheduling Reserves as deemed necessary for conservative operations.[46] 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.[47] The result is substantial discretion for PJM to increase the demand for DASR under a variety of circumstances. PJM invoked adjusted fixed demand on 13 days during 2017. All days were between May 17 and September 26. 58 of the top 60 hours with highest DASR market clearing price were all during days when adjusted fixed demand was invoked.

The MMU recommends that PJM modify the DASR Market to ensure that all resources cleared incur a real-time performance obligation.

## Market Concentration

DASR market three pivotal supplier test results are provided in Table 10-25.

### Table 10-25 DASR market three pivotal supplier test results and number of hours with DASRMCP above $0: 2016 through 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 | Apr | 402 | 9.5% |
| 2017 | May | 250 | 44.0% |
| 2017 | Jun | 242 | 37.8% |
| 2017 | Jul | 341 | 36.8% |
| 2017 | Aug | 165 | 8.3% |
| 2017 | Sep | 179 | 12.8% |
| 2017 | Oct | 154 | 0.7% |
| 2017 | Nov | 92 | 3.2% |
| 2017 | Dec | 72 | 17.1% |
| 2017 | Average | 200 | 15.9% |

43 See PJM "Manual 13: Emergency Operations," Rev. 65 (Jan. 1, 2018) at 12.

44 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>.

45 See PJM "Manual 11: Energy & Ancillary Services Market Operations," Rev. 92 (Nov. 1, 2017) at 166 at 11.2.1 Day-Ahead Scheduling Reserve Market Requirement.

46 See PJM "Manual 11: Energy & Ancillary Services Market Operations," Rev. 92 (Nov. 1, 2017) at 167 at 11.2.1 Day-Ahead Scheduling Reserve Market Requirement.

47 See PJM "Manual 13: Emergency Operations," Rev. 64, (June 1, 2017) at 58 at 3.2 Conservative Operations.

## 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.[48] Units that do not offer have their offers set to $0.00 per MW during the day-ahead market clearing process.

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 2017, 39.2 percent of generation units offered DASR at a daily price above $0.00. This compares to 36.2 percent in 2016. In 2017, 14.8 percent of daily offers were above $5.00 per MW.

## Market Performance

In 2017, the DASR Market cleared at a price above $0 in 2,398 hours. The weighted average DASR price for all 2,398 hours when the DASRMCP was above $0.00 was $2.11. In 2016, the weighted average DASR price for all hours when the DASRMCP was above $0.00 was $2.99. In 2017, the average cleared MW in all hours was 4,477.3 MW. The average cleared MW in all hours when the DASRMCP was above $0.00 was 5,233.1 MW. The highest DASR price was $174.45 on September 25, 2017.

The introduction of Adjusted Fixed Demand (AFD) on March 1, 2015, created a bifurcated market (Table 10-27). 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. In 2017, PJM added AFD to the normal 5.52 percent of forecast load in 336 hours. The difference in market clearing price, MW cleared, obligation incurred, and charges to PJM load are substantial (Table 10-26).

Table 10-26 Impact of Adjusted Fixed Demand on DASR prices and demand: 2017

| Metric | Year | Number Hours | Weighted Day-Ahead Scheduling Reserve Market Clearing Price (DASRMCP) | Average Additional DASR MW | Average Hourly Total DASR MW |
|---|---|---|---|---|---|
| All Hours | 2017 | 8,761 | $0.85 | 173.3 | 4,477.4 |
| All Hours when DASRMCP > $0 | 2017 | 2,398 | $2.11 | 555.4 | 5,233.1 |
| All Hours when AFD is used | 2017 | 336 | $9.07 | 4,519.7 | 10,194.9 |

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.

48 See PJM "Manual 11: Energy & Ancillary Services Market Operations," Rev. 92 (Nov. 1, 2017) p. 152.

### Table 10-27 DASR Market, regular hours vs. adjusted fixed demand hours: 2016 through 2017

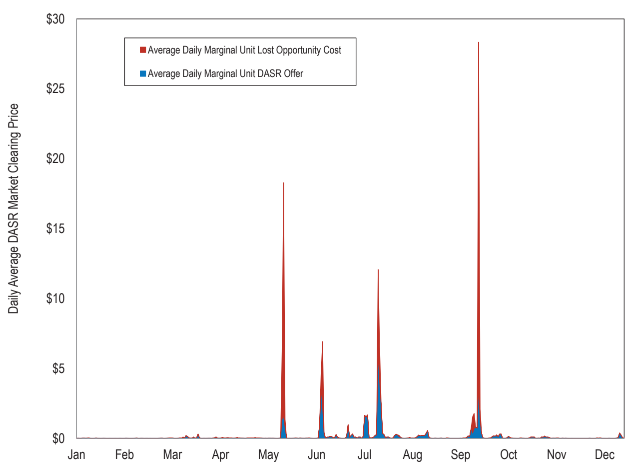
| | | Number of Hours DASRMCP>$0 | | Weighted DASRMCP | | Average PJM Load MW | | Hourly Average Cleared DASR MW | | Average Hourly DASR Credits | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | Month | Normal Hour | AFD Hour | Normal Hour | AFD Hour | Normal Hour | AFD Hour | Normal Hour | AFD Hour | Normal Hour | AFD Hour |
| 2016 | Jan | 326 | 0 | $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 | $0.04 | | 83,994 | | 4,175 | | $175 | |
| 2016 | Apr | 393 | 0 | $0.26 | | 80,925 | | 4,083 | | $1,060 | |
| 2016 | May | 259 | 0 | $0.43 | | 89,181 | | 4,228 | | $1,839 | |
| 2016 | Jun | 191 | 0 | $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 | | 82,824 | | 4,265 | | $2,494 | |
| 2016 | Nov | 350 | 0 | $0.10 | | 84,561 | | 4,095 | | $420 | |
| 2016 | Dec | 210 | 0 | $0.04 | | 102,293 | | 4,444 | | $169 | |
| 2016 | Total | 3,434 | 522 | $0.40 | $8.42 | 98,355 | 111,301 | 4,761 | 10,092 | $2,047 | $91,249 |
| | | | | | | | | | | | |
| 2017 | Jan | 93 | 0 | $0.02 | | 106,095 | | 4,386 | | $91 | |
| 2017 | Feb | 49 | 0 | $0.02 | | 96,628 | | 4,444 | | $92 | |
| 2017 | Mar | 359 | 0 | $0.08 | | 91,182 | | 4,092 | | $329 | |
| 2017 | Apr | 402 | 0 | $0.04 | | 80,834 | | 3,828 | | $159 | |
| 2017 | May | 250 | 48 | $0.07 | $18.13 | 85,581 | 98,184 | 4,004 | 10,727 | $280 | $194,491 |
| 2017 | Jun | 242 | 73 | $0.18 | $6.63 | 108,482 | 116,172 | 5,099 | 11,713 | $907 | $77,542 |
| 2017 | Jul | 341 | 115 | $0.29 | $6.41 | 114,832 | 117,568 | 5,288 | 10,669 | $1,551 | $68,397 |
| 2017 | Aug | 165 | 12 | $0.42 | $1.23 | 114,916 | 125,601 | 5,515 | 10,585 | $2,318 | $12,980 |
| 2017 | Sep | 179 | 22 | $1.17 | $40.30 | 105,850 | 104,097 | 5,111 | 11,652 | $5,960 | $466,893 |
| 2017 | Oct | 154 | 0 | $0.33 | | 89,402 | | 4,404 | | $1,446 | |
| 2017 | Nov | 92 | 0 | $0.20 | | 91,098 | | 4,950 | | $972 | |
| 2017 | Dec | 72 | 0 | $0.27 | | 110,878 | | 5,675 | | $1,542 | |
| 2017 | Total | 2,398 | 270 | $0.26 | $14.54 | 100,489 | 112,324 | 4,641 | 11,317 | $1,298 | $164,060 |

The implementation of AFD in 522 hours of 2016 and 270 hours of 2017 significantly increased the cost of DASR as a result of increases in DASR MW cleared and corresponding increases in the DASR clearing prices (Table 10-28).

Table 10-28 DASR Market all hours of DASR market clearing price greater than $0: 2016 through 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 | 3,932 | | | 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 | $117,995 |
| 2017 | Apr | 402 | $0.04 | 80,834 | 1,539,010 | 0 | $63,852 |
| 2017 | May | 250 | $6.76 | 87,849 | 1,303,480 | 246,420 | $8,809,449 |
| 2017 | Jun | 242 | $3.20 | 110,611 | 1,677,956 | 383,822 | $5,365,628 |
| 2017 | Jul | 341 | $3.39 | 115,755 | 2,422,053 | 516,238 | $8,216,211 |
| 2017 | Aug | 165 | $0.53 | 115,693 | 970,853 | 49,896 | $510,353 |
| 2017 | Sep | 179 | $10.59 | 105,635 | 1,058,754 | 136,480 | $11,207,356 |
| 2017 | Oct | 154 | $0.33 | 89,402 | 678,175 | | $222,717 |
| 2017 | Nov | 92 | $0.20 | 91,098 | 455,371 | | $89,460 |
| 2017 | Dec | 72 | $0.27 | 110,878 | 408,569 | | $111,029 |
| 2017 | Average | 200 | $2.12 | 100,138 | 1,050,733 | 148,095 | $2,893,914 |
| 2017 | Total | 2,398 | | | 12,608,800 | 1,332,856 | $34,726,963 |

Figure 10-15 Daily average components of DASR clearing price ($/MW), marginal unit offer and LOC: 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 10-15). DASR prices increase at peak loads as a result of high LOCs. DASR prices were low to moderate in January through April, 2017. The weighted average DASRMCP on September 25, 2017, of $28.34 per MW was a three year high. A hot weather alert declared for that day led to 142,119 MW additional DASR and three consecutive hourly DASR prices above $100.

# 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.

## Market Design

PJM's regulation market design is a result of Order No. 755.[49] The objective of PJM's regulation market design is to minimize the cost to provide regulation using two resource types in a single market.

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

49 *Frequency Regulation Compensation in the Organized Wholesale Power Markets*, Order No. 755, 137 FERC ¶ 61,064 at P 2 (2011).

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 MBF and performance score translate a RegD resource's capability (actual) MW into marginal effective MW and offers into $/effective MW.

The regulation market solution is intended to meet the regulation requirement with the least cost combination of RegA and RegD. When solving for the least cost combination of RegA and RegD MW to meet the regulation requirement, the Regulation Market will substitute RegD MW for RegA MW when RegD is cheaper. Performance adjusted RegA MW are used as the common unit of measure, called effective MW, of regulation service. All resource MW (RegA and RegD) are converted into effective MW. RegA MW are converted into effective MW by multiplying the RegA MW offered by their performance score. RegD MW are converted into effective MW by multiplying the RegD offered by their performance score and by the marginal benefit function (MBF). The regulation requirement is defined as the total effective MW required to provide a defined amount of area control error (ACE) control.

The Regulation Market converts performance adjusted RegD MW into effective MW using the marginal benefit function (MBF) in the PJM design. The MBF is used to convert incremental additions of RegD MW into incremental effective MW. The total effective MW for a given amount of RegD MW equal the area under the MBF curve (the sum of the incremental effective MW contributions). RegA and RegD resources should be paid the same price per marginal effective MW.

The 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. The MBF should be equal to the marginal rate of technical substitution (MRTS) between RegA and RegD, holding the level of regulation service constant. The MRTS is the marginal measure of substitutability of RegD resources for RegA resources in satisfying a defined regulation requirement at feasible combinations of RegA and RegD MW. Consistently applying the MBF from optimization to settlement is the only way to ensure that the rate of substitution between RegA and RegD in providing a defined level of regulation is reflected in the relative value of RegA and RegD resources. 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.

At any valid combination of RegA and RegD, regulation offers are converted to dollars per effective MW using the RegD offer and the MBF associated with that combination of RegA and RegD. The marginal contribution of a RegD MW to effective MW 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 MBF of 0.5 and a performance score of 100 percent would be calculated as offering 0.5 effective MW (0.5 MBF 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).

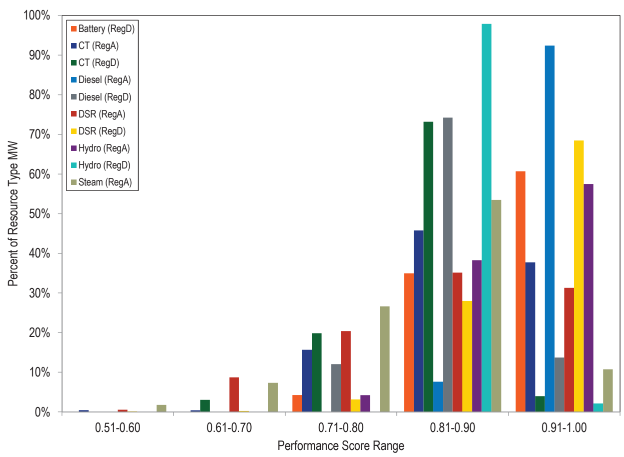
Regulation performance scores (0.0 to 1.0) measure the response of a regulating resource to its assigned regulation signal (RegA or RegD) every 10 seconds by measuring: delay, the time delay of the regulation response to a change in the regulation signal; correlation, the correlation between the regulating resource output and the regulation signal; and precision, the difference between the regulation response and the regulation requested.[50] Performance scores are reported on an hourly basis for each resource.

Figure 10-16 and Figure 10-17 show the average performance score by resource type and the signal followed in 2017. In these figures, the MW used are

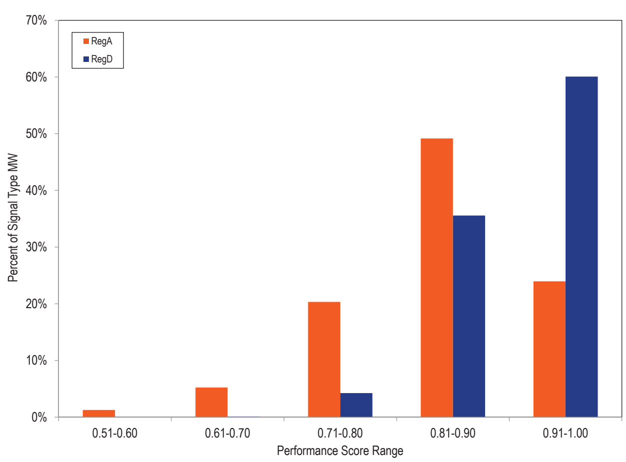
50 PJM "Manual 12: Balancing Operations," Rev. 37 (Nov. 16, 2017) at 4.5.6, p 54.

actual MW and the performance score is the hourly performance score of the regulation resource.[51] Each category (color bar) is based on the percentage of the full performance score distribution for each resource (or signal) type. As Figure 10-17 shows, 60.0 percent of RegD resources had average performance scores within the 0.91-1.00 range, and 24.0 percent of RegA resources had average performance scores within that range.

### Figure 10-16 Hourly average performance score by unit type: 2017




### Figure 10-17 Hourly average performance score by regulation signal type: 2017




Each cleared resource in a class (RegA or RegD) is allocated a portion of the class signal (RegA or RegD). This portion of the class signal is based on the cleared regulation MW of the resource relative to the cleared MW cleared for that class. This signal is called the Total Regulation Signal (TREG) for the resource. A resource with 10 MW of capability will be provided a TREG signal asking for a positive or negative regulation movement between negative and positive 10 MW around its regulation set point.

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 12 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. This is done so the total of RMPCP plus RMCCP equals the total clearing price (RMCP) but the RMPCP is maximized.

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.

## Market Design Issues

PJM's current regulation market design is severely flawed and does not follow the appropriate basic design logic. The market results do not represent the least cost solution for the defined level of regulation service.

51 Except where explicitly referred to as effective MW or effective regulation MW, MW means actual MW unadjusted for either MBF or performance factor.

To address the identified market flaws, the MMU and PJM developed a joint proposal which was approved by the PJM Members Committee on July 27, 2017 and filed with FERC on October 17, 2017.[52] The PJM/MMU joint proposal addresses issues with the inconsistent application of the marginal benefit factor throughout the optimization and settlement process in the PJM Regulation Market.

The MBF related issues with the Regulation Market have been raised in the PJM stakeholder process. In 2015, PJM stakeholders approved an interim, partial 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 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 implemented on January 9, 2017. These modifications included 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.

The January design changes appear to have been intended to make RegD more valuable. That is not a reasonable design goal. The design goal should be to determine the least cost way to provide needed regulation. The RegA signal is now slower than it was previously, which may make RegA following resources less useful as ACE control. RegA is now explicitly used to support the conditional energy neutrality of RegD. The RegD signal is now the difference between ACE and RegA. RegA is required to offset RegD when RegD moves in the opposite direction of that required by ACE control in order to permit RegD to recharge. These changes in the signal design will allow PJM to accommodate more RegD in its market solutions. The new signal design is not making the most efficient use of RegA and RegD resources. The explicit reliance on RegA to offset issues with RegD is a significant conceptual change to the design that is inconsistent with the long term design goal for regulation. PJM increased the regulation requirement as part of these changes.

The January design changes replaced off peak and on peak hours with nonramp and ramp hours with definitions that vary by season. The regulation requirement for ramp hours was increased from 700 MW to 800 MW (Table 10-29). These market changes still do not address the fundamental issues in the optimization or the lack of consistency in the application of the MBF.

### Table 10-29 Seasonal regulation requirement definitions[53]

| Season | Dates | Nonramp Hours | Ramp Hours |
|---|---|---|---|
| Winter | Dec 1 - Feb 28(29) | 00:00 - 03:59<br>09:00 - 15:59 | 04:00 - 08:59<br>16:00 - 23:59 |
| Spring | Mar 1 - May 31 | 00:00 - 04:59<br>08:00 - 16:59 | 05:00 - 07:59<br>17:00 - 23:59 |
| Summer | Jun 1 - Aug 31 | 00:00 - 04:59<br>14:00 - 17:59 | 05:00 - 13:59<br>18:00 - 23:59 |
| Fall | Sep 1 - Nov 30 | 00:00 - 04:59<br>08:00 - 16:59 | 05:00 - 07:59<br>17:00 - 23:59 |

## Performance Scores

Performance scores, by class and unit, are not an indicator of how well resources contribute to ACE control. Performance scores are an indicator only of how well the resources follow their TREG signal. High performance scores with poor signal design are not a meaningful measure of performance. For example, if ACE indicates the need for more regulation but RegD resources have provided all their available energy, the RegD regulation signal will be in the opposite direction of what is needed to control ACE. So, despite moving in the wrong direction for ACE control, RegD resources would get a good performance score for following the RegD signal and will be paid for moving in the wrong direction.

The RegD signal prior to January 9, 2017, is an example of a signal that resulted in high performance scores, but due to 15 minute energy neutrality built into the signal, ran counter to ACE control at times. Energy neutrality means that energy produced equals energy used within a defined timeframe. With 15 minute energy neutrality, if a battery were following the regulation signal to provide MWh for 7.5 minutes, it would have to consume the same amount of MWh for the next 7.5 minutes. When neutrality correction of the RegD signal is triggered, it

52 18 CFR § 385.211 (2017)

53 See PJM. "Regulation Requirement Definition," <http://www.pjm.com/~/media/markets-ops/ancillary/regulation-requirement-definition.ashx>.

overrides ACE control in favor of achieving zero net energy over the 15 minute period. When this occurs, the RegD signal runs counter to the control of ACE and hurts rather than helps ACE. In that situation, the control of ACE, which must also offset the negative impacts of RegD, depends entirely on RegA resources following the RegA signal. High performance scores under the signal design prior to January 9, 2017, was not an indication of good ACE control.

The January design changes did not address the fundamental issues with the definition of performance or the nature of payments for performance in the regulation market design. The regulation signal should not be designed to favor a particular technology. The signal should be designed to result in the lowest cost of regulation to the market. Only with a performance score based on full substitutability among resource types should payments be based on following the signal. The MRTS must be redesigned to reflect the actual capabilities of technologies to provide regulation. The PJM regulation market design remains fundamentally flawed.

In addition, the absence of a performance 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.

## Regulation Signal

With any signal design for substitutable resources, the MBF function should be determined by the ability of RegA and RegD resources to follow the signal, including conditions under which neutrality cannot be maintained by RegD resources. The ability of energy limited RegD to provide ACE control depends on the availability of excess RegA capability to support RegD under the conditional neutrality design. When RegD resources are largely energy limited resources, a correctly calculated MBF would exhibit a rapid decrease in the MBF value for every MW of RegD added. This means that only a small amount of energy limited RegD is economic. The current and proposed signals and corresponding MBF functions do not reflect these principles or the actual substitutability of resource types.

## MBF Issues

The MBF function, as implemented in the PJM Regulation Market, is not equal to the MRTS between RegA and RegD. The MBF is not consistently applied throughout the market design, from optimization to settlement, and market clearing does not confirm that the resulting combinations of RegA and RegD are realistic and can meet the defined regulation demand. The calculation of total regulation cleared using the MBF is incorrect.[54]

The result has been that the PJM Regulation Market has over procured RegD relative to RegA in most hours, has provided a consistently inefficient market signal to participants regarding the value of RegD in every hour, and has overpaid for RegD. In 2015, 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 PJM/MMU joint proposal, filed with FERC on October 17, 2017,[55] addresses issues with the inconsistent application of the marginal benefit factor throughout the optimization and settlement process in the PJM Regulation Market.

## Marginal Benefit Factor Not Correctly Defined

The MBF used in the PJM Regulation Market did not accurately reflect the MRTS between RegA and RegD resources under the old market design and it does not accurately reflect the MRTS between RegA and RegD resources under the modified design. The MBF function is incorrectly defined and improperly implemented in the current PJM Regulation Market.

The MBF should be the marginal rate of technical substitution between RegA and RegD MW at different, feasible combinations of RegA and RegD that can be used to provide a defined level of regulation service. The objective of the market design is to find, given

54 The MBF, as used in this report, refers to PJM's incorrectly calculated MBF and not the MBF equivalent to the MRTS.
55 18 CFR § 385.211 (2017)

the relative costs of RegA and RegD MW, the least cost feasible combination of RegA and RegD MW. If the MBF 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 and may not be a feasible way to reach the target level of regulation.

The MBF 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 implemented a FERC order that required the MBF to be fixed at 1.0 for settlement calculations only. On October 2, 2013, FERC directed PJM to eliminate the use of the MBF 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.[56] That rule continues in effect. The result of the current FERC order is that the MBF is used in market clearing to determine the relative value of an additional MW of RegD, but the MBF is not used in the settlement for RegD.

If the MBF were consistently applied, every resource would receive the same clearing price per marginal effective MW. But the MBF is not consistently applied and resources do not receive the same clearing price per marginal effective MW.

While prices are set on the basis of dollars per effective MW, only RegA resources receive payments based on this price per effective MW.[57] RegA resources are paid the RMCCP times MW times the performance factor times the MBF, plus the RMPCP times MW times the performance factor times the MBF. (The RegA MBF is 1.0.) RegD resources do not receive payments based on this price per effective MW. RegD resources are paid the RMCCP times MW times the performance factor, plus the RMPCP times MW times the performance factor times the mileage ratio.[58] As a result, the current market design does not send the correct price signal to the RegD resources.

56 145 FERC ¶ 61,011 (2013).

57 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.

58 Performance adjusted RegD MW are converted to effective MW by multiplying the performance adjusted MW by the market clearing MRTS.

Figure 10-18 compares the daily average MBF and the mileage ratio for excursion and nonexcursion hours. Excursion hours (hours ending 7:00, 8:00, 18:00-21:00) were hours in which PJM had decided that more RegA was needed and PJM would not clear any RegD with an MBF less than 1.0.[59] Excursion hours were discontinued by PJM as of July 31, 2017. The shift in both the MBF values and the mileage ratio (Figure 10-18) resulted from the design changes implemented on January 9, 2017.

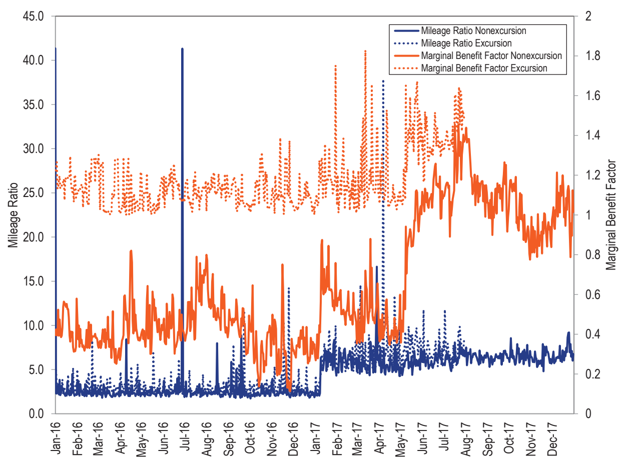
The change in design decreased RegA mileage (the change in MW output in response to regulation signal per MW of capability), increased the proportion of cleared RegD resources' capability that was called by the RegD signal (increased REG for a given MW) to better match offered capability, increased the mileage required of RegD resources and changed the energy neutrality component of the signal from a strict 15 minute neutrality to a conditional 30 minute neutrality. The changes in signal design increased the mileage ratio (the ratio of RegD mileage to RegA mileage). In addition, to adapt to the 30 minute neutrality requirement, RegD resources decreased their offered capability to maintain their performance. The reduction in offered capability reduced the amount of RegD MW clearing and increased the amount of RegA MW clearing, meaning a higher MBF in every hour.

The weighted average mileage ratio during nonexcursion hours increased from 2.70 in 2016, to 6.11 in 2017 (an increase of 126.6 percent). The high mileage ratio values are the result of the mechanics of the mileage ratio calculation. The extreme mileage ratios result when the RegA signal is fixed at a single value ("pegged") to control ACE and the RegD signal is not. If RegA is held at a constant MW output, mileage is zero for RegA. The result of a fixed RegA signal is that RegA mileage is very small and therefore the mileage ratio is very large.

These results are an example of why it is not appropriate to use the mileage ratio, rather than the MBF, to measure the relative value of RegA and RegD resources. In these events, RegA resources are providing ACE control by providing a fixed level of MW output which means zero mileage, while RegD resources alternate between helping and hurting ACE control, both of which result in positive mileage.

59 See "PJM Manual 11: Energy & Ancillary Services Market Operations," Rev. 91 (July 27, 2017) at 69.

## Figure 10-18 Daily average MBF and mileage ratio during excursion and nonexcursion hours: 2016 through 2017[60]




The increase in the average mileage ratio caused by the signal design changes introduced on January 9, 2017 caused a large increase in payments to RegD resources on a performance adjusted MW basis. The average daily payment per performance adjusted RegD MW increased by 66.1 percent, from $17.43 in the period from January 1, 2016, through January 8, 2017, to $28.94 in the period between January 9, 2017, and December 31, 2017.

Table 10-30 shows RegD resource payments on a performance adjusted MW basis and RegA resource payments on a performance adjusted MW basis by month, from January 1, 2016, through December 31, 2017. In 2016, RegD resources earned 12.1 percent more per performance adjusted MW than RegA resources. In 2017, RegD resources earned 78.7 percent more per performance adjusted MW than RegA resources.

## Table 10-30 Average monthly price paid per performance adjusted MW of RegD and RegA: 2016 through 2017

| | | Settlement Payments | | |
|---|---|---|---|---|
| Year | Month | RegD ($/Performance Adjusted RegD MW) | RegA ($/Performance Adjusted MW) | Percent Performance Adjusted RegD/RegA Under/Over Payment |
| 2016 | Jan | $17.20 | $15.60 | 10.3% |
| | Feb | $19.55 | $17.56 | 11.3% |
| | Mar | $15.00 | $13.21 | 13.5% |
| | Apr | $21.10 | $18.87 | 11.8% |
| | May | $18.31 | $15.42 | 18.8% |
| | Jun | $14.93 | $13.81 | 8.1% |
| | Jul | $19.34 | $17.48 | 10.6% |
| | Aug | $18.57 | $17.15 | 8.3% |
| | Sep | $19.38 | $17.47 | 10.9% |
| | Oct | $17.58 | $15.44 | 13.9% |
| | Nov | $15.39 | $13.01 | 18.3% |
| | Dec | $12.38 | $11.15 | 11.0% |
| 2016 Yearly | | $17.39 | $15.51 | 12.1% |
| 2017 | Jan | $17.07 | $13.62 | 25.4% |
| | Feb | $16.58 | $10.64 | 55.8% |
| | Mar | $26.76 | $15.06 | 77.7% |
| | Apr | $32.60 | $15.58 | 109.2% |
| | May | $28.45 | $17.89 | 59.0% |
| | Jun | $28.88 | $13.23 | 118.2% |
| | Jul | $28.49 | $15.00 | 89.9% |
| | Aug | $32.06 | $13.24 | 142.1% |
| | Sep | $37.89 | $21.33 | 77.6% |
| | Oct | $32.37 | $16.11 | 100.9% |
| | Nov | $26.81 | $15.62 | 71.7% |
| | Dec | $36.00 | $25.13 | 43.3% |
| 2017 Yearly | | $28.66 | $16.04 | 78.7% |

The current settlement process does not result in paying RegA and RegD resources 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 MBF is not used in settlements. When the MBF is above one, RegD resources are underpaid on a per effective MW basis, although this could be offset by a high mileage ratio. When the MBF is less than one, RegD resources are overpaid on a per effective MW basis. The average MBF was less than 1.0 in 2016 (0.60) and 2017 (0.96), resulting in an average overpayment of RegD resources.

The effect of using the mileage ratio instead of the MBF to convert RegD MW into effective MW for purposes of settlement is illustrated in Table 10-31. Table 10-31 compares the monthly average payment to RegD per effective MW under the current settlement process to the monthly average payment RegD resources should have received using the MBF to convert RegD MW to effective MW. This also shows that using the MBF would result in RegA and RegD resources being paid exactly the same on a per effective MW basis. The MBF averaged less than one in each month of 2016, while the average daily mileage ratio was 2.79, resulting in RegD resources being paid $14.6 million (1,565.7 percent) more than they should have been paid per effective MW in

60 Excursion hours were discontinued as of 00:00 on July 31, 2017.

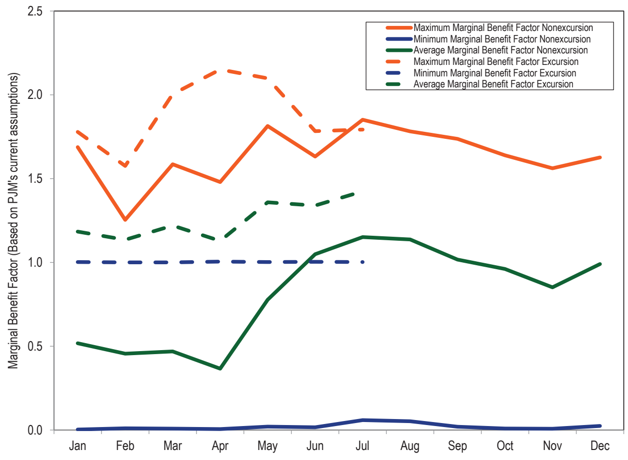
2016. In 2017, the MBF average was higher, but also averaged less than one in six months of the year, while the average daily mileage ratio was 6.32, resulting in RegD resources being paid $17.4 million (288.3 percent) more than they should have been.

### Table 10-31 Average monthly price paid per effective MW of RegD and RegA under mileage and MBF based settlement: 2016 through 2017

| | | RegD Settlement Payments | | | | |
|---|---|---|---|---|---|---|
| Year | Month | Mileage Based ($/Effective RegD MW) | Marginal Rate of Technical Substitution Based ($/Effective RegD MW) | RegA ($/Effective MW) | Percent RegD Under/ Over Payment | Total RegD Under/ Over Payment ($) |
| 2016 | Jan | $30.61 | $15.60 | $15.60 | 96.2% | $1,319,364 |
| | Feb | $43.33 | $17.56 | $17.56 | 146.8% | $1,591,651 |
| | Mar | $70.02 | $13.21 | $13.21 | 430.1% | $1,375,711 |
| | Apr | $90.59 | $18.87 | $18.87 | 380.1% | $1,335,655 |
| | May | $449.89 | $15.42 | $15.42 | 2,817.9% | $1,452,512 |
| | Jun | $181.02 | $13.81 | $13.81 | 1,210.8% | $996,391 |
| | Jul | $782.84 | $17.48 | $17.48 | 4,378.3% | $884,677 |
| | Aug | $43.91 | $17.15 | $17.15 | 156.1% | $985,398 |
| | Sep | $1,057.96 | $17.47 | $17.47 | 5,954.5% | $1,259,051 |
| | Oct | $166.40 | $15.44 | $15.44 | 977.9% | $1,251,166 |
| | Nov | $36.01 | $13.01 | $13.01 | 176.8% | $1,109,221 |
| | Dec | $57.00 | $11.15 | $11.15 | 411.4% | $1,041,258 |
| 2016 Yearly | | $258.17 | $15.50 | $15.50 | 1,565.7% | $14,602,055 |
| 2017 | Jan | $80.44 | $13.62 | $13.62 | 490.7% | $956,485 |
| | Feb | $293.97 | $10.64 | $10.64 | 2,662.3% | $1,161,959 |
| | Mar | $80.90 | $15.06 | $15.06 | 437.2% | $1,977,295 |
| | Apr | $79.84 | $15.58 | $15.58 | 412.4% | $2,848,281 |
| | May | $34.79 | $17.89 | $17.89 | 94.4% | $1,229,953 |
| | Jun | $24.18 | $13.23 | $13.23 | 82.7% | $1,498,653 |
| | Jul | $22.16 | $15.00 | $15.00 | 47.7% | $995,254 |
| | Aug | $26.53 | $13.24 | $13.24 | 100.4% | $1,881,033 |
| | Sep | $35.67 | $21.33 | $21.33 | 67.2% | $1,588,929 |
| | Oct | $33.29 | $16.11 | $16.11 | 106.7% | $1,675,170 |
| | Nov | $27.43 | $15.62 | $15.62 | 75.6% | $1,145,674 |
| | Dec | $30.24 | $25.13 | $25.13 | 20.3% | $479,142 |
| 2017 Yearly | | $62.44 | $16.08 | $16.08 | 288.3% | $17,437,828 |

Figure 10-19 shows, for 2017, the maximum, minimum and average MBF, by month, for excursion and nonexcursion hours. The average MBF during excursion hours from January 1, 2017, to July 30, 2017, was 1.26, and the average MBF during nonexcursion hours in 2017 was 0.84. The average MBF during excursion hours in 2016 was 1.12, and the average MBF during nonexcursion hours in 2016 was 0.41. The floor MBF for excursion hours was set to 1.0.

### Figure 10-19 Maximum, minimum, and average PJM calculated MBF by month for excursion and nonexcursion hours: 2017[61]




61 Excursion hours were discontinued as of 00:00 on July 31, 2017.

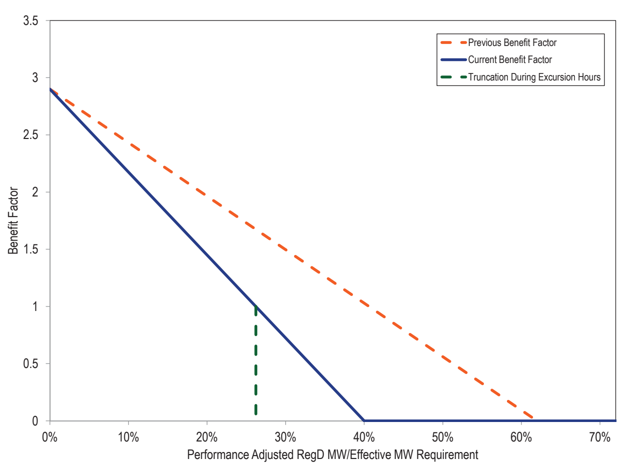
The increase in the average MBF seen in Figure 10-19 during the second quarter of 2017 is a result of a decrease in the eligible and cleared RegD MW. Table 10-32 shows performance adjusted and effective MW that were eligible and cleared during 2016 and 2017.

### Table 10-32 Performance adjusted and effective RegD MW eligible and cleared: 2016 and 2017

| Performance Adjusted RegD MW | | | |
|---|---|---|---|
| | 2016 | 2017 | Change |
| Actual Eligible | 375.2 | 316.3 | (15.7%) |
| Effective Eligible | 340.9 | 316.3 | (7.2%) |
| Actual Cleared | 223.4 | 186.6 | (16.5%) |
| Effective Cleared | 339.5 | 309.2 | (8.9%) |

Figure 10-20 shows the MBF curve before and after the December 14, 2015, modification. Figure 10-20 shows the change in RegA for a change in RegD (MBF of RegD on the y-axis) for given ratio of RegD MW as a percentage of the effective MW requirement (Percentage RegD on the x-axis). The objective of the modification of the MBF was to reduce the operational issues caused by the over procurement of RegD. The modification to the MBF curve reduced the amount of RegD procured, but did not correct for identified issues with the definition of the MBF that are causing the over procurement to occur.

### Figure 10-20 MBF 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 MBF throughout the optimization, assignment and settlement process.[62]

## MBF Creates Results in Market Solutions that are not Feasible

An additional significant problem that results from using the incorrect MBF is that the 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 even when there are not enough RegA MW clearing the market to support this market solution.

The problem is illustrated in Table 10-33, for both the MBF curve used prior to December 14, 2015, and the current MBF curve. In Table 10-33, the contribution to the total regulation requirement of 800.0 MW for a ramp hour is given on both a performance adjusted RegD MW basis and effective RegD MW basis. For example, if the market cleared 320.0 MW of performance adjusted RegD (40 percent of the 800.0 performance adjusted MW needed) at a price of zero, the market would calculate that as 464.0 effective MW of RegD (area under curve) consistent with the MBF of 0.00, and determine it would need 336.0 MW of RegA to meet the 800.0 MW requirement using the current MBF curve. The resulting proportion of actual RegD MW to total regulation cleared would be 48.8 percent for the current MBF curve (320.0 actual RegD MW/(320.0 actual RegD MW + 336.0 actual RegA)), rather than the 40.0 percent defined 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 than under the prior MBF curve (48.8 percent versus 65.1 percent), the error is not eliminated. The result should be to maintain the desired proportions of RegA and RegD regardless of the amount of RegD cleared. To do this, the MBF must be defined as the relationship between RegA MW and RegD MW, rather than the percent of RegD.

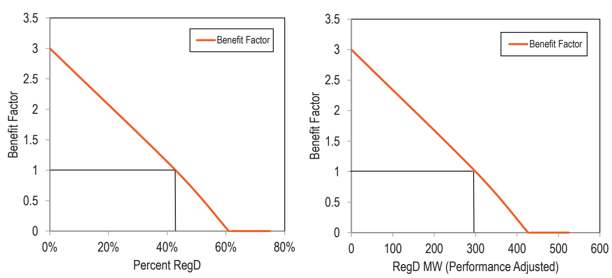
62 See "Regulation Market Review," Operating Committee meeting (May 5, 2015) <http://www.pjm.com/~/media/committees-groups/committees/oc/20150505/20150505-item-17-regulation-market-review.ashx>.

Table 10-33 MBF assumed RegD proportions versus market solution realized RegD proportions[63]

| RegD Percent of 800 MW | RegD MW (Performance Adjusted) | MBF (Previous) | MBF (Current) | Effective MW from RegD MW (Previous) | Effective MW from RegD MW (Current) | Residual A (800 MW Target, Previous) | Residual A (800 MW Target, Current) | RegD/ (RegA+RegD, Previous) | RegD/ (RegA+RegD, Current) |
|---|---|---|---|---|---|---|---|---|---|
| 5.0% | 40.0 | 2.67 | 2.54 | 111.3 | 108.8 | 688.7 | 691.3 | 5.5% | 5.5% |
| 10.0% | 80.0 | 2.43 | 2.18 | 213.3 | 203.0 | 586.7 | 597.0 | 12.0% | 11.8% |
| 15.0% | 120.0 | 2.20 | 1.81 | 305.9 | 282.8 | 494.1 | 517.3 | 19.5% | 18.8% |
| 20.0% | 160.0 | 1.96 | 1.45 | 389.2 | 348.0 | 410.8 | 452.0 | 28.0% | 26.1% |
| 25.0% | 200.0 | 1.73 | 1.09 | 463.1 | 398.8 | 336.9 | 401.3 | 37.2% | 33.3% |
| 30.0% | 240.0 | 1.50 | 0.73 | 527.6 | 435.0 | 272.4 | 365.0 | 46.8% | 39.7% |
| 35.0% | 280.0 | 1.26 | 0.36 | 582.8 | 456.8 | 217.2 | 343.3 | 56.3% | 44.9% |
| 40.0% | 320.0 | 1.03 | 0.00 | 628.6 | 464.0 | 171.4 | 336.0 | 65.1% | 48.8% |
| 45.0% | 360.0 | 0.80 | - | 665.1 | - | 134.9 | - | 72.7% | - |
| 50.0% | 400.0 | 0.56 | - | 692.3 | - | 107.7 | - | 78.8% | - |
| 55.0% | 440.0 | 0.33 | - | 710.0 | - | 90.0 | - | 83.0% | - |
| 60.0% | 480.0 | 0.09 | - | 718.5 | - | 81.5 | - | 85.5% | - |

An example illustrates the issue. Figure 10-21 shows the same MBF curve, in terms of RegD percent (left diagram) and RegD MW (right diagram) in a scenario where 700 MW of effective MW are needed and the market clears 300 MW of RegD (actual MW), all priced at $0.00, and 400 MW of RegA. Figure 10-21 shows that the 300 MW of cleared RegD are 42.9 percent of total cleared actual MW and that the MBF is 1.0.

Figure 10-21 Example MBF functions with percent RegD and RegD MW




## The Market Buys Too Much RegD

In 2015, the MMU determined that the PJM market design was buying too much RegD because the regulation market solution understates the amount of effective MW provided by RegD. 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 provided by a single resource (one 100 MW unit) will appear to provide fewer effective MW than 100 MW of RegD provided by two 50 MW units although they provide exactly the same total effective MW. This is the unit block issue.

The understatement of RegD was amplified by the treatment, in the market solution, of all RegD resources with the same price as a single resource for purposes of assigning a benefit factor and calculating total effective MW. All of the MW associated with multiple units with the same price were assigned the MBF of the last MW of the last unit of that block of resources. PJM calculates the total effective MW as the product of the MW and the marginal MBF, rather than the area under the MBF curve. This resulted in understating total effective MW from RegD resources cleared. This price block issue was solved by the modification of December 14, 2015.

The unit block issue was not addressed by the modification made on December 14, 2015. A complete correction of the effective MW calculation requires the use of the area under the curve.

Using PJM's unit block method, all RegD resources are assigned the lowest MBF associated with the last RegD MW purchased. In this example (Figure 10-22), all 300 MW have an MBF of 1.0. PJM calculates total effective MW from RegD resources to be 300 (300 MW x 1.0 = 300 effective MW). In Figure 10-22, PJM's price block/unit block calculation of total effective MW from RegD is represented by the area of the blue rectangle which is 300 effective MW.

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.

63 This example assumes that the calculation of effective MW from RegD was calculated correctly as the area under the MBF curve.

RegD is providing effective MW equal to the area of the green triangle plus the blue rectangle in Figure 10-22. This equals 600 effective MW from RegD resources, not 300 effective MW. The actual total effective MW cleared in the market is 300 more effective MW than needed to meet the regulation requirement.

### Figure 10-22 Illustration of correct method for calculating effective MW

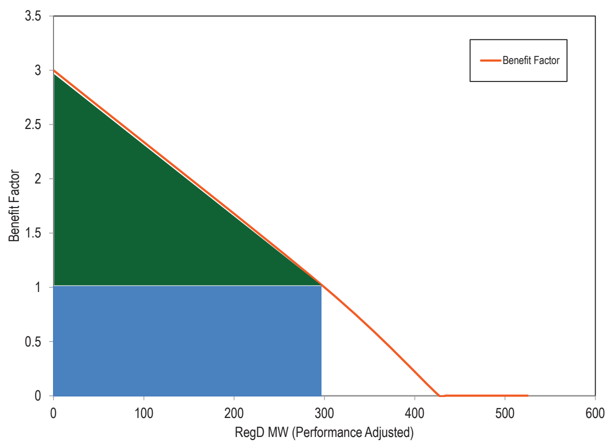
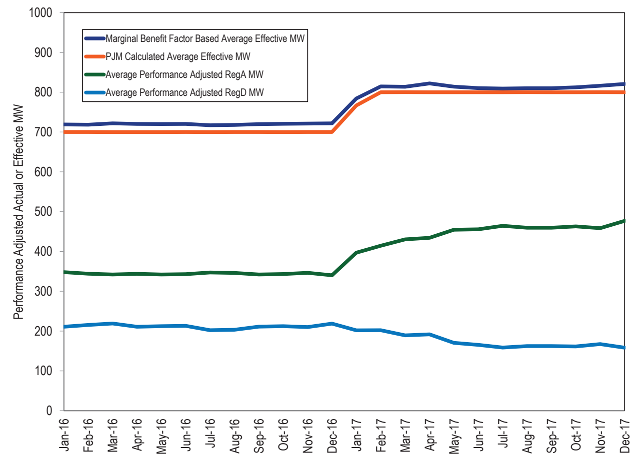



Figure 10-23 shows the average monthly peak and ramp total effective MW as calculated by PJM's MBF and as calculated by a correctly applied MBF for the 2016 and 2017. The figure also shows the monthly average performance adjusted RegA MW and RegD MW cleared in the Regulation Market for the period.

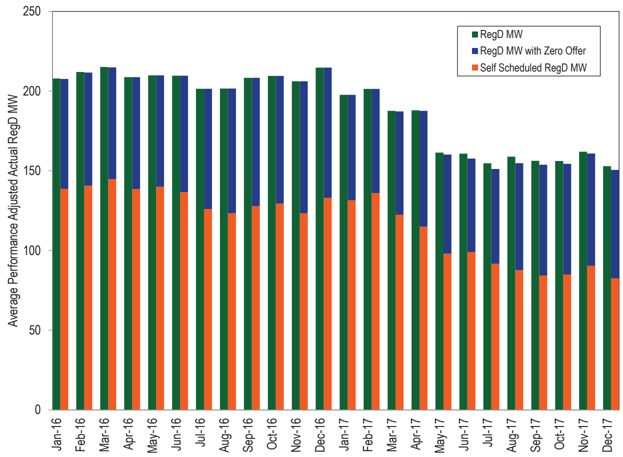
As a result of the changes made on January 9, 2017, the average cleared performance adjusted RegD MW during on peak hours decreased from 218.6 MW in December 2016, to 158.2 (a decrease of 27.6 percent) during ramp hours in December 2017. The average cleared performance adjusted RegA MW during on peak hours increased from 340.2 MW in December 2016, to 476.6 MW (an increase of 40.1 percent) during ramp hours in December 2017.

### Figure 10-23 Average monthly total effective MW and RegA and RegD performance adjusted MW: PJM market calculated versus benefit factor based: 2016 through 2017




The excess procurement of RegD combined with the overpayment of RegD 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 10-24 shows, by month, the proportion of cleared RegD MW with an effective price of $0.00 from January 1, 2016, through December 31, 2017. The figure shows that all RegD MW clearing the market in the period between January 1, 2016, and April 30, 2017, had an effective offer of $0.00. From May 1, 2017 through December 31, 2017, an average of 98.4 percent of cleared RegD MW had an effective cost of $0.00. The total level of RegD clearing the market leveled off beginning in January 2016 because the market cleared the maximum allowed RegD MW. Due to the changes implemented in January 2017, the total level of RegD cleared in the market decreased 24.1 percent in 2017 compared to 2016.

Figure 10-24 Average cleared RegD MW and average cleared RegD with an effective price of $0.00 by month: 2016 through 2017

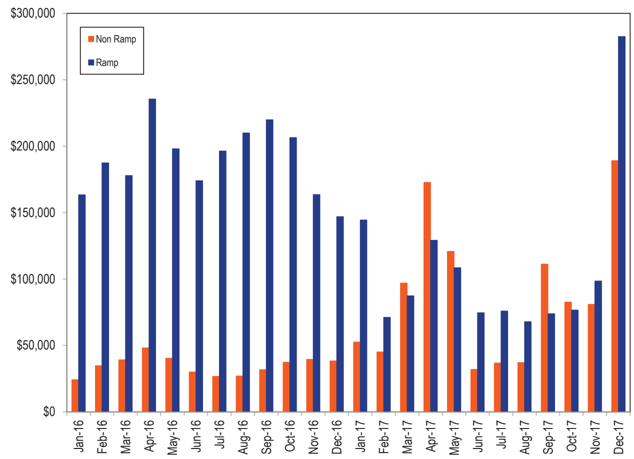



## The Cost of Buying Too Much Regulation

Figure 10-25 shows the estimated cost of the excess effective MW cleared by month, peak and off peak, from January 1, 2017, through December 31, 2017, caused by PJM's calculation of effective MW from RegD resources using mileage rather than MBF. To determine this excess cost, the total effective MW of RegD are calculated using the full area under the PJM MBF curve, and the difference between that value and the value used by PJM is multiplied by the price in each hour. The calculation of excess cost shown in Figure 10-25 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, holding the actual market price and the mileage ratio based settlement constant and ignoring the actual MRTS.

In 2017, the estimated total cost of excess effective RegD MW during ramp and nonramp hours was $1.29 million and $1.06 million. In 2016, the estimated total cost of excess RegD MW during on peak and off peak hours was $2.28 million and $0.42 million. The increase in the cost of excess RegD MW during December 2017 was due to an almost $10 increase in the average clearing price of regulation in that month. The implementation of the partial solution to the effective MW calculation and the changes in the MBF curve in December of 2015 reduced, but did not eliminate, the excess effective MW clearing in the regulation market.

Figure 10-25 Cost of excess effective MW cleared by month, peak and off peak: 2016 through 2017[64]




## Market Structure

### Supply

Table 10-34 shows capability MW (performance adjusted), average daily offer MW (performance adjusted), average hourly eligible MW (performance adjusted and effective), and average hourly cleared MW (performance adjusted and effective) for all hours in 2017.[65] Total MW are adjusted by the historic 100-hour moving average performance score to get performance adjusted MW, and additionally by the resource specific benefit factor to get effective MW. A resource can choose to follow either signal. 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 offered as available for the day. Eligible MW are calculated from the hourly offers from units with daily offers and units that are offered as unavailable for the day, but still offer MW into some hours. Units with daily offers are permitted to offer above or below their daily offer from hour to hour. As a result of these hourly MW adjustments, the average hourly Eligible MW can be higher than the Offered MW.

64 Prior to January 9, 2017, on peak hours were defined between 05:00-23:59, off peak hours were defined as 00:00-04:59. After January 9, 2017, ramp and nonramp hours are defined seasonally. Please see Table 10-1 for a list of what hours are considered ramp and nonramp.

65 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.

In 2017, the average hourly eligible supply of regulation for nonramp hours was 1,136.1 performance adjusted MW (869.0 effective MW). This was a decrease of 90.6 performance adjusted MW (an increase of 7.8 effective MW) from 2016, when the average hourly eligible supply of regulation was 1,226.8 performance adjusted MW (861.2 effective MW). In the 2017, the average hourly eligible supply of regulation for ramp hours was 1,427.2 performance adjusted MW (1,183.4 effective MW). This was an increase of 231.0 performance adjusted MW (233.4 effective MW) from the 2016, when the average hourly eligible supply of regulation was 1,196.3 performance adjusted MW (950.0 effective MW).

The ratio of the average hourly eligible supply of regulation to average hourly regulation demand (performance adjusted cleared MW) for ramp hours was 1.98 in the 2017. This is an increase of 5.4 percent from 2016, when the ratio was 1.88. The ratio of the average hourly eligible supply of regulation to average hourly regulation demand (performance adjusted cleared MW) for nonramp hours was 2.33 in 2017. This is a decrease of 2.0 percent from 2016, when the ratio was 2.38.

### Table 10-34 PJM regulation capability, daily offer and hourly eligible: 2017[66 67]

| | | | By Resource Type | | By Signal Type | |
|---|---|---|---|---|---|---|
| | | All Regulation | Generating Resources | Demand Resources | RegA Following Resources | RegD Following Resources |
| Capability MW | Daily | 10,464.3 | 10,434.8 | 29.5 | 10,082.9 | 706.5 |
| Offered MW | Daily | 4,193.1 | 4,175.9 | 17.2 | 3,857.3 | 335.8 |
| Actual Eligible MW | Ramp | 1,427.2 | 1,413.0 | 14.3 | 1,102.4 | 324.9 |
| | Nonramp | 1,136.1 | 1,122.8 | 13.3 | 828.6 | 307.6 |
| Effective Eligible MW | Ramp | 1,183.4 | 1,164.4 | 19.0 | 822.5 | 360.8 |
| | Nonramp | 869.0 | 853.4 | 15.6 | 598.3 | 270.7 |
| Actual Cleared MW | Ramp | 720.0 | 711.5 | 8.5 | 528.9 | 191.1 |
| | Nonramp | 487.9 | 480.4 | 7.5 | 306.0 | 181.9 |
| Effective Cleared MW | Ramp | 796.6 | 779.3 | 17.3 | 447.2 | 349.5 |
| | Nonramp | 526.9 | 512.2 | 14.6 | 258.9 | 268.0 |

Table 10-35 provides the settled regulation MW by source unit type, the total settled regulation MW provided by all resources, and the percent of settled regulation provided by unit type. In Table 10-35 the MW have been adjusted by the performance score since this adjustment forms the basis of payment for units providing regulation. Total regulation performance adjusted capability MW increased 24.4 percent from 4,912,907.0 MW in 2016 to 6,111,190.2 MW in 2017. The average proportion of regulation provided by battery units had the largest increase, providing 41.2 percent of regulation in 2016 and 46.5 percent of regulation in 2017. Hydro units had the largest decrease in average proportion of regulation provided, decreasing from 18.9 percent in 2016, to 15.0 percent in 2017. The total regulation credits in 2017 were $104,209,864, up 24.0 percent from $84,063,566 in 2016.

### Table 10-35 PJM regulation by source: 2016 and 2017[68]

| | 2016 | | | | 2017 | | | |
|---|---|---|---|---|---|---|---|---|
| Source | Number of Units | Performance Adjusted Settled Regulation (MW) | Percent of Settled Regulation | Total Regulation Credits | Number of Units | Performance Adjusted Settled Regulation (MW) | Percent of Settled Regulation | Total Regulation Credits |
| Battery | 21 | 2,023,139.6 | 41.2% | $31,150,301 | 22 | 2,839,294.4 | 46.5% | $38,907,116 |
| Coal | 49 | 427,069.7 | 8.7% | $9,604,655 | 45 | 401,196.2 | 6.6% | $10,426,826 |
| Hydro | 39 | 926,915.3 | 18.9% | $18,261,418 | 27 | 919,036.7 | 15.0% | $18,440,308 |
| Natural Gas | 152 | 1,489,276.0 | 30.3% | $24,287,130 | 156 | 1,854,870.9 | 30.4% | $35,145,576 |
| DR | 35 | 46,506.5 | 0.9% | $760,062 | 28 | 96,791.9 | 1.6% | $1,290,038 |
| Total | 296 | 4,912,907.0 | 100.0% | $84,063,566 | 278 | 6,111,190.2 | 100.0% | $104,209,864 |

66 Average Daily Offer MW excludes units that have offers but are unavailable for the day.

67 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.

68 Biomass data have been added to the natural gas category for confidentiality purposes.

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 10-36).

Table 10-36 Active battery storage projects in the PJM queue system by submitted year: 2012 to 2017

| Year | Number of Storage Projects | Total Capacity (MW) |
|---|---|---|
| 2012 | 1 | 4.5 |
| 2013 | 0 | 0.0 |
| 2014 | 7 | 128.4 |
| 2015 | 33 | 186.1 |
| 2016 | 9 | 81.6 |
| 2017 | 5 | 91.5 |
| Total | 55 | 492.1 |

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 MBF for RegA resources is 1.0, the effective MW of RegA resources were lower than the offered MW in 2017, because the average performance score was less than 1.00. For 2017, the MW weighted average RegA performance score was 0.85 and there were 221 resources following the RegA signal.

For RegD resources, the total effective MW do not equal performance adjusted MW because the MBF for RegD resources can range from 0.0 to 2.9. In 2017, the MBF for cleared RegD resources ranged from 0.003 to 1.851 with an average over all nonexcursion hours of 0.837 and from 1.000 to 2.151 with an average over all excursion hours of 1.257. In 2017, the MW weighted average RegD resource performance score was 0.91 and there were 61 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 hours (Table 10-29).

Table 10-37 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.

The nonramp regulation requirement of 525.0 effective MW was provided by a combination of RegA and RegD resources equal to 488.1 hourly average MW in 2017. This is a decrease of 28.1 MW from 2016, when the average hourly total regulation cleared MW for nonramp hours were 516.2 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 720.2 hourly average MW in 2017. This is an increase of 84.2 MW from 2016, where the average hourly regulation cleared MW for ramp hours were 636.0 MW.

### Table 10-37 PJM Regulation Market required MW and ratio of eligible supply to requirement for ramp and nonramp hours: 2016 and 2017[69]

| | | 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 |
| | Apr | 633.8 | 730.6 | 699.9 | 800.0 | 1.78 | 1.86 | 1.32 | 1.41 |
| | May | 625.4 | 723.6 | 699.9 | 800.0 | 1.82 | 1.88 | 1.29 | 1.44 |
| | Jun | 632.2 | 719.9 | 700.1 | 800.0 | 1.98 | 1.98 | 1.38 | 1.49 |
| | Jul | 628.7 | 727.6 | 700.0 | 799.9 | 1.85 | 2.00 | 1.37 | 1.52 |
| | Aug | 630.6 | 727.8 | 700.1 | 800.3 | 1.88 | 1.97 | 1.35 | 1.50 |
| | Sep | 628.5 | 728.3 | 700.1 | 799.9 | 1.95 | 1.90 | 1.38 | 1.46 |
| | Oct | 630.8 | 716.8 | 700.0 | 800.0 | 1.90 | 2.09 | 1.34 | 1.59 |
| | Nov | 628.6 | 713.6 | 700.1 | 800.1 | 1.89 | 1.99 | 1.37 | 1.50 |
| | Dec | 631.5 | 742.6 | 700.2 | 799.9 | 1.97 | 1.91 | 1.38 | 1.48 |
| 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 |
| | Apr | 513.1 | 519.0 | 525.0 | 525.0 | 2.23 | 2.20 | 1.54 | 1.60 |
| | May | 504.5 | 479.7 | 525.0 | 525.1 | 2.24 | 2.26 | 1.52 | 1.59 |
| | Jun | 509.0 | 471.9 | 525.2 | 525.1 | 2.62 | 2.31 | 1.78 | 1.63 |
| | Jul | 506.9 | 484.9 | 525.0 | 541.0 | 2.42 | 2.32 | 1.65 | 1.66 |
| | Aug | 502.0 | 481.8 | 525.0 | 535.2 | 2.58 | 2.41 | 1.74 | 1.71 |
| | Sep | 508.3 | 475.8 | 525.0 | 526.4 | 2.47 | 2.26 | 1.65 | 1.62 |
| | Oct | 511.6 | 470.5 | 525.0 | 525.2 | 2.36 | 2.45 | 1.60 | 1.74 |
| | Nov | 502.4 | 472.8 | 525.0 | 525.1 | 2.49 | 2.34 | 1.73 | 1.67 |
| | Dec | 516.2 | 489.5 | 525.1 | 525.1 | 2.57 | 2.37 | 1.79 | 1.71 |

## Market Concentration

In 2017, the effective MW weighted average HHI of RegA resources was 2677 which is highly concentrated and the weighted average HHI of RegD resources was 1604 which is also highly concentrated.[70] The weighted average HHI of all resources was 1136, 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 10-38 includes a monthly summary of three pivotal supplier (TPS) results. In 2017, 85.7 percent of hours had three or fewer pivotal suppliers. The MMU concludes that the PJM Regulation Market in 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.

### Table 10-38 Regulation market monthly three pivotal supplier results: 2015 through 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% | 92.9% |
| May | 99.3% | 94.0% | 88.7% |
| Jun | 98.6% | 89.3% | 89.2% |
| Jul | 98.8% | 92.2% | 91.0% |
| Aug | 97.7% | 93.7% | 88.0% |
| Sep | 97.1% | 94.0% | 82.6% |
| Oct | 96.1% | 90.6% | 68.1% |
| Nov | 99.2% | 96.2% | 72.5% |
| Dec | 97.2% | 90.4% | 79.3% |
| Average | 97.8% | 92.2% | 85.7% |

69 The regulation requirement for January 2017 includes eight days of 700 effective MW and 23 days of 800 effective MW.

70 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.

# 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.[71] 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.[72]

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. Batteries and flywheels have zero cost for lower efficiency from providing regulation instead of energy, as they are not net energy producers. There is 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.[73]

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.[74]

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 10-40).[75] Figure 10-26 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.[76] Self scheduled regulation comprised an average of 39.0 percent during ramp hours and 46.3 percent during nonramp hours in 2017.

Figure 10-26 Off peak, on peak, nonramp, and ramp regulation levels: 2016 through 2017[77]

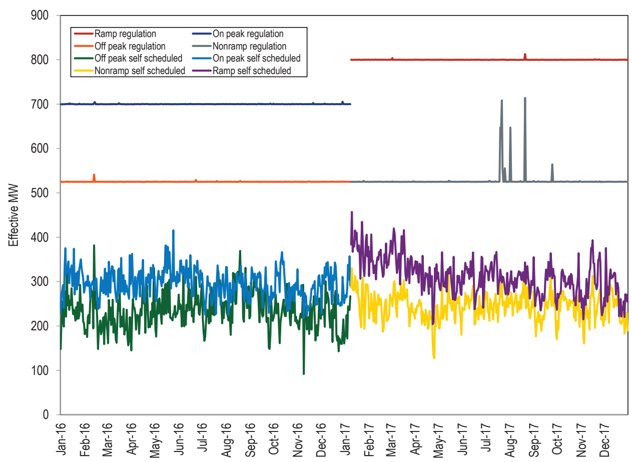



Table 10-39 shows the role of RegD resources in the regulation market. RegD resources are both a growing proportion of the market (10.9 percent of the total effective MW at the start of the performance based regulation market design in October 2012 and 43.1 percent of the total effective MW in December 2017) and a growing proportion of resources that self schedule (10.1 percent of all self scheduled MW in October 2012 and 21.9 percent of all self scheduled MW in December 2017). The increase in the share of RegD in 2016 was a result of the use of the unit block method of calculating the MBF over the previous price block method (See

71 See PJM Manual 11: Energy & Ancillary Services Market Operations, Rev. 92 (Nov. 1, 2017) at 64.
72 Id. at 69.
73 See "PJM Manual 15: Cost Development Guidelines," Rev. 29 (May 15, 2017) at 62.
74 See "PJM Manual 11: Energy & Ancillary Services Market Operations," Rev. 92 (Nov 1, 2017) at 67.
75 See "PJM Manual 28: Operating Agreement Accounting," Rev. 77 (Nov. 1, 2017) at 4.1 at 22.
76 See "PJM Manual 11: Energy & Ancillary Services Market Operations," Rev. 92 (Nov. 1, 2017) at 3.2.9 at 78.
77 The MW increase during the nonramp hours of Q3 was a result of PJM operations treating those hours as ramp hours.

Figure 10-22). The decrease in the RegD share of total effective MW for 2017 was a result of a decrease in the amount of eligible MW of RegD (Table 10-32) in response to the changes to the regulation market on January 9, 2017.

## Table 10-39 RegD self scheduled regulation by month: October 31, 2012 through December 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% |
| 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% |

## Table 10-39 RegD self scheduled regulation by month: October 31, 2012 through December 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 |
|---|---|---|---|---|---|---|---|---|
| 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% |
| 2017 | Apr | 159.9 | 306.4 | 255.0 | 639.6 | 39.9% | 25.0% | 47.9% |
| 2017 | May | 167.6 | 297.0 | 265.7 | 639.7 | 41.5% | 26.2% | 46.4% |
| 2017 | Jun | 178.6 | 315.6 | 284.3 | 696.9 | 40.8% | 25.6% | 45.3% |
| 2017 | Jul | 171.9 | 310.3 | 290.0 | 703.1 | 41.3% | 24.5% | 44.1% |
| 2017 | Aug | 176.7 | 314.0 | 286.3 | 700.9 | 40.8% | 25.2% | 44.8% |
| 2017 | Sep | 156.9 | 297.8 | 259.0 | 640.4 | 40.4% | 24.5% | 46.5% |
| 2017 | Oct | 158.6 | 295.3 | 263.7 | 639.7 | 41.2% | 24.8% | 46.2% |
| 2017 | Nov | 158.6 | 298.1 | 261.7 | 640.4 | 40.9% | 24.8% | 46.5% |
| 2017 | Dec | 147.7 | 290.8 | 260.6 | 674.0 | 38.7% | 21.9% | 43.1% |
| 2017 Average | | 164.1 | 286.2 | 269.6 | 332.0 | 40.6% | 8.2% | 45.7% |

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 2017, 55.1 percent was purchased in the PJM market, 39.4 percent was self scheduled, and 5.5 percent was purchased bilaterally (Table 10-40). Table 10-41 shows the total regulation by source including spot market regulation, self scheduled regulation, and bilateral regulation for each year from 2012 to 2017. Table 10-40 and Table 10-41 are based on settled (purchased) MW.

## Table 10-40 Regulation sources: spot market, self scheduled, bilateral purchases: 2016 through 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 | 191,278.5 | 48.9% | 176,628.1 | 45.1% | 23,642.5 | 6.0% | 391,549.0 |
| Total | | 2,260,701.6 | 48.6% | 2,104,775.1 | 45.2% | 287,809.5 | 6.2% | 4,653,286.2 |
| 2017 | Jan | 181,386.7 | 45.8% | 188,924.6 | 47.7% | 25,490.5 | 6.4% | 395,801.8 |
| 2017 | Feb | 179,488.3 | 50.4% | 154,308.8 | 43.3% | 22,371.0 | 6.3% | 356,168.1 |
| 2017 | Mar | 174,026.3 | 46.3% | 177,638.3 | 47.3% | 23,963.0 | 6.4% | 375,627.5 |
| 2017 | Apr | 206,895.4 | 55.7% | 145,424.6 | 39.1% | 19,207.5 | 5.2% | 371,527.5 |
| 2017 | May | 212,510.8 | 57.8% | 139,361.6 | 37.9% | 15,967.5 | 4.3% | 367,839.9 |
| 2017 | Jun | 221,942.4 | 57.5% | 142,537.9 | 36.9% | 21,535.0 | 5.6% | 386,015.3 |
| 2017 | Jul | 227,034.0 | 55.8% | 152,610.9 | 37.5% | 27,183.5 | 6.7% | 406,828.4 |
| 2017 | Aug | 238,692.9 | 59.2% | 141,756.7 | 35.1% | 22,844.5 | 5.7% | 403,294.0 |
| 2017 | Sep | 206,361.1 | 58.1% | 130,432.8 | 36.7% | 18,197.0 | 5.1% | 354,990.9 |
| 2017 | Oct | 213,228.1 | 58.3% | 136,134.9 | 37.2% | 16,631.0 | 4.5% | 365,994.1 |
| 2017 | Nov | 201,998.5 | 57.5% | 132,863.4 | 37.8% | 16,257.5 | 4.6% | 351,119.3 |
| 2017 | Dec | 233,681.7 | 59.1% | 141,051.3 | 35.7% | 20,536.5 | 5.2% | 395,269.5 |
| Total | | 2,497,246.1 | 55.1% | 1,783,045.7 | 39.4% | 250,184.5 | 5.5% | 4,530,476.4 |

Table 10-41 Regulation sources: 2012 through 2017

| Year | 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 | 6,149,110.0 | 78.6% | 1,484,446.2 | 19.0% | 193,408.0 | 2.5% | 7,826,964.2 |
| 2013 | 3,088,944.5 | 57.7% | 2,064,156.7 | 38.5% | 204,260.5 | 3.8% | 5,357,361.7 |
| 2014 | 2,327,314.4 | 49.3% | 2,161,996.5 | 45.8% | 231,218.0 | 4.9% | 4,720,528.9 |
| 2015 | 2,546,688.3 | 54.4% | 1,888,040.0 | 40.3% | 250,386.1 | 5.3% | 4,685,114.3 |
| 2016 | 2,260,701.6 | 48.6% | 2,104,775.1 | 45.2% | 287,809.5 | 6.2% | 4,653,286.2 |
| 2017 | 2,497,246.1 | 55.1% | 1,783,045.7 | 39.4% | 250,184.5 | 5.5% | 4,530,476.4 |

In 2017, DR provided an average of 8.5 MW of regulation per hour during ramp hours (8.0 MW of regulation per hour during ramp hours in 2016), and an average of 7.5 MW of regulation per hour during nonramp hours (5.9 MW of regulation per hour during off peak hours 2016). Generating units supplied an average of 711.5 MW of regulation per hour during ramp hours (627.9 MW of regulation per hour during ramp hours in 2016), and an average of 480.4 MW per hour during nonramp hours (510.2 MW of regulation per hour during nonramp hours in 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 10-45). The weighted average RMCP for 2017 was $16.78 per effective MW. This is an increase of $1.05 per MW, or 6.7 percent, from the weighted average RMCP of $15.73 per MW in 2016. The increase in the regulation clearing price was the result of an increase in energy prices and the related increase in the opportunity cost component of RMCP. The decrease in self supply and $0.00 offers from RegD resources since 2016 also contributed to higher 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. The increase in December was the result of increases in energy prices and the corresponding increase in the opportunity cost component of the RMCP.

Figure 10-27 shows the daily weighted average regulation market clearing price and the opportunity cost component for the marginal units in the PJM Regulation Market on a performance adjusted MW basis. This data is based on actual five minute interval operational data. As illustrates, the opportunity cost (blue line) is the largest component of the clearing price. The increase in December was the result of increases in energy prices and the corresponding increase in the opportunity cost component of the RMCP.

Figure 10-27 PJM regulation market daily weighted average market-clearing price, marginal unit opportunity cost and offer price (Dollars per MW): 2017

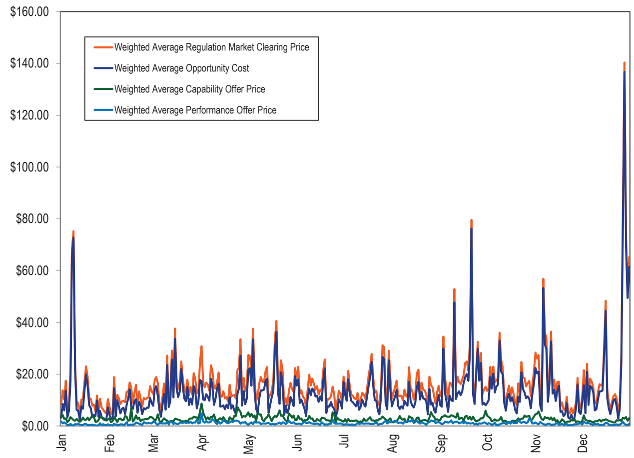



Table 10-42 shows the components of the monthly average regulation prices. NA is the unexplained portion of the total weighted average market price.

Table 10-42 PJM regulation market monthly component of price (Dollars per MW): 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 | $0.95 | $14.08 |
| Feb | $7.49 | $2.84 | $0.75 | $11.08 | ($0.05) | $11.12 |
| Mar | $12.81 | $2.50 | $1.21 | $16.52 | $0.20 | $16.32 |
| Apr | $10.96 | $3.65 | $1.65 | $16.26 | $0.04 | $16.21 |
| May | $14.22 | $3.60 | $1.08 | $18.90 | $0.05 | $18.85 |
| Jun | $10.31 | $2.63 | $0.98 | $13.92 | $0.08 | $13.85 |
| Jul | $12.52 | $2.29 | $0.89 | $15.71 | $0.05 | $15.66 |
| Aug | $9.79 | $2.57 | $1.49 | $13.85 | $0.15 | $13.70 |
| Sep | $17.63 | $3.30 | $1.21 | $22.13 | $0.16 | $21.98 |
| Oct | $13.14 | $2.57 | $1.18 | $16.88 | ($0.07) | $16.96 |
| Nov | $13.39 | $2.62 | $0.74 | $16.86 | $0.21 | $16.65 |
| Dec | $23.39 | $2.19 | $0.73 | $26.31 | $0.28 | $26.03 |
| Average | $13.12 | $2.79 | $1.04 | $16.96 | $0.17 | $16.78 |

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 10-43. Total scheduled regulation is based on settled performance adjusted MW. The total of all regulation charges for 2017 was $104.3 million, compared to $84.4 million for 2016.

## Table 10-43 Total regulation charges: 2016 through 2017[78]

| 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 | 412,599.7 | $7,594,184 | $15.65 | $18.41 | 85.1% |
| 2016 | Feb | 383,918.8 | $7,682,435 | $17.63 | $20.01 | 88.1% |
| 2016 | Mar | 396,882.6 | $6,111,918 | $13.43 | $15.40 | 87.2% |
| 2016 | Apr | 384,853.5 | $8,372,956 | $19.07 | $21.76 | 87.7% |
| 2016 | May | 391,328.7 | $7,220,908 | $15.67 | $18.45 | 84.9% |
| 2016 | Jun | 379,273.1 | $5,997,055 | $14.03 | $15.81 | 88.7% |
| 2016 | Jul | 386,423.4 | $7,959,676 | $17.86 | $20.60 | 86.7% |
| 2016 | Aug | 386,057.1 | $7,707,370 | $17.58 | $19.96 | 88.1% |
| 2016 | Sep | 376,493.8 | $7,783,970 | $17.91 | $20.67 | 86.6% |
| 2016 | Oct | 389,241.0 | $7,019,998 | $15.68 | $18.04 | 87.0% |
| 2016 | Nov | 374,665.6 | $5,777,522 | $13.12 | $15.42 | 85.1% |
| 2016 | Dec | 391,549.0 | $5,133,457 | $11.17 | $13.11 | 85.2% |
| 2016 Annual | | 4,653,286.2 | $84,361,450 | $15.73 | $18.14 | 86.7% |
| 2017 | Jan | 395,801.8 | $6,851,605 | $14.08 | $17.31 | 81.4% |
| 2017 | Feb | 356,168.1 | $5,332,548 | $11.12 | $14.97 | 74.3% |
| 2017 | Mar | 375,627.5 | $8,604,453 | $16.32 | $22.91 | 71.2% |
| 2017 | Apr | 371,527.5 | $9,048,650 | $16.21 | $24.36 | 66.6% |
| 2017 | May | 367,839.9 | $8,943,812 | $18.85 | $24.31 | 77.5% |
| 2017 | Jun | 386,015.3 | $7,726,835 | $13.85 | $20.02 | 69.2% |
| 2017 | Jul | 406,828.4 | $8,698,944 | $15.66 | $21.38 | 73.2% |
| 2017 | Aug | 403,294.0 | $8,396,203 | $13.70 | $20.82 | 65.8% |
| 2017 | Sep | 354,990.9 | $10,511,205 | $21.98 | $29.61 | 74.2% |
| 2017 | Oct | 365,994.1 | $8,807,785 | $16.96 | $24.07 | 70.5% |
| 2017 | Nov | 351,119.3 | $7,994,687 | $16.65 | $22.77 | 73.1% |
| 2017 | Dec | 395,269.5 | $13,385,274 | $26.03 | $33.86 | 76.9% |
| 2017 Annual | | 4,530,476.4 | $104,302,003 | $16.78 | $23.03 | 72.8% |

The capability, performance, and opportunity cost components of the cost of regulation are shown in Table 10-44. Total scheduled regulation is based on settled performance adjusted MW. In 2017, the monthly average total cost of regulation was $23.03, 27.0 percent higher than $18.14 in 2016. In 2017, the monthly average capability component cost of regulation was $14.37, 0.1 percent higher than $14.35 in 2016. In 2017, the monthly average performance component cost of regulation was $6.76, 187.2 percent higher than $2.35 in 2016.

78 Weighted average market clearing prices presented here are taken from PJM settlements data, and differ from the values reported in Table 10-13, which are from five minute interval operational data. The MMU is investigating the cause of the discrepancies with PJM.

### Table 10-44 Components of regulation cost: 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 | 412,599.7 | $14.49 | $1.97 | $1.95 | $18.41 |
| | Feb | 383,918.8 | $16.00 | $2.61 | $1.40 | $20.01 |
| | Mar | 396,882.6 | $12.01 | $2.25 | $1.14 | $15.40 |
| | Apr | 384,853.5 | $17.38 | $2.70 | $1.67 | $21.76 |
| | May | 391,328.7 | $13.56 | $3.50 | $1.39 | $18.45 |
| | Jun | 379,273.1 | $13.33 | $1.38 | $1.10 | $15.81 |
| | Jul | 386,423.4 | $16.52 | $2.27 | $1.80 | $20.60 |
| | Aug | 386,057.1 | $16.74 | $1.66 | $1.56 | $19.96 |
| | Sep | 376,493.8 | $16.68 | $2.32 | $1.68 | $20.67 |
| | Oct | 389,241.0 | $14.11 | $2.73 | $1.19 | $18.04 |
| | Nov | 374,665.6 | $11.28 | $3.11 | $1.03 | $15.42 |
| | Dec | 391,549.0 | $10.14 | $1.73 | $1.25 | $13.11 |
| 2016 Annual | | 4,653,286.2 | $14.35 | $2.35 | $1.43 | $18.14 |
| 2017 | Jan | 395,801.8 | $13.19 | $2.43 | $1.69 | $17.31 |
| | Feb | 356,168.1 | $9.91 | $3.68 | $1.38 | $14.97 |
| | Mar | 375,627.5 | $13.93 | $6.99 | $1.98 | $22.91 |
| | Apr | 371,527.5 | $12.94 | $9.78 | $1.64 | $24.36 |
| | May | 367,839.9 | $16.77 | $5.78 | $1.77 | $24.31 |
| | Jun | 386,015.3 | $10.81 | $7.95 | $1.26 | $20.02 |
| | Jul | 406,828.4 | $13.19 | $6.37 | $1.82 | $21.38 |
| | Aug | 403,294.0 | $10.10 | $9.34 | $1.38 | $20.82 |
| | Sep | 354,990.9 | $18.83 | $8.82 | $1.96 | $29.61 |
| | Oct | 365,994.1 | $13.88 | $8.51 | $1.67 | $24.07 |
| | Nov | 351,119.3 | $14.55 | $6.12 | $2.09 | $22.77 |
| | Dec | 395,269.5 | $24.30 | $5.29 | $4.28 | $33.86 |
| 2017 Annual | | 4,530,476.4 | $14.37 | $6.76 | $1.91 | $23.03 |

Table 10-45 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 2017 was 72.9 percent, a 16.0 percent decrease from 86.7 percent in 2016.

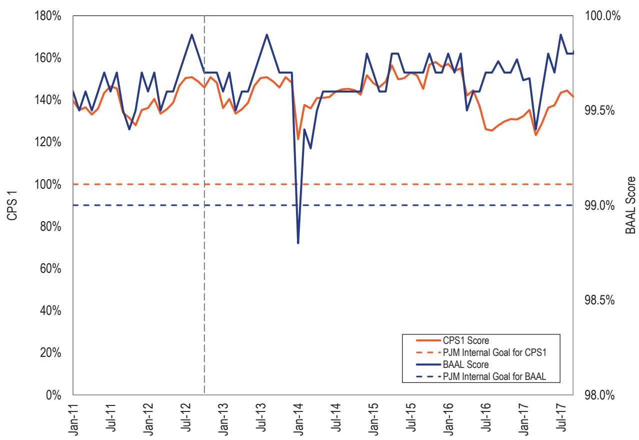
### Table 10-45 Comparison of average price and cost for PJM regulation: 2009 through 2017

| Year | Weighted Regulation Market Price | Weighted Regulation Market Cost | Regulation Price as Percent Cost |
|---|---|---|---|
| 2009 | $22.99 | $30.68 | 74.9% |
| 2010 | $18.00 | $32.86 | 54.8% |
| 2011 | $16.48 | $29.72 | 55.5% |
| 2012 | $19.02 | $25.32 | 75.1% |
| 2013 | $30.85 | $35.79 | 86.2% |
| 2014 | $44.48 | $53.82 | 82.6% |
| 2015 | $31.92 | $38.36 | 83.2% |
| 2016 | $15.73 | $18.13 | 86.7% |
| 2017 | $16.78 | $23.02 | 72.9% |

## Performance Standards

PJM's performance as measured by CPS1 and BAAL standards is shown in Figure 10-28 for every month from January 2011 through June 2017 with the dashed vertical line marking the date (October 1, 2012) of the implementation of the Performance Based Regulation Market design.[79] 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.

### Figure 10-28 PJM monthly CPS1 and BAAL performance: 2011 through 2017




79 See *2017 State of the Market Report for PJM*, Appendix F: Ancillary Services.

## 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.[80] [81] PJM identified zones with black start shortages and began awarding contracts on January 14, 2014. PJM and the MMU coordinated closely during the selection process.

PJM issued two additional 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.

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.[82]

In 2017, total black start charges were $69.5 million, a decrease of $0.139 million (-0.2 percent) from the same period of 2016. Operating reserve charges for black start service decreased from $0.279 million in 2016 to $0.257 million in 2017. Table 10-46 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 reserve charges were allocated to black start, resulting in the increase in operating reserve charges. As of April 2015, all ALR units had been replaced and no longer provided black start service. 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.

80 See PJM. "RTO-Wide Five-Year Selection Process Request for Proposal for Black Start Service," (July 1, 2013).
81 RFPs issued can be found on the PJM website. See PJM. <http://www.pjm.com/markets-and-operations/ancillary-services.aspx>.
82 OATT Schedule 6A (paras. 25, 26 and 27 outline how charges are to be applied).

### Table 10-46 Black start revenue requirement charges: 2010 through 2017

| Year | Revenue Requirement Charges | Operating Reserve Charges | Total |
|---|---|---|---|
| 2010 | $11,490,379 | $0 | $11,490,379 |
| 2011 | $13,695,331 | $0 | $13,695,331 |
| 2012 | $18,749,617 | $8,384,651 | $27,134,269 |
| 2013 | $20,874,535 | $86,701,561 | $107,576,097 |
| 2014 | $26,945,112 | $32,906,733 | $59,851,845 |
| 2015 | $56,425,648 | $5,175,644 | $61,601,292 |
| 2016 | $69,376,257 | $279,017 | $69,655,275 |
| 2017 | $69,258,169 | $257,174 | $69,515,342 |

Black start zonal charges in 2017 ranged from $0.06 per MW-day in the DLCO Zone (total charges were $51,114) to $4.28 per MW-day in the PENELEC Zone (total charges were $4,543,929). For each zone, Table 10-47 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 $1.16 per MW day of reserve capacity during 2017.

Table 10-48 provides a revenue requirement estimate by zone for the 2016/2017, 2017/2018 and 2018/2019 delivery years.[83] 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, changes in recovery rates, and owner provided cost estimates of incoming black start units at the time of publication and may change significantly.

### Table 10-47 Black start zonal charges for network transmission use: 2016 and 2017

| | 2016 | | | | | 2017 | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Zone | Revenue Requirement Charges | Operating Reserve Charges | Total Charges | Peak Load (MW) | Black Start Rate ($/MW-day) | Revenue Requirement Charges | Operating Reserve Charges | Total Charges | Peak Load (MW) | Black Start Rate ($/MW-day) |
| AECO | $2,433,149 | $18,723 | $2,451,872 | 2,553 | $2.62 | $2,689,333 | $9,974 | $2,699,307 | 2,673 | $2.77 |
| AEP | $16,315,571 | $23,597 | $16,339,168 | 24,725 | $1.81 | $17,515,655 | $38,221 | $17,553,876 | 22,474 | $2.14 |
| APS | $3,988,584 | $2,304 | $3,990,888 | 9,594 | $1.14 | $3,863,022 | $1,394 | $3,864,416 | 8,717 | $1.21 |
| ATSI | $3,012,032 | $1,974 | $3,014,006 | 12,356 | $0.67 | $3,025,757 | $0 | $3,025,757 | 12,752 | $0.65 |
| BGE | $7,119,749 | $3,069 | $7,122,818 | 6,712 | $2.90 | $4,180,070 | $3,310 | $4,183,379 | 6,601 | $1.74 |
| ComEd | $4,841,605 | $32,498 | $4,874,103 | 20,162 | $0.66 | $4,889,894 | $21,923 | $4,911,817 | 21,175 | $0.64 |
| DAY | $236,870 | $8,784 | $245,654 | 3,281 | $0.20 | $255,338 | $9,966 | $265,304 | 3,342 | $0.22 |
| DEOK | $1,149,317 | $586 | $1,149,903 | 5,123 | $0.61 | $1,043,068 | $3,622 | $1,046,690 | 5,308 | $0.54 |
| DELCO | $50,515 | $27,932 | $78,447 | 21,651 | $0.01 | $51,114 | $12,906 | $64,020 | 19,538 | $0.01 |
| Dominion | $3,732,558 | $22,118 | $3,754,676 | 4,114 | $2.49 | $4,297,174 | $33,766 | $4,330,940 | 4,127 | $2.88 |
| DPL | $1,788,543 | $8,852 | $1,797,395 | 2,804 | $1.75 | $2,280,454 | $7,735 | $2,288,189 | 2,797 | $2.24 |
| EKPC | $383,134 | $1,970 | $385,104 | 3,490 | $0.30 | $414,454 | $0 | $414,454 | 2,878 | $0.39 |
| JCPL | $6,829,572 | $0 | $6,829,572 | 5,818 | $3.21 | $6,821,817 | $9,358 | $6,831,175 | 5,955 | $3.14 |
| Met-Ed | $577,892 | $85,259 | $663,150 | 2,798 | $0.65 | $607,876 | $70,880 | $678,756 | 2,947 | $0.63 |
| PECO | $1,580,952 | $1,253 | $1,582,205 | 8,094 | $0.53 | $1,643,443 | $1,777 | $1,645,220 | 8,364 | $0.54 |
| PENELEC | $4,526,003 | $3,372 | $4,529,376 | 3,024 | $4.09 | $4,543,929 | $1,623 | $4,545,552 | 2,909 | $4.28 |
| Pepco | $2,526,409 | $23,055 | $2,549,464 | 6,268 | $1.11 | $2,521,020 | $16,114 | $2,537,133 | 6,584 | $1.06 |
| PPL | $1,143,931 | $0 | $1,143,931 | 8,055 | $0.39 | $1,211,901 | $0 | $1,211,901 | 7,025 | $0.47 |
| PSEG | $4,201,398 | $2,303 | $4,203,701 | 9,595 | $1.20 | $4,180,537 | $2,805 | $4,183,342 | 9,800 | $1.17 |
| RECO | $0 | $0 | $0 | NA/ | NA | $0 | $0 | $0 | NA | NA |
| (Imp/Exp/Wheels) | $2,938,473 | $11,367 | $2,949,840 | 7,065 | $1.14 | $3,222,313 | $11,802 | $3,234,114 | 7,617 | $1.16 |
| Total | $69,376,257 | $279,017 | $69,655,274 | 167,283 | $1.14 | $69,258,169 | $257,174 | $69,515,342 | 163,583 | $1.16 |

83 The System Restoration Strategy Task Force requested that the MMU provide estimated black start revenue requirements.

### Table 10-48 Black start zonal revenue requirement estimate: 2017/2018 through 2019/2020 delivery years

| Zone | 2017 / 2018 Revenue Requirement | 2018 / 2019 Revenue Requirement | 2019 / 2020 Revenue Requirement |
|---|---|---|---|
| AECO | $2,900,000 | $2,850,000 | $2,850,000 |
| AEP | $19,000,000 | $18,750,000 | $18,800,000 |
| APS | $4,100,000 | $4,100,000 | $4,100,000 |
| ATSI | $3,150,000 | $3,150,000 | $3,150,000 |
| BGE | $2,050,000 | $500,000 | $450,000 |
| ComEd | $5,200,000 | $4,400,000 | $4,550,000 |
| DAY | $300,000 | $200,000 | $250,000 |
| DEOK | $1,100,000 | $400,000 | $400,000 |
| DLCO | $100,000 | $1,150,000 | $2,250,000 |
| Dominion | $4,450,000 | $3,600,000 | $3,650,000 |
| DPL | $2,400,000 | $2,300,000 | $2,300,000 |
| EKPC | $450,000 | $350,000 | $350,000 |
| JCPL | $7,200,000 | $7,100,000 | $7,100,000 |
| Met-Ed | $700,000 | $550,000 | $550,000 |
| PECO | $1,800,000 | $1,450,000 | $1,450,000 |
| PENELEC | $4,800,000 | $4,650,000 | $4,650,000 |
| Pepco | $2,650,000 | $2,600,000 | $2,600,000 |
| PPL | $1,300,000 | $1,200,000 | $1,200,000 |
| PSEG | $4,350,000 | $4,300,000 | $4,300,000 |
| RECO | $0 | $0 | $0 |
| Total | $68,000,000 | $63,600,000 | $64,950,000 |

## NERC – CIP

Currently, no black start units have requested new or additional black start NERC – CIP Capital Costs.[84]

## Minimum Tank Suction Level (MTSL)

Some units that participate in the PJM Energy Market have oil tanks. All oil tanks at PJM units have a MTSL regardless of whether the units provide black start service (unless they use direct current pumps). The MTSL is the amount of fuel at the bottom of a tank which cannot be recovered for use.

PJM has required that customers pay black start unit owners carrying cost recovery for one hundred percent of the MTSL for tanks which are shared with units in the energy market. These tanks were sized to meet the needs of the generating units, which use significantly more fuel than the black start units. In some instances the MTSL is greater than the total amount of fuel that the black start unit needs to operate to meet its black start obligations. When a black start diesel is added at the site of an oil-fired generating unit, the additional MTSL is zero.

84 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."

Figure 10-29 illustrates how the size of the oil tank does not change with the addition of the black start unit. Figure 10-30 shows how the MTSL could be proportionally divided between the generator and the black start unit. The tank is 4,000,000 gallons with an MTSL of 800,000 gallons leaving 3,200,000 gallons of usable fuel. The black start unit running 16 hours using 12,000 gallons per hour would need a total of 192,000 gallons, or six percent of the total usable fuel. Assigning six percent of the MTSL (800,000 gallons) would yield 48,000 gallons which could be assigned to the black start proportion for the MTSL.

The MMU recommends that for oil tanks which are shared with other resources that only a proportionate share of the MTSL be allocated for black start units. The MMU further recommends that the PJM tariff be updated to clearly state how the MTSL will be calculated for black start units sharing oil tanks.

### Figure 10-29 Oil tank MTSL not changed from addition of black start generator

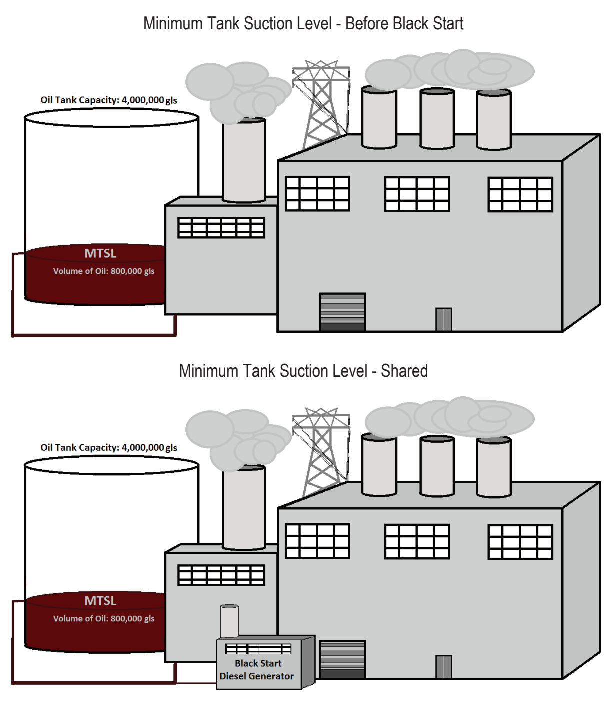
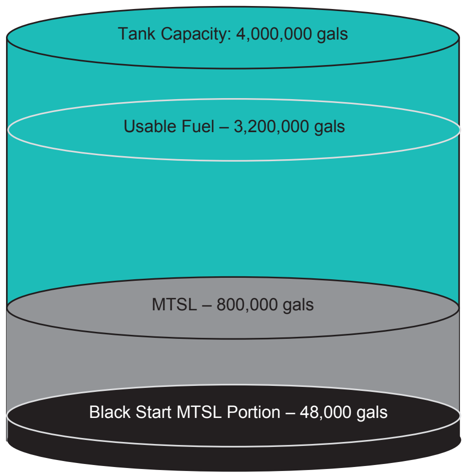


Figure 10-30 Oil tank black start MTSL portion




## 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.[85]

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).[86] 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.[87] Zonal reactive supply revenue requirement charges are allocated monthly to PJM customers proportionally to their zone and to any nonzone (i.e. outside of the PJM Region) peak transmission use and point to point transmission reservations.[88]

In 2016, the FERC began to reexamine its policies on reactive compensation.[89] 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.[90] 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 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.[91] There is no reason 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 reason 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

85 See "PJM Manual 27: Open Access Transmission Tariff Accounting," Rev. 88, (Nov. 16, 2017) at 3.
86 OATT Schedule 2.
87 See PJM. Markets & Operations: Billing, Settlements & Credit, "Reactive Revenue Requirements,"<http://www.pjm.com/~/media/markets-ops/settlements/reactive-revenue-requirements-table-may-2016.ashx> (June 8, 2016).
88 OATT Schedule 2.
89 See *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).
90 See 88 FERC ¶ 61,141 (1999).
91 See *Reactive Power Requirements for Non-Synchronous Generation*, Order No. 827, 155 FERC ¶ 61,277 at P 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.")

markets.[92] The Commission has recently extended the interconnection service requirement to have reactive capability to wind and solar units, which previously had been exempt.[93] 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.

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.[94] 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.[95]

There are two ways to address the cost of reactive in the PJM market design.

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.[96] 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. This approach also requires that any capacity resource calculating unit specific net revenues must include the cost of service reactive revenues in the calculation.

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.

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

92 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).

93 *Reactive Power Requirements for Non-Synchronous Generation*, Order No. 827, 155 FERC ¶ 61,277 (2016); *see also* 151 FERC ¶ 61,097 at P 28 (2015).

94 See OATT Attachment O Appendix 2 § 4.7.

95 See 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.").

96 See OATT Attachment DD § 5.10(a)(iv).

logic.[97] 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.[98] 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.[99]

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.[100] 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.

## 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. FERC has initiated a number of investigations into the basis for reactive rates, and the MMU has intervened in and is participating in those proceedings.[101]

Under the *AEP* method, units must establish their MVAR rating based on "the capability of the generators to produce VArs."[102] Typically this has meant reliance on manufacturers' specified nameplate power factor.[103] More

97 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.").

98 *Id.*

99 *Id.*

100 See FERC Docket No. AD16-17-000.

101 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.

102 *AEP mimeo* at 31.

103 See, e.g., *id.*

recently, the Commission has, in the *Wabash* Orders, required that "reactive power revenue requirement filings must include reactive power test reports."[104] 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.[105]

The Commission has identified a significant issue. Tests are essential to "evaluate and analyze" proposed reactive revenue requirements.[106] 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 reveals whether the tested capability changes. 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.[107] PJM determined in 1999 that nameplate MVAR and power factor ratings do not reflect the value to the system operator of a unit's reactive output after it is interconnected at a specific location.[108] 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.

The estimated capability costs also include estimated heating losses relative to MVAR output.[109] Heating losses are variable costs and not fixed costs and should not be included in the definition of reactive capability costs.[110] 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.

104 154 FERC ¶ 61,246 at P 28 (2016); see also 154 FERC ¶ 61,246 at P 29 (*Wabash* Orders).

105 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.").

106 154 FERC ¶ 61,246 at P 28 (2016); see also 154 FERC ¶ 61,246 at P 29.

107 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) <http://www.pjm.com/~/media/training/nerc-certifications/gen-exam-materials/gof/20160104-reactive-reserves-and-d-curve.ashx>.

108 *Id.*, including Attachment.

109 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).

110 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.

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.[111] 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.[112] 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.[113] 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 rate 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.[114] 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 FERC concerning reactive capability rates for PJM units.[115]

## Reactive Costs

In 2017, total reactive charges were $334.3 million, an 11.9 percent increase from the 2016 level of $298.7 million. Reactive service charges increased in 2017 to $20.4 million from $2.5 million in 2016. [116] All $20.4 million in 2017 were paid for reactive service provided by 43 units in 682 hours.

Table 10-49 shows reactive service charges in 2016 and 2017, reactive capability revenue requirement charges and total charges.

111 See, e.g., OATT Schedule 2; 114 FERC ¶ 61,318 (2006).
112 See 149 FERC ¶ 61,132 (2014); 151 FERC ¶ 61,224 (2015); OATT Schedule 2.
113 *Id.*
114 See OATT Attachment DD §§ 6.4, 6.8(d).
115 See, e.g., FERC Dockets Nos. EL16-44 et al.; ER16-1456; EL16-57 et al.; EL16-51 et al.; ER16-1004; EL16-32; EL16-72; EL16-66; EL16-65; EL16-54; EL16-90 et al.; EL16-103 et al.; EL16-89 et al.; EL16-98 et al.; EL16-79 et al.; EL16-80 et al.; EL16-81 et al.; EL16-82 et al.; EL16-83 et al.; ER16-2217 et al.; EL17-19; EL16-118.
116 See *2017 State of the Market Report for PJM*, Vol. II, Section 4, "Energy Uplift."

Table 10-49 Reactive zonal charges for network transmission use: 2016 and 2017

| | 2016 | | | 2017 | | |
|---|---|---|---|---|---|---|
| Zone | Reactive Service Charges | Reactive Capability Revenue Requirement Charges | Total Charges | Reactive Service Charges | Reactive Capability Revenue Requirement Charges | Total Charges |
| AECO | $250 | $5,540,070 | $5,540,320 | $8,686 | $5,153,350 | $5,162,036 |
| AEP | $76,833 | $37,511,221 | $37,588,054 | $178,314 | $38,485,823 | $38,664,137 |
| APS | $1,440 | $16,627,252 | $16,628,691 | $135,676 | $16,529,834 | $16,665,510 |
| ATSI | $1,860 | $21,875,067 | $21,876,927 | $77,078 | $21,724,645 | $21,801,723 |
| BGE | $895 | $7,570,608 | $7,571,503 | $1,694,486 | $8,058,207 | $9,752,694 |
| ComEd | $1,025,426 | $27,483,380 | $28,508,806 | $13,242,447 | $34,259,938 | $47,502,385 |
| DAY | $501 | $8,330,616 | $8,331,117 | $15,845 | $7,303,133 | $7,318,978 |
| DEOK | $765 | $5,892,359 | $5,893,124 | $25,386 | $6,443,803 | $6,469,188 |
| Dominion | $19,204 | $29,873,735 | $29,892,939 | $120,722 | $34,703,394 | $34,824,116 |
| DPL | $786,662 | $12,155,068 | $12,941,730 | $1,308,524 | $11,309,455 | $12,617,979 |
| DLCO | $365 | $0 | $365 | $12,737 | $0 | $12,737 |
| EKPC | $162,131 | $2,157,625 | $2,319,756 | $20,528 | $2,146,656 | $2,167,184 |
| JCPL | $608 | $9,038,682 | $9,039,289 | $19,441 | $8,813,833 | $8,833,274 |
| Met-Ed | $15,525 | $5,975,372 | $5,990,897 | $68,170 | $5,105,042 | $5,173,212 |
| PECO | $1,113 | $22,801,912 | $22,803,026 | $103,510 | $22,065,666 | $22,169,175 |
| PENELEC | $250,696 | $9,292,379 | $9,543,075 | $1,675,853 | $11,256,785 | $12,932,638 |
| Pepco | $136,334 | $6,052,073 | $6,188,408 | $1,595,597 | $8,698,177 | $10,293,774 |
| PPL | $16,500 | $20,168,339 | $20,184,839 | $37,886 | $24,002,097 | $24,039,984 |
| PSEG | $1,133 | $29,699,248 | $29,700,380 | $37,255 | $27,163,090 | $27,200,345 |
| RECO | $37 | $0 | $37 | $1,239 | $0 | $1,239 |
| (Imp/Exp/Wheels) | $0 | $18,135,485 | $18,135,485 | $0 | $20,692,410 | $20,692,410 |
| Total | $2,498,279 | $296,180,491 | $298,678,770 | $20,379,379 | $313,915,338 | $334,294,716 |

# Frequency Response

On November 17, 2016, FERC issued a Notice of Proposed Rulemaking (NOPR) to amend existing Large and Small Generator Interconnection Agreements to require all new generation facilities to maintain and operate a functioning governor or equivalent controls as a precondition for interconnection. The NOPR further amends the agreements to include maximum droop and deadband setting as operating provisions. The NOPR did not propose any headroom requirement nor did it propose a compensation mechanism.[117]

In response to the NOPR, PJM formed a task force under its Markets and Reliability Committee (MRC) to review the NOPR and to propose changes to its tariff and operating manuals and consider compensation mechanisms if needed, the Primary Frequency Response Senior Task Force (PFRSTF).

The MMU recommends that capability to operate under the proposed deadband (+/- 0.036 HZ) and droop (5 percent) settings be mandated as a condition of interconnection and that such capability be required of both new and existing resources. The MMU recommends that no additional compensation be provided as the current PJM market design provides adequate compensation.

## Frequency Control Definition

There are four distinct types of frequency control, distinguished by response timeframe and operational nature: Inertial Response, Primary Frequency Response, Secondary Frequency Control, and Tertiary Frequency Control.

- **Inertial Response.** Inertial response to frequency excursion is the natural resistance of rotating mass turbine generators to change in their stored kinetic energy. This response is immediate and resists short term changes to ACE from the instant of the disturbance up to twenty seconds after the disturbance.
- **Primary Frequency Response.** Primary frequency response is a response to a disturbance based on a local detection of frequency and local operational control settings. Primary frequency response begins within a few seconds and extends up to a minute. The purpose of primary frequency response is to arrest and stabilize the system until other measures

117 157 FERC ¶ 61,122 (2016)

(secondary and tertiary frequency response) become active.

- **Secondary Frequency Control.** Secondary frequency control is called regulation. In PJM it begins taking effect within 10 to fifteen seconds and can maintain itself for several minutes up to an hour in some cases. It is controlled by PJM which detects the grid frequency, calculates a counterbalancing signal, and transmits that signal to all regulating resources.
- **Tertiary Frequency Control.** Tertiary frequency control and imbalance control lasting 10 minutes to an hour is available in PJM as Primary Reserve. It is initiated by an all call from the PJM control center.

# 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 $326.1 million or 31.9 percent, from $1,023.7 million in 2016 to $697.6 million in 2017.
- **Day-Ahead Congestion.** Day-ahead congestion costs decreased by $367.4 million or 33.4 percent, from $1,100.4 million in 2016 to $733.1 million in 2017.
- **Balancing Congestion.** Balancing congestion costs increased by $41.3 million or 53.8 percent, from -$76.8 million in 2016 to -$35.5 million in 2017.
- **Real-Time Congestion.** Real-time congestion costs decreased by $236.1 million or 22.4 percent, from $1,053.7 million in 2016 to $817.5 million in 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 January 18, 2018, and are subject to change, based on continued PJM billing updates.

- **Monthly Congestion.** Monthly total congestion costs in 2017 ranged from $30.1 million in August to $121.7 million in December.
- **Geographic Differences in CLMP.** Differences in CLMP among eastern, southern and western control zones in PJM were primarily a result of congestion on the Braidwood - East Frankfort Line, the Conastone - Peach Bottom Line, the Emilie – Falls Line, the Graceton - Safe Harbor Line and the 5004/5005 Interface.
- **Congestion Frequency.** Congestion frequency continued to be significantly higher in the Day-Ahead Energy Market than in the Real-Time Energy Market in 2017. The number of congestion event hours in the Day-Ahead Energy Market was about 13 times the number of congestion event hours in the Real-Time Energy Market.

  Day-ahead congestion frequency increased by 9.3 percent from 275,298 congestion event hours in 2016 to 300,923 congestion event hours in 2017.

  Real-time congestion frequency decreased by 15.1 percent from 26,370 congestion event hours in 2016 to 22,400 congestion event hours in 2017.
- **Congested Facilities.** Day-ahead, congestion-event hours increased on flowgates and transformers and decreased on interfaces and lines. Real-time, congestion-event hours increased on interfaces and decreased on lines, flowgates and transformers.

  The Braidwood - East Frankfort Line was the largest contributor to congestion costs in 2017. With $43.4 million in total congestion costs, it accounted for 6.2 percent of the total PJM congestion costs in 2017.
- **Zonal Congestion.** ComEd had the largest total congestion costs among all control zones in 2017. ComEd had $215.8 million in total congestion costs, comprised of -$237.5 million in total load congestion payments, -$460.2 million in total generation congestion credits and -$6.8 million in explicit congestion costs. The Braidwood – East Frankfort Line, the Cherry Valley Transformer, the Alpine – Belvidere Flowgate, the Brokaw - Leroy Flowgate and the Bryron – Cherry Valley Flowgate contributed $89.6 million, or 41.5 percent of the total ComEd control zone congestion costs.
- **Ownership.** In 2017, financial entities were net receivers and physical entities were net payers of congestion charges. In 2017, financial entities were paid $19.9 million in congestion credits compared to $10.8 million received in congestion credits in 2016. In 2017, physical entities paid $717.5 million in congestion charges, a decrease of $316.9 million or 30.6 percent compared to 2016.

## Marginal Loss Cost

- **Total Marginal Loss Costs.** Total marginal loss costs decreased by $5.7 million or 0.8 percent, from $696.5 million in 2016 to $690.8 million in 2017. The loss MWh in PJM decreased by 233.8 GWh or 1.5 percent, from 15,153.9 GWh in 2016 to 14,920.1 GWh in 2017. The loss component of real-time LMP in 2017 was $0.0145, compared to $0.0144 in 2016.
- **Monthly Total Marginal Loss Costs.** Monthly total marginal loss costs in 2017 ranged from $44.2 million in April to $91.5 million in December.
- **Day-Ahead Marginal Loss Costs.** Day-ahead marginal loss costs decreased by $3.3 million or 0.4 percent, from $773.2 million in 2016 to $769.9 million in 2017.
- **Balancing Marginal Loss Costs.** Balancing marginal loss costs decreased by $2.4 million or 3.1 percent, from -$76.7 million in 2016 to -$79.1 million in 2017.
- **Total Marginal Loss Surplus.** The total marginal loss surplus decreased in 2017 by $12.6 million or 5.5 percent, from $227.2 million in 2016, to $214.6 million in 2017.

## Energy Cost

- **Total Energy Costs.** Total energy costs decreased by $8.9 million or 1.9 percent, from -$466.3 million in 2016 to -$475.2 million in 2017.
- **Day-Ahead Energy Costs.** Day-ahead energy costs decreased by $7.9 million or 1.2 percent, from -$640.6 million in 2016 to -$648.5 million in 2017.
- **Balancing Energy Costs.** Balancing energy costs decreased by $17.8 million or 9.7 percent, from $184.0 million in 2016 to $166.2 million in 2017.
- **Monthly Total Energy Costs.** Monthly total energy costs in 2017 ranged from -$61.9 million in December to -$31.0 million in April.

## 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, 86.5 and 98.1 percent of total congestion costs including congestion in the Day-Ahead Energy Market and the balancing energy market for the 2014/2015, 2015/2016 and 2016/2017 planning periods. For the first seven months of the 2017/2018 planning period ARRs and self scheduled FTRs offset 79.4 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.[5] The first derivative of total losses with respect to the power flow equals marginal losses. Congestion cost reflects the incremental cost of relieving transmission constraints while maintaining system power balance. Congestion occurs when available, least-cost energy cannot be delivered to all loads because transmission facilities are not adequate to deliver that energy. When the least-cost available energy cannot be delivered to load in a transmission constrained area, higher cost units in the constrained area must be dispatched to meet that load.[6] The result is that the price of energy in the constrained area is higher than in the unconstrained area because of the combination of transmission limitations and the cost of local generation. 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 December 31, 2008 through 2017.[7]

The load-weighted average real-time LMP increased $1.76 or 6.0 percent from $29.23 in 2016 to $30.99 in 2017. The load-weighted average congestion component decreased by $0.02 from $0.04 in 2016 to $0.02 in 2017. The load-weighted average loss component in 2017 was $0.0145 compared to $0.0144 in 2016. The load-

5 For additional information, see the *MMU Technical Reference for PJM Markets*, at "Marginal Losses," <http://www.monitoringanalytics.com/reports/Technical_References/docs/2010-som-pjm-technical-reference.pdf>.

6 This is referred to as dispatching units out of economic merit order. Economic merit order is the order of all generator offers from lowest to highest cost. Congestion occurs when loadings on transmission facilities mean the next unit in merit order cannot be used and a higher cost unit must be used in its place.

7 The PJM real-time, load-weighted price is weighted by accounting load, which differs from the state-estimated load used in determination of the energy component (SMP). In the Real-Time Energy Market, the distributed load reference bus is weighted by state-estimated load in real time. When the LMP is calculated in real time, the energy component equals the system load-weighted price. But real-time bus-specific loads are adjusted, after the fact, based on updated load information from meters. This meter adjusted load is accounting load that is used in settlements and is used to calculate reported PJM load-weighted prices. This after the fact adjustment means that the Real-Time Energy Market energy component of LMP (SMP) and the PJM real-time, load-weighted LMP are not equal. The difference between the real-time energy component of LMP and the PJM-wide real-time, load-weighted LMP is a result of the difference between state-estimated and metered loads used to weight the load-weighted reference bus and the load-weighted LMP.

weighted average energy component increased by $1.77 or 6.1 percent from $29.18 in 2016 to $30.96 in 2017.

### Table 11-1 PJM real-time, load-weighted average LMP components (Dollars per MWh): 2008 through 2017[8]

| | Real-Time LMP | Energy Component | Congestion Component | Loss Component |
|---|---|---|---|---|
| 2008 | $71.13 | $71.02 | $0.06 | $0.05 |
| 2009 | $39.05 | $38.97 | $0.05 | $0.03 |
| 2010 | $48.35 | $48.23 | $0.08 | $0.04 |
| 2011 | $45.94 | $45.87 | $0.05 | $0.02 |
| 2012 | $35.23 | $35.18 | $0.04 | $0.01 |
| 2013 | $38.66 | $38.64 | $0.01 | $0.02 |
| 2014 | $53.14 | $53.13 | ($0.02) | $0.02 |
| 2015 | $36.16 | $36.11 | $0.04 | $0.02 |
| 2016 | $29.23 | $29.18 | $0.04 | $0.01 |
| 2017 | $30.99 | $30.96 | $0.02 | $0.01 |

Table 11-2 shows the PJM day-ahead, load-weighted average LMP components for 2008 through 2017.[9] The load-weighted average day-ahead LMP increased $1.17, or 3.9 percent, from $29.68 in 2016 to $30.85 in 2017. The load-weighted average congestion component decreased $0.09, or 65.1 percent, from $0.14 in 2016 to $0.05 in 2017. The load-weighted average loss component decreased from -$0.0132 in 2016 to -$0.0167 in 2017. The load-weighted average energy component increased $1.26, or 4.3 percent, from $29.55 in 2016 to $30.81 in 2017.

### Table 11-2 PJM day-ahead, load-weighted average LMP components (Dollars per MWh): 2008 through 2017

| | Day-Ahead LMP | Energy Component | Congestion Component | Loss Component |
|---|---|---|---|---|
| 2008 | $70.25 | $70.56 | ($0.08) | ($0.22) |
| 2009 | $38.82 | $38.96 | ($0.04) | ($0.09) |
| 2010 | $47.65 | $47.67 | $0.05 | ($0.07) |
| 2011 | $45.19 | $45.40 | ($0.06) | ($0.15) |
| 2012 | $34.55 | $34.46 | $0.11 | ($0.01) |
| 2013 | $38.93 | $38.79 | $0.13 | $0.00 |
| 2014 | $53.62 | $53.38 | $0.26 | ($0.02) |
| 2015 | $36.73 | $36.51 | $0.24 | ($0.01) |
| 2016 | $29.68 | $29.55 | $0.14 | ($0.01) |
| 2017 | $30.85 | $30.81 | $0.05 | ($0.02) |

Table 11-3 shows the PJM real-time, load-weighted average LMP by constrained and unconstrained hours. In 2017, December had the highest real-time, load-weighted average LMP in the constrained hours which was $44.60.

### Table 11-3 PJM real-time, load-weighted average LMP by constrained and unconstrained hours (Dollars per MWh): 2016 and 2017

| | 2016 | | 2017 | |
|---|---|---|---|---|
| | Constrained Hours | Unconstrained Hours | Constrained Hours | Unconstrained Hours |
| Jan | $31.18 | $20.73 | $32.96 | $26.37 |
| Feb | $26.99 | $17.67 | $25.82 | $24.26 |
| Mar | $23.02 | $10.71 | $32.56 | $26.54 |
| Apr | $29.40 | $21.24 | $29.26 | $23.90 |
| May | $25.13 | $19.98 | $32.27 | $23.90 |
| Jun | $30.03 | $16.32 | $29.23 | $18.80 |
| Jul | $32.82 | $23.20 | $34.22 | $26.33 |
| Aug | $36.25 | $22.88 | $28.39 | $24.66 |
| Sep | $31.37 | $15.98 | $33.79 | $21.28 |
| Oct | $28.15 | $20.48 | $28.69 | $29.20 |
| Nov | $25.73 | $25.23 | $29.43 | $23.26 |
| Dec | $32.81 | $28.17 | $44.60 | $24.74 |
| Avg | $29.75 | $21.55 | $31.81 | $24.42 |

## Zonal Components

The real-time components of LMP for each control zone are presented in Table 11-4 for 2016 and 2017. In 2017, BGE had the highest real-time congestion component of all control zones and AECO had the lowest real-time congestion component.

8 Calculated values shown in Section 11, "Congestion and Marginal Losses," are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

9 In the Real-Time Energy Market, the energy component (SMP) equals the system load-weighted price, with the caveat about state-estimated versus metered load. However, in the Day-Ahead Energy Market the day-ahead energy component of LMP (SMP) and the PJM day-ahead, load-weighted LMP are not equal. The difference between the day-ahead energy component of LMP and the PJM day-ahead, load-weighted LMP is a result of the difference in the types of load used to weight the load-weighted reference bus and the load-weighted LMP. In the Day-Ahead Energy Market, the distributed load reference bus is weighted by fixed-demand bids only and the day-ahead SMP is, therefore, a system fixed demand weighted price. The day-ahead, load-weighted LMP calculation uses all types of demand, including fixed, price-sensitive and decrement bids.

Table 11-4 Zonal and PJM real-time, load-weighted average LMP components (Dollars per MWh): 2016 and 2017

| | 2016 | | | | 2017 | | | |
|---|---|---|---|---|---|---|---|---|
| | Real-Time LMP | Energy Component | Congestion Component | Loss Component | Real-Time LMP | Energy Component | Congestion Component | Loss Component |
| AECO | $26.93 | $29.54 | ($3.12) | $0.51 | $29.63 | $31.03 | ($1.86) | $0.46 |
| AEP | $29.14 | $28.98 | $0.39 | ($0.24) | $30.17 | $30.78 | ($0.31) | ($0.31) |
| APS | $29.75 | $29.06 | $0.69 | $0.00 | $31.32 | $30.92 | $0.34 | $0.06 |
| ATSI | $29.78 | $29.01 | $0.13 | $0.64 | $31.23 | $30.70 | $0.01 | $0.52 |
| BGE | $38.62 | $29.41 | $8.16 | $1.05 | $34.76 | $31.28 | $2.43 | $1.06 |
| ComEd | $27.66 | $29.11 | ($0.51) | ($0.94) | $28.29 | $30.82 | ($1.35) | ($1.19) |
| DAY | $29.36 | $29.16 | ($0.25) | $0.45 | $31.06 | $30.87 | ($0.27) | $0.46 |
| DEOK | $28.62 | $29.17 | $0.16 | ($0.72) | $30.55 | $30.91 | $0.40 | ($0.77) |
| DLCO | $29.20 | $29.15 | $0.29 | ($0.24) | $30.63 | $30.82 | ($0.04) | ($0.15) |
| Dominion | $32.15 | $29.38 | $2.62 | $0.15 | $33.49 | $31.21 | $1.90 | $0.38 |
| DPL | $29.66 | $29.50 | ($0.67) | $0.83 | $33.39 | $31.35 | $1.15 | $0.89 |
| EKPC | $28.21 | $29.30 | ($0.31) | ($0.78) | $29.19 | $31.34 | ($1.32) | ($0.82) |
| JCPL | $26.36 | $29.66 | ($3.59) | $0.29 | $30.74 | $31.30 | ($0.94) | $0.38 |
| Met-Ed | $26.04 | $29.16 | ($3.29) | $0.17 | $31.15 | $30.97 | ($0.07) | $0.25 |
| PECO | $25.57 | $29.25 | ($3.79) | $0.11 | $29.80 | $31.04 | ($1.38) | $0.14 |
| PENELEC | $27.57 | $28.80 | ($1.57) | $0.34 | $30.48 | $30.60 | ($0.33) | $0.22 |
| Pepco | $34.12 | $29.42 | $4.11 | $0.59 | $33.70 | $31.19 | $1.82 | $0.69 |
| PPL | $25.43 | $29.04 | ($3.60) | ($0.01) | $29.99 | $30.96 | ($0.99) | $0.02 |
| PSEG | $26.24 | $29.23 | ($3.24) | $0.25 | $30.92 | $30.91 | ($0.37) | $0.38 |
| RECO | $27.05 | $29.76 | ($3.01) | $0.30 | $31.26 | $31.28 | ($0.43) | $0.41 |
| PJM | $29.23 | $29.18 | $0.04 | $0.01 | $30.99 | $30.96 | $0.02 | $0.01 |

The day-ahead components of LMP for each control zone are presented in Table 11-5 for 2016 and 2017. In 2017, BGE had the highest day-ahead congestion component of all control zones and AECO had the lowest day-ahead congestion component.

Table 11-5 Zonal and PJM day-ahead, load-weighted average LMP components (Dollars per MWh): 2016 and 2017

| | 2016 | | | | 2017 | | | |
|---|---|---|---|---|---|---|---|---|
| | Day-Ahead LMP | Energy Component | Congestion Component | Loss Component | Day-Ahead LMP | Energy Component | Congestion Component | Loss Component |
| AECO | $27.48 | $30.02 | ($3.02) | $0.48 | $29.14 | $30.94 | ($1.98) | $0.18 |
| AEP | $29.46 | $29.41 | $0.30 | ($0.24) | $30.56 | $30.75 | $0.05 | ($0.24) |
| APS | $30.18 | $29.40 | $0.87 | ($0.09) | $31.17 | $30.75 | $0.42 | ($0.00) |
| ATSI | $29.77 | $29.41 | ($0.04) | $0.40 | $31.23 | $30.62 | $0.22 | $0.39 |
| BGE | $39.59 | $29.98 | $8.68 | $0.93 | $34.78 | $31.14 | $2.72 | $0.92 |
| ComEd | $28.00 | $29.50 | ($0.72) | ($0.79) | $28.24 | $30.67 | ($1.59) | ($0.84) |
| DAY | $29.67 | $29.46 | ($0.18) | $0.39 | $31.37 | $30.82 | $0.01 | $0.54 |
| DEOK | $29.30 | $29.61 | $0.31 | ($0.62) | $31.00 | $30.86 | $0.66 | ($0.52) |
| DLCO | $29.12 | $29.57 | ($0.06) | ($0.39) | $30.76 | $30.74 | $0.23 | ($0.21) |
| Dominion | $33.02 | $29.84 | $3.01 | $0.17 | $33.59 | $31.14 | $2.04 | $0.42 |
| DPL | $31.00 | $30.03 | $0.27 | $0.70 | $32.18 | $31.22 | $0.45 | $0.52 |
| EKPC | $28.62 | $29.79 | ($0.37) | ($0.81) | $29.95 | $31.32 | ($0.63) | ($0.73) |
| JCPL | $26.52 | $30.01 | ($3.81) | $0.32 | $29.92 | $31.06 | ($1.29) | $0.15 |
| Met-Ed | $26.22 | $29.41 | ($3.23) | $0.04 | $30.44 | $30.80 | ($0.34) | ($0.03) |
| PECO | $25.90 | $29.60 | ($3.77) | $0.07 | $28.97 | $30.76 | ($1.71) | ($0.08) |
| PENELEC | $27.86 | $29.08 | ($1.42) | $0.21 | $29.98 | $30.61 | ($0.65) | $0.02 |
| Pepco | $34.95 | $29.65 | $4.77 | $0.53 | $33.71 | $30.95 | $2.11 | $0.64 |
| PPL | $25.68 | $29.36 | ($3.57) | ($0.11) | $29.30 | $30.74 | ($1.17) | ($0.26) |
| PSEG | $26.83 | $29.75 | ($3.30) | $0.38 | $30.47 | $30.86 | ($0.62) | $0.23 |
| RECO | $27.28 | $30.03 | ($3.16) | $0.41 | $30.66 | $31.07 | ($0.66) | $0.25 |
| PJM | $29.68 | $29.55 | $0.14 | ($0.01) | $30.85 | $30.81 | $0.05 | ($0.02) |

## Hub Components

The real-time components of LMP for each hub are presented in Table 11-6 for 2016 and 2017.

### Table 11-6 Hub real-time, load-weighted average LMP components (Dollars per MWh): 2016 and 2017

| | 2016 | | | | 2017 | | | |
|---|---|---|---|---|---|---|---|---|
| | Real-Time LMP | Energy Component | Congestion Component | Loss Component | Real-Time LMP | Energy Component | Congestion Component | Loss Component |
| AEP Gen Hub | $27.97 | $29.67 | ($0.47) | ($1.23) | $28.98 | $30.94 | ($0.71) | ($1.25) |
| AEP-DAY Hub | $29.08 | $29.41 | $0.01 | ($0.34) | $30.02 | $30.95 | ($0.45) | ($0.47) |
| ATSI Gen Hub | $28.99 | $28.81 | ($0.00) | $0.18 | $30.31 | $30.63 | ($0.28) | ($0.04) |
| Chicago Gen Hub | $25.97 | $28.65 | ($1.35) | ($1.33) | $27.17 | $30.55 | ($1.79) | ($1.59) |
| Chicago Hub | $28.13 | $29.45 | ($0.44) | ($0.89) | $28.83 | $31.27 | ($1.31) | ($1.13) |
| Dominion Hub | $31.68 | $29.61 | $2.21 | ($0.13) | $33.70 | $31.81 | $1.75 | $0.15 |
| Eastern Hub | $28.74 | $28.68 | ($0.72) | $0.78 | $32.02 | $30.42 | $0.78 | $0.83 |
| N Illinois Hub | $27.21 | $28.92 | ($0.64) | ($1.07) | $27.82 | $30.69 | ($1.57) | ($1.30) |
| New Jersey Hub | $26.32 | $29.39 | ($3.35) | $0.28 | $30.65 | $31.03 | ($0.75) | $0.37 |
| Ohio Hub | $28.93 | $29.08 | $0.07 | ($0.22) | $30.14 | $30.91 | ($0.36) | ($0.41) |
| West Interface Hub | $29.87 | $29.18 | $0.90 | ($0.22) | $31.38 | $31.13 | $0.50 | ($0.25) |
| Western Hub | $31.63 | $30.58 | $1.00 | $0.05 | $32.45 | $32.12 | $0.26 | $0.07 |

The day-ahead components of LMP for each hub are presented in Table 11-7 for 2016 and 2017.

### Table 11-7 Hub day-ahead, load-weighted average LMP components (Dollars per MWh): 2016 and 2017

| | 2016 | | | | 2017 | | | |
|---|---|---|---|---|---|---|---|---|
| | Day-Ahead LMP | Energy Component | Congestion Component | Loss Component | Day-Ahead LMP | Energy Component | Congestion Component | Loss Component |
| AEP Gen Hub | $28.11 | $29.60 | ($0.32) | ($1.17) | $29.53 | $30.80 | ($0.18) | ($1.09) |
| AEP-DAY Hub | $28.89 | $29.18 | $0.06 | ($0.35) | $30.14 | $30.49 | $0.03 | ($0.38) |
| ATSI Gen Hub | $26.12 | $25.98 | $0.10 | $0.03 | $28.32 | $28.13 | $0.24 | ($0.05) |
| Chicago Gen Hub | $25.71 | $28.49 | ($1.62) | ($1.16) | $26.56 | $29.95 | ($2.14) | ($1.26) |
| Chicago Hub | $27.77 | $29.17 | ($0.73) | ($0.68) | $27.63 | $30.03 | ($1.66) | ($0.74) |
| Dominion Hub | $32.44 | $29.87 | $2.64 | ($0.07) | $33.31 | $31.24 | $1.84 | $0.22 |
| Eastern Hub | $30.84 | $29.79 | $0.29 | $0.76 | $32.15 | $31.00 | $0.59 | $0.56 |
| N Illinois Hub | $27.38 | $29.04 | ($0.75) | ($0.91) | $27.36 | $30.11 | ($1.77) | ($0.97) |
| New Jersey Hub | $26.65 | $29.76 | ($3.45) | $0.34 | $30.15 | $30.92 | ($0.95) | $0.18 |
| Ohio Hub | $28.85 | $29.08 | $0.04 | ($0.27) | $30.09 | $30.39 | $0.03 | ($0.33) |
| West Interface Hub | $30.31 | $29.68 | $0.93 | ($0.30) | $30.14 | $29.53 | $0.81 | ($0.20) |
| Western Hub | $30.41 | $29.17 | $1.31 | ($0.06) | $30.99 | $30.81 | $0.32 | ($0.14) |

## Component Costs

Table 11-8 shows the total energy, loss and congestion component costs and the total PJM billing for 2008 through 2017. These totals are actually net energy, loss and congestion costs. Total congestion cost and marginal loss cost decreased in 2017 compared to 2016.

### Table 11-8 Total PJM costs by component (Dollars (Millions)): 2008 through 2017[10 11]

| | Component Costs (Millions) | | | | | |
|---|---|---|---|---|---|---|
| | Energy Costs | Loss Costs | Congestion Costs | Total Costs | Total PJM Billing | Total Costs Percent of PJM Billing |
| 2008 | ($1,193) | $2,497 | $2,052 | $3,355 | $34,306 | 9.8% |
| 2009 | ($629) | $1,268 | $719 | $1,358 | $26,550 | 5.1% |
| 2010 | ($798) | $1,635 | $1,423 | $2,260 | $34,771 | 6.5% |
| 2011 | ($794) | $1,380 | $999 | $1,585 | $35,887 | 4.4% |
| 2012 | ($593) | $982 | $529 | $918 | $29,181 | 3.1% |
| 2013 | ($688) | $1,035 | $677 | $1,025 | $33,860 | 3.0% |
| 2014 | ($978) | $1,466 | $1,932 | $2,421 | $50,030 | 4.8% |
| 2015 | ($627) | $969 | $1,385 | $1,727 | $42,630 | 4.1% |
| 2016 | ($466) | $697 | $1,024 | $1,254 | $39,050 | 3.2% |
| 2017 | ($475) | $691 | $698 | $913 | $40,170 | 2.3% |

10 The energy costs, loss costs and congestion costs include net inadvertent charges.
11 Total PJM billing is provided by PJM. The MMU is not able to verify the calculation.

# Congestion

## Congestion Accounting

Congestion occurs in the Day-Ahead and Real-Time Energy Markets.[12] Total congestion costs are equal to the net implicit congestion bill plus net explicit congestion costs plus net inadvertent congestion charges, incurred in both the Day-Ahead Energy Market and the balancing energy market.

In the analysis of total congestion costs, load congestion payments are netted against generation congestion credits on an hourly basis, by billing organization, and then summed for the given period.

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.[13]

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

12 When the term *congestion charge* is used in documents by PJM's Market Settlement Operations, it has the same meaning as the term *congestion costs* as used here.

13 OA Schedule 1 §3.7.

by a PJM member and when negative, measure the total congestion credit paid 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.[14]

The congestion metric requires careful review when considering the significance of congestion. The net congestion bill is calculated by subtracting generating congestion credits from load congestion payments. The logic is that congestion payments by load are offset by congestion revenues to generation, for the area analyzed. The net congestion bill is the source of payments to FTR Holders. When load pays more for congestion in an area than generation receives, the positive difference is the source of payments to FTR Holders as it is a measure of the value of transmission in bringing lower cost generation into the area.

Total congestion costs in PJM in 2017 were $697.6 million, which was comprised of load congestion payments of $209.7 million, generation credits of -$506.9 million and explicit congestion of -$19.0 million.

## Total Congestion

Table 11-9 shows total congestion in 2008 through 2017. Total congestion costs in Table 11-9 include congestion costs associated with PJM facilities and those associated with reciprocal, coordinated flowgates in MISO and in NYISO.[15 16]

### Table 11-9 Total PJM congestion (Dollars (Millions)): 2008 through 2017

| | Congestion Costs (Millions) | | | |
|---|---|---|---|---|
| | Congestion Cost | Percent Change | Total PJM Billing | Percent of PJM Billing |
| 2008 | $2,052 | NA | $34,306 | 6.0% |
| 2009 | $719 | (65.0%) | $26,550 | 2.7% |
| 2010 | $1,423 | 98.0% | $34,771 | 4.1% |
| 2011 | $999 | (29.8%) | $35,887 | 2.8% |
| 2012 | $529 | (47.0%) | $29,181 | 1.8% |
| 2013 | $677 | 28.0% | $33,860 | 2.0% |
| 2014 | $1,932 | 185.5% | $50,030 | 3.9% |
| 2015 | $1,385 | (28.3%) | $42,630 | 3.2% |
| 2016 | $1,024 | (26.1%) | $39,050 | 2.6% |
| 2017 | $698 | (31.9%) | $40,170 | 1.7% |

Table 11-10 shows total congestion by day-ahead and balancing component for the January through December period, by year. Table 11-10 shows that total negative balancing congestion was lower in 2017 than in 2008 through 2016. The decrease in the level of negative balancing congestion was a result of a large decrease in the level of negative balancing congestion explicit costs. Table 11-11 and Table 11-12 show that the decrease in the level of negative balancing explicit costs was the result of a decrease in the level of negative balancing explicit congestion caused by up to congestion (UTCs) which went from -$47.0 million in 2016 to -$10.8 million in 2017. The decrease in the level of negative balancing explicit congestion cost by up to congestion (UTCs) was the result of PJM's actions to reduce negative balancing by addressing modelling differences between the day-ahead and real-time market models and the lower overall congestion in the system.

14 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>.

15 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>.

16 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 11-10 Total PJM congestion costs by accounting category by market (Dollars (Millions)): 2008 through 2017

| | Congestion Costs (Millions) | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Day-Ahead | | | | Balancing | | | | | |
| | Load Payments | Generation Credits | Explicit Costs | Total | Load Payments | Generation Credits | Explicit Costs | Total | Inadvertent Charges | Grand Total |
| 2008 | $1,260.3 | ($1,133.1) | $203.0 | $2,596.5 | ($225.9) | $79.2 | ($239.5) | ($544.6) | $0.0 | $2,051.8 |
| 2009 | $292.3 | ($525.2) | $83.9 | $901.4 | ($39.0) | $10.1 | ($133.4) | ($182.4) | $0.0 | $719.0 |
| 2010 | $376.4 | ($1,239.8) | $96.9 | $1,713.1 | ($37.5) | $72.8 | ($179.5) | ($289.8) | ($0.0) | $1,423.3 |
| 2011 | $400.5 | ($777.6) | $66.9 | $1,245.0 | $53.5 | $109.5 | ($190.0) | ($246.0) | $0.0 | $999.0 |
| 2012 | $122.7 | ($525.3) | $131.9 | $779.9 | ($7.6) | $57.9 | ($185.4) | ($250.9) | $0.0 | $529.0 |
| 2013 | $281.2 | ($592.5) | $137.6 | $1,011.3 | $5.9 | $131.3 | ($209.0) | ($334.4) | $0.0 | $676.9 |
| 2014 | $595.5 | ($1,671.2) | ($35.4) | $2,231.3 | $52.7 | $218.1 | ($133.6) | ($299.1) | $0.0 | $1,932.2 |
| 2015 | $614.2 | ($967.6) | $50.3 | $1,632.1 | $0.6 | $69.8 | ($177.6) | ($246.9) | $0.0 | $1,385.3 |
| 2016 | $405.3 | ($654.1) | $41.0 | $1,100.4 | ($4.5) | $28.4 | ($43.9) | ($76.8) | ($0.0) | $1,023.7 |
| 2017 | $187.6 | ($554.1) | ($8.6) | $733.1 | $22.2 | $47.2 | ($10.4) | ($35.5) | $0.0 | $697.6 |

Table 11-11 and Table 11-12 show the total congestion costs for each transaction type in 2017 and 2016. Table 11-11 shows that in 2017 DECs paid $4.3 million in congestion costs in the day-ahead market, were paid $17.1 million in congestion credits in the balancing energy market, and were paid $12.8 million in total congestion credits. In 2017, INCs were paid $10.3 million in congestion credits in the day-ahead market, paid $0.2 million in congestion charges in the balancing energy market and received $10.2 million in total congestion credits. In 2017, up to congestion (UTCs) were paid $8.9 million in congestion credits in the day-ahead market, were paid $10.8 million in congestion credits in the balancing market and were paid $19.7 million in total congestion credits.

Table 11-11 Total PJM congestion costs by transaction type by market (Dollars (Millions)): 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 | $4.3 | $0.0 | $0.0 | $4.3 | ($17.1) | $0.0 | $0.0 | ($17.1) | $0.0 | ($12.8) |
| Demand | $35.7 | $0.0 | $0.0 | $35.7 | $40.2 | $0.0 | $0.0 | $40.2 | $0.0 | $75.9 |
| 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 | $1.0 | $1.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $1.0 |
| Export | ($29.7) | $0.0 | ($0.5) | ($30.3) | ($4.4) | $0.0 | $1.8 | ($2.6) | $0.0 | ($32.9) |
| Generation | $0.0 | ($739.9) | $0.0 | $739.9 | $0.0 | $53.5 | $0.0 | ($53.5) | $0.0 | $686.3 |
| 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 | ($1.7) | $0.0 | $1.7 | $0.0 | ($9.5) | ($0.9) | $8.7 | $0.0 | $10.4 |
| INC | $0.0 | $10.3 | $0.0 | ($10.3) | $0.0 | ($0.2) | $0.0 | $0.2 | $0.0 | ($10.2) |
| Internal Bilateral | $177.4 | $177.3 | ($0.1) | ($0.0) | $3.6 | $3.6 | ($0.0) | ($0.0) | $0.0 | ($0.0) |
| Up to Congestion | $0.0 | $0.0 | ($8.9) | ($8.9) | $0.0 | $0.0 | ($10.8) | ($10.8) | $0.0 | ($19.7) |
| Wheel In | $0.0 | ($0.1) | $0.1 | $0.2 | $0.0 | ($0.2) | ($0.1) | $0.1 | $0.0 | $0.3 |
| Wheel Out | ($0.1) | $0.0 | $0.0 | ($0.1) | ($0.2) | $0.0 | $0.0 | ($0.2) | $0.0 | ($0.4) |
| Total | $187.6 | ($554.1) | ($8.6) | $733.1 | $22.2 | $47.2 | ($10.4) | ($35.5) | $0.0 | $697.6 |

Table 11-12 Total PJM congestion costs by transaction type by market (Dollars (Millions)): 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 | $56.3 | $0.0 | $0.0 | $56.3 | ($59.6) | $0.0 | $0.0 | ($59.6) | $0.0 | ($3.3) |
| Demand | $61.3 | $0.0 | $0.0 | $61.3 | $45.5 | $0.0 | $0.0 | $45.5 | $0.0 | $106.8 |
| 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 | $4.9 | $4.9 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $4.9 |
| Explicit Congestion Only | ($72.6) | $0.0 | ($0.5) | ($73.1) | ($9.8) | $0.0 | $2.0 | ($7.9) | $0.0 | ($81.0) |
| Generation | $0.0 | ($1,043.0) | $0.0 | $1,043.0 | $0.0 | $33.9 | $0.0 | ($33.9) | $0.0 | $1,009.1 |
| Grandfathered Overuse | $0.0 | $0.0 | $0.3 | $0.3 | $0.0 | $0.0 | $0.2 | $0.2 | $0.0 | $0.5 |
| Import | $0.0 | ($6.3) | $0.1 | $6.4 | $0.0 | ($7.8) | $0.9 | $8.8 | $0.0 | $15.2 |
| INC | $0.0 | $33.1 | $0.0 | ($33.1) | $0.0 | ($17.2) | $0.0 | $17.2 | $0.0 | ($15.9) |
| Internal Bilateral | $382.4 | $384.2 | $1.8 | ($0.0) | $19.5 | $19.5 | $0.0 | ($0.0) | $0.0 | ($0.0) |
| Up to Congestion | $0.0 | $0.0 | $32.7 | $32.7 | $0.0 | $0.0 | ($47.0) | ($47.0) | $0.0 | ($14.3) |
| Wheel In | $0.0 | ($22.1) | $1.7 | $23.7 | $0.0 | ($0.1) | $0.0 | $0.1 | $0.0 | $23.8 |
| Wheel Out | ($22.1) | $0.0 | $0.0 | ($22.1) | ($0.1) | $0.0 | $0.0 | ($0.1) | $0.0 | ($22.1) |
| Total | $405.3 | ($654.1) | $41.0 | $1,100.4 | ($4.5) | $28.3 | ($43.9) | ($76.8) | $0.0 | $1,023.7 |

Table 11-13 shows the change in total congestion cost incurred by transaction type from 2016 to 2017. Total congestion cost incurred by generation decreased by $322.8 million, and total congestion cost incurred by demand decreased by $30.9 million.

The total congestion payments to up to congestion transactions (UTCs) increased by $5.4 million, from $14.3 million in 2016 to $19.7 million 2017. Total day-ahead congestion costs paid by UTCs decreased by $41.6 million from $32.7 million in 2016 to -$8.9 million in 2017. In other words, UTCs paid $32.7 million in congestion charges in 2016 and were paid $8.9 million in congestion credits in 2017 in the day-ahead market. Over the same period balancing congestion payments to UTCs decreased by $36.2 million, from $47.0 million in 2016 to $10.8 million in 2017.

Table 11-13 Change in total PJM congestion costs by transaction type by market: 2016 to 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 | ($51.9) | $0.0 | $0.0 | ($51.9) | $42.5 | $0.0 | $0.0 | $42.5 | $0.0 | ($9.4) |
| Demand | ($25.7) | $0.0 | $0.0 | ($25.7) | ($5.3) | $0.0 | $0.0 | ($5.3) | $0.0 | ($30.9) |
| 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 | ($3.9) | ($3.9) | $0.0 | $0.0 | ($0.0) | ($0.0) | $0.0 | ($3.9) |
| Export | $42.9 | $0.0 | ($0.1) | $42.8 | $5.4 | $0.0 | ($0.2) | $5.2 | $0.0 | $48.1 |
| Generation | $0.0 | $303.1 | $0.0 | ($303.1) | $0.0 | $19.6 | $0.0 | ($19.6) | $0.0 | ($322.8) |
| Grandfathered Overuse | $0.0 | $0.0 | ($0.4) | ($0.4) | $0.0 | $0.0 | ($0.5) | ($0.5) | $0.0 | ($1.0) |
| Import | $0.0 | $4.5 | ($0.1) | ($4.7) | $0.0 | ($1.7) | ($1.8) | ($0.1) | $0.0 | ($4.7) |
| INC | $0.0 | ($22.7) | $0.0 | $22.7 | $0.0 | $17.0 | $0.0 | ($17.0) | $0.0 | $5.7 |
| Internal Bilateral | ($205.0) | ($206.9) | ($1.9) | ($0.0) | ($15.9) | ($15.9) | ($0.0) | ($0.0) | $0.0 | ($0.0) |
| Up to Congestion | $0.0 | $0.0 | ($41.6) | ($41.6) | $0.0 | $0.0 | $36.2 | $36.2 | $0.0 | ($5.4) |
| Wheel In | $0.0 | $21.9 | ($1.6) | ($23.5) | $0.0 | ($0.2) | ($0.2) | ($0.0) | $0.0 | ($23.5) |
| Wheel Out | $21.9 | $0.0 | $0.0 | $21.9 | ($0.2) | $0.0 | $0.0 | ($0.2) | $0.0 | $21.8 |
| Total | ($217.8) | $100.0 | ($49.6) | ($367.4) | $26.7 | $18.9 | $33.5 | $41.3 | $0.0 | ($326.1) |

## Monthly Congestion

Table 11-14 shows that monthly total congestion costs ranged from $30.1 million in August to $121.7 million in December, 2017. The high congestion cost in December was caused by high day-ahead congestion costs from December 27, 2017 through December 31, 2017. The total day-ahead congestion costs of those five days contributed 58.2 percent ($81.4 million out of $139.8 million) of total day-ahead congestion costs in December. The total day-ahead congestion costs from December 27, 2017 through December 31, 2017 were mainly a result of the 5004/5005 Interface, Carson – Rawlings Line and Cloverdale Transformer constraints. The high day-ahead load, high gas prices, dispatch of high cost units resulted in high shadow prices for those constraints and high negative CLMPs on the low side of those constraints which resulted in high negative day-ahead generation credits on those days. Negative generation credits are positive congestion costs.

### Table 11-14 Monthly PJM congestion costs by market (Dollars (Millions)): 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 | ($2.5) | $0.0 | $51.6 |
| Apr | $81.2 | ($3.0) | $0.0 | $78.2 | $30.7 | ($0.1) | $0.0 | $30.5 |
| May | $41.6 | $7.5 | ($0.0) | $49.1 | $36.7 | ($4.0) | $0.0 | $32.7 |
| Jun | $68.2 | ($8.6) | ($0.0) | $59.6 | $64.5 | ($0.2) | $0.0 | $64.4 |
| Jul | $124.4 | ($13.6) | ($0.0) | $110.8 | $51.7 | ($10.4) | $0.0 | $41.3 |
| Aug | $116.0 | ($5.0) | ($0.0) | $111.0 | $34.3 | ($4.2) | $0.0 | $30.1 |
| Sep | $123.4 | ($2.1) | ($0.0) | $121.4 | $99.7 | ($1.2) | $0.0 | $98.5 |
| Oct | $115.7 | ($12.6) | ($0.0) | $103.1 | $50.8 | $11.3 | $0.0 | $62.1 |
| Nov | $48.9 | ($0.9) | ($0.0) | $48.0 | $59.9 | ($1.5) | ($0.0) | $58.3 |
| Dec | $58.0 | ($7.8) | ($0.0) | $50.3 | $139.8 | ($18.1) | ($0.0) | $121.7 |
| Total | $1,100.4 | ($76.8) | ($0.0) | $1,023.7 | $733.1 | ($35.5) | $0.0 | $697.6 |

Figure 11-1 shows PJM monthly total congestion cost for January 1, 2009 through December 31, 2017.

### Figure 11-1 PJM monthly total congestion cost (Dollars (Millions)): 2009 through 2017

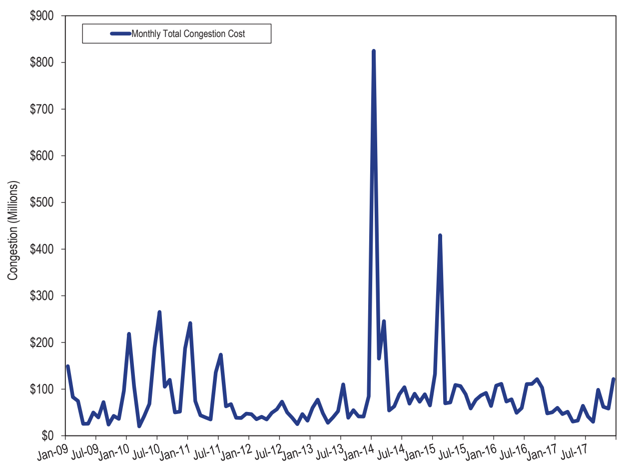



Table 11-15 shows the monthly total congestion costs for each virtual transaction type in 2017 and Table 11-16 shows the monthly total congestion costs for each virtual transaction type in 2016. Virtual transaction congestion costs, when positive, measure the total congestion cost to the virtual transaction and when negative, measure the total congestion credit to the virtual transaction. Table 11-15 and Table 11-16 show that virtuals were paid in 2017 and in 2016.

Table 11-15 Monthly PJM congestion costs by virtual transaction type and by market (Dollars (Millions)): 2017

| | Congestion Costs (Millions) | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Day-Ahead | | | | Balancing | | | | |
| | DEC | INC | Up to Congestion | Total | DEC | INC | Up to Congestion | Virtual Total | 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) |
| Apr | ($1.5) | $0.2 | $0.7 | ($0.6) | $1.3 | ($0.6) | $0.6 | $1.4 | $0.8 |
| May | ($3.5) | $1.4 | $0.2 | ($1.8) | $1.7 | ($3.2) | $0.6 | ($0.9) | ($2.7) |
| Jun | ($0.3) | $1.0 | ($0.3) | $0.3 | $0.2 | ($1.5) | $1.4 | $0.0 | $0.4 |
| Jul | $0.6 | $1.1 | $1.0 | $2.7 | ($2.2) | ($3.2) | ($5.1) | ($10.5) | ($7.9) |
| Aug | $2.0 | $0.4 | $1.6 | $3.9 | ($2.1) | ($1.3) | ($2.7) | ($6.1) | ($2.2) |
| Sep | $2.3 | $0.9 | ($3.8) | ($0.6) | ($2.6) | ($2.2) | ($2.7) | ($7.5) | ($8.1) |
| Oct | $1.8 | ($8.6) | ($3.9) | ($10.8) | ($2.5) | $7.6 | $3.8 | $8.9 | ($1.9) |
| Nov | $2.0 | ($4.3) | $1.0 | ($1.3) | ($3.1) | $3.0 | ($2.1) | ($2.2) | ($3.5) |
| Dec | $1.9 | ($0.2) | ($7.6) | ($5.9) | ($3.6) | $1.9 | ($5.5) | ($7.2) | ($13.1) |
| Total | $4.3 | ($10.3) | ($8.9) | ($14.9) | ($17.1) | $0.2 | ($10.8) | ($27.7) | ($42.7) |

Table 11-16 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 | Total | DEC | INC | Up to Congestion | Total | 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 2017, there were 300,923 day-ahead, congestion-event hours compared to 275,298 day-ahead congestion-event hours in 2016. Of 2017 day-ahead congestion-event hours, only 11,342 (3.8 percent) were also constrained in the Real-Time Energy Market. In 2017, there were 22,400 real-time, congestion-event hours compared to 26,370 real-time, congestion-event hours in 2016. Of 2017 real-time congestion-event hours, 11,121 (49.6 percent) were also constrained in the Day-Ahead Energy Market.

The top five constraints in terms of congestion costs contributed $154.4 million, or 22.1 percent, of the total PJM congestion costs in 2017. The top five constraints were the Braidwood - East Frankfort, the Conastone - Peach Bottom Line, the Emilie – Falls Line, the Graceton - Safe Harbor Line and the 5004/5005 Interface.

The top three constraints by total congestion costs changed from Conastone - Northwest Line, Graceton Transformer, and Bagley – Gracetone Line in the BGE Zone in 2016 to the Braidwood - East Frankfort Line in the ComEd Zone, the Emilie – Falls Line in the Pepco Zone in 2017 and the Conastone - Peach Bottom Line in the PECO Zone. The change in the BGE Zone was primarily a result of the completion of RTEP upgrades and and the end of outages in the BGE Zone related to the RTEP upgrades.

## Congestion by Facility Type and Voltage

In 2017, day-ahead, congestion-event hours increased on flowgates and transformers and decreased on lines and interfaces.

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 23,893 event hours in 2016 to 29,064 event hours in 2017. 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 ComEd, PENELEC and PSEG zones. The decrease in day-ahead, congestion-event hours on interfaces was a result of the decrease in day-ahead, congestion-event hours on AEP - DOM and Bedington - Black Oak. The decrease in day-ahead, congestion-event hours on lines was primarily a result of a decrease in day-ahead, congestion-event hours on lines in AECO, BGE and ComEd zones.

Real-time, congestion-event hours increased on interfaces and decreased on flowgates, lines and transformers. The increase in real-time, congestion-event hours on interfaces was primarily a result of the increase in real-time, congestion-event hours on the 5004/5005 interface. The 5004/5005 interface constraints were caused by the Keystone substation equipment outages in December. 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 NYISO. 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, ComEd and DPL zones.

Day-ahead congestion costs decreased on all types of facilities except interfaces in 2017 compared to 2016, as indicated by the decrease in day-ahead load-weighted CLMP. The load-weighted average congestion component decreased $0.09, or 65.1 percent, from $0.14 in 2016 to $0.05 in 2017.

Balancing congestion costs increased on flowgates and lines and decreased on interfaces and transformers in 2017 compared to 2016. Table 11-17 provides congestion-event hour subtotals and congestion cost subtotals comparing 2017 results by facility type: line, transformer, interface, flowgate and unclassified facilities.[17] [18]

Table 11-18 presents this information for 2016.

### Table 11-17 Congestion summary (By facility type): 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 | ($52.9) | ($207.3) | ($24.6) | $129.8 | $7.0 | $6.4 | ($2.7) | ($2.2) | $127.6 | 29,579 | 5,975 |
| Interface | $16.0 | ($58.8) | ($7.0) | $67.8 | $4.9 | $14.2 | $5.7 | ($3.6) | $64.2 | 4,635 | 439 |
| Line | $186.3 | ($233.0) | $12.6 | $431.9 | $5.8 | $20.3 | ($0.0) | ($14.5) | $417.4 | 155,443 | 12,963 |
| Other | $4.9 | ($6.2) | $1.0 | $12.1 | $0.7 | $1.3 | $0.9 | $0.3 | $12.4 | 16,623 | 529 |
| Transformer | $33.2 | ($48.7) | $9.4 | $91.3 | $3.8 | $3.8 | ($13.6) | ($13.6) | $77.6 | 94,643 | 2,494 |
| Unclassified | $0.1 | ($0.0) | $0.0 | $0.2 | $0.0 | $1.2 | ($0.7) | ($1.8) | ($1.7) | NA | NA |
| Total | $187.6 | ($554.1) | ($8.6) | $733.1 | $22.2 | $47.2 | ($10.4) | ($35.5) | $697.6 | 300,923 | 22,400 |

### Table 11-18 Congestion summary (By facility type): 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 |

17 Unclassified are congestion costs related to nontransmission facility constraints in the Day-Ahead Energy 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.

18 The term flowgate refers to MISO reciprocal coordinated flowgates and NYISO M2M flowgates.

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Flowgate | ($30.8) | ($261.2) | ($16.5) | $213.9 | ($0.1) | $17.5 | ($15.6) | ($33.3) | $180.7 | 23,964 | 6,039 |
| Interface | $29.5 | ($20.5) | ($2.5) | $47.6 | $0.3 | $0.3 | $0.2 | $0.2 | $47.8 | 4,959 | 155 |
| Line | $313.1 | ($256.5) | $44.7 | $614.3 | ($1.6) | $9.7 | ($28.0) | ($39.3) | $575.0 | 161,398 | 16,610 |
| Other | $2.2 | ($1.8) | $0.6 | $4.6 | $0.3 | ($0.1) | ($0.9) | ($0.4) | $4.2 | 13,520 | 203 |
| Transformer | $91.3 | ($113.9) | $14.5 | $219.7 | ($2.1) | $3.0 | ($3.4) | ($8.5) | $211.2 | 71,457 | 3,363 |
| Unclassified | ($0.1) | ($0.2) | $0.1 | $0.3 | ($1.3) | ($2.0) | $3.8 | $4.5 | $4.8 | NA | NA |
| Total | $405.3 | ($654.1) | $41.0 | $1,100.4 | ($4.5) | $28.4 | ($43.9) | ($76.8) | $1,023.7 | 275,298 | 26,370 |

Table 11-19 and Table 11-20 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 11-19. In 2017, there were 300,923 congestion-event hours in the Day-Ahead Energy Market. Of those day-ahead congestion-event hours, only 11,342 (3.8 percent) were also constrained in the Real-Time Energy Market. In 2016, of the 275,298 day-ahead congestion-event hours, only 14,435 (5.2 percent) were binding in the Real-Time Energy Market.[19]

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 11-20. In 2017, of the 22,400 congestion-event hours in the Real-Time Energy Market, 11,121 (49.6 percent) were also constrained in the Day-Ahead Energy Market. In 2016, of the 26,370 real-time congestion-event hours, 14,339 (54.4 percent) were also in the Day-Ahead Energy Market.

## Table 11-19 Congestion event hours (day-ahead against real-time): 2016 and 2017

| | Congestion Event Hours | | | | | |
|---|---|---|---|---|---|---|
| | 2016 | | | 2017 | | |
| Type | Day-Ahead Constrained | Corresponding Real-Time Constrained | Percent | Day-Ahead Constrained | Corresponding Real-Time Constrained | Percent |
| Flowgate | 23,964 | 2,682 | 11.2% | 29,579 | 2,464 | 8.3% |
| Interface | 4,959 | 75 | 1.5% | 4,635 | 268 | 5.8% |
| Line | 161,398 | 9,425 | 5.8% | 155,443 | 7,726 | 5.0% |
| Other | 13,520 | 9 | 0.1% | 16,623 | 28 | 0.2% |
| Transformer | 71,457 | 2,244 | 3.1% | 94,643 | 856 | 0.9% |
| Total | 275,298 | 14,435 | 5.2% | 300,923 | 11,342 | 3.8% |

## Table 11-20 Congestion event hours (real-time against day-ahead): 2016 and 2017

| | Congestion Event Hours | | | | | |
|---|---|---|---|---|---|---|
| | 2016 | | | 2017 | | |
| Type | Real-Time Constrained | Corresponding Day-Ahead Constrained | Percent | Real-Time Constrained | Corresponding Day-Ahead Constrained | Percent |
| Flowgate | 6,039 | 2,657 | 44.0% | 5,975 | 2,473 | 41.4% |
| Interface | 155 | 85 | 54.8% | 439 | 331 | 75.4% |
| Line | 16,610 | 9,343 | 56.2% | 12,963 | 7,475 | 57.7% |
| Other | 203 | 9 | 4.4% | 529 | 28 | 5.3% |
| Transformer | 3,363 | 2,245 | 66.8% | 2,494 | 814 | 32.6% |
| Total | 26,370 | 14,339 | 54.4% | 22,400 | 11,121 | 49.6% |

Table 11-21 shows congestion costs by facility voltage class for 2017. Congestion costs in 2017 decreased for all facilities except 500 kV, 115 kV and 13kV compared to 2016 (Table 11-22).

## Table 11-21 Congestion summary (By facility voltage): 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 | $0.6 | ($1.2) | $0.8 | $2.6 | ($0.2) | $0.0 | $0.0 | ($0.2) | $2.4 | 1,070 | 35 |

19 Constraints are mapped to transmission facilities. In the Day-Ahead Energy Market, within a given hour, a single facility may be associated with multiple constraints. In such situations, the same facility accounts for more than one constraint-hour for a given hour in the Day-Ahead Energy Market. Similarly in the real-time market a facility may account for more than one constraint-hour within a given hour.

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 500 | $74.5 | ($70.2) | ($5.7) | $139.0 | $7.9 | $17.2 | $8.8 | ($0.4) | $138.6 | 9,061 | 1,533 |
| 345 | ($11.0) | ($140.4) | $1.0 | $130.4 | $8.3 | $9.3 | ($16.8) | ($17.8) | $112.6 | 59,380 | 3,220 |
| 230 | $121.0 | ($47.5) | $1.6 | $170.1 | $7.3 | $18.7 | ($1.6) | ($13.0) | $157.1 | 47,474 | 5,750 |
| 161 | ($0.0) | ($0.3) | ($0.0) | $0.3 | ($0.1) | $0.1 | ($0.1) | ($0.2) | $0.0 | 33 | 34 |
| 138 | ($10.6) | ($266.5) | ($4.1) | $251.8 | $4.2 | $13.5 | ($4.2) | ($13.6) | $238.2 | 128,573 | 8,795 |
| 115 | $3.7 | ($34.5) | $0.1 | $38.2 | ($0.8) | $2.2 | $1.3 | ($1.7) | $36.6 | 30,626 | 1,913 |
| 69 | $9.1 | $7.2 | ($2.7) | ($0.9) | ($4.5) | ($15.1) | $2.7 | $13.2 | $12.4 | 17,329 | 1,120 |
| 35 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | 15 | 0 |
| 34 | $0.3 | $0.0 | $0.2 | $0.5 | $0.0 | $0.0 | $0.0 | $0.0 | $0.5 | 5,573 | 0 |
| 18 | ($0.0) | ($0.6) | $0.2 | $0.8 | $0.0 | $0.0 | $0.0 | $0.0 | $0.8 | 1,677 | 0 |
| 17 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | 11 | 0 |
| 13 | $0.0 | ($0.0) | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | 101 | 0 |
| Unclassified | $0.1 | ($0.0) | $0.0 | $0.2 | $0.0 | $1.2 | ($0.7) | ($1.8) | ($1.7) | NA | NA |
| Total | $187.6 | ($554.1) | ($8.6) | $733.1 | $22.2 | $47.2 | ($10.4) | ($35.5) | $697.6 | 300,923 | 22,400 |

## Table 11-22 Congestion summary (By facility voltage): 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 | $0.6 | ($2.0) | $1.4 | $4.1 | $0.0 | ($0.0) | ($0.0) | ($0.0) | $4.1 | 1,527 | 5 |
| 500 | $55.3 | ($42.1) | ($1.2) | $96.2 | $4.5 | $4.3 | $3.6 | $3.8 | $100.0 | 8,373 | 1,085 |
| 345 | ($13.0) | ($170.8) | $21.5 | $179.3 | $1.1 | $19.2 | ($25.7) | ($43.9) | $135.4 | 49,044 | 4,720 |
| 230 | $297.9 | ($102.0) | ($2.1) | $397.8 | $10.3 | ($0.4) | $3.6 | $14.3 | $412.1 | 43,862 | 7,939 |
| 161 | ($20.2) | ($60.5) | ($10.4) | $29.8 | ($2.6) | $4.4 | $1.7 | ($5.2) | $24.6 | 5,262 | 1,427 |
| 138 | $34.3 | ($275.4) | $26.2 | $335.8 | ($5.7) | $18.6 | ($26.2) | ($50.5) | $285.3 | 117,296 | 7,139 |
| 115 | $21.5 | ($16.0) | $3.0 | $40.5 | ($2.5) | $0.7 | ($3.9) | ($7.1) | $33.4 | 22,359 | 1,202 |
| 69 | $28.6 | $15.0 | $2.3 | $15.8 | ($8.4) | ($16.5) | ($0.9) | $7.2 | $23.0 | 22,822 | 2,794 |
| 34.5 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | 48 | 0 |
| 34 | $0.6 | $0.0 | $0.2 | $0.8 | ($0.0) | $0.0 | $0.1 | $0.1 | $0.8 | 4,607 | 59 |
| 13 | $0.0 | ($0.0) | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | 59 | 0 |
| 12 | ($0.0) | ($0.1) | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | 39 | 0 |
| Unclassified | ($0.1) | ($0.2) | $0.1 | $0.3 | ($1.3) | ($2.0) | $3.8 | $4.5 | $4.8 | NA | NA |
| Total | $405.3 | ($654.1) | $41.0 | $1,100.4 | ($4.5) | $28.4 | ($43.9) | ($76.8) | $1,023.7 | 275,298 | 26,370 |

## Constraint Duration

Table 11-23 lists the constraints in 2016 and 2017 that were most frequently binding and Table 11-24 shows the constraints which experienced the largest change in congestion-event hours from 2016 to 2017.

### Table 11-23 Top 25 constraints with frequent occurrence: 2016 and 2017[20]

| | | | Event Hours | | | | | | Percent of Annual Hours | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Day-Ahead | | | Real-Time | | | Day-Ahead | | | Real-Time | | |
| No. | Constraint | Type | 2016 | 2017 | Change | 2016 | 2017 | Change | 2016 | 2017 | Change | 2016 | 2017 | Change |
| 1 | Quad Cities | Transformer | 1,046 | 9,457 | 8,411 | 0 | 0 | 0 | 12% | 108% | 96% | 0% | 0% | 0% |
| 2 | Olive | Other | 6,092 | 6,460 | 368 | 0 | 0 | 0 | 70% | 74% | 4% | 0% | 0% | 0% |
| 3 | Emilie - Falls | Line | 2,617 | 5,171 | 2,554 | 329 | 895 | 566 | 30% | 59% | 29% | 4% | 10% | 6% |
| 4 | Zion | Line | 2,929 | 4,644 | 1,715 | 0 | 0 | 0 | 33% | 53% | 19% | 0% | 0% | 0% |
| 5 | Waukegan | Transformer | 2,326 | 4,579 | 2,253 | 0 | 0 | 0 | 27% | 52% | 26% | 0% | 0% | 0% |
| 6 | Braidwood - East Frankfort | Line | 2,130 | 4,171 | 2,041 | 337 | 301 | (36) | 24% | 47% | 23% | 4% | 3% | (0%) |
| 7 | East Bend | Transformer | 2,700 | 4,464 | 1,764 | 0 | 0 | 0 | 31% | 51% | 20% | 0% | 0% | 0% |
| 8 | Hinchmans | Transformer | 222 | 4,378 | 4,156 | 0 | 0 | 0 | 3% | 50% | 47% | 0% | 0% | 0% |
| 9 | Graceton - Safe Harbor | Line | 590 | 3,118 | 2,528 | 131 | 1,151 | 1,020 | 7% | 35% | 29% | 1% | 13% | 12% |
| 10 | Loretto - Vienna | Line | 1,867 | 3,950 | 2,083 | 6 | 60 | 54 | 21% | 45% | 24% | 0% | 1% | 1% |
| 11 | Conastone - Peach Bottom | Line | 2,407 | 3,159 | 752 | 699 | 840 | 141 | 27% | 36% | 8% | 8% | 10% | 2% |
| 12 | Westwood | Flowgate | 950 | 3,399 | 2,449 | 137 | 198 | 61 | 11% | 39% | 28% | 2% | 2% | 1% |
| 13 | West Chicago | Transformer | 2,222 | 3,490 | 1,268 | 0 | 0 | 0 | 25% | 40% | 14% | 0% | 0% | 0% |
| 14 | Cherry Valley | Transformer | 5,319 | 3,007 | (2,312) | 774 | 149 | (625) | 61% | 34% | (26%) | 9% | 2% | (7%) |
| 15 | Saddlebrook | Transformer | 1,810 | 3,098 | 1,288 | 0 | 0 | 0 | 21% | 35% | 15% | 0% | 0% | 0% |
| 16 | Howard - Shelby | Line | 4,169 | 3,041 | (1,128) | 0 | 0 | 0 | 48% | 35% | (13%) | 0% | 0% | 0% |
| 17 | Electric Junction | Transformer | 0 | 2,906 | 2,906 | 0 | 0 | 0 | 0% | 33% | 33% | 0% | 0% | 0% |
| 18 | Gould Street - Westport | Line | 2,782 | 2,800 | 18 | 27 | 0 | (27) | 32% | 32% | 0% | 0% | 0% | (0%) |
| 19 | Essex Co. RRF | Transformer | 1,202 | 2,793 | 1,591 | 0 | 0 | 0 | 14% | 32% | 18% | 0% | 0% | 0% |
| 20 | Tanners Creek | Transformer | 2,548 | 2,679 | 131 | 0 | 0 | 0 | 29% | 30% | 1% | 0% | 0% | 0% |
| 21 | West Moulton - City Of St. Marys | Line | 3,718 | 2,677 | (1,041) | 0 | 0 | 0 | 42% | 30% | (12%) | 0% | 0% | 0% |
| 22 | Hudson | Transformer | 2,795 | 2,610 | (185) | 0 | 0 | 0 | 32% | 30% | (2%) | 0% | 0% | 0% |
| 23 | Liquid Carbonics | Transformer | 1,340 | 2,586 | 1,246 | 0 | 0 | 0 | 15% | 29% | 14% | 0% | 0% | 0% |
| 24 | Elwood | Other | 3,849 | 2,571 | (1,278) | 0 | 0 | 0 | 44% | 29% | (15%) | 0% | 0% | 0% |
| 25 | Maywood | Transformer | 3,422 | 2,540 | (882) | 0 | 0 | 0 | 39% | 29% | (10%) | 0% | 0% | 0% |

20 The constraints are presented in descending order of total of day-ahead event hours and real-time event hours in 2017.

## Table 11-24 Top 25 constraints with largest year-to-year change in occurrence: 2016 and 2017[21]

| | | | Event Hours | | | | | | Percent of Annual Hours | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Day-Ahead | | | Real-Time | | | Day-Ahead | | | Real-Time | | |
| No. | Constraint | Type | 2016 | 2017 | Change | 2016 | 2017 | Change | 2016 | 2017 | Change | 2016 | 2017 | Change |
| 1 | Quad Cities | Transformer | 1,046 | 9,457 | 8,411 | 0 | 0 | 0 | 12% | 108% | 96% | 0% | 0% | 0% |
| 2 | Monroe - Vineland | Line | 5,354 | 343 | (5,011) | 439 | 13 | (426) | 61% | 4% | (57%) | 5% | 0% | (5%) |
| 3 | Mercer IP - Galesburg | Flowgate | 3,510 | 0 | (3,510) | 1,155 | 0 | (1,155) | 40% | 0% | (40%) | 13% | 0% | (13%) |
| 4 | Graceton | Transformer | 3,117 | 0 | (3,117) | 1,298 | 0 | (1,298) | 36% | 0% | (36%) | 15% | 0% | (15%) |
| 5 | Bagley - Graceton | Line | 3,313 | 554 | (2,759) | 1,685 | 127 | (1,558) | 38% | 6% | (32%) | 19% | 1% | (18%) |
| 6 | Hinchmans | Transformer | 222 | 4,378 | 4,156 | 0 | 0 | 0 | 3% | 50% | 47% | 0% | 0% | 0% |
| 7 | Graceton - Safe Harbor | Line | 590 | 3,118 | 2,528 | 131 | 1,151 | 1,020 | 7% | 35% | 29% | 1% | 13% | 12% |
| 8 | East Danville - Banister | Line | 3,643 | 237 | (3,406) | 20 | 2 | (18) | 42% | 3% | (39%) | 0% | 0% | (0%) |
| 9 | Conastone - Northwest | Line | 2,776 | 975 | (1,801) | 1,840 | 228 | (1,612) | 32% | 11% | (21%) | 21% | 3% | (18%) |
| 10 | Emilie - Falls | Line | 2,617 | 5,171 | 2,554 | 329 | 895 | 566 | 30% | 59% | 29% | 4% | 10% | 6% |
| 11 | Cherry Valley | Transformer | 5,319 | 3,007 | (2,312) | 774 | 149 | (625) | 61% | 34% | (26%) | 9% | 2% | (7%) |
| 12 | Electric Junction | Transformer | 0 | 2,906 | 2,906 | 0 | 0 | 0 | 0% | 33% | 33% | 0% | 0% | 0% |
| 13 | Westwood | Flowgate | 950 | 3,399 | 2,449 | 137 | 198 | 61 | 11% | 39% | 28% | 2% | 2% | 1% |
| 14 | Reynolds - Magnetation | Flowgate | 2,062 | 297 | (1,765) | 680 | 31 | (649) | 24% | 3% | (20%) | 8% | 0% | (7%) |
| 15 | Seneca | Transformer | 146 | 2,495 | 2,349 | 0 | 0 | 0 | 2% | 28% | 27% | 0% | 0% | 0% |
| 16 | Beryl - Westvaco | Line | 0 | 2,306 | 2,306 | 0 | 0 | 0 | 0% | 26% | 26% | 0% | 0% | 0% |
| 17 | Waukegan | Transformer | 2,326 | 4,579 | 2,253 | 0 | 0 | 0 | 27% | 52% | 26% | 0% | 0% | 0% |
| 18 | Mardela - Vienna | Line | 2,367 | 577 | (1,790) | 380 | 5 | (375) | 27% | 7% | (20%) | 4% | 0% | (4%) |
| 19 | Tidd | Transformer | 2,422 | 276 | (2,146) | 0 | 0 | 0 | 28% | 3% | (25%) | 0% | 0% | 0% |
| 20 | Havana E - Havana S | Flowgate | 118 | 2,260 | 2,142 | 0 | 0 | 0 | 1% | 26% | 24% | 0% | 0% | 0% |
| 21 | Loretto - Vienna | Line | 1,867 | 3,950 | 2,083 | 6 | 60 | 54 | 21% | 45% | 24% | 0% | 1% | 1% |
| 22 | Kincaid - Pana North | Line | 2,127 | 0 | (2,127) | 0 | 0 | 0 | 24% | 0% | (24%) | 0% | 0% | 0% |
| 23 | Halifax - Roanoke Rapids | Line | 0 | 2,069 | 2,069 | 0 | 0 | 0 | 0% | 24% | 24% | 0% | 0% | 0% |
| 24 | Braidwood | Transformer | 4,138 | 2,086 | (2,052) | 0 | 0 | 0 | 47% | 24% | (23%) | 0% | 0% | 0% |
| 25 | Braidwood - East Frankfort | Line | 2,130 | 4,171 | 2,041 | 337 | 301 | (36) | 24% | 47% | 23% | 4% | 3% | (0%) |

21 The constraints are presented in descending order of absolute value of day-ahead event hour changes plus real-time event hour changes from 2016 to 2017.

## Constraint Costs

Table 11-25 and Table 11-26 show the top constraints affecting congestion costs by facility for 2017 and 2016. The Braidwood – East Frankfort Line was the largest contributor to congestion costs in 2017. With $43.4 million in total congestion costs, it accounted for 6.2 percent of the total PJM congestion costs in 2017.

### Table 11-25 Top 25 constraints affecting PJM congestion costs (By facility): 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 |
| 1 | Braidwood - East Frankfort | Line | ComEd | ($4.7) | ($49.7) | $0.3 | $45.3 | $0.7 | $1.9 | ($0.7) | ($1.9) | $43.4 | 6.2% |
| 2 | Conastone - Peach Bottom | Line | 500 | $38.7 | $1.6 | $0.1 | $37.2 | $2.0 | $1.3 | $1.5 | $2.2 | $39.5 | 5.7% |
| 3 | Emilie - Falls | Line | PECO | $12.0 | ($13.6) | ($0.1) | $25.6 | ($0.1) | $1.2 | $0.8 | ($0.4) | $25.1 | 3.6% |
| 4 | Graceton - Safe Harbor | Line | BGE | $30.2 | $7.1 | ($0.0) | $23.1 | $1.7 | $2.3 | $1.4 | $0.8 | $23.9 | 3.4% |
| 5 | 5004/5005 Interface | Interface | 500 | ($9.9) | ($38.7) | ($3.8) | $25.0 | $4.3 | $11.4 | $4.6 | ($2.5) | $22.5 | 3.2% |
| 6 | AP South | Interface | 500 | $15.3 | ($9.2) | ($2.4) | $22.1 | ($0.0) | $1.3 | $0.9 | ($0.5) | $21.6 | 3.1% |
| 7 | Westwood | Flowgate | MISO | ($22.1) | ($41.3) | $0.5 | $19.7 | $1.2 | $0.8 | ($0.5) | ($0.1) | $19.6 | 2.8% |
| 8 | Cherry Valley | Transformer | ComEd | $8.9 | ($10.1) | $2.1 | $21.0 | ($0.6) | $0.9 | ($0.9) | ($2.3) | $18.7 | 2.7% |
| 9 | Carson - Rawlings | Line | Dominion | $14.5 | ($4.3) | $0.8 | $19.6 | $1.0 | $1.6 | ($0.8) | ($1.4) | $18.2 | 2.6% |
| 10 | Conastone - Otter Creek | Line | PPL | $23.0 | $8.5 | ($0.5) | $13.9 | $1.5 | $1.8 | $1.5 | $1.2 | $15.1 | 2.2% |
| 11 | Conastone - Northwest | Line | BGE | $12.7 | ($1.1) | ($0.4) | $13.4 | $0.4 | $0.7 | $1.0 | $0.7 | $14.1 | 2.0% |
| 12 | Three Mile Island | Transformer | 500 | $7.4 | ($4.9) | ($0.3) | $11.9 | ($0.1) | ($0.6) | $0.9 | $1.4 | $13.3 | 1.9% |
| 13 | Butler - Shanorma | Line | APS | ($10.5) | ($20.9) | $1.0 | $11.4 | $0.0 | $0.0 | $0.0 | $0.0 | $11.4 | 1.6% |
| 14 | Lakeview - Greenfield | Line | ATSI | ($3.5) | ($14.5) | $0.2 | $11.2 | $0.1 | $0.7 | $0.3 | ($0.4) | $10.8 | 1.5% |
| 15 | Alpine - Belvidere | Flowgate | MISO | ($2.3) | ($14.0) | ($0.9) | $10.8 | $0.0 | $0.0 | $0.0 | $0.0 | $10.8 | 1.5% |
| 16 | Bedington - Black Oak | Interface | 500 | $5.5 | ($4.1) | ($0.2) | $9.3 | $0.1 | $0.3 | $0.4 | $0.2 | $9.5 | 1.4% |
| 17 | Person - Sedge Hill | Line | Dominion | $16.2 | $3.5 | $2.0 | $14.7 | $0.6 | $2.7 | ($3.2) | ($5.3) | $9.3 | 1.3% |
| 18 | Lake George - Aetna | Flowgate | MISO | ($1.1) | ($9.0) | ($1.5) | $6.4 | ($2.2) | $0.9 | $5.8 | $2.7 | $9.2 | 1.3% |
| 19 | Batesville - Hubble | Flowgate | MISO | ($5.5) | ($19.4) | ($4.5) | $9.4 | ($0.2) | ($1.2) | ($1.6) | ($0.6) | $8.9 | 1.3% |
| 20 | Byron - Cherry Valley | Flowgate | MISO | ($0.9) | ($9.3) | ($0.4) | $8.0 | $0.0 | $0.0 | $0.0 | $0.0 | $8.0 | 1.1% |
| 21 | AEP - DOM | Interface | 500 | $3.3 | ($4.3) | ($0.1) | $7.5 | $0.5 | $0.5 | $0.2 | $0.3 | $7.8 | 1.1% |
| 22 | Brunner Island - Yorkanna | Line | Met-Ed | $6.0 | ($1.6) | ($0.3) | $7.3 | ($0.0) | ($0.1) | $0.1 | $0.2 | $7.5 | 1.1% |
| 23 | Brokaw - Leroy | Flowgate | MISO | $0.8 | ($7.6) | ($3.7) | $4.8 | $0.2 | $0.3 | $2.6 | $2.5 | $7.3 | 1.0% |
| 24 | Loretto - Vienna | Line | DPL | $8.8 | $2.3 | $0.7 | $7.2 | ($0.4) | $0.1 | $0.2 | ($0.3) | $6.9 | 1.0% |
| 25 | Pleasant View - Ashburn | Line | Dominion | $5.8 | ($3.7) | ($0.3) | $9.1 | ($1.1) | $1.0 | ($0.1) | ($2.3) | $6.8 | 1.0% |

## Table 11-26 Top 25 constraints affecting PJM congestion costs (By facility): 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 |
| 1 | Conastone - Northwest | Line | BGE | $114.8 | $7.4 | ($4.6) | $102.8 | $3.9 | ($2.4) | $6.5 | $12.7 | $115.5 | 11.3% |
| 2 | Graceton | Transformer | BGE | $53.1 | ($21.0) | ($0.9) | $73.3 | ($0.9) | ($4.7) | $1.8 | $5.6 | $78.9 | 7.7% |
| 3 | Bagley - Graceton | Line | BGE | $72.5 | $5.8 | ($1.9) | $64.8 | $2.7 | ($2.7) | $2.2 | $7.7 | $72.5 | 7.1% |
| 4 | Cherry Valley | Transformer | ComEd | $20.4 | ($27.9) | $3.9 | $52.3 | ($3.0) | $2.6 | ($5.7) | ($11.3) | $40.9 | 4.0% |
| 5 | Cherry Valley | Flowgate | MISO | ($5.7) | ($44.0) | ($0.5) | $37.8 | $0.0 | $0.0 | $0.0 | $0.0 | $37.8 | 3.7% |
| 6 | Conastone - Peach Bottom | Line | 500 | $27.9 | ($0.2) | $0.8 | $28.9 | $1.3 | $0.9 | $0.0 | $0.4 | $29.3 | 2.9% |
| 7 | Braidwood - East Frankfort | Line | ComEd | ($3.8) | ($38.2) | $0.8 | $35.2 | $0.5 | $3.3 | ($3.5) | ($6.3) | $28.9 | 2.8% |
| 8 | Mercer IP - Galesburg | Flowgate | MISO | ($17.1) | ($49.9) | ($8.9) | $23.9 | ($0.2) | $3.6 | $2.2 | ($1.6) | $22.3 | 2.2% |
| 9 | Byron - Cherry Valley | Flowgate | MISO | ($5.5) | ($22.6) | $0.9 | $18.0 | $0.0 | $0.0 | $0.0 | $0.0 | $18.0 | 1.8% |
| 10 | Milford - Steele | Line | DPL | ($8.6) | ($26.7) | $0.1 | $18.1 | $2.2 | $1.4 | ($1.7) | ($0.9) | $17.2 | 1.7% |
| 11 | AP South | Interface | 500 | $13.8 | ($4.9) | ($1.9) | $16.8 | $0.1 | $0.1 | $0.0 | $0.0 | $16.8 | 1.6% |
| 12 | Dixon - McGirr Rd | Flowgate | MISO | ($5.0) | ($22.9) | ($1.2) | $16.7 | $0.0 | $0.0 | $0.0 | $0.0 | $16.7 | 1.6% |
| 13 | Reynolds - Magnetation | Flowgate | MISO | ($5.1) | ($23.9) | $0.9 | $19.8 | $0.5 | $1.5 | ($2.6) | ($3.5) | $16.2 | 1.6% |
| 14 | Bedington - Black Oak | Interface | 500 | $9.5 | ($6.2) | ($0.6) | $15.2 | $0.2 | $0.2 | $0.1 | $0.1 | $15.3 | 1.5% |
| 15 | Coolspring - Milford | Line | DPL | $1.3 | ($11.8) | ($0.0) | $13.1 | ($1.0) | ($1.8) | $0.3 | $1.1 | $14.1 | 1.4% |
| 16 | Loudoun | Transformer | Dominion | $1.1 | ($9.8) | ($0.2) | $10.6 | $1.5 | $2.2 | $3.4 | $2.7 | $13.3 | 1.3% |
| 17 | Person - Halifax | Flowgate | MISO | $29.9 | $16.1 | ($0.2) | $13.5 | $0.0 | $0.0 | ($0.2) | ($0.2) | $13.3 | 1.3% |
| 18 | Kanawha River - Matt Funk | Line | AEP | $2.7 | ($17.1) | ($1.1) | $18.8 | ($0.7) | $2.5 | ($3.3) | ($6.6) | $12.2 | 1.2% |
| 19 | Plymouth Meeting - Whitpain | Line | PECO | ($0.6) | ($10.9) | ($0.1) | $10.2 | ($0.1) | $0.1 | $0.2 | ($0.0) | $10.1 | 1.0% |
| 20 | AEP - DOM | Interface | 500 | $3.5 | ($4.5) | $0.2 | $8.2 | $0.3 | ($0.0) | $0.1 | $0.3 | $8.5 | 0.8% |
| 21 | Braidwood - East Frankfurt | Flowgate | MISO | ($0.1) | ($7.7) | $0.7 | $8.4 | $0.0 | $0.0 | $0.0 | $0.0 | $8.4 | 0.8% |
| 22 | Cherry Valley - Silver Lake | Flowgate | MISO | ($1.8) | ($9.4) | $0.8 | $8.4 | $0.0 | $0.0 | $0.0 | $0.0 | $8.4 | 0.8% |
| 23 | Brambleton - Loudoun | Line | Dominion | ($2.9) | ($10.2) | $0.2 | $7.5 | $0.2 | ($0.1) | $0.4 | $0.6 | $8.1 | 0.8% |
| 24 | Kanawha | Transformer | AEP | $0.1 | ($7.1) | $0.7 | $7.9 | $0.0 | $0.0 | $0.0 | $0.0 | $7.9 | 0.8% |
| 25 | Stockton - Kenney | Line | DPL | ($2.5) | $3.4 | ($1.9) | ($7.8) | $0.0 | $0.0 | $0.0 | $0.0 | ($7.8) | (0.8%) |

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 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 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 2017.

Figure 11-2 Location of the top 10 constraints by PJM total congestion costs: 2017

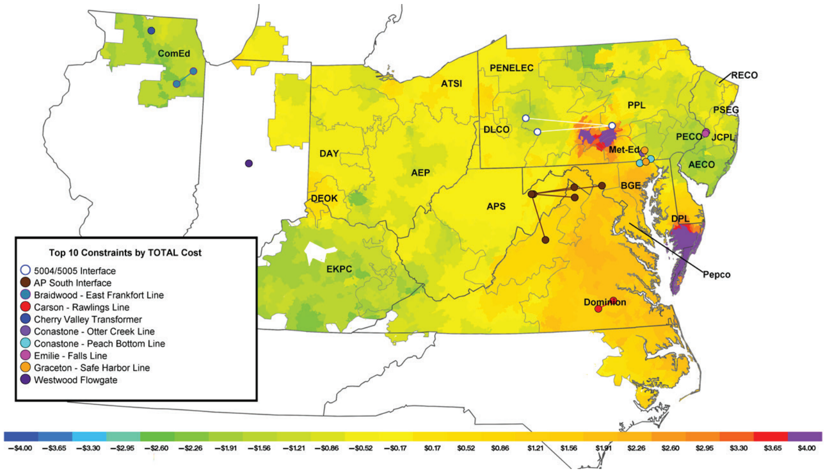



Figure 11-3 Location of the top 10 constraints by PJM balancing congestion costs: 2017

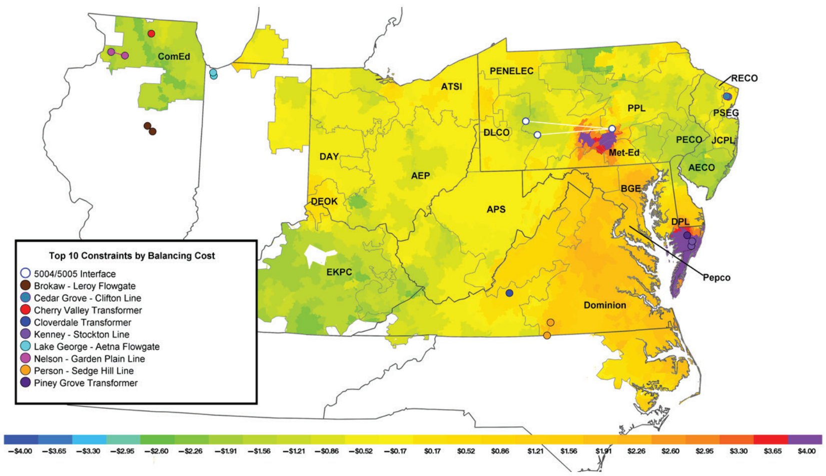
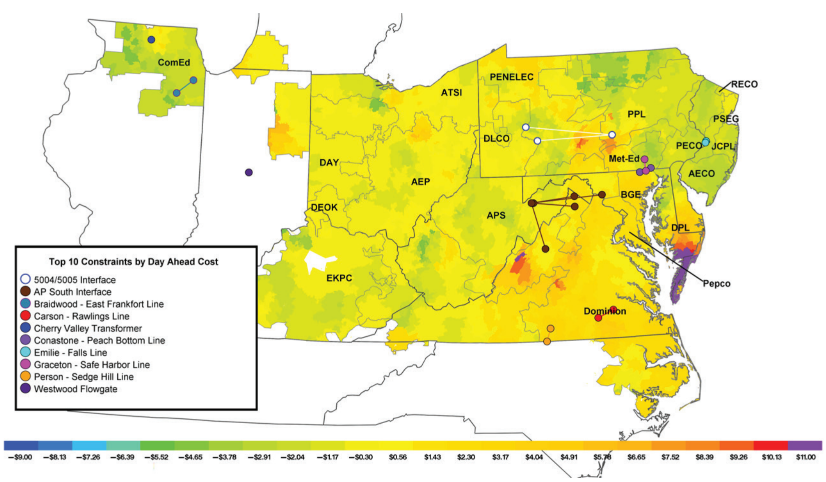



Figure 11-4 Location of the top 10 constraints by PJM day-ahead congestion costs: 2017



## 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.[22] A flowgate is a facility or group of facilities that may act as constraint points on the regional system.[23] PJM models these coordinated flowgates and controls for them in its security-constrained, economic dispatch.

As of December 31, 2017, PJM had 140 flowgates eligible for M2M (Market to Market) coordination and MISO had 234 flowgates eligible for M2M coordination.

Table 11-27 and Table 11-28 show the MISO flowgates which PJM and/or MISO took dispatch action to control during 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 2017, the Westwood Flowgate made the most significant contribution to positive congestion while the Roxana - Praxair Flowgate made the most significant contribution to negative congestion.

### Table 11-27 Top 20 congestion cost impacts from MISO flowgates affecting PJM dispatch (By facility): 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 | Westwood | ($22.1) | ($41.3) | $0.5 | $19.7 | $1.2 | $0.8 | ($0.5) | ($0.1) | $19.6 | 3,399 | 198 |
| 2 | Alpine - Belvidere | ($2.3) | ($14.0) | ($0.9) | $10.8 | $0.0 | $0.0 | $0.0 | $0.0 | $10.8 | 339 | 0 |
| 3 | Lake George - Aetna | ($1.1) | ($9.0) | ($1.5) | $6.4 | ($2.2) | $0.9 | $5.8 | $2.7 | $9.2 | 483 | 244 |
| 4 | Batesville - Hubble | ($5.5) | ($19.4) | ($4.5) | $9.4 | ($0.2) | ($1.2) | ($1.6) | ($0.6) | $8.9 | 379 | 158 |
| 5 | Byron - Cherry Valley | ($0.9) | ($9.3) | ($0.4) | $8.0 | $0.0 | $0.0 | $0.0 | $0.0 | $8.0 | 347 | 0 |
| 6 | Brokaw - Leroy | $0.8 | ($7.6) | ($3.7) | $4.8 | $0.2 | $0.3 | $2.6 | $2.5 | $7.3 | 1,744 | 528 |
| 7 | Greentown | ($1.4) | ($7.6) | ($0.7) | $5.6 | ($0.8) | ($0.2) | $1.1 | $0.5 | $6.1 | 425 | 248 |
| 8 | Havana E - Havana S | ($2.6) | ($8.3) | ($0.2) | $5.5 | $0.0 | $0.0 | $0.0 | $0.0 | $5.5 | 2,260 | 0 |
| 9 | Dresden | ($0.3) | ($4.8) | ($0.2) | $4.3 | $0.0 | $0.0 | $0.0 | $0.0 | $4.3 | 1,216 | 0 |
| 10 | Nelson | ($2.2) | ($6.6) | ($0.3) | $4.1 | $0.0 | $0.0 | $0.0 | $0.0 | $4.1 | 534 | 0 |
| 11 | Shadelnd - Lafaysouth | ($4.4) | ($7.7) | $0.1 | $3.5 | $6.7 | $4.7 | ($2.3) | ($0.3) | $3.2 | 1,055 | 669 |
| 12 | Nucor - Whitestown | ($0.8) | ($5.1) | ($1.1) | $3.2 | $0.1 | $0.1 | ($0.1) | ($0.1) | $3.1 | 519 | 19 |
| 13 | Roxana - Praxair | ($0.1) | $0.4 | ($0.5) | ($1.0) | $1.3 | $0.0 | ($3.4) | ($2.1) | ($3.0) | 1,734 | 290 |
| 14 | Todd Hunter | ($0.6) | ($3.6) | ($0.0) | $2.9 | $0.0 | $0.0 | $0.0 | $0.0 | $2.9 | 988 | 0 |
| 15 | Burnham - Munster | $0.2 | ($2.3) | $0.2 | $2.7 | $0.0 | $0.0 | $0.0 | $0.0 | $2.7 | 760 | 0 |
| 16 | Quad Cities | ($1.3) | ($3.8) | $0.2 | $2.7 | $0.0 | $0.0 | $0.0 | $0.0 | $2.7 | 460 | 0 |
| 17 | Pleasant Prairie - Zion | ($0.6) | ($3.3) | ($0.1) | $2.7 | $0.0 | $0.1 | ($0.2) | ($0.2) | $2.4 | 2,052 | 395 |
| 18 | Olive - Bosserman | $1.2 | ($1.5) | ($0.4) | $2.3 | $0.0 | $0.0 | $0.0 | $0.0 | $2.3 | 133 | 0 |
| 19 | Havana South - Mason City West | ($0.6) | ($2.1) | $0.1 | $1.6 | $0.2 | ($0.3) | ($0.0) | $0.4 | $2.0 | 753 | 181 |
| 20 | Reynolds - Magnetation | ($0.3) | ($1.9) | $0.4 | $2.0 | $0.0 | ($0.1) | ($0.1) | ($0.0) | $2.0 | 297 | 31 |

22 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.," (December 11, 2008), Section 6.1, Effective Date: May 30, 2016. <http://www.pjm.com/documents/agreements.aspx>.

23 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.," (December 11, 2008), Section 2.2.24, Effective Date: February 14, 2017. <http://www.pjm.com/documents/agreements.aspx>.

### Table 11-28 Top 20 congestion cost impacts from MISO flowgates affecting PJM dispatch (By facility): 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 | Cherry Valley | ($5.7) | ($44.0) | ($0.5) | $37.8 | $0.0 | $0.0 | $0.0 | $0.0 | $37.8 | 1,329 | 0 |
| 2 | Mercer IP - Galesburg | ($17.1) | ($49.9) | ($8.9) | $23.9 | ($0.2) | $3.6 | $2.2 | ($1.6) | $22.3 | 3,510 | 1,155 |
| 3 | Byron - Cherry Valley | ($5.5) | ($22.6) | $0.9 | $18.0 | $0.0 | $0.0 | $0.0 | $0.0 | $18.0 | 298 | 0 |
| 4 | Dixon - McGirr Rd | ($5.0) | ($22.9) | ($1.2) | $16.7 | $0.0 | $0.0 | $0.0 | $0.0 | $16.7 | 1,779 | 0 |
| 5 | Reynolds - Magnetation | ($5.1) | ($23.9) | $0.9 | $19.8 | $0.5 | $1.5 | ($2.6) | ($3.5) | $16.2 | 2,062 | 680 |
| 6 | Person - Halifax | $29.9 | $16.1 | ($0.2) | $13.5 | $0.0 | $0.0 | ($0.2) | ($0.2) | $13.3 | 719 | 5 |
| 7 | Braidwood - East Frankfurt | ($0.1) | ($7.7) | $0.7 | $8.4 | $0.0 | $0.0 | $0.0 | $0.0 | $8.4 | 616 | 0 |
| 8 | Cherry Valley - Silver Lake | ($1.8) | ($9.4) | $0.8 | $8.4 | $0.0 | $0.0 | $0.0 | $0.0 | $8.4 | 484 | 0 |
| 9 | Dumont | ($1.4) | ($10.3) | ($1.3) | $7.6 | $0.0 | $0.0 | $0.0 | $0.0 | $7.6 | 472 | 0 |
| 10 | Alpine - Belvidere | ($1.9) | ($9.5) | ($0.1) | $7.5 | $0.0 | $0.0 | $0.0 | $0.0 | $7.5 | 496 | 0 |
| 11 | Batesville - Hubble | ($3.2) | ($11.3) | ($1.0) | $7.1 | $0.5 | ($0.5) | ($2.3) | ($1.2) | $5.8 | 419 | 134 |
| 12 | Westwood | ($1.6) | ($6.5) | ($0.8) | $4.2 | $0.4 | $0.0 | $0.3 | $0.7 | $4.9 | 950 | 137 |
| 13 | Cayuga | ($0.6) | ($2.4) | ($0.1) | $1.7 | ($0.6) | $3.9 | ($1.6) | ($6.1) | ($4.4) | 147 | 74 |
| 14 | Oak Grove - Galesburg | ($3.3) | ($8.3) | ($1.1) | $3.9 | $0.1 | $0.2 | $0.2 | $0.1 | $4.0 | 1,336 | 174 |
| 15 | Michigan City - Bosserman | ($0.6) | ($5.1) | ($1.7) | $2.8 | $0.0 | $0.0 | $0.0 | $0.0 | $2.8 | 623 | 0 |
| 16 | Pleasant Prairie - Zion | ($0.7) | ($3.2) | $0.0 | $2.5 | $0.1 | $0.2 | ($0.2) | ($0.3) | $2.2 | 1,249 | 409 |
| 17 | West Dekalb - Glidden | ($0.4) | ($2.5) | $0.1 | $2.1 | $0.0 | $0.0 | $0.0 | $0.0 | $2.1 | 318 | 0 |
| 18 | Greentown | ($0.1) | ($1.2) | ($0.1) | $1.1 | $0.6 | $3.6 | ($0.1) | ($3.1) | ($2.0) | 164 | 26 |
| 19 | Roxana - Praxair | ($0.7) | ($3.3) | ($1.6) | $1.0 | $0.7 | ($0.1) | ($3.6) | ($2.9) | ($1.9) | 884 | 143 |
| 20 | Reynold - Monticello | ($0.5) | ($3.3) | $0.7 | $3.5 | $0.4 | $1.1 | ($0.9) | ($1.6) | $1.9 | 561 | 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.[24] Only a subset of all transmission constraints that exist in either market are eligible for coordinated congestion management. This subset of transmission constraints is identified as M2M flowgates. Flowgates eligible for the M2M coordination process are called M2M flowgates.[25]

Table 11-29 and Table 11-30 show the NYISO flowgates which PJM and/or NYISO took dispatch action to control during 2017 and 2016, and which had the greatest congestion cost impact on PJM.

### Table 11-29 Top congestion cost impacts from NYISO flowgates affecting PJM dispatch (By facility): 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 11-30 Top three congestion cost impacts from NYISO flowgates affecting PJM dispatch (By facility): 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 | ($0.1) | ($0.4) | $0.0 | $0.3 | $0.6 | $1.7 | ($0.2) | ($1.3) | ($1.0) | 64 | 1,074 |
| 2 | West Central Ties | Flowgate | NYISO | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | ($0.0) | ($0.0) | ($0.0) | 0 | 6 |
| 3 | Dysinger East | Flowgate | NYISO | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | ($0.0) | $0.0 | $0.0 | $0.0 | 0 | 2 |

24 See "New York Independent System Operator, Inc. NYISO Tariffs," (June 21, 2017) Section 35.3.1, Effective Date: January 15, 2013. <http://www.pjm.com/documents/agreements.aspx>.
25 See "New York Independent System Operator, Inc. NYISO Tariffs," (June 21, 2017) Section 35.23, Effective Date: May 1, 2017. <http://www.pjm.com/documents/agreements.aspx>.

## Congestion-Event Summary for the 500 kV System

Constraints on the 500 kV system generally have a regional impact. Table 11-31 and Table 11-32 show the 500 kV constraints affecting congestion costs in PJM for 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 11-31 Regional constraints summary (By facility): 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 | Conastone - Peach Bottom | Line | 500 | $38.7 | $1.6 | $0.1 | $37.2 | $2.0 | $1.3 | $1.5 | $2.2 | $39.5 | 3,159 | 840 |
| 2 | 5004/5005 Interface | Interface | 500 | ($9.9) | ($38.7) | ($3.8) | $25.0 | $4.3 | $11.4 | $4.6 | ($2.5) | $22.5 | 173 | 104 |
| 3 | AP South | Interface | 500 | $15.3 | ($9.2) | ($2.4) | $22.1 | ($0.0) | $1.3 | $0.9 | ($0.5) | $21.6 | 1,315 | 74 |
| 4 | Three Mile Island | Transformer | 500 | $7.4 | ($4.9) | ($0.3) | $11.9 | ($0.1) | ($0.6) | $0.9 | $1.4 | $13.3 | 540 | 86 |
| 5 | Bedington - Black Oak | Interface | 500 | $5.5 | ($4.1) | ($0.2) | $9.3 | $0.1 | $0.3 | $0.4 | $0.2 | $9.5 | 1,215 | 61 |
| 6 | AEP - DOM | Interface | 500 | $3.3 | ($4.3) | ($0.1) | $7.5 | $0.5 | $0.5 | $0.2 | $0.3 | $7.8 | 948 | 33 |
| 7 | West | Interface | 500 | ($0.4) | ($2.1) | ($0.2) | $1.6 | $0.0 | $0.0 | $0.0 | $0.0 | $1.6 | 180 | 0 |
| 8 | Limerick | Transformer | 500 | ($0.0) | ($1.4) | ($0.0) | $1.3 | $0.0 | $0.0 | $0.0 | $0.0 | $1.3 | 67 | 0 |
| 9 | Conastone | Transformer | 500 | $0.3 | ($0.1) | $0.0 | $0.4 | $0.0 | $0.0 | $0.0 | $0.0 | $0.4 | 33 | 2 |
| 10 | Cabot - Keystone | Line | 500 | ($0.1) | ($0.5) | $0.1 | $0.5 | $0.1 | $0.2 | ($0.0) | ($0.2) | $0.3 | 97 | 18 |
| 11 | East | Interface | 500 | ($0.5) | ($1.1) | ($0.1) | $0.6 | $0.2 | $0.7 | $0.2 | ($0.3) | $0.3 | 131 | 10 |
| 12 | Belmont | Transformer | 500 | ($0.0) | ($0.2) | ($0.1) | $0.1 | $0.0 | $0.1 | ($0.3) | ($0.4) | ($0.3) | 42 | 52 |
| 13 | Keeney - Rockspring | Line | 500 | ($0.1) | ($0.3) | $0.0 | $0.2 | $0.0 | $0.0 | $0.0 | $0.0 | $0.2 | 39 | 0 |
| 14 | 502 Junction | Transformer | 500 | $0.0 | ($0.1) | $0.0 | $0.1 | $0.0 | $0.0 | $0.0 | $0.0 | $0.1 | 42 | 0 |
| 15 | Bristers - Ox | Line | 500 | $0.0 | ($0.0) | $0.0 | $0.1 | $0.0 | $0.0 | $0.0 | $0.0 | $0.1 | 14 | 0 |
| 16 | Redlion | Transformer | 500 | $0.0 | ($0.1) | $0.0 | $0.1 | $0.0 | $0.0 | $0.0 | $0.0 | $0.1 | 55 | 0 |
| 17 | Central | Interface | 500 | ($0.1) | ($0.2) | ($0.0) | $0.1 | $0.0 | $0.0 | $0.0 | $0.0 | $0.1 | 2 | 0 |
| 18 | Elroy - Hosensack | Line | 500 | ($0.0) | ($0.1) | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | 7 | 0 |
| 19 | Cabot | Other | 500 | ($0.0) | ($0.1) | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | 8 | 0 |
| 20 | Hope Creek - Red Lion | Line | 500 | $0.0 | ($0.0) | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | 15 | 0 |

### Table 11-32 Regional constraints summary (By facility): 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 | Conastone - Peach Bottom | Line | 500 | $27.9 | ($0.2) | $0.8 | $28.9 | $1.3 | $0.9 | $0.0 | $0.4 | $29.3 | 2,407 | 699 |
| 2 | AP South | Interface | 500 | $13.8 | ($4.9) | ($1.9) | $16.8 | $0.1 | $0.1 | $0.0 | $0.0 | $16.8 | 1,076 | 14 |
| 3 | Bedington - Black Oak | Interface | 500 | $9.5 | ($6.2) | ($0.6) | $15.2 | $0.2 | $0.2 | $0.1 | $0.1 | $15.3 | 1,515 | 105 |
| 4 | AEP - DOM | Interface | 500 | $3.5 | ($4.5) | $0.2 | $8.2 | $0.3 | ($0.0) | $0.1 | $0.3 | $8.5 | 1,604 | 5 |
| 5 | 502 Junction | Transformer | 500 | $0.3 | ($3.3) | $0.1 | $3.7 | $0.0 | $0.1 | ($0.0) | ($0.1) | $3.6 | 321 | 2 |
| 6 | Three Mile Island | Transformer | 500 | $1.2 | ($1.5) | $0.3 | $3.0 | $0.1 | ($0.0) | $0.1 | $0.2 | $3.2 | 298 | 47 |
| 7 | Brambleton - Mosby | Line | 500 | ($0.5) | ($3.5) | $0.1 | $3.0 | $0.0 | $0.0 | $0.0 | $0.0 | $3.0 | 151 | 0 |
| 8 | West | Interface | 500 | ($0.9) | ($3.1) | ($0.1) | $2.1 | $0.2 | ($0.1) | ($0.0) | $0.3 | $2.4 | 165 | 2 |
| 9 | Belmont | Transformer | 500 | $0.0 | $0.0 | $0.0 | $0.0 | ($0.2) | $0.0 | ($0.9) | ($1.1) | ($1.1) | 0 | 6 |
| 10 | East | Interface | 500 | ($0.7) | ($1.6) | ($0.0) | $0.9 | $0.0 | $0.0 | $0.0 | $0.0 | $0.9 | 112 | 0 |
| 11 | 5004/5005 Interface | Interface | 500 | ($0.2) | ($1.1) | ($0.1) | $0.8 | $0.0 | $0.0 | $0.0 | $0.0 | $0.8 | 42 | 0 |
| 12 | Yukon | Transformer | 500 | $0.0 | $0.0 | $0.0 | $0.0 | $0.2 | $0.1 | $0.6 | $0.7 | $0.7 | 0 | 16 |
| 13 | Bristers - Ox | Line | 500 | $0.0 | ($0.0) | $0.0 | $0.1 | $0.4 | $0.2 | $0.2 | $0.4 | $0.5 | 25 | 6 |
| 14 | Keeney - Rockspring | Line | 500 | ($0.3) | ($0.7) | $0.1 | $0.5 | $0.0 | $0.0 | $0.0 | $0.0 | $0.5 | 81 | 0 |
| 15 | Redlion | Transformer | 500 | ($0.0) | ($0.2) | $0.1 | $0.3 | $0.0 | $0.0 | $0.0 | $0.0 | $0.3 | 68 | 0 |
| 16 | Carson | Transformer | 500 | $0.0 | ($0.0) | $0.0 | $0.0 | $0.2 | $0.2 | ($0.3) | ($0.3) | ($0.3) | 7 | 4 |
| 17 | Cabot - Keystone | Line | 500 | ($0.0) | ($0.0) | $0.0 | $0.0 | $0.2 | $0.2 | ($0.2) | ($0.1) | ($0.1) | 2 | 10 |
| 18 | Keeney - Rockspri | Line | 500 | $0.0 | $0.0 | $0.0 | $0.0 | $0.1 | $0.0 | $0.1 | $0.1 | $0.1 | 0 | 11 |
| 19 | Wylie Ridge | Transformer | 500 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | ($0.0) | ($0.1) | ($0.1) | 0 | 6 |
| 20 | Conastone | Transformer | 500 | $0.0 | ($0.0) | $0.0 | $0.1 | $0.0 | $0.0 | $0.0 | $0.0 | $0.1 | 2 | 0 |

## Congestion Costs by Physical and Financial Participants

In order to evaluate the recipients and payers of congestion, the MMU categorized all participants in PJM as either physical or financial. Physical entities include utilities and customers which primarily take physical positions in PJM markets. Financial entities include banks and hedge funds which primarily take financial positions in PJM markets. International market participants that primarily take financial positions in PJM markets are generally considered to be financial entities even if they are utilities in their own countries.

Financial entities received $10.8 million (Table 11-34) in net congestion credits in 2016 and $19.9 million in net congestion credits in 2017. Physical entities paid $1,034.4 million in congestion charges in 2016 and $717.5 million in congestion charges in 2017.

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 2016, the total day-ahead explicit congestion cost was $41.0, of which $32.7 million (79.8 percent) was credited to UTCs. For the same period, the total balancing explicit congestion cost was -$43.9 million, of which -$47.0 million (107.1 percent) was credited to UTCs. In 2017, the total explicit congestion cost was -$10.0 million, of which -$19.7 million (104.0 percent) was contributed by 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.[26] That potential refund period ended, after 15 months, on December 7, 2015.[27]

In 2016, the average hourly UTC submitted MW increased 70.3 percent and UTC cleared MW increased 78.6 percent, compared to 2015.[28] Day-ahead congestion event hours increased by 48.9 percent from 184,851 congestion event hours in 2015 to 275,298 congestion event hours in 2016.

In 2017, the average hourly UTC submitted MW decreased 3.3 percent and UTC cleared MW increased 1.6 percent, compared to 2016. Day-ahead congestion event hours increased by 9.3 percent from 275,298 congestion event hours in 2016 to 300,923 congestion event hours in 2017.

Figure 11-5 shows the daily day-ahead and real-time congestion event hours for January 1, 2014 through December 31, 2017.

### Table 11-33 Congestion cost by type of participant: 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 | $17.6 | $14.5 | ($18.3) | ($15.2) | ($11.6) | ($7.8) | ($0.9) | ($4.7) | $0.0 | ($19.9) |
| Physical | $169.9 | ($568.6) | $9.8 | $748.3 | $33.8 | $55.0 | ($9.5) | ($30.8) | $0.0 | $717.5 |
| Total | $187.6 | ($554.1) | ($8.6) | $733.1 | $22.2 | $47.2 | ($10.4) | ($35.5) | $0.0 | $697.6 |

### Table 11-34 Congestion cost by type of participant: 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 | $24.2 | ($1.7) | $10.2 | $36.1 | ($34.4) | ($11.8) | ($24.3) | ($46.9) | $0.0 | ($10.8) |
| Physical | $381.2 | ($652.4) | $30.8 | $1,064.3 | $29.9 | $40.2 | ($19.6) | ($29.9) | $0.0 | $1,034.4 |
| Total | $405.3 | ($654.1) | $41.0 | $1,100.4 | ($4.5) | $28.4 | ($43.9) | ($76.8) | $0.0 | $1,023.7 |

26 See 18 CFR § 385.213 (2014).
27 See 148 FERC ¶ 61,144 (2014); 16 U.S.C. § 824e.
28 See 2016 State of the Market Report for PJM, Volume 2 Section 3: Energy Market, Table 3-35.

Figure 11-5 Daily congestion event hours: 2014 through 2017

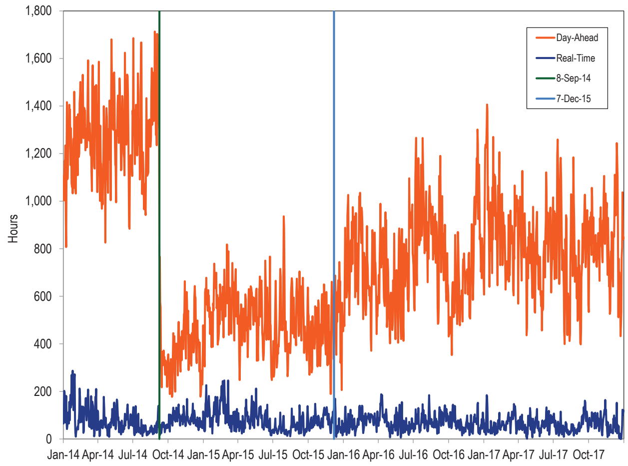
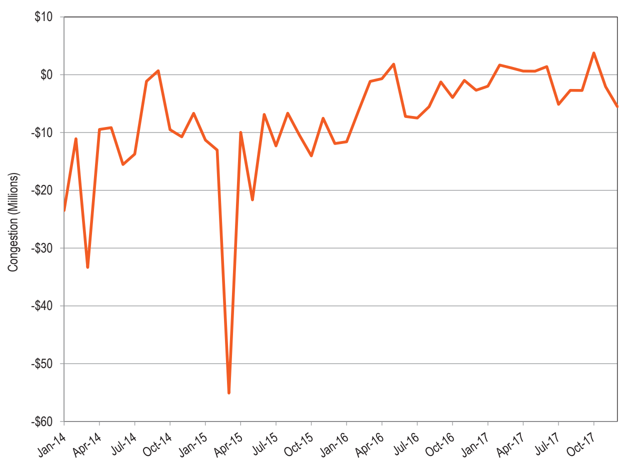



Figure 11-6 shows the change in up to congestion balancing explicit congestion costs from 2014 through 2017. Within this period, Figure 11-6 shows the highest monthly payment ($55.1 million) in balancing congestion credits to up to congestion transactions occurred in March of 2015 and the highest monthly charge ($3.8 million) in balancing congestion charges occurred in October of 2017.

Figure 11-6 Monthly balancing congestion cost incurred by up to congestion: 2014 through 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.[29] 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.[30] 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.

29 OA Schedule 1 §3.7
30 *Id.*

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.[31]

- **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.
- **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

31 See PJM. "Manual 28: Operating Agreement Accounting," Rev. 77 (Nov. 1, 2017) at 70.

in a credit. Inadvertent loss charges are common costs, not directly attributable to specific participants, that are distributed on a load ratio basis.[32]

## Total Marginal Loss Cost

The total marginal loss cost in PJM for 2017 was $690.8 million, which was comprised of load loss payments of -$40.9 million, generation loss credits of -$766.9 million, explicit loss costs of -$35.1 million and inadvertent loss charges of $0.0 million (Table 11-36).

Monthly marginal loss costs in 2017 ranged from $44.2 million in April to $91.5 million in December. Total marginal loss surplus decreased in 2017 by $12.6 million or 5.5 percent from $227.2 million in 2016 to $214.6 million in 2017.

Table 11-35 shows the total marginal loss costs as a component of total energy related costs for January 1 through December 31, 2008 through 2017.

### Table 11-35 Total component costs (Dollars (Millions)): 2008 through 2017[33]

| | Loss Costs | Percent Change | Total PJM Billing | Percent of PJM Billing |
|---|---|---|---|---|
| 2008 | $2,497 | NA | $34,306 | 7.3% |
| 2009 | $1,268 | (49.2%) | $26,550 | 4.8% |
| 2010 | $1,635 | 29.0% | $34,771 | 4.7% |
| 2011 | $1,380 | (15.6%) | $35,887 | 3.8% |
| 2012 | $982 | (28.8%) | $29,181 | 3.4% |
| 2013 | $1,035 | 5.5% | $33,860 | 3.1% |
| 2014 | $1,466 | 41.6% | $50,030 | 2.9% |
| 2015 | $969 | (33.9%) | $42,630 | 2.3% |
| 2016 | $697 | (28.1%) | $39,050 | 1.8% |
| 2017 | $691 | (0.8%) | $40,170 | 1.7% |

Table 11-36 shows PJM total marginal loss costs by accounting category for January 1 through December 31, 2008 through 2017. Table 11-37 shows PJM total marginal loss costs by accounting category by market for January 1 through December 31, 2008 through 2017.

### Table 11-36 Total PJM marginal loss costs by accounting category (Dollars (Millions)): 2008 through 2017

| | Marginal Loss Costs (Millions) | | | | |
|---|---|---|---|---|---|
| | Load Payments | Generation Credits | Explicit Costs | Inadvertent Charges | Total |
| 2008 | ($237.2) | ($2,641.5) | $92.4 | $0.0 | $2,496.7 |
| 2009 | ($78.5) | ($1,314.3) | $32.0 | ($0.0) | $1,267.7 |
| 2010 | ($122.3) | ($1,707.0) | $50.2 | ($0.0) | $1,634.8 |
| 2011 | ($174.0) | ($1,551.9) | $1.6 | $0.0 | $1,379.5 |
| 2012 | ($11.1) | ($1,036.8) | ($44.0) | $0.0 | $981.7 |
| 2013 | ($4.1) | ($1,083.3) | ($43.9) | ($0.0) | $1,035.3 |
| 2014 | ($59.2) | ($1,581.3) | ($56.0) | $0.0 | $1,466.1 |
| 2015 | ($31.7) | ($1,021.0) | ($20.5) | $0.0 | $968.7 |
| 2016 | ($55.0) | ($782.1) | ($30.6) | ($0.0) | $696.5 |
| 2017 | ($40.9) | ($766.9) | ($35.1) | $0.0 | $690.8 |

32 OA Schedule 1 §3.7.
33 The loss costs include net inadvertent charges.

### Table 11-37 Total PJM marginal loss costs by accounting category by market (Dollars (Millions)): 2008 through 2017

| | Marginal Loss Costs (Millions) | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Day-Ahead | | | | Balancing | | | | | |
| | Load Payments | Generation Credits | Explicit Costs | Total | Load Payments | Generation Credits | Explicit Costs | Total | Inadvertent Charges | Grand Total |
| 2008 | ($158.1) | ($2,582.2) | $134.3 | $2,558.4 | ($79.1) | ($59.4) | ($42.0) | ($61.7) | $0.0 | $2,496.7 |
| 2009 | ($84.7) | ($1,311.7) | $65.4 | $1,292.3 | $6.2 | ($2.7) | ($33.5) | ($24.6) | ($0.0) | $1,267.7 |
| 2010 | ($146.3) | ($1,716.1) | $95.8 | $1,665.6 | $23.9 | $9.1 | ($45.6) | ($30.8) | ($0.0) | $1,634.8 |
| 2011 | ($215.4) | ($1,592.1) | $53.8 | $1,430.5 | $41.4 | $40.2 | ($52.2) | ($51.0) | $0.0 | $1,379.5 |
| 2012 | ($43.0) | ($1,060.3) | ($13.4) | $1,003.8 | $32.0 | $23.4 | ($30.6) | ($22.1) | $0.0 | $981.7 |
| 2013 | ($37.1) | ($1,112.4) | $62.4 | $1,137.8 | $33.0 | $29.1 | ($106.4) | ($102.5) | ($0.0) | $1,035.3 |
| 2014 | ($113.9) | ($1,618.8) | $66.6 | $1,571.4 | $54.7 | $37.5 | ($122.5) | ($105.3) | $0.0 | $1,466.1 |
| 2015 | ($53.4) | ($1,032.2) | $33.8 | $1,012.6 | $21.7 | $11.3 | ($54.3) | ($43.9) | $0.0 | $968.7 |
| 2016 | ($61.7) | ($781.6) | $53.4 | $773.2 | $6.8 | ($0.5) | ($84.0) | ($76.7) | ($0.0) | $696.5 |
| 2017 | ($52.2) | ($767.2) | $54.9 | $769.9 | $11.3 | $0.3 | ($90.0) | ($79.1) | $0.0 | $690.8 |

Table 11-38 and Table 11-39 show the total loss costs for each transaction type in 2017 and 2016. In 2017, generation paid loss costs of $731.9 million, 105.9 percent of total loss costs. In 2016, generation paid loss costs of $727.1 million, 104.4 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 2017, DECs were paid $7.7 million in loss credits in the day-ahead market, paid $6.0 million in congestion costs in the balancing energy market and received $1.7 million in net payment for losses. In 2017, INCs paid $13.8 million in loss costs in the day-ahead market, were paid $12.0 million in congestion credits in the balancing energy market and paid $1.8 million in net payment for losses. In 2017, up to congestion paid $54.9 million in loss costs in the day-ahead market, were paid $90.0 million in loss credits in the balancing energy market and received $35.1 million in net payment for losses.

### Table 11-38 Total PJM loss costs by transaction type by market (Dollars (Millions)):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 | ($7.7) | $0.0 | $0.0 | ($7.7) | $6.0 | $0.0 | $0.0 | $6.0 | $0.0 | ($1.7) |
| Demand | ($5.6) | $0.0 | $0.0 | ($5.6) | $11.4 | $0.0 | $0.0 | $11.4 | $0.0 | $5.8 |
| Demand Response | ($0.0) | $0.0 | $0.0 | ($0.0) | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| Export | ($17.3) | $0.0 | $0.1 | ($17.2) | ($7.8) | $0.0 | $0.8 | ($7.0) | $0.0 | ($24.2) |
| Generation | $0.0 | ($730.0) | $0.0 | $730.0 | $0.0 | ($1.9) | $0.0 | $1.9 | $0.0 | $731.9 |
| Grandfathered Overuse | $0.0 | $0.0 | ($0.5) | ($0.5) | $0.0 | $0.0 | ($0.4) | ($0.4) | $0.0 | ($0.9) |
| Import | $0.0 | ($1.9) | $0.0 | $1.9 | $0.0 | ($11.5) | ($0.3) | $11.2 | $0.0 | $13.1 |
| INC | $0.0 | ($13.8) | $0.0 | $13.8 | $0.0 | $12.0 | $0.0 | ($12.0) | $0.0 | $1.8 |
| Internal Bilateral | ($21.6) | ($21.5) | $0.1 | ($0.0) | $1.7 | $1.7 | $0.0 | ($0.0) | $0.0 | ($0.0) |
| Up to Congestion | $0.0 | $0.0 | $54.9 | $54.9 | $0.0 | $0.0 | ($90.0) | ($90.0) | $0.0 | ($35.1) |
| Wheel In | $0.0 | ($0.0) | $0.4 | $0.4 | $0.0 | ($0.0) | ($0.0) | $0.0 | $0.0 | $0.4 |
| Wheel Out | ($0.0) | $0.0 | $0.0 | ($0.0) | ($0.0) | $0.0 | $0.0 | ($0.0) | $0.0 | ($0.0) |
| Total | ($52.2) | ($767.2) | $54.9 | $769.9 | $11.3 | $0.3 | ($90.0) | ($79.1) | $0.0 | $690.8 |

Table 11-39 Total PJM loss costs by transaction type by market (Dollars (Millions)): 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 | ($5.2) | $0.0 | $0.0 | ($5.2) | $2.2 | $0.0 | $0.0 | $2.2 | $0.0 | ($3.0) |
| Demand | ($5.6) | $0.0 | $0.0 | ($5.6) | $9.3 | $0.0 | $0.0 | $9.3 | $0.0 | $3.7 |
| Demand Response | ($0.0) | $0.0 | $0.0 | ($0.0) | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| Export | ($18.9) | $0.0 | $0.3 | ($18.6) | ($6.2) | $0.0 | $0.7 | ($5.5) | $0.0 | ($24.1) |
| Generation | $0.0 | ($732.6) | $0.0 | $732.6 | $0.0 | $5.4 | $0.0 | ($5.4) | $0.0 | $727.1 |
| Grandfathered Overuse | $0.0 | $0.0 | ($0.7) | ($0.7) | $0.0 | $0.0 | ($0.4) | ($0.4) | $0.0 | ($1.1) |
| Import | $0.0 | ($5.3) | $0.7 | $6.1 | $0.0 | ($18.5) | $0.5 | $19.0 | $0.0 | $25.0 |
| INC | $0.0 | ($11.9) | $0.0 | $11.9 | $0.0 | $11.1 | $0.0 | ($11.1) | $0.0 | $0.7 |
| Internal Bilateral | ($32.1) | ($31.8) | $0.3 | ($0.0) | $1.4 | $1.4 | $0.0 | ($0.0) | $0.0 | ($0.0) |
| Up to Congestion | $0.0 | $0.0 | $51.6 | $51.6 | $0.0 | $0.0 | ($84.8) | ($84.8) | $0.0 | ($33.1) |
| Wheel In | $0.0 | $0.0 | $1.2 | $1.2 | $0.0 | $0.0 | ($0.0) | ($0.0) | $0.0 | $1.2 |
| Total | ($61.7) | ($781.6) | $53.4 | $773.2 | $6.8 | ($0.5) | ($84.0) | ($76.7) | $0.0 | $696.5 |

## Monthly Marginal Loss Costs

Table 11-40 shows a monthly summary of marginal loss costs by market type for January 1, 2016 through December 31, 2017.

Table 11-40 Monthly marginal loss costs by market (Millions): 2016 and 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 | $50.8 | ($6.6) | $0.0 | $44.2 |
| May | $40.4 | ($3.9) | ($0.0) | $36.6 | $55.0 | ($4.9) | $0.0 | $50.1 |
| Jun | $59.6 | ($6.5) | ($0.0) | $53.1 | $59.0 | ($4.2) | $0.0 | $54.8 |
| Jul | $93.8 | ($7.5) | ($0.0) | $86.4 | $78.7 | ($7.1) | $0.0 | $71.6 |
| Aug | $95.6 | ($9.8) | ($0.0) | $85.8 | $64.4 | ($7.6) | $0.0 | $56.8 |
| Sep | $70.6 | ($6.6) | ($0.0) | $64.0 | $58.3 | ($6.2) | $0.0 | $52.0 |
| Oct | $51.6 | ($6.6) | ($0.0) | $45.0 | $51.8 | ($4.7) | $0.0 | $47.1 |
| Nov | $49.0 | ($6.9) | ($0.0) | $42.1 | $55.3 | ($4.0) | $0.0 | $51.3 |
| Dec | $77.2 | ($9.7) | ($0.0) | $67.5 | $96.8 | ($5.3) | $0.0 | $91.5 |
| Total | $773.2 | ($76.7) | ($0.0) | $696.5 | $769.9 | ($79.1) | $0.0 | $690.8 |

Figure 11-7 shows PJM monthly marginal loss costs for January 1, 2008 through December 31, 2017.

Figure 11-7 PJM monthly marginal loss costs (Dollars (Millions)): 2017

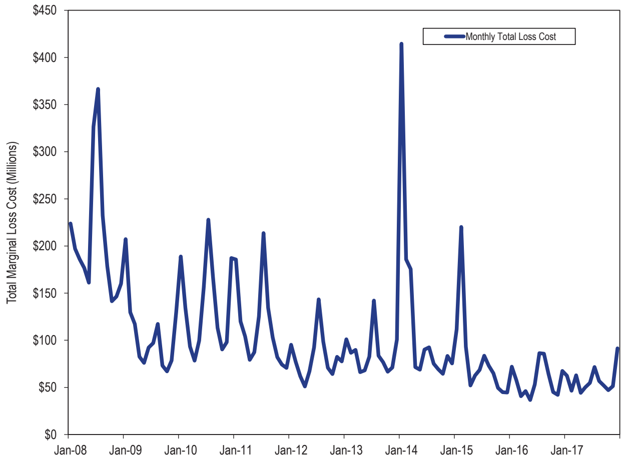


Table 11-41 and Table 11-42 show the monthly total loss costs for each virtual transaction type in 2017 and 2016.

Table 11-41 Monthly PJM loss costs by virtual transaction type and by market (Dollars (Millions)): 2017

| | Loss Costs (Millions) | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Day-Ahead | | | | Balancing | | | | |
| | DEC | INC | Up to Congestion | Total | DEC | INC | Up to Congestion | Total | 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) |
| Apr | ($1.1) | $0.8 | $4.5 | $4.2 | $1.0 | ($0.9) | ($6.8) | ($6.6) | ($2.4) |
| May | ($1.3) | $1.6 | $4.3 | $4.6 | $1.1 | ($1.3) | ($6.4) | ($6.7) | ($2.1) |
| Jun | ($0.8) | $1.1 | $3.8 | $4.1 | $0.8 | ($0.9) | ($5.8) | ($5.9) | ($1.7) |
| Jul | ($1.0) | $1.4 | $5.1 | $5.5 | $0.9 | ($0.9) | ($8.0) | ($8.1) | ($2.7) |
| Aug | ($0.3) | $0.6 | $5.0 | $5.3 | $0.3 | ($0.6) | ($7.8) | ($8.1) | ($2.8) |
| Sep | ($0.4) | $1.0 | $2.9 | $3.5 | $0.5 | ($1.1) | ($7.4) | ($8.0) | ($4.5) |
| Oct | ($0.2) | $0.8 | $3.6 | $4.2 | $0.4 | ($0.9) | ($5.9) | ($6.4) | ($2.2) |
| Nov | ($0.3) | $0.7 | $3.7 | $4.2 | $0.2 | ($0.7) | ($5.4) | ($5.8) | ($1.6) |
| Dec | ($0.1) | $0.4 | $4.6 | $4.9 | ($0.2) | ($0.3) | ($7.4) | ($7.9) | ($3.0) |
| Total | ($7.7) | $13.8 | $54.9 | $61.0 | $6.0 | ($12.0) | ($90.0) | ($96.1) | ($35.1) |

Table 11-42 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 | Total | DEC | INC | Up to Congestion | Total | 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 11-43 shows the total energy costs, the total marginal loss costs collected, the net residual market adjustments and total marginal loss credits redistributed for 2008 through 2017. The total marginal loss surplus decreased $12.6 million in 2017 from 2016.

Table 11-43 Marginal loss credits (Dollars (Millions)): 2008 through 2017[34]

| | Loss Credit Accounting (Millions) | | | | | |
|---|---|---|---|---|---|---|
| | | | Net Residual Market Adjustment | | | |
| | Total Energy Charges | Total Marginal Loss Charges | Known Day-Ahead Error | Day-Ahead Loss MW Congestion | Balancing Loss MW Congestion | Total Loss Surplus |
| 2008 | ($1,193.2) | $2,496.7 | $0.0 | $0.0 | $0.0 | $1,303.5 |
| 2009 | ($628.8) | $1,267.7 | $0.0 | ($0.7) | ($0.0) | $639.7 |
| 2010 | ($797.9) | $1,634.8 | $0.1 | $0.7 | ($0.0) | $836.4 |
| 2011 | ($793.8) | $1,379.5 | $0.1 | ($1.0) | $0.1 | $586.7 |
| 2012 | ($593.0) | $981.7 | $0.0 | $2.0 | ($0.0) | $386.7 |
| 2013 | ($687.6) | $1,035.3 | $0.1 | $3.0 | ($0.0) | $344.8 |
| 2014 | ($977.7) | $1,466.1 | ($0.0) | $6.3 | $0.1 | $482.1 |
| 2015 | ($627.4) | $968.7 | ($0.0) | $5.1 | ($0.1) | $336.3 |
| 2016 | ($466.3) | $696.5 | ($0.0) | $3.2 | ($0.2) | $227.2 |
| 2017 | ($475.2) | $690.8 | $0.0 | $1.1 | ($0.1) | $214.6 |

# 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 be more accurately thought of as net energy costs.

## Total Energy Costs

The total energy cost for 2017 was -$475.2 million, which was comprised of load energy payments of $35,152.1 million, generation energy credits of $35,643.4 million, explicit energy costs of $0.0 million and inadvertent energy charges of $7.1 million. The monthly energy costs for 2017 ranged from -$61.9 million in December to -$31.0 million in April.

Table 11-44 shows total energy component costs and total PJM billing, for January 1 through December 31, 2008 through 2017. The total energy component costs are net energy costs.

Table 11-44 Total PJM costs by energy component (Dollars (Millions)): 2008 through 2017[35]

| | Energy Costs | Percent Change | Total PJM Billing | Percent of PJM Billing |
|---|---|---|---|---|
| 2008 | ($1,193) | NA | $34,306 | (3.5%) |
| 2009 | ($629) | (47.3%) | $26,550 | (2.4%) |
| 2010 | ($798) | 26.9% | $34,771 | (2.3%) |
| 2011 | ($794) | (0.5%) | $35,887 | (2.2%) |
| 2012 | ($593) | (25.3%) | $29,181 | (2.0%) |
| 2013 | ($688) | 15.9% | $33,860 | (2.0%) |
| 2014 | ($978) | 42.2% | $50,030 | (2.0%) |
| 2015 | ($627) | (35.8%) | $42,630 | (1.5%) |
| 2016 | ($466) | (25.7%) | $39,050 | (1.2%) |
| 2017 | ($475) | 1.9% | $40,170 | (1.2%) |

Energy costs for January 1 through December 31, 2008 through 2017 are shown in Table 11-45 and Table 11-46. Table 11-45 shows PJM energy costs by accounting category for January 1 through December 31, 2008 through 2017 and Table 11-46 shows PJM energy costs by market category for January 1 through December 31, 2008 through 2017.

34 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.

35 The energy costs include net inadvertent charges.

### Table 11-45 Total PJM energy costs by accounting category (Dollars (Millions)): 2008 through 2017

| | Energy Costs (Millions) | | | | |
|---|---|---|---|---|---|
| | Load Payments | Generation Credits | Explicit Costs | Inadvertent Charges | Total |
| 2008 | $105,665.6 | $106,860.0 | $0.0 | $1.2 | ($1,193.2) |
| 2009 | $42,535.2 | $43,165.7 | $0.0 | $1.7 | ($628.8) |
| 2010 | $53,101.5 | $53,886.9 | $0.0 | ($12.6) | ($797.9) |
| 2011 | $47,658.9 | $48,481.0 | $0.0 | $28.3 | ($793.8) |
| 2012 | $37,471.3 | $38,073.5 | $0.0 | $9.1 | ($593.0) |
| 2013 | $42,774.3 | $43,454.6 | $0.0 | ($7.4) | ($687.6) |
| 2014 | $60,258.5 | $61,232.0 | $0.0 | ($4.2) | ($977.7) |
| 2015 | $40,601.8 | $41,231.9 | $0.0 | $2.7 | ($627.4) |
| 2016 | $34,053.6 | $34,510.1 | $0.0 | ($9.8) | ($466.3) |
| 2017 | $35,152.1 | $35,634.4 | $0.0 | $7.1 | ($475.2) |

### Table 11-46 Total PJM energy costs by market category (Dollars (Millions)): 2008 through 2017

| | Energy Costs (Millions) | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Day-Ahead | | | | Balancing | | | | | |
| | Load Payments | Generation Credits | Explicit Costs | Total | Load Payments | Generation Credits | Explicit Costs | Total | Inadvertent Charges | Grand Total |
| 2008 | $81,789.8 | $83,120.0 | $0.0 | ($1,330.1) | $23,875.8 | $23,740.0 | $0.0 | $135.7 | $1.2 | ($1,193.2) |
| 2009 | $42,683.8 | $43,351.2 | $0.0 | ($667.4) | ($148.5) | ($185.5) | $0.0 | $36.9 | $1.7 | ($628.8) |
| 2010 | $53,164.9 | $53,979.1 | $0.0 | ($814.1) | ($63.4) | ($92.2) | $0.0 | $28.8 | ($12.6) | ($797.9) |
| 2011 | $48,144.9 | $48,880.0 | $0.0 | ($735.2) | ($485.9) | ($399.1) | $0.0 | ($86.9) | $28.3 | ($793.8) |
| 2012 | $37,641.2 | $38,251.1 | $0.0 | ($609.9) | ($169.9) | ($177.6) | $0.0 | $7.7 | $9.1 | ($593.0) |
| 2013 | $42,795.2 | $43,628.9 | $0.0 | ($833.7) | ($20.9) | ($174.4) | $0.0 | $153.5 | ($7.4) | ($687.6) |
| 2014 | $60,325.2 | $61,668.9 | $0.0 | ($1,343.7) | ($66.7) | ($436.9) | $0.0 | $370.2 | ($4.2) | ($977.7) |
| 2015 | $40,837.8 | $41,595.7 | $0.0 | ($757.9) | ($236.0) | ($363.8) | $0.0 | $127.8 | $2.7 | ($627.4) |
| 2016 | $34,245.1 | $34,885.7 | $0.0 | ($640.6) | ($191.5) | ($375.6) | $0.0 | $184.0 | ($9.8) | ($466.3) |
| 2017 | $35,490.1 | $36,138.6 | $0.0 | ($648.5) | ($338.0) | ($504.2) | $0.0 | $166.2 | $7.1 | ($475.2) |

Table 11-47 and Table 11-48 show the total energy costs for each transaction type in 2017 and 2016. In 2017, generation was paid $24,566.8 million and demand paid $23,484.2 million in net energy payment. In 2016, generation was paid $23,752.0 million and demand paid $23,099.8 million in net energy payment.

### Table 11-47 Total PJM energy costs by transaction type by market (Dollars (Millions)): 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 | $1,092.8 | $0.0 | $0.0 | $1,092.8 | ($1,095.6) | $0.0 | $0.0 | ($1,095.6) | ($2.9) |
| Demand | $23,433.7 | $0.0 | $0.0 | $23,433.7 | $50.5 | $0.0 | $0.0 | $50.5 | $23,484.2 |
| Demand Response | ($0.6) | $0.0 | $0.0 | ($0.6) | $0.6 | $0.0 | $0.0 | $0.6 | ($0.0) |
| Export | $707.1 | $0.0 | $0.0 | $707.1 | $346.6 | $0.0 | $0.0 | $346.6 | $1,053.6 |
| Generation | $0.0 | $24,616.7 | $0.0 | ($24,616.7) | $0.0 | ($50.0) | $0.0 | $50.0 | ($24,566.8) |
| Import | $0.0 | $81.1 | $0.0 | ($81.1) | $0.0 | $361.2 | $0.0 | ($361.2) | ($442.2) |
| INC | $0.0 | $1,183.6 | $0.0 | ($1,183.6) | $0.0 | ($1,175.3) | $0.0 | $1,175.3 | ($8.2) |
| Internal Bilateral | $10,257.2 | $10,257.2 | $0.0 | ($0.0) | $359.9 | $359.9 | $0.0 | $0.0 | ($0.0) |
| Wheel In | $0.0 | $0.3 | $0.0 | ($0.3) | $0.0 | $0.8 | $0.0 | ($0.8) | ($1.2) |
| Wheel Out | $0.3 | $0.0 | $0.0 | $0.3 | $0.8 | $0.0 | $0.0 | $0.8 | $1.2 |
| Total | $35,490.4 | $36,139.0 | $0.0 | ($648.5) | ($337.2) | ($503.4) | $0.0 | $166.2 | ($482.3) |

Table 11-48 Total PJM energy costs by transaction type by market (Dollars (Millions)): 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 | $1,254.0 | $0.0 | $0.0 | $1,254.0 | ($1,239.3) | $0.0 | $0.0 | ($1,239.3) | $14.7 |
| Demand | $22,886.5 | $0.0 | $0.0 | $22,886.5 | $213.3 | $0.0 | $0.0 | $213.3 | $23,099.8 |
| Demand Response | ($1.0) | $0.0 | $0.0 | ($1.0) | $1.0 | $0.0 | $0.0 | $1.0 | ($0.1) |
| Export | $653.2 | $0.0 | $0.0 | $653.2 | $308.0 | $0.0 | $0.0 | $308.0 | $961.2 |
| Generation | $0.0 | $23,956.2 | $0.0 | ($23,956.2) | $0.0 | ($204.2) | $0.0 | $204.2 | ($23,752.0) |
| Import | $0.0 | $201.8 | $0.0 | ($201.8) | $0.0 | $553.5 | $0.0 | ($553.5) | ($755.3) |
| INC | $0.0 | $1,275.2 | $0.0 | ($1,275.2) | $0.0 | ($1,250.4) | $0.0 | $1,250.4 | ($24.8) |
| Internal Bilateral | $9,452.4 | $9,452.4 | $0.0 | $0.0 | $525.5 | $525.5 | $0.0 | $0.0 | $0.0 |
| Total | $34,245.1 | $34,885.7 | $0.0 | ($640.6) | ($191.5) | ($375.6) | $0.0 | $184.0 | ($456.6) |

## Monthly Energy Costs

Table 11-49 shows a monthly summary of energy costs by market type for 2017. Marginal total energy costs in 2017 decreased from 2016. Monthly total energy costs in 2017 ranged from -$61.9 million in December to -$31.0 million in April.

Table 11-49 Monthly energy costs by market type (Dollars (Millions)): 2016 and 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) | $17.5 | $0.2 | ($42.2) |
| Apr | ($43.6) | $12.7 | $0.3 | ($30.6) | ($46.7) | $15.2 | $0.5 | ($31.0) |
| May | ($37.4) | $11.5 | ($0.3) | ($26.1) | ($46.2) | $12.6 | $1.0 | ($32.6) |
| Jun | ($50.9) | $17.6 | ($0.6) | ($33.8) | ($45.8) | $8.6 | $0.7 | ($36.4) |
| Jul | ($74.3) | $17.5 | ($0.9) | ($57.8) | ($61.3) | $14.7 | $1.2 | ($45.4) |
| Aug | ($72.9) | $18.2 | ($1.2) | ($55.9) | ($52.7) | $12.8 | $1.1 | ($38.9) |
| Sep | ($54.0) | $14.8 | ($1.2) | ($40.5) | ($47.9) | $9.0 | $1.3 | ($37.5) |
| Oct | ($42.7) | $16.4 | ($3.5) | ($29.9) | ($43.7) | $8.2 | $1.7 | ($33.8) |
| Nov | ($43.9) | $16.7 | ($1.5) | ($28.8) | ($45.4) | $9.7 | $0.1 | ($35.5) |
| Dec | ($70.4) | $22.9 | ($1.8) | ($49.4) | ($75.1) | $12.4 | $0.8 | ($61.9) |
| Total | ($640.6) | $184.0 | ($9.8) | ($466.3) | ($648.5) | $166.2 | $7.1 | ($475.2) |

Figure 11-8 shows PJM monthly energy costs for January 1, 2008 through December 31, 2017.

Figure 11-8 PJM monthly energy costs (Millions): 2008 through 2017

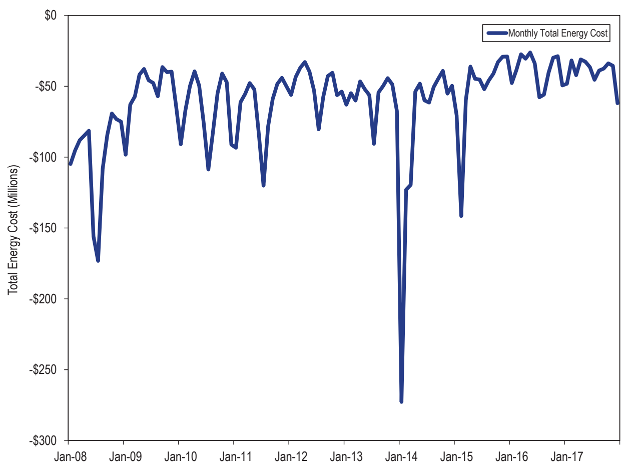


Table 11-50 and Table 11-51 show the monthly total energy costs for each virtual transaction type in 2017 and 2016. In 2017, DECs paid $1,092.8 million in energy costs in the day-ahead market, were paid $1,095.6 million in energy credits in the balancing energy market and were paid $2.9 million in net payment for energy. In 2017, INCs were paid $1,183.6 million in energy credits in the day-ahead market, paid $1,175.3 million in energy costs in the balancing market and received $8.2 million in net payment for energy. In 2016, DECs paid $1,254.0 million in energy costs in the day-ahead market, were paid $1,239.3 million in energy credits in the balancing energy market and paid $14.7 million in net payment for energy. In 2016, INCs were paid $1,275.2 million in energy credits in the day-ahead market, paid $1,250.4 million in energy cost in the balancing energy market and received $24.8 million in net payment for energy.

#### Table 11-50 Monthly PJM energy costs by virtual transaction type and by market (Dollars (Millions)): 2017

| | Energy Costs (Millions) | | | | | | |
|---|---|---|---|---|---|---|---|
| | Day-Ahead | | | Balancing | | | |
| | DEC | INC | Total | DEC | INC | Total | 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) |
| Apr | $109.6 | ($106.8) | $2.9 | ($104.2) | $102.0 | ($2.2) | $0.7 |
| May | $112.6 | ($123.9) | ($11.3) | ($114.0) | $124.9 | $10.9 | ($0.4) |
| Jun | $88.3 | ($77.5) | $10.8 | ($87.2) | $76.6 | ($10.6) | $0.2 |
| Jul | $90.2 | ($92.9) | ($2.7) | ($93.2) | $95.0 | $1.8 | ($0.9) |
| Aug | $68.5 | ($70.2) | ($1.6) | ($66.9) | $68.5 | $1.5 | ($0.1) |
| Sep | $81.6 | ($72.7) | $8.9 | ($88.6) | $73.8 | ($14.8) | ($6.0) |
| Oct | $68.6 | ($83.7) | ($15.1) | ($66.5) | $81.1 | $14.6 | ($0.5) |
| Nov | $59.5 | ($75.3) | ($15.8) | ($57.0) | $72.7 | $15.8 | ($0.0) |
| Dec | $91.9 | ($88.8) | $3.0 | ($97.3) | $92.6 | ($4.7) | ($1.6) |
| Total | $1,092.8 | ($1,183.6) | ($90.8) | ($1,095.6) | $1,175.3 | $79.7 | ($11.1) |

#### Table 11-51 Monthly PJM energy costs by virtual transaction type and by market (Dollars (Millions)): 2016

| | Energy Costs (Millions) | | | | | | |
|---|---|---|---|---|---|---|---|
| | Day-Ahead | | | Balancing | | | |
| | DEC | INC | Total | DEC | INC | Total | 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[1]

## Overview

### Planned Generation and Retirements

- **Planned Generation.** As of December 31, 2017, 99,452.5 MW of capacity were in generation request queues for construction through 2024, compared to an installed capacity of 201,496.5 MW as of December 31, 2017. Of the capacity in queues, 9,880.7 MW, or 9.9 percent, are uprates and the rest are new generation. Wind projects account for 18,287.9 MW of nameplate capacity or 18.4 percent of the capacity in the queues. Natural gas fired projects account for 59,999.8 MW of capacity or 60.3 percent of the capacity in the queues.
- **Generation Retirements.** 32,699.3 MW have been, or are planned to be, retired between 2011 and 2020. Of that, 6,935.9 MW are planned to retire after December 31, 2017. In 2017, 2,126.8 MW were retired. Of the 6,935.9 MW pending retirement, 4,620.0 MW (66.6 percent) 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 coal fired steam units retire. There are 199.0 MW of coal fired steam capacity and 59,999.8 MW of gas fired capacity in the queue. The replacement of coal fired 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.[2] PJM's process is designed to ensure that new generation is added in a reliable and systematic manner. 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. The queue process results in a substantial number of projects that drop out. Excluding currently active projects and projects currently under construction, 3,685 projects, representing 474,780.1 MW, have entered the queue process since its inception. Of those, 753 projects, representing 51,560.5 MW, went into service. Of the projects that entered the queue process, 68.2 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 associated with the submittal of large numbers of requests at the end of the queue window, which resulted in revisions to the PJM Open Access Transmission Tariff, effective October 31, 2016.[3] [4] 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.[5]
- 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."[6] Where

1 Totals presented in this section include corrections to historical data and may not match totals presented in previous reports.

2 See OATT Parts IV & VI.
3 See Earlier Queue Submittal Task Force at <http://www.pjm.com/committees-and-groups/closed-groups/eqstf.aspx>.
4 See Letter Order, ER16-2518-000 (Oct. 7, 2016).
5 157 FERC ¶ 61,212 (2016).
6 See OATT § 1 (Transmission Owner).

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)

- The Transmission Expansion Advisory Committee (TEAC) regularly reviews internal and external proposals to improve transmission reliability throughout PJM. These proposals are periodically presented to the PJM Board of Managers for authorization. In 2017, the PJM Board approved over $1.7 billion in upgrades.
- There are currently three backbone projects under development, Surry Skiffes Creek 500kV, and the conversion of the Marion-Bayonne and Bayway-Linden lines from 138 kV to 345 kV.[7]
- Through December 31, 2017, PJM has completed two market efficiency cycles. In the first cycle, PJM received 92 proposals for 11 identified issues. In the second market efficiency cycle, PJM received 96 proposals for four identified issues.
- The first Targeted Market Efficiency Process (TMEP) analysis included the investigation of congestion on 50 market to market flowgates. The study resulted in the evaluation of 13 potential upgrades, resulting in the recommendation of five TMEP projects. The five projects address $59 million in historical congestion, with a TMEP benefit of $99.6 million. The projects have a total cost of $20 million, with a 5.0 average benefit/cost ratio. PJM and MISO presented the five recommended projects to their boards in December, 2017, and both boards approved all five projects.[8]
- On April 6, 2017, the PJM Board lifted the suspension of the Artificial Island project. The project is expected to be in service by June 2020.

## 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.[9]
- There were 15,613 transmission outage requests submitted in the 2017/2018 planning period. Of the requested outages, 73.4 percent were planned for five days or shorter and 8.5 percent were planned for longer than 30 days. Of the requested outages, 43.7 percent were late according to the rules in PJM's Manual 3.

## Recommendations

The MMU recommends improvements to the planning process.

- The MMU recommends that PJM continue to incorporate the principle that the goal of transmission planning should be the incorporation of transmission investment decisions into market driven processes as much as possible. (Priority: Low. First reported 2001. Status: Not adopted.)
- The MMU recommends the creation of a mechanism to permit a direct comparison, or competition, between transmission and generation alternatives, including which alternative is less costly and who bears the risks associated with each alternative. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that rules be implemented to permit competition to provide financing for transmission projects. This competition could

7 See "2017 RTEP Process Scope and Input Assumptions White Paper," P 25. <http://www.pjm.com/-/media/library/reports-notices/2017-rtep/20170731-rtep-input-assumptions-and-scope-whitepaper.ashx?la=en>.

8 See PJM. "MISO PJM IPSAC," (January 12, 2018) <http://www.pjm.com/-/media/committees-groups/stakeholder-meetings/ipsac/20180112/20180112-ipsac-presentation.ashx>.

9 PJM. "Manual 03: Transmission Operations," Rev. 52 (Dec. 22, 2017) Section 4.

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.[10] (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

10 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>.

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.)

- The MMU recommends that PJM limit the scope of supplemental projects that can obtain exceptions to the Order No. 1000 process, to ensure maximum competition. (Priority: Medium. New recommendation. Status: Not adopted.)

## Conclusion

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

Managing the generation queues is a highly complex process. The PJM queue evaluation process has been substantially improved in recent years and it is more efficient and effective as a result. The PJM queue evaluation process should continue to be improved to help 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 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.

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

There are currently no market incentives for transmission owners to submit and complete transmission outages in a timely and efficient manner. Requiring transmission owners to pay does not create an effective incentive when those payments are passed through to transmission customers. The process for the submission of planned transmission outages needs to be carefully reviewed and redesigned to limit the ability of transmission owners to submit transmission outages that are late for FTR auction bid submission dates and are late for the Day-Ahead Energy Market. The submission of late transmission outages can inappropriately affect market outcomes when market participants do not have the ability to modify market bids and offers.

# Planned Generation and Retirements

## Planned Generation Additions

Expected net revenues provide incentives to build new generation to serve PJM markets. The amount of planned new generation in PJM reflects investors' perception of the incentives provided by the combination of revenues from the PJM energy, capacity and ancillary service markets. On December 31, 2017, 99,452.5 MW of capacity were in generation request queues for construction through 2024, compared to an installed capacity of 201,496.5 MW as of December 31, 2017. Although it is clear that not all generation in the queues will be built, PJM has added capacity.[11] In 2017, 5,124.5 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 through T were open for six months. Starting in February 2008, Queues U through 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 AD1 closed on September 30, 2017. Queue AD2 began on October 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.[12]

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.[13]

Table 12-1 shows MW in queues by expected completion date and MW changes in the queues between December 31, 2016, and December 31, 2017, for ongoing projects, i.e. projects with the status active, under construction or suspended.[14] Projects that are already in service are not included here. The total MW in queues increased by 17,516.2 MW, or 21.4 percent, from 81,936.3 MW at the end of 2016 to 99,452.5 MW on December 31, 2017.

### Table 12-1 Queue comparison by expected completion year (MW): December 31, 2016 to December 31, 2017[15]

| | | | Year Change | |
|---|---|---|---|---|
| Year | As of 12/31/2016 | As of 12/31/2017 | MW | Percent |
| 2016 | 21,064.0 | 0.0 | (21,064.0) | (100.0%) |
| 2017 | 12,957.0 | 10,827.9 | (2,129.1) | (16.4%) |
| 2018 | 14,859.6 | 22,367.2 | 7,507.6 | 50.5% |
| 2019 | 18,416.5 | 26,679.1 | 8,262.6 | 44.9% |
| 2020 | 10,869.3 | 24,903.5 | 14,034.2 | 129.1% |
| 2021 | 1,925.9 | 10,983.9 | 9,058.0 | 470.3% |
| 2022 | 250.0 | 3,690.9 | 3,440.9 | 1,376.4% |
| 2023 | 0.0 | 0.0 | 0.0 | 0.0% |
| 2024 | 1,594.0 | 0.0 | (1,594.0) | (100.0%) |
| Total | 81,936.3 | 99,452.5 | 17,516.2 | 21.4% |

Table 12-2 shows the project status changes in more detail and how scheduled queue capacity has changed between December 31, 2016, and December 31, 2017. For example, 28,415.2 MW entered the queue between January 1, 2017 and December 31, 2017. Of those 28,415.2 MW, 9,657.3 MW have been withdrawn. Of the total 63,727.4 MW marked as active at the beginning of 2017, 6,941.0 MW were withdrawn, 2,810.1 MW were suspended, 1,705.6 MW started construction, and 398.3 MW went into service by December 31, 2017. The Under Construction column shows that 791.4 MW came out of suspension and 1,705.6 MW began construction in 2017, in addition to the 16,489.3 MW of capacity that maintained the status under construction from December 31, 2016 through December 31, 2017.

11 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>.

12 See "PJM Manual 14C Generation and Transmission Interconnection Process," Rev. 12 (June 22, 2017) Section 3.7

13 PJM does not track the duration of suspensions or PJM termination of projects.

14 Expected completion dates are entered when the project enters the queue. Actual completion dates are generally different than expected completion dates.

15 Wind and solar capacity in Table 12-1 through Table 12-4 have not been adjusted to reflect derating.

## Table 12-2 Change in project status (MW): December 31, 2016 to December 31, 2017

| | | Status at 12/31/2017 | | | | |
|---|---|---|---|---|---|---|
| Status at 12/31/2016 | Total at 12/31/2016 | Active | Suspended | Under Construction | In Service | Withdrawn |
| (Entered during 2017) | | 18,757.8 | 0.0 | 0.0 | 0.0 | 9,657.3 |
| Active | 63,727.4 | 51,872.4 | 2,810.1 | 1,705.6 | 398.3 | 6,941.0 |
| Suspended | 5,790.0 | 371.0 | 3,645.3 | 791.4 | 0.0 | 982.3 |
| Under Construction | 24,012.9 | 108.9 | 2,900.7 | 16,489.3 | 4,228.1 | 285.9 |
| In Service | 46,934.1 | 0.0 | 0.0 | 0.0 | 46,934.1 | 0.0 |
| Withdrawn | 305,900.6 | 0.0 | 0.0 | 0.0 | 0.0 | 305,900.6 |
| Total | 446,365.0 | 71,110.1 | 9,356.1 | 18,986.3 | 51,560.5 | 323,767.2 |

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 December 31, 2017, there are 99,452.5 MW of capacity in queues that are not yet in service, of which 9.4 percent are suspended, 19.1 percent are under construction and 71.5 percent have not begun construction.

## Table 12-3 Capacity in PJM queues (MW): December 31, 2017[16]

| Queue | Active | In Service | Under Construction | Suspended | Withdrawn | Total |
|---|---|---|---|---|---|---|
| A Expired 31-Jan-98 | 0.0 | 8,631.0 | 0.0 | 0.0 | 17,252.0 | 25,883.0 |
| 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 | 42.0 | 0.0 | 0.0 | 846.0 | 888.0 |
| K Expired 31-Jul-03 | 0.0 | 99.0 | 0.0 | 0.0 | 485.3 | 584.3 |
| 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 | 8,090.2 | 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 | 1,240.0 | 19,468.9 | 22,755.3 |
| S Expired 31-Jul-07 | 0.0 | 3,669.5 | 0.0 | 70.0 | 12,396.5 | 16,136.0 |
| T Expired 31-Jan-08 | 0.0 | 3,014.0 | 1,208.0 | 300.0 | 23,013.3 | 27,535.3 |
| U Expired 31-Jan-09 | 200.0 | 837.3 | 649.9 | 820.0 | 30,829.6 | 33,336.8 |
| V Expired 31-Jan-10 | 390.0 | 2,748.6 | 36.1 | 761.0 | 12,877.6 | 16,813.3 |
| W Expired 31-Jan-11 | 663.0 | 2,175.7 | 837.1 | 618.8 | 19,759.2 | 24,053.7 |
| X Expired 31-Jan-12 | 1,687.5 | 4,601.2 | 3,258.9 | 1,979.0 | 18,816.3 | 30,343.0 |
| Y Expired 30-Apr-13 | 470.5 | 2,433.1 | 3,036.6 | 267.2 | 19,532.2 | 25,739.5 |
| Z Expired 30-Apr-14 | 997.0 | 714.4 | 5,543.4 | 114.3 | 6,931.5 | 14,300.7 |
| AA1 Expired 31-Oct-14 | 3,542.3 | 199.8 | 2,215.0 | 396.1 | 5,645.5 | 11,998.7 |
| AA2 Expired 30-Apr-15 | 4,814.2 | 320.9 | 676.5 | 2,474.9 | 7,779.8 | 16,066.3 |
| AB1 Expired 31-Oct-15 | 11,863.1 | 64.0 | 715.9 | 170.7 | 7,629.9 | 20,443.6 |
| AB2 Expired 31-Mar-16 | 10,854.9 | 122.1 | 20.9 | 103.6 | 4,163.0 | 15,264.5 |
| AC1 Through 30-Sep-16 | 16,538.4 | 18.7 | 0.0 | 40.5 | 3,490.8 | 20,088.5 |
| AC2 Through 30-Apr-17 | 6,612.7 | 0.0 | 0.0 | 0.0 | 5,772.0 | 12,384.7 |
| AD1 Through 30-Sep-17 | 10,482.8 | 0.0 | 0.0 | 0.0 | 1,225.0 | 11,707.8 |
| AD2 Through 30-Apr-18 | 1,993.7 | 0.0 | 0.0 | 0.0 | 82.4 | 2,076.1 |
| Total | 71,110.1 | 51,560.5 | 18,986.3 | 9,356.1 | 323,767.2 | 474,780.1 |

16 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.[17] As of December 31, 2017, 99,452.5 MW of capacity were in generation request queues for construction through 2024, compared to 93,533.3 MW at December 31, 2016.[18] Table 12-4 also shows the planned retirements for each zone.

### Table 12-4 Queue capacity by LDA, control zone and fuel (MW): December 31, 2017[19]

| LDA | Zone | Biomass | CC | CT | Coal | Diesel | Fuel Cell | Hydro | Nuclear | Solar | Storage | Wind | Other | Total Queue Capacity | Planned Retirements |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| EMAAC | AECO | 0.0 | 1,674.6 | 462.0 | 0.0 | 0.0 | 1.9 | 0.0 | 0.0 | 24.2 | 20.0 | 25.0 | 0.0 | 2,207.7 | 303.0 |
| | DPL | 4.0 | 1,111.0 | 0.0 | 0.0 | 25.2 | 0.0 | 0.0 | 0.0 | 1,386.7 | 21.0 | 649.6 | 0.0 | 3,197.5 | 0.0 |
| | JCPL | 0.0 | 1,842.1 | 0.0 | 0.0 | 0.0 | 0.4 | 0.0 | 0.0 | 196.7 | 85.0 | 0.0 | 0.0 | 2,124.2 | 614.5 |
| | PECO | 0.0 | 1,309.0 | 0.0 | 0.0 | 4.5 | 0.0 | 0.0 | 94.0 | 18.0 | 0.0 | 0.0 | 0.0 | 1,425.5 | 50.8 |
| | PSEG | 0.0 | 3,241.5 | 2.0 | 24.0 | 0.0 | 3.4 | 0.0 | 0.0 | 69.8 | 0.0 | 0.0 | 0.0 | 3,340.7 | 611.0 |
| | RECO | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | EMAAC Total | 4.0 | 9,178.2 | 464.0 | 24.0 | 29.7 | 5.7 | 0.0 | 94.0 | 1,695.4 | 126.0 | 674.6 | 0.0 | 12,295.6 | 1,579.3 |
| SWMAAC | BGE | 0.0 | 0.0 | 0.0 | 0.0 | 1.3 | 0.0 | 0.4 | 30.3 | 22.0 | 0.1 | 0.0 | 0.0 | 54.1 | 534.0 |
| | Pepco | 0.0 | 1,932.6 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 65.3 | 0.0 | 0.0 | 0.0 | 1,997.9 | 0.0 |
| | SWMAAC Total | 0.0 | 1,932.6 | 0.0 | 0.0 | 1.3 | 0.0 | 0.4 | 30.3 | 87.3 | 0.1 | 0.0 | 0.0 | 2,051.9 | 534.0 |
| WMAAC | Met-Ed | 0.0 | 485.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 158.0 | 0.0 | 0.0 | 30.0 | 673.0 | 805.0 |
| | PENELEC | 0.0 | 1,333.0 | 756.1 | 0.0 | 126.4 | 0.0 | 0.0 | 0.0 | 63.5 | 0.0 | 458.8 | 590.0 | 3,327.8 | 110.0 |
| | PPL | 16.0 | 5,449.0 | 19.9 | 0.0 | 19.9 | 0.0 | 0.0 | 0.0 | 30.0 | 120.0 | 441.1 | 0.0 | 6,095.9 | 8.2 |
| | WMAAC Total | 16.0 | 7,267.0 | 776.0 | 0.0 | 146.3 | 0.0 | 0.0 | 0.0 | 251.5 | 120.0 | 899.8 | 620.0 | 10,096.6 | 923.2 |
| Non-MAAC | AEP | 0.0 | 9,449.0 | 413.0 | 119.0 | 15.2 | 0.0 | 34.0 | 28.0 | 4,963.5 | 40.0 | 8,283.6 | 30.0 | 23,375.3 | 0.0 |
| | APS | 0.0 | 5,805.1 | 100.0 | 10.0 | 119.6 | 0.0 | 15.0 | 0.0 | 673.3 | 37.8 | 1,170.7 | 0.0 | 7,931.5 | 27.4 |
| | ATSI | 0.0 | 5,191.0 | 70.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 646.0 | 0.0 | 1,316.1 | 0.0 | 7,223.0 | 776.0 |
| | ComEd | 0.0 | 8,270.2 | 1,127.0 | 0.0 | 18.8 | 0.0 | 22.7 | 0.0 | 1,025.5 | 86.5 | 4,599.7 | 64.0 | 15,214.4 | 4.0 |
| | DAY | 0.0 | 1,150.0 | 0.0 | 12.0 | 0.0 | 0.0 | 0.0 | 0.0 | 762.9 | 39.9 | 300.0 | 0.0 | 2,264.8 | 2,364.0 |
| | DEOK | 0.0 | 513.0 | 0.0 | 20.0 | 0.0 | 0.0 | 0.0 | 0.0 | 300.0 | 19.8 | 0.0 | 0.0 | 852.8 | 0.0 |
| | DLCO | 0.0 | 205.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 20.0 | 20.0 | 0.0 | 0.0 | 245.0 | 0.0 |
| | Dominion | 62.5 | 6,849.7 | 155.0 | 14.0 | 8.0 | 0.0 | 5.5 | 0.0 | 9,514.5 | 34.0 | 1,043.5 | 0.0 | 17,686.7 | 728.0 |
| | EKPC | 0.0 | 0.0 | 75.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 100.0 | 0.0 | 0.0 | 0.0 | 175.0 | 0.0 |
| | RMU | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 40.0 | 0.0 | 0.0 | 0.0 | 40.0 | 0.0 |
| | Non-MAAC Total | 62.5 | 37,433.0 | 1,940.0 | 175.0 | 161.6 | 0.0 | 77.2 | 28.0 | 18,045.6 | 278.0 | 16,713.5 | 94.0 | 75,008.4 | 3,899.4 |
| Total in PJM | Total | 82.5 | 55,810.8 | 3,180.0 | 199.0 | 338.9 | 5.7 | 77.6 | 152.3 | 20,079.8 | 524.1 | 18,287.9 | 714.0 | 99,452.5 | 6,935.9 |

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 coal fired steam units retire. As of December 31, 2017, there were 15,162.3 MW of gas fired capacity under construction in PJM. As of December 31, 2017, there were only 108.0 MW of coal fired steam capacity under construction in PJM. With respect to retirements, 4,620 MW of coal fired steam capacity and 661.8 MW of natural gas capacity are slated for deactivation between December 31, 2017, and December 31, 2020. The replacement of coal fired 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, 32,699.3 MW have been, or are planned to be, retired between 2011 and 2020.[20] Of that, 6,935.9 MW are planned to retire after December 31, 2017. In 2017, 2,126.8 MW were retired. Of the 6,935.9 MW pending retirement, 4,620.0 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.

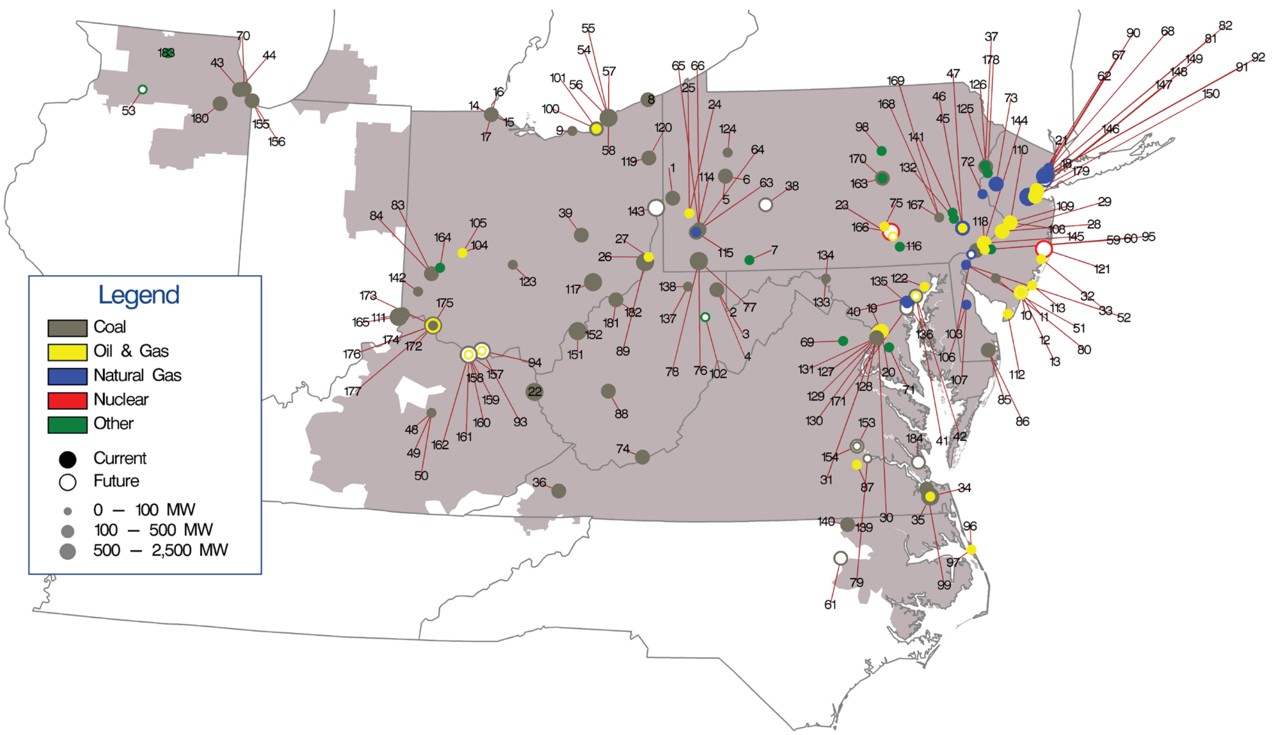
17 Unit types designated as reciprocating engines are classified as diesel.
18 Since wind resources cannot be dispatched on demand, PJM rules previously required that the unforced capacity of wind resources be derated to 20 percent of nameplate capacity until actual generation data are available. Beginning 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 15,910.5 MW of wind resources and 12,449.5 MW of solar resources, the 99,452.5 MW currently active in the queue would be reduced to 71,092.5 MW.
19 This data includes only projects with a status of active, under-construction, or suspended.
20 See PJM "Generator Deactivation Summary Sheets," at <http://www.pjm.com/planning/generation-deactivation/gd-summaries.aspx> (December 29, 2017).

## Table 12-5 Summary of PJM unit retirements by fuel (MW): 2011 through 2020

| | Battery | Coal | Diesel | Heavy Oil | Hydro | Kerosene | Landfill Gas | Light Oil | Natural Gas | Nuclear | Waste Coal | Wind | Wood Waste | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Retirements 2011 | 0.0 | 543.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 131.0 | 522.5 | 0.0 | 0.0 | 0.0 | 0.0 | 1,196.5 |
| Retirements 2012 | 0.0 | 5,907.9 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 788.0 | 250.0 | 0.0 | 0.0 | 0.0 | 16.0 | 6,961.9 |
| Retirements 2013 | 0.0 | 2,558.9 | 2.9 | 166.0 | 0.0 | 0.0 | 7.0 | 3.0 | 82.0 | 0.0 | 31.0 | 0.0 | 8.0 | 2,858.8 |
| Retirements 2014 | 0.0 | 2,239.0 | 50.0 | 0.0 | 0.0 | 184.0 | 15.3 | 188.0 | 294.0 | 0.0 | 0.0 | 0.0 | 0.0 | 2,970.3 |
| Retirements 2015 | 0.0 | 7,064.8 | 0.0 | 0.0 | 0.0 | 644.2 | 2.0 | 222.3 | 1,319.0 | 0.0 | 0.0 | 10.4 | 0.0 | 9,262.7 |
| Retirements 2016 | 0.0 | 243.0 | 51.0 | 0.0 | 0.5 | 0.0 | 9.9 | 22.0 | 74.0 | 0.0 | 0.0 | 0.0 | 0.0 | 400.4 |
| Retirements 2017 | 40.0 | 2,038.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.8 | 0.0 | 34.0 | 0.0 | 0.0 | 0.0 | 0.0 | 2,112.8 |
| Planned Retirements (2018 and later) | 27.4 | 4,620.0 | 2.4 | 148.0 | 0.0 | 0.0 | 4.0 | 52.8 | 661.8 | 1,419.5 | 0.0 | 0.0 | 0.0 | 6,935.9 |
| Total | 67.4 | 25,214.6 | 106.3 | 314.0 | 0.5 | 828.2 | 39.0 | 1,407.1 | 3,237.3 | 1,419.5 | 31.0 | 10.4 | 24.0 | 32,699.3 |

A map of the retirements between 2011 and 2020 is shown in Figure 12-1 with a mapping to unit names identified in Table 12-6.

## Figure 12-1 Map of PJM unit retirements: 2011 through 2020



## Table 12-6 Unit identification for map of PJM unit retirements: 2011 through 2020

| ID | Unit | ID | Unit | ID | Unit | ID | Unit | ID | Unit | ID | Unit |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | AES Beaver Valley | 36 | Clinch River 3 | 71 | GUDE Landfill | 106 | McKee 1 | 141 | Rolling Hills Landfill Generator | 176 | Walter C Beckjord 5-6 |
| 2 | Albright 1 | 37 | Columbia Dam Hydro | 72 | Gilbert 1-4 | 107 | McKee 2 | 142 | SMART Paper | 177 | Walter C Beckjord GT 1-4 |
| 3 | Albright 2 | 38 | Colver Power Project | 73 | Glen Gardner 1-8 | 108 | Mercer 1 | 143 | Sammis 1-4 | 178 | Warren County Landfill |
| 4 | Albright 3 | 39 | Conesville 3 | 74 | Glen Lyn 5-6 | 109 | Mercer 2 | 144 | Schuylkill 1 | 178 | Werner 1-4 |
| 5 | Armstrong 1 | 40 | Crane 1 | 75 | Harrisburg 4 CT | 110 | Mercer 3 | 145 | Schuylkill Diesel | 180 | Will County 3 |
| 6 | Armstrong 2 | 41 | Crane 2 | 76 | Hatfield's Ferry 1 | 111 | Miami Fort 6 | 146 | Sewaren 1 | 151 | Willow Island 1 |
| 7 | Arnold (Green Mtn. Wind Farm | 42 | Crane GT1 | 77 | Hatfield's Ferry 2 | 112 | Middle 1-3 | 147 | Sewaren 2 | 152 | Willow Island 2 |
| 8 | Ashtabula 5 | 43 | Crawford 7 | 78 | Hatfield's Ferry 3 | 113 | Missouri Ave B,C,D | 148 | Sewaren 3 | 153 | Winnebago Landfill |
| 9 | Avon Lake 7 | 44 | Crawford 8 | 79 | Hopewell James River Cogeneration | 114 | Mitchell 2 | 149 | Sewaren 4 | 154 | Yorktown 1-2 |
| 10 | BL England 1 | 45 | Cromby 1 | 80 | Howard Down 10 | 115 | Mitchell 3 | 150 | Sewaren 6 | | |
| 11 | BL England 2 | 46 | Cromby 2 | 81 | Hudson 1 | 116 | Modern Power Landfill NUG | 151 | Sporn 1-4 | | |
| 12 | BL England 3 | 47 | Cromby D | 82 | Hudson 2 | 117 | Muskingum River 1-5 | 152 | Sporn 5 | | |
| 13 | BL England Diesel Units 1-4 | 48 | Dale 1-2 | 83 | Hutchings 1-3, 5-6 | 118 | National Park 1 | 153 | Spruance NUG1 (Rich 1-2) | | |
| 14 | Bay Shore 1 | 49 | Dale 3 | 84 | Hutchings 4 | 119 | Niles 1 | 154 | Spruance NUG2 (Rich 3-4) | | |
| 15 | Bay Shore 2 | 50 | Dale 4 | 85 | Indian River 1 | 120 | Niles 2 | 155 | State Line 3 | | |
| 16 | Bay Shore 3 | 51 | Deepwater 1 | 86 | Indian River 3 | 121 | Oyster Creek | 156 | State Line 4 | | |
| 17 | Bay Shore 4 | 52 | Deepwater 6 | 87 | Ingenco Petersburg | 122 | Perryman 2 | 157 | Stuart 1 | | |
| 18 | Bayonne Cogen Plant (CC) | 53 | Dixon Lee Landfill Generator | 88 | Kanawha River 1-2 | 123 | Picway 5 | 158 | Stuart 2 | | |
| 19 | Benning 15 | 54 | Eastlake 1 | 89 | Kanmer 1-3 | 124 | Piney Creek NUG | 159 | Stuart 3 | | |
| 20 | Benning 16 | 55 | Eastlake 2 | 90 | Kearny 10 | 125 | Portland 1 | 160 | Stuart 4 | | |
| 21 | Bergen 3 | 56 | Eastlake 3 | 91 | Kearny 11 | 126 | Portland 2 | 161 | Stuart Diesels 1-4 | | |
| 22 | Big Sandy 2 | 57 | Eastlake 4 | 92 | Kearny 9 | 127 | Potomac River 1 | 162 | Stuart Diesels 1-4 | | |
| 23 | Brunner Island Diesels | 58 | Eastlake 5 | 93 | Killen 2 | 128 | Potomac River 2 | 163 | Sunbury 1-4 | | |
| 24 | Brunot Island 1B | 59 | Eddystone 1 | 94 | Killen CT | 129 | Potomac River 3 | 164 | Tait Battery | | |
| 25 | Brunot Island 1C | 60 | Eddystone 2 | 95 | Kinsley Landfill | 130 | Potomac River 4 | 165 | Tanners Creek 1-4 | | |
| 26 | Burger 3 | 61 | Edgecomb NUG (Rocky 1-2) | 96 | Kitty Hawk GT 1 | 131 | Potomac River 5 | 166 | Three Mile Island Unit 1 | | |
| 27 | Burger EMD | 62 | Edison 1-3 | 97 | Kitty Hawk GT 2 | 132 | Pottstown LF (Moser) | 167 | Titus 1 | | |
| 28 | Burlington 8,11 | 63 | Elrama 1 | 98 | Koppers Co. IPP | 133 | R Paul Smith 3 | 168 | Titus 2 | | |
| 29 | Burlington 9 | 64 | Elrama 2 | 99 | Lake Kingman | 134 | R Paul Smith 4 | 169 | Titus 3 | | |
| 30 | Buzzard Point East Banks 1,2,4-8 | 65 | Elrama 3 | 100 | Lake Shore 18 | 135 | Riverside 4 | 170 | Viking Energy NUG | | |
| 31 | Buzzard Point West Banks 1-9 | 66 | Elrama 4 | 101 | Lake Shore EMD | 136 | Riverside 6 | 171 | Wagner 2 | | |
| 32 | Cedar 1 | 67 | Essex 10-11 | 102 | Laurel Mountain Battery | 137 | Riversville 5 | 172 | Walter C Beckjord 1 | | |
| 33 | Cedar 2 | 68 | Essex 12 | 103 | MH50 Markus Hook Co-gen | 138 | Riversville 6 | 173 | Walter C Beckjord 2 | | |
| 34 | Chesapeake 1-4 | 69 | Fauquier County Landfill | 104 | Mad River CTs A | 139 | Roanoke Valley 1 | 174 | Walter C Beckjord 3 | | |
| 35 | Chesapeake 7-10 | 70 | Fisk Street 19 | 105 | Mad River CTs B | 140 | Roanoke Valley 2 | 175 | Walter C Beckjord 4 | | |

The list of pending retirements is shown in Table 12-7.

## Table 12-7 Planned retirement of PJM units: December 31, 2017[21]

| Unit | Zone | ICAP (MW) | Fuel | Unit Type | Projected Deactivation Date |
|---|---|---|---|---|---|
| BL England 3 | AECO | 148.0 | Heavy Oil | Steam | 24-Jan-18 |
| Brunner Island Diesels | PPL | 8.2 | Light Oil | Diesel | 25-Feb-18 |
| Dixon Lee Landfill Generator | ComEd | 4.0 | Landfill Gas | Diesel | 06-Mar-18 |
| Yorktown 1-2 | Dominion | 323.0 | Coal | Steam | 13-Mar-18 |
| Laurel Mountain Battery | APS | 27.4 | Battery | Battery | 16-Mar-18 |
| Hopewell James River Cogeneration | Dominion | 89.0 | Coal | Steam | 31-May-18 |
| Crane 1 | BGE | 190.0 | Coal | Steam | 01-Jun-18 |
| Crane 2 | BGE | 195.0 | Coal | Steam | 01-Jun-18 |
| Killen 2 | DAY | 600.0 | Coal | Steam | 01-Jun-18 |
| Stuart 2 | DAY | 577.0 | Coal | Steam | 01-Jun-18 |
| Stuart 3 | DAY | 577.0 | Coal | Steam | 01-Jun-18 |
| Stuart 4 | DAY | 577.0 | Coal | Steam | 01-Jun-18 |
| Stuart Diesels 1-4 | DAY | 2.4 | Diesel | Diesel | 01-Jun-18 |
| Killen CT | DAY | 24.0 | Light Oil | CT | 01-Jun-18 |
| Stuart Diesels 1-4 | DAY | 6.6 | Light Oil | Diesel | 01-Jun-18 |
| Sewaren 1 | PSEG | 104.0 | Natural Gas | Steam | 01-Jun-18 |
| Sewaren 2 | PSEG | 118.0 | Natural Gas | Steam | 01-Jun-18 |
| Sewaren 3 | PSEG | 107.0 | Natural Gas | Steam | 01-Jun-18 |
| Sewaren 4 | PSEG | 124.0 | Natural Gas | Steam | 01-Jun-18 |
| Bayonne Cogen Plant (CC) | PSEG | 158.0 | Natural Gas | Steam | 01-Nov-18 |
| Spruance NUG1 (aka Spruance 1 Rich 1-2) | Dominion | 115.5 | Coal | Steam | 12-Jan-19 |
| Spruance NUG2 (aka Spruance 2 Rich 3-4) | Dominion | 85.0 | Coal | Steam | 12-Jan-19 |
| BL England 2 | AECO | 155.0 | Coal | Steam | 30-Apr-19 |
| MH50 Markus Hook Co-gen | PECO | 50.8 | Natural Gas | Steam | 13-May-19 |
| Three Mile Island Unit 1 Nuclear Generating Station | Met-Ed | 805.0 | Nuclear | Nuclear | 30-Sep-19 |
| Crane GT1 | BGE | 14.0 | Light Oil | CT | 31-Oct-19 |
| Oyster Creek Nuclear Generating Station | JCPL | 614.5 | Nuclear | Nuclear | 31-Dec-19 |
| Sammis 1-4 | ATSI | 640.0 | Coal | Steam | 31-May-20 |
| Wagner 2 | BGE | 135.0 | Coal | Steam | 01-Jun-20 |
| Colver Power Project | PENELEC | 110.0 | Coal | Steam | 01-Sep-20 |
| Bay Shore 1 | ATSI | 136.0 | Coal | Steam | 01-Oct-20 |
| Edgecomb NUG (aka Edgecomb Rocky 1-2) | Dominion | 115.5 | Coal | Steam | 31-Oct-20 |
| Total | | 6,935.9 | | | |

Table 12-8 shows the capacity, average size, and average age of units retiring in PJM, from 2011 through 2020, while Table 12-9 shows these retirements by state. The majority, 77.1 percent, of all MW retiring during this period are coal fired steam units. These coal fired steam units have an average age of 54.2 years and an average size of 172.7 MW. Over half of the retiring coal fired steam units, 55.0 percent, are located in either Ohio or Pennsylvania. Retirements have generally consisted of smaller subcritical coal fired steam units and those without adequate environmental controls to remain viable beyond 2017.

21 Units designated as external installed capacity have been removed.

### Table 12-8 Retirements by fuel type: 2011 through 2020

| Fuel | Number of Units | Avg. Size (MW) | Avg. Age at Retirement (Years) | Total MW | Percent |
|---|---|---|---|---|---|
| Battery | 2 | 33.7 | 6.5 | 67.4 | 0.2% |
| Coal | 146 | 172.7 | 54.2 | 25,214.6 | 77.1% |
| Diesel | 5 | 21.3 | 39.8 | 106.3 | 0.3% |
| Heavy Oil | 2 | 157.0 | 48.9 | 314.0 | 1.0% |
| Hydro | 1 | 0.5 | 113.8 | 0.5 | 0.0% |
| Kerosene | 20 | 41.4 | 45.5 | 828.2 | 2.5% |
| Landfill Gas | 10 | 3.9 | 13.1 | 39.0 | 0.1% |
| Light Oil | 32 | 44.0 | 43.6 | 1,407.1 | 4.3% |
| Natural Gas | 55 | 58.9 | 47.3 | 3,237.3 | 9.9% |
| Nuclear | 2 | 709.8 | 47.8 | 1,419.5 | 4.3% |
| Waste Coal | 1 | 31.0 | 20.3 | 31.0 | 0.1% |
| Wind | 1 | 10.4 | 15.6 | 10.4 | 0.0% |
| Wood Waste | 2 | 12.0 | 23.2 | 24.0 | 0.1% |
| Total | 279 | 117.2 | 48.8 | 32,699.3 | 100.0% |

### Table 12-9 Retirements (MW) by fuel type and state: 2011 through 2020

| State | Battery | Coal | Diesel | Heavy Oil | Hydro | Kerosene | Landfill Gas | Light Oil | Natural Gas | Nuclear | Waste Coal | Wind | Wood Waste | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| DC | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 788.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 788.0 |
| DE | 0.0 | 254.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 34.0 | 0.0 | 0.0 | 0.0 | 0.0 | 288.0 |
| IL | 0.0 | 1,624.0 | 0.0 | 0.0 | 0.0 | 0.0 | 10.4 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 1,634.4 |
| IN | 0.0 | 982.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 982.0 |
| KY | 0.0 | 995.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 995.0 |
| MD | 0.0 | 635.0 | 51.0 | 0.0 | 0.0 | 0.0 | 0.8 | 14.0 | 189.0 | 0.0 | 0.0 | 0.0 | 0.0 | 889.8 |
| NC | 0.0 | 324.5 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 31.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 355.5 |
| NJ | 0.0 | 1,543.0 | 0.0 | 148.0 | 0.5 | 828.2 | 9.8 | 220.0 | 2,680.5 | 614.5 | 0.0 | 0.0 | 0.0 | 6,044.5 |
| OH | 40.0 | 9,248.6 | 52.4 | 0.0 | 0.0 | 0.0 | 0.0 | 228.9 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 9,569.9 |
| PA | 0.0 | 4,627.0 | 0.0 | 166.0 | 0.0 | 0.0 | 16.0 | 57.9 | 333.8 | 805.0 | 31.0 | 10.4 | 24.0 | 6,071.1 |
| VA | 0.0 | 2,340.5 | 2.9 | 0.0 | 0.0 | 0.0 | 2.0 | 67.3 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 2,412.7 |
| WV | 27.4 | 2,641.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 2,668.4 |
| Total | 67.4 | 25,214.6 | 106.3 | 314.0 | 0.5 | 828.2 | 39.0 | 1,407.1 | 3,237.3 | 1,419.5 | 31.0 | 10.4 | 24.0 | 32,699.3 |

## Generation Deactivations in 2017

Table 12-10 shows the units that were deactivated in 2017.

### Table 12-10 Unit deactivations in 2017

| Company | Unit Name | ICAP (MW) | Primary Fuel | Zone Name | Average Age (Years) | Retirement Date |
|---|---|---|---|---|---|---|
| Dominion Resources, Inc. | Roanoke Valley 1 | 165.0 | Coal | Dominion | 22.8 | 01-Mar-17 |
| Dominion Resources, Inc. | Roanoke Valley 2 | 44.0 | Coal | Dominion | 21.8 | 01-Mar-17 |
| City of Dover | McKee 1 | 17.0 | Natural Gas | DPL | 55.4 | 31-May-17 |
| City of Dover | McKee 2 | 17.0 | Natural Gas | DPL | 55.3 | 31-May-17 |
| Public Service Enterprise Group Incorporated | Hudson 2 | 620.0 | Coal | PSEG | 48.5 | 01-Jun-17 |
| Public Service Enterprise Group Incorporated | Mercer 1 | 316.0 | Coal | PSEG | 56.5 | 01-Jun-17 |
| Public Service Enterprise Group Incorporated | Mercer 2 | 316.0 | Coal | PSEG | 56.0 | 01-Jun-17 |
| Northeast Maryland Waste Disposal Authority | GUDE Landfill | 0.8 | Landfill Gas | Pepco | 8.8 | 24-Aug-17 |
| Dynegy Inc. | Stuart 1 | 225.0 | Coal | DAY | 46.5 | 30-Sep-17 |
| The AES Corporation | Stuart 1 | 202.0 | Coal | DAY | 46.5 | 30-Sep-17 |
| American Electric Power Company, Inc. | Stuart 1 | 150.0 | Coal | DAY | 46.5 | 30-Sep-17 |
| The AES Corporation | Tait Battery | 40.0 | Battery | DAY | 4.4 | 13-Dec-17 |
| Total | | 2,112.8 | | | | |

## Existing Generation Mix

As of December 31, 2017, PJM had an installed capacity of 201,496.5 MW (Table 12-11). This measure differs from capacity market installed capacity because it includes energy-only units, excludes all external units, and uses nameplate values for solar and wind resources.

### Table 12-11 Existing PJM capacity: December 31, 2017 (By zone and unit type (MW))[22]

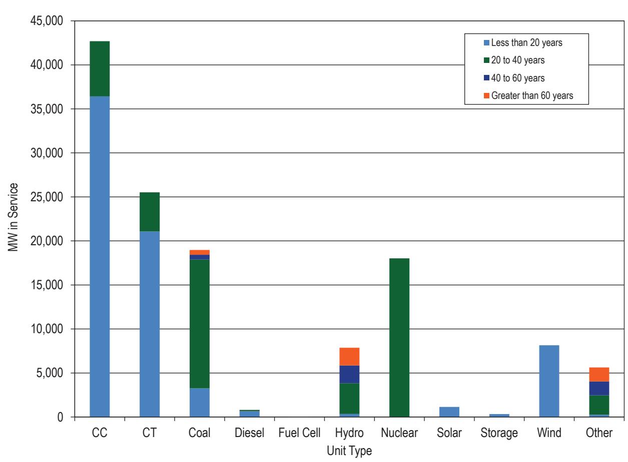
| ZONE | CC | CT | Coal | Diesel | Fuel Cell | Hydro | Nuclear | Solar | Storage | Wind | Other | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| AECO | 901.9 | 570.7 | 613.9 | 14.6 | 1.6 | 0.0 | 0.0 | 59.4 | 0.0 | 7.5 | 202.0 | 2,371.5 |
| AEP | 6,840.0 | 3,682.2 | 18,159.8 | 80.3 | 0.0 | 1,071.9 | 2,071.0 | 14.7 | 6.0 | 2,474.0 | 738.0 | 35,137.9 |
| APS | 1,749.0 | 1,560.9 | 5,409.0 | 47.9 | 0.0 | 129.2 | 0.0 | 46.1 | 78.9 | 1,191.5 | 0.0 | 10,212.5 |
| ATSI | 1,570.5 | 1,618.3 | 5,394.0 | 63.7 | 0.0 | 0.0 | 2,134.0 | 0.0 | 0.0 | 0.0 | 325.0 | 11,105.5 |
| BGE | 0.0 | 936.6 | 2,098.0 | 22.4 | 0.0 | 0.4 | 1,716.0 | 1.1 | 0.0 | 0.0 | 823.5 | 5,598.0 |
| ComEd | 3,146.1 | 7,244.0 | 3,840.1 | 109.1 | 0.0 | 0.0 | 10,473.5 | 9.0 | 127.6 | 3,081.9 | 1,326.0 | 29,357.3 |
| DAY | 0.0 | 1,368.5 | 2,331.0 | 47.5 | 0.0 | 0.0 | 0.0 | 1.1 | 40.0 | 0.0 | 0.0 | 3,788.1 |
| DEOK | 47.2 | 654.0 | 3,934.0 | 4.8 | 0.0 | 112.0 | 0.0 | 0.0 | 20.0 | 0.0 | 47.0 | 4,819.0 |
| DLCO | 244.0 | 15.0 | 660.0 | 0.0 | 0.0 | 6.3 | 1,777.0 | 0.0 | 0.0 | 0.0 | 0.0 | 2,702.3 |
| Dominion | 8,371.6 | 4,092.7 | 4,903.6 | 171.8 | 0.0 | 3,589.3 | 3,581.3 | 337.6 | 0.0 | 208.0 | 2,662.4 | 27,918.3 |
| DPL | 2,498.5 | 1,820.4 | 437.0 | 162.1 | 30.0 | 0.0 | 0.0 | 213.4 | 0.0 | 0.0 | 1,149.0 | 6,310.4 |
| EKPC | 0.0 | 774.0 | 1,687.0 | 0.0 | 0.0 | 70.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 2,531.0 |
| JCPL | 2,682.5 | 763.1 | 0.0 | 16.1 | 0.0 | 400.0 | 614.5 | 260.6 | 0.0 | 0.0 | 25.5 | 4,762.3 |
| Met-Ed | 2,630.8 | 401.7 | 35.0 | 33.4 | 0.0 | 19.5 | 805.0 | 0.0 | 0.0 | 0.0 | 165.0 | 4,090.4 |
| PECO | 3,209.0 | 834.0 | 3.3 | 2.9 | 0.0 | 3,284.0 | 4,546.8 | 3.0 | 1.0 | 0.0 | 975.8 | 12,859.8 |
| PENELEC | 850.0 | 407.5 | 6,056.5 | 150.0 | 0.0 | 590.8 | 0.0 | 0.0 | 28.4 | 958.8 | 743.0 | 9,785.0 |
| Pepco | 1,827.0 | 1,204.7 | 2,433.0 | 11.1 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 1,216.1 | 6,691.9 |
| PPL | 2,657.9 | 616.5 | 2,225.5 | 55.5 | 0.0 | 706.6 | 2,520.0 | 15.0 | 20.0 | 219.7 | 2,944.4 | 11,981.1 |
| PSEG | 4,000.3 | 1,134.0 | 0.0 | 11.1 | 0.0 | 5.0 | 3,493.0 | 182.7 | 4.0 | 0.0 | 644.1 | 9,474.2 |
| 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 |
| Total | 43,226.3 | 29,698.8 | 60,220.7 | 1,004.3 | 31.6 | 9,985.0 | 33,732.1 | 1,143.7 | 325.9 | 8,141.4 | 13,986.8 | 201,496.5 |

Figure 12-2 and Table 12-12 show the age of PJM generators by unit type. Units older than 40 years comprise 80,669.0 MW, or 40.0 percent, of the total capacity of 201,496.5 MW.

### Table 12-12 PJM capacity (MW) by age (years): December 31, 2017

| Age (years) | CC | CT | Coal | Diesel | Fuel Cell | Hydro | Nuclear | Solar | Storage | Wind | Other | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Less than 20 | 36,420.8 | 21,072.4 | 3,250.0 | 666.8 | 31.6 | 339.7 | 0.0 | 1,143.7 | 325.9 | 8,141.4 | 247.9 | 71,640.1 |
| 20 to 40 | 6,273.5 | 4,441.8 | 14,632.8 | 117.9 | 0.0 | 3,493.2 | 18,018.9 | 0.0 | 0.0 | 0.0 | 2,209.3 | 49,187.4 |
| 40 to 60 | 532.0 | 4,184.6 | 41,790.4 | 215.6 | 0.0 | 4,133.0 | 15,713.2 | 0.0 | 0.0 | 0.0 | 9,946.1 | 76,514.9 |
| Greater than 60 | 0.0 | 0.0 | 547.5 | 4.0 | 0.0 | 2,019.1 | 0.0 | 0.0 | 0.0 | 0.0 | 1,583.5 | 4,154.1 |
| Total | 43,226.3 | 29,698.8 | 60,220.7 | 1,004.3 | 31.6 | 9,985.0 | 33,732.1 | 1,143.7 | 325.9 | 8,141.4 | 13,986.8 | 201,496.5 |

### Figure 12-2 PJM capacity (MW) by age (years): December 31, 2017




22 The capacity described in this section refers to all capacity in PJM at the summer installed capacity rating, regardless of whether the capacity entered the RPM Auction. This table previously included external units.

# 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. The Earlier Queue Submittal Task Force (EQSTF) was established in August 2015, to further address the issue.[24]

## 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.

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.[25] The revised OATT completed the EQSTF work assignment. The final meeting of the EQSTF was held on March 21, 2016.

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 Queue Analysis

In the study phase of the interconnection planning process, a series of studies are performed to determine the feasibility, impact, and cost of projects in the queue. Table 12-13 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.

23 See PJM Interconnection, L.L.C., Docket No. ER12-1177 (Feb. 29, 2012).

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

25 See Letter Order, ER16-2518-000 (Oct. 7, 2016).

### Table 12-13 PJM generation planning process

| Process Step | Start on | Financial Obligation | Days for PJM to Complete | Days for Applicant to Decide Whether to Continue |
|---|---|---|---|---|
| Feasibility Study | Close of current queue | Cost of study (partially refundable deposit) | 90 | 30 |
| System Impact Study | Upon acceptance of the System Impact Study Agreement | Cost of study (partially refundable deposit) | 120 | 30 |
| Facilities Study | Upon acceptance of the Facilities Study Agreement | Cost of study (refundable deposit) | Varies | 60 |
| Schedule of Work | Upon acceptance of Interconnection Service Agreement (ISA) | Letter of credit for upgrade costs | Varies | 37 |
| Construction (only for new generation) | Upon acceptance of Interconnection Construction Service Agreement (ICSA) | None | Varies | NA |

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.[26] 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 12-14 and Table 12-15.

## Withdrawn Projects

Table 12-14 shows the milestone status when projects were withdrawn, for all withdrawn projects. Of the projects withdrawn, 52.9 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.[27] [28] Withdrawing at or beyond this point is uncommon; only 257 projects, or 12.2 percent, of all projects withdrawn were withdrawn after reaching this milestone.

### Table 12-14 Last milestone at time of withdrawal: 1997 through 2017

| Milestone Completed | Projects Withdrawn | Percent | Average Days | Maximum Days |
|---|---|---|---|---|
| Never Started | 283 | 13.4% | 173 | 1,235 |
| Feasibility Study | 832 | 39.5% | 344 | 3,238 |
| System Impact Study | 468 | 22.2% | 604 | 3,174 |
| Facilities Study | 266 | 12.6% | 1,340 | 4,210 |
| Construction Service Agreement (CSA) or beyond | 257 | 12.2% | 1,538 | 4,249 |
| Total | 2,106 | 100.0% | | |

Table 12-15 and Table 12-16 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 1,007 days, or 2.8 years, between entering a queue and going into service. For withdrawn projects, there is an average time of 650 days, or 1.8 years, between entering a queue and withdrawing.

### Table 12-15 Average project queue times (days): December 31, 2017

| Status | Average (Days) | Standard Deviation | Minimum | Maximum |
|---|---|---|---|---|
| Active | 945 | 528 | 99 | 3,745 |
| In-Service | 1,007 | 720 | 1 | 4,024 |
| Suspended | 2,059 | 1,150 | 696 | 4,773 |
| Under Construction | 1,928 | 1,049 | 473 | 4,977 |
| Withdrawn | 650 | 685 | 1 | 4,249 |

## Average Time in Queue

Table 12-16 presents information on the time in the stages of the queue for those projects not yet in service. Of the 826 projects in the queue as of December 31, 2017, 62 had a completed feasibility study and 127 were under construction.

26 See PJM. "Manual 14B: PJM Region Transmission Planning Process," Rev. 40 (Oct. 26, 2017), p.82.

27 "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 12 (June 22, 2017).

28 See PJM. "Manual 14C: Generation and Transmission Interconnection Facility Construction," Rev. 12 (June 22, 2017).

Table 12-16 PJM generation planning summary: December 31, 2017

| Milestone Reached | Number of Projects | Percent of Total Projects | Average Days | Maximum Days |
|---|---|---|---|---|
| Under Review | 461 | 55.8% | 838 | 2,039 |
| Feasibility Study | 62 | 7.5% | 1,165 | 1,972 |
| System Impact Study | 110 | 13.3% | 1,065 | 3,194 |
| Facilities Study | 66 | 8.0% | 2,226 | 4,260 |
| Construction Service Agreement (CSA) or beyond | 127 | 15.4% | 2,335 | 4,977 |
| Total | 826 | 100.0% | | |

## Queue Analysis by Fuel Group

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 12-17 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 1,056 projects entered in 2015, 2016, and 2017, 786 projects, 74.4 percent, were renewable. Of the 351 projects entered in 2017, 282 projects, 80.3 percent, were renewable.

Table 12-17 Number of projects entered in the queue: December 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 | 382 | 54 | 441 |
| 2011 | 6 | 265 | 78 | 349 |
| 2012 | 2 | 73 | 80 | 155 |
| 2013 | 1 | 78 | 73 | 152 |
| 2014 | 0 | 122 | 68 | 190 |
| 2015 | 0 | 192 | 114 | 306 |
| 2016 | 2 | 312 | 85 | 399 |
| 2017 | 2 | 282 | 67 | 351 |
| Total | 69 | 2,237 | 1,389 | 3,695 |

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 39.7 percent of the nameplate MW currently active in the queue (Table 12-18).

Table 12-18 Queue details by fuel group: December 31, 2017

| Fuel Group | Number of Projects | Percent of Projects | MW | Percent MW |
|---|---|---|---|---|
| Nuclear | 8 | 1.0% | 152.3 | 0.2% |
| Renewable | 588 | 70.3% | 39,808.3 | 39.7% |
| Traditional | 240 | 28.7% | 60,248.4 | 60.1% |
| Total | 836 | 100.0% | 100,209.0 | 100.0% |

## Queue Analysis by Fuel Type and Project Classification

Table 12-19 shows the current status of all generation queue projects by fuel type and project classification from January 1, 1997, through December 31, 2017. For example, between January 1, 1997 and December 31, 2017, 156 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 3,685 projects in PJM generation queues. A total of 3,001 projects have been classified as new generation and 684 projects have been classified as upgrades. Wind, solar and natural gas projects have accounted for 2,914 projects, or 79.1 percent, of all 3,685 generation queue projects. A total of 20 new projects from either project classification entered the generation queue between October 1, 2017 and December 31, 2017.

### Table 12-19 Status of all generation queue projects: 1997 through 2017

| | | Number of Projects | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Project Status | Project Classification | Biomass | Coal | Diesel | Hydro | LFG | Natural Gas | Nuclear | Oil | Other | Solar | Storage | Wind | TOTAL |
| In Service | New Generation | 7 | 9 | 6 | 11 | 75 | 95 | 1 | 4 | 3 | 122 | 18 | 64 | 415 |
| | Upgrade | 6 | 45 | 3 | 17 | 17 | 156 | 42 | 14 | 4 | 16 | 3 | 15 | 338 |
| Under Construction | New Generation | 0 | 0 | 0 | 3 | 2 | 29 | 0 | 0 | 0 | 30 | 23 | 18 | 105 |
| | Upgrade | 1 | 4 | 1 | 0 | 0 | 21 | 0 | 0 | 0 | 2 | 2 | 1 | 32 |
| Suspended | New Generation | 1 | 0 | 0 | 0 | 0 | 17 | 0 | 0 | 0 | 35 | 6 | 21 | 80 |
| | Upgrade | 0 | 0 | 0 | 0 | 0 | 6 | 0 | 0 | 0 | 0 | 4 | 3 | 13 |
| Withdrawn | New Generation | 38 | 55 | 12 | 40 | 79 | 434 | 9 | 9 | 10 | 794 | 80 | 377 | 1,937 |
| | Upgrade | 2 | 13 | 1 | 2 | 10 | 80 | 9 | 13 | 2 | 13 | 8 | 16 | 169 |
| Active | New Generation | 0 | 0 | 0 | 1 | 4 | 74 | 1 | 0 | 0 | 316 | 17 | 51 | 464 |
| | Upgrade | 1 | 5 | 3 | 2 | 2 | 72 | 7 | 0 | 0 | 28 | 4 | 8 | 132 |
| Total Projects | New Generation | 46 | 64 | 18 | 55 | 160 | 649 | 11 | 13 | 13 | 1,297 | 144 | 531 | 3,001 |
| | Upgrade | 10 | 67 | 8 | 21 | 29 | 335 | 58 | 27 | 6 | 59 | 21 | 43 | 684 |

Table 12-20 shows the MW in Table 12-19 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, 81.0 percent of all hydro projects classified as upgrades are currently in service in PJM, 9.5 percent of hydro upgrades were withdrawn and 9.5 percent of hydro upgrades are active in the queue. From January 1, 1997, through December 31, 2017, nuclear 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 Status of all generation queue projects as a percent of total projects by classification: 1997 through 2017

| | | Percent of Total Projects by Classification | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Project Status | Project Classification | Biomass | Coal | Diesel | Hydro | LFG | Natural Gas | Nuclear | Oil | Other | Solar | Storage | Wind |
| In Service | New Generation | 15.2% | 14.1% | 33.3% | 20.0% | 46.9% | 14.6% | 9.1% | 30.8% | 23.1% | 9.4% | 12.5% | 12.1% |
| | Upgrade | 60.0% | 67.2% | 37.5% | 81.0% | 58.6% | 46.6% | 72.4% | 51.9% | 66.7% | 27.1% | 14.3% | 34.9% |
| Under Construction | New Generation | 0.0% | 0.0% | 0.0% | 5.5% | 1.3% | 4.5% | 0.0% | 0.0% | 0.0% | 2.3% | 16.0% | 3.4% |
| | Upgrade | 10.0% | 6.0% | 12.5% | 0.0% | 0.0% | 6.3% | 0.0% | 0.0% | 0.0% | 3.4% | 9.5% | 2.3% |
| Suspended | New Generation | 2.2% | 0.0% | 0.0% | 0.0% | 0.0% | 2.6% | 0.0% | 0.0% | 0.0% | 2.7% | 4.2% | 4.0% |
| | Upgrade | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 1.8% | 0.0% | 0.0% | 0.0% | 0.0% | 19.0% | 7.0% |
| Withdrawn | New Generation | 82.6% | 85.9% | 66.7% | 72.7% | 49.4% | 66.9% | 81.8% | 69.2% | 76.9% | 61.2% | 55.6% | 71.0% |
| | Upgrade | 20.0% | 19.4% | 12.5% | 9.5% | 34.5% | 23.9% | 15.5% | 48.1% | 33.3% | 22.0% | 38.1% | 37.2% |
| Active | New Generation | 0.0% | 0.0% | 0.0% | 1.8% | 2.5% | 11.4% | 9.1% | 0.0% | 0.0% | 24.4% | 11.8% | 9.6% |
| | Upgrade | 10.0% | 7.5% | 37.5% | 9.5% | 6.9% | 21.5% | 12.1% | 0.0% | 0.0% | 47.5% | 19.0% | 18.6% |

Table 12-21 shows the nameplate generating capacity of projects in the PJM generation queue by technology type and project classification. For example, the 377 new generation wind projects that have been withdrawn from the queue as of December 31, 2017, listed in Table 12-19 constitute 59,559.4 MW of nameplate capacity. The 514 new generation and upgrade natural gas projects that have been withdrawn in the same time period constitute 197,711.7 MW of nameplate capacity.

### Table 12-21 Status of all generation capacity (MW) in the PJM generation queue: 1997 through 2017

| | | Project MW | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Project Status | Project Classification | Biomass | Coal | Diesel | Hydro | LFG | Natural Gas | Nuclear | Oil | Other | Solar | Storage | Wind | TOTAL |
| In Service | New Generation | 225.7 | 1,378.0 | 69.5 | 578.1 | 407.0 | 26,919.1 | 9.0 | 607.0 | 50.0 | 1,141.4 | 161.4 | 7,009.6 | 38,555.7 |
| | Upgrade | 58.8 | 747.5 | 25.3 | 622.6 | 54.5 | 6,820.5 | 3,912.8 | 125.8 | 547.5 | 19.4 | 36.4 | 33.7 | 13,004.7 |
| Under Construction | New Generation | 0.0 | 0.0 | 0.0 | 23.1 | 11.2 | 13,707.2 | 0.0 | 0.0 | 0.0 | 510.8 | 40.6 | 3,011.3 | 17,304.2 |
| | Upgrade | 62.5 | 108.0 | 0.0 | 0.0 | 0.0 | 1,455.1 | 0.0 | 0.0 | 0.0 | 4.5 | 52.0 | 0.0 | 1,682.1 |
| Suspended | New Generation | 16.0 | 0.0 | 0.0 | 0.0 | 0.0 | 4,554.5 | 0.0 | 0.0 | 0.0 | 396.4 | 75.8 | 3,657.7 | 8,700.4 |
| | Upgrade | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 430.7 | 0.0 | 0.0 | 0.0 | 0.0 | 50.0 | 175.0 | 655.7 |
| Withdrawn | New Generation | 1,061.5 | 33,511.6 | 63.9 | 1,988.0 | 448.4 | 188,838.1 | 8,161.0 | 1,721.0 | 843.8 | 14,645.4 | 815.9 | 59,559.3 | 311,658.0 |
| | Upgrade | 37.1 | 865.0 | 4.0 | 56.0 | 48.7 | 8,873.6 | 916.0 | 589.0 | 24.0 | 169.1 | 142.1 | 384.6 | 12,109.2 |
| Active | New Generation | 0.0 | 0.0 | 0.0 | 15.0 | 29.4 | 34,269.7 | 28.0 | 0.0 | 0.0 | 17,770.8 | 276.9 | 11,177.4 | 63,567.1 |
| | Upgrade | 4.0 | 91.0 | 7.0 | 39.5 | 2.0 | 5,582.6 | 124.3 | 0.0 | 0.0 | 1,397.3 | 28.8 | 266.5 | 7,542.9 |
| Total Projects | New Generation | 1,303.2 | 34,889.6 | 133.4 | 2,604.2 | 896.0 | 268,288.6 | 8,198.0 | 2,328.0 | 893.8 | 34,464.8 | 1,370.5 | 84,415.4 | 439,785.5 |
| | Upgrade | 162.4 | 1,811.5 | 36.3 | 718.1 | 105.2 | 23,162.5 | 4,953.1 | 714.8 | 571.5 | 1,590.3 | 309.3 | 859.8 | 34,994.6 |

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 2017 was primarily a result of new projects in AEP.

### Figure 12-3 Queue project MW by fuel type and queue entry year: 1997 through 2017

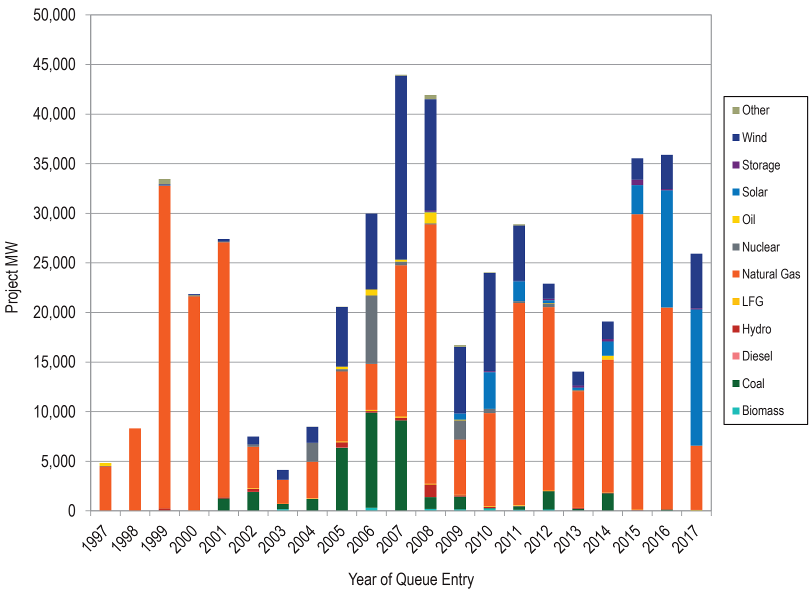



Table 12-22 shows the MW in Table 12-21 by share by classification as new generation or upgrade. Within a fuel type the shares of upgrades add to 100 percent and the shares of new generation add to 100 percent. For example, 70.6 percent of wind projects classified as new generation have been withdrawn from the queue between January 1, 1997, and December 31, 2017.

## Table 12-22 Status of all generation queue projects as percent of total MW in project classification: 1997 through 2017

| | | Percent of Total Project MW by Classification | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Project Status | Project Classification | Biomass | Coal | Diesel | Hydro | LFG | Natural Gas | Nuclear | Oil | Other | Solar | Storage | Wind |
| In Service | New Generation | 17.3% | 3.9% | 52.1% | 22.2% | 45.4% | 10.0% | 0.1% | 26.1% | 5.6% | 3.3% | 11.8% | 8.3% |
| | Upgrade | 36.2% | 41.3% | 69.7% | 86.7% | 51.8% | 29.4% | 79.0% | 17.6% | 95.8% | 1.2% | 11.8% | 3.9% |
| Under Construction | New Generation | 0.0% | 0.0% | 0.0% | 0.9% | 1.2% | 5.1% | 0.0% | 0.0% | 0.0% | 1.5% | 3.0% | 3.6% |
| | Upgrade | 38.5% | 6.0% | 0.0% | 0.0% | 0.0% | 6.3% | 0.0% | 0.0% | 0.0% | 0.3% | 16.8% | 0.0% |
| Suspended | New Generation | 1.2% | 0.0% | 0.0% | 0.0% | 0.0% | 1.7% | 0.0% | 0.0% | 0.0% | 1.2% | 5.5% | 4.3% |
| | Upgrade | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 1.9% | 0.0% | 0.0% | 0.0% | 0.0% | 16.2% | 20.4% |
| Withdrawn | New Generation | 81.5% | 96.1% | 47.9% | 76.3% | 50.0% | 70.4% | 99.5% | 73.9% | 94.4% | 42.5% | 59.5% | 70.6% |
| | Upgrade | 22.8% | 47.8% | 11.0% | 7.8% | 46.3% | 38.3% | 18.5% | 82.4% | 4.2% | 10.6% | 45.9% | 44.7% |
| Active | New Generation | 0.0% | 0.0% | 0.0% | 0.6% | 3.3% | 12.8% | 0.3% | 0.0% | 0.0% | 51.6% | 20.2% | 13.2% |
| | Upgrade | 2.5% | 5.0% | 19.3% | 5.5% | 1.9% | 24.1% | 2.5% | 0.0% | 0.0% | 87.9% | 9.3% | 31.0% |

## Natural Gas Project Analysis

Table 12-23 shows the status of all natural gas projects by number of projects that entered PJM generation queues from January 1, 1997 through December 31, 2017, by zone. Of the 134 natural gas projects classified either as new generation or upgrade currently active in the PJM generation queue, 50 projects, 37.3 percent, are located within AEP, ComEd and APS.

## Table 12-23 Status of all natural gas generation queue projects: 1997 through 2017

| | | Number of Projects | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Project Status | Project Classification | AECO | AEP | APS | 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 | 0 | 2 | 6 | 2 | 0 | 1 | 5 | 8 | 0 | 0 | 8 | 4 | 6 | 8 | 7 | 9 | 12 | 0 | 87 |
| | Upgrade | 7 | 15 | 0 | 1 | 1 | 12 | 6 | 0 | 31 | 15 | 0 | 0 | 5 | 2 | 9 | 5 | 5 | 6 | 27 | 0 | 147 |
| Under Construction | New Generation | 3 | 1 | 0 | 1 | 1 | 0 | 0 | 1 | 3 | 0 | 1 | 0 | 1 | 1 | 2 | 2 | 2 | 5 | 2 | 0 | 26 |
| | Upgrade | 0 | 1 | 0 | 1 | 0 | 2 | 0 | 0 | 2 | 0 | 0 | 0 | 1 | 0 | 5 | 0 | 1 | 4 | 3 | 0 | 20 |
| Suspended | New Generation | 1 | 2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 0 | 0 | 7 | 1 | 0 | 0 | 0 | 12 |
| | Upgrade | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 0 | 0 | 1 | 2 | 0 | 0 | 0 | 4 |
| Withdrawn | New Generation | 26 | 18 | 0 | 13 | 8 | 10 | 0 | 1 | 17 | 17 | 2 | 3 | 25 | 25 | 42 | 50 | 33 | 40 | 63 | 2 | 395 |
| | Upgrade | 6 | 7 | 0 | 4 | 0 | 2 | 0 | 1 | 7 | 4 | 0 | 0 | 5 | 8 | 3 | 4 | 3 | 5 | 16 | 0 | 75 |
| Active | New Generation | 5 | 11 | 0 | 4 | 0 | 11 | 1 | 0 | 3 | 2 | 0 | 1 | 1 | 0 | 1 | 5 | 0 | 4 | 19 | 0 | 68 |
| | Upgrade | 4 | 11 | 0 | 5 | 0 | 17 | 0 | 0 | 11 | 1 | 0 | 0 | 3 | 2 | 1 | 5 | 1 | 4 | 1 | 0 | 66 |
| Total Projects | New Generation | 42 | 34 | 0 | 20 | 15 | 23 | 1 | 3 | 28 | 27 | 3 | 4 | 36 | 30 | 51 | 72 | 43 | 58 | 96 | 2 | 588 |
| | Upgrade | 17 | 34 | 0 | 11 | 1 | 33 | 6 | 1 | 51 | 20 | 0 | 0 | 15 | 12 | 18 | 15 | 12 | 19 | 47 | 0 | 312 |

Table 12-24 shows the status of all gas projects by MW that entered PJM generation queues from January 1, 1997 through December 31, 2017, by zone. Of the 36,126.7 MW of natural gas projects classified either as new generation or upgrade currently active in the PJM generation queue, 17,085.2 MW, 47.3 percent, are located within AEP, ComEd and APS.

### Table 12-24 Status of all natural gas generation capacity (MW) in the PJM generation queue: 1997 through 2017

| Project Status | Project Classification | Project MW | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | AECO | AEP | APS | ATSI | BGE | ComEd | DAY | DEOK | Dominion | DPL | DLCO |
| In Service | New Generation | 1,016.2 | 1,322.0 | 0.0 | 815.5 | 390.0 | 629.0 | 0.0 | 20.0 | 4,011.0 | 1,587.2 | 0.0 |
| | Upgrade | 265.7 | 414.0 | 0.0 | 40.0 | 2.5 | 864.0 | 60.0 | 0.0 | 1,476.7 | 198.0 | 0.0 |
| Under Construction | New Generation | 453.5 | 675.0 | 0.0 | 800.0 | 1.3 | 0.0 | 0.0 | 513.0 | 2,855.1 | 0.0 | 205.0 |
| | Upgrade | 0.0 | 6.0 | 0.0 | 161.0 | 0.0 | 32.6 | 0.0 | 0.0 | 195.0 | 0.0 | 0.0 |
| Suspended | New Generation | 235.0 | 1,579.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | Upgrade | 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 | 6,923.8 | 9,632.0 | 0.0 | 5,420.7 | 3,122.1 | 4,533.0 | 0.0 | 134.5 | 10,475.0 | 4,842.4 | 665.0 |
| | Upgrade | 122.8 | 711.0 | 0.0 | 111.0 | 0.0 | 75.0 | 0.0 | 36.0 | 305.3 | 668.0 | 0.0 |
| Active | New Generation | 1,176.4 | 7,203.0 | 0.0 | 4,047.0 | 0.0 | 6,779.2 | 1,150.0 | 0.0 | 3,544.5 | 1,051.0 | 0.0 |
| | Upgrade | 273.6 | 441.0 | 0.0 | 253.0 | 0.0 | 2,662.0 | 0.0 | 0.0 | 410.1 | 60.0 | 0.0 |
| Total Projects | New Generation | 9,805.0 | 20,411.0 | 0.0 | 11,083.2 | 3,513.4 | 11,941.2 | 1,150.0 | 667.5 | 20,885.6 | 7,480.6 | 870.0 |
| | Upgrade | 662.1 | 1,572.0 | 0.0 | 565.0 | 2.5 | 3,633.6 | 60.0 | 36.0 | 2,387.1 | 926.0 | 0.0 |

| Project Status | Project Classification | Project MW | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | EKPC | JCPL | Met-Ed | PECO | PENELEC | Pepco | PPL | PSEG | RECO | TOTAL |
| In Service | New Generation | 0.0 | 2,070.3 | 2,117.0 | 2,464.0 | 1,267.1 | 842.0 | 2,826.9 | 2,804.9 | 0.0 | 24,183.1 |
| | Upgrade | 0.0 | 224.0 | 44.1 | 780.5 | 87.0 | 121.1 | 327.3 | 1,057.9 | 0.0 | 5,962.8 |
| Under Construction | New Generation | 0.0 | 0.4 | 450.0 | 760.5 | 1,640.0 | 755.0 | 3,074.0 | 570.0 | 0.0 | 12,752.8 |
| | Upgrade | 0.0 | 0.0 | 0.0 | 241.0 | 0.0 | 64.5 | 524.0 | 231.0 | 0.0 | 1,455.1 |
| Suspended | New Generation | 0.0 | 440.0 | 0.0 | 0.0 | 146.8 | 894.0 | 0.0 | 0.0 | 0.0 | 3,294.8 |
| | Upgrade | 0.0 | 200.0 | 0.0 | 0.0 | 1.6 | 144.1 | 0.0 | 0.0 | 0.0 | 345.7 |
| Withdrawn | New Generation | 991.8 | 11,461.2 | 13,001.0 | 23,120.0 | 17,030.9 | 20,414.2 | 16,795.7 | 23,524.0 | 6.9 | 172,094.1 |
| | Upgrade | 0.0 | 253.0 | 1,742.0 | 240.0 | 1,040.6 | 85.0 | 500.0 | 2,404.9 | 0.0 | 8,294.6 |
| Active | New Generation | 75.0 | 1,092.2 | 0.0 | 220.0 | 685.9 | 0.0 | 1,554.8 | 2,394.8 | 0.0 | 30,973.8 |
| | Upgrade | 0.0 | 109.9 | 65.0 | 88.0 | 328.2 | 75.0 | 336.0 | 51.1 | 0.0 | 5,152.9 |
| Total Projects | New Generation | 1,066.8 | 15,064.1 | 15,568.0 | 26,564.5 | 20,770.7 | 22,905.2 | 24,251.4 | 29,293.6 | 6.9 | 243,298.6 |
| | Upgrade | 0.0 | 786.9 | 1,851.1 | 1,349.5 | 1,457.4 | 489.7 | 1,687.3 | 3,744.9 | 0.0 | 21,211.1 |

## Wind Project Analysis

Table 12-25 shows the status of all wind generation projects that entered PJM generation queues from January 1, 1997 through December 31, 2017, by zone. Of the 65 wind projects to achieve in service status, 56 projects, 86.2 percent are located within ComEd, AEP, APS and PENELEC. Of the 53 wind projects currently active in the PJM generation queue, 43 projects, 81.1 percent are located within ComEd, AEP, APS and PENELEC.

### Table 12-25 Status of all wind generation queue projects: 1997 through 2017

| Project Status | Project Classification | Number of Projects | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | AECO | AEP | APS | ATSI | BGE | ComEd | DAY | DEOK | Dominion | DPL | DLCO | EKPC | JCPL | Met-Ed | PECO | PENELEC | Pepco | PPL | PSEG | RECO | TOTAL |
| In Service | New Generation | 1 | 11 | 0 | 0 | 0 | 17 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 20 | 0 | 4 | 0 | 0 | 53 |
| | Upgrade | 0 | 0 | 0 | 0 | 0 | 2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 6 | 0 | 4 | 0 | 0 | 12 |
| Under Construction | New Generation | 0 | 3 | 0 | 0 | 0 | 4 | 0 | 0 | 4 | 1 | 0 | 0 | 0 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 13 |
| | 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 | 10 | 0 | 1 | 0 | 1 | 2 | 0 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 2 | 0 | 1 | 0 | 0 | 19 |
| | Upgrade | 1 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 2 |
| Withdrawn | New Generation | 15 | 83 | 0 | 6 | 0 | 95 | 13 | 0 | 16 | 7 | 0 | 1 | 0 | 0 | 0 | 61 | 0 | 40 | 1 | 0 | 338 |
| | Upgrade | 1 | 0 | 0 | 0 | 0 | 1 | 0 | 0 | 2 | 0 | 0 | 0 | 0 | 0 | 0 | 4 | 0 | 2 | 0 | 0 | 10 |
| Active | New Generation | 0 | 22 | 0 | 3 | 0 | 14 | 0 | 0 | 2 | 2 | 0 | 0 | 0 | 0 | 0 | 1 | 0 | 3 | 0 | 0 | 47 |
| | Upgrade | 0 | 0 | 0 | 0 | 0 | 4 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 2 | 0 | 0 | 0 | 0 | 6 |
| Total Projects | New Generation | 17 | 129 | 0 | 10 | 0 | 131 | 15 | 0 | 23 | 10 | 0 | 1 | 0 | 0 | 0 | 85 | 0 | 48 | 1 | 0 | 470 |
| | Upgrade | 2 | 1 | 0 | 0 | 0 | 7 | 0 | 0 | 2 | 0 | 0 | 0 | 0 | 0 | 0 | 12 | 0 | 6 | 0 | 0 | 30 |

Table 12-26 shows the wind project capacity in MW of all wind generation projects that have entered the PJM generation queue from January 1, 1997 through December 31, 2017, by zone. Of the 6,039.3 MW of wind generation capacity to achieve in service status, 5,805.3 MW, or 96. percent of nameplate capacity is located within ComEd, AEP, APS and PENELEC. Of the 11,066.9 MW of wind generation capacity currently active in the PJM generation queue, 9,183.6 MW of generation capacity or 83.0 percent is located within ComEd, AEP, APS and PENELEC.

### Table 12-26 Status of all wind generation capacity (MW) in the PJM generation queue: 1997 through 2017

| | Project | Project MW | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Project Status | Classification | AECO | AEP | APS | ATSI | BGE | ComEd | DAY | DEOK | Dominion | DPL | DLCO |
| In Service | New Generation | 7.5 | 2,390.4 | 0.0 | 0.0 | 0.0 | 2,413.5 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | Upgrade | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Under Construction | New Generation | 0.0 | 499.9 | 0.0 | 0.0 | 0.0 | 978.5 | 0.0 | 0.0 | 740.3 | 150.0 | 0.0 |
| | Upgrade | 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 | 1,830.0 | 0.0 | 500.0 | 0.0 | 500.0 | 300.0 | 0.0 | 76.6 | 0.0 | 0.0 |
| | Upgrade | 5.0 | 100.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Withdrawn | New Generation | 3,626.4 | 15,596.4 | 0.0 | 645.6 | 0.0 | 22,315.8 | 1,828.0 | 0.0 | 2,361.5 | 2,255.0 | 0.0 |
| | Upgrade | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 4.0 | 0.0 | 0.0 | 82.0 | 0.0 | 0.0 |
| Active | New Generation | 0.0 | 5,853.7 | 0.0 | 816.1 | 0.0 | 2,945.5 | 0.0 | 0.0 | 226.6 | 499.6 | 0.0 |
| | Upgrade | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 175.7 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Total Projects | New Generation | 3,653.9 | 26,170.4 | 0.0 | 1,961.7 | 0.0 | 29,153.3 | 2,128.0 | 0.0 | 3,405.0 | 2,904.6 | 0.0 |
| | Upgrade | 5.0 | 100.0 | 0.0 | 0.0 | 0.0 | 179.7 | 0.0 | 0.0 | 82.0 | 0.0 | 0.0 |

| | Project | Project MW | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Project Status | Classification | EKPC | JCPL | Met-Ed | PECO | PENELEC | Pepco | PPL | PSEG | RECO | TOTAL |
| In Service | New Generation | 0.0 | 0.0 | 0.0 | 0.0 | 995.0 | 0.0 | 199.2 | 0.0 | 0.0 | 6,005.6 |
| | Upgrade | 0.0 | 0.0 | 0.0 | 0.0 | 6.4 | 0.0 | 27.3 | 0.0 | 0.0 | 33.7 |
| Under Construction | New Generation | 0.0 | 0.0 | 0.0 | 0.0 | 70.0 | 0.0 | 0.0 | 0.0 | 0.0 | 2,438.7 |
| | Upgrade | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Suspended | New Generation | 0.0 | 0.0 | 0.0 | 0.0 | 180.0 | 0.0 | 100.0 | 0.0 | 0.0 | 3,506.6 |
| | Upgrade | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 105.0 |
| Withdrawn | New Generation | 150.3 | 0.0 | 0.0 | 0.0 | 5,059.0 | 0.0 | 2,766.3 | 20.0 | 0.0 | 56,624.3 |
| | Upgrade | 0.0 | 0.0 | 0.0 | 0.0 | 192.6 | 0.0 | 6.0 | 0.0 | 0.0 | 284.6 |
| Active | New Generation | 0.0 | 0.0 | 0.0 | 0.0 | 138.0 | 0.0 | 341.1 | 0.0 | 0.0 | 10,820.4 |
| | Upgrade | 0.0 | 0.0 | 0.0 | 0.0 | 70.8 | 0.0 | 0.0 | 0.0 | 0.0 | 246.5 |
| Total Projects | New Generation | 150.3 | 0.0 | 0.0 | 0.0 | 6,442.0 | 0.0 | 3,406.6 | 20.0 | 0.0 | 79,395.6 |
| | Upgrade | 0.0 | 0.0 | 0.0 | 0.0 | 269.7 | 0.0 | 33.3 | 0.0 | 0.0 | 669.8 |

## Solar Project Analysis

Table 12-27 shows the status of all solar generation projects that have entered the PJM generation queue from January 1, 1997 through December 31, 2017, by zone. Of a total of 1,269 solar projects ever to enter the PJM generation queue, 515 projects, or 40.6 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 4.3 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, 40.4 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 332 active new generation solar projects, 141 projects, or 42.5 percent of all currently active new generation solar projects are located in Dominion. Out of 141 active new generation solar projects, 69, or 20.8 percent of all currently active new generation solar projects are located in AEP.

### Table 12-27 Status of all solar generation queue projects: 1997 through 2017

| | Project | Number of Projects | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Project Status | Classification | AECO | AEP | APS | ATSI | BGE | ComEd | DAY | DEOK | Dominion | DPL | DLCO | EKPC | JCPL | Met-Ed | PECO | PENELEC | Pepco | PPL | PSEG | RECO | TOTAL |
| In Service | New Generation | 7 | 4 | 0 | 0 | 1 | 1 | 1 | 0 | 15 | 9 | 0 | 0 | 39 | 0 | 1 | 0 | 0 | 2 | 38 | 0 | 118 |
| | 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 | 0 | 2 | 0 | 0 | 2 | 0 | 1 | 0 | 5 | 5 | 0 | 0 | 8 | 0 | 0 | 0 | 0 | 0 | 6 | 0 | 29 |
| | Upgrade | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 2 |
| Suspended | New Generation | 0 | 5 | 0 | 0 | 0 | 0 | 1 | 0 | 1 | 1 | 0 | 0 | 6 | 1 | 0 | 1 | 0 | 0 | 2 | 0 | 18 |
| | 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 | 155 | 52 | 0 | 7 | 10 | 9 | 8 | 10 | 97 | 101 | 0 | 3 | 163 | 12 | 6 | 10 | 9 | 27 | 62 | 0 | 741 |
| | Upgrade | 1 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 0 | 0 | 0 | 5 | 0 | 0 | 0 | 0 | 0 | 1 | 0 | 13 |
| Active | New Generation | 4 | 66 | 0 | 5 | 0 | 23 | 10 | 3 | 125 | 45 | 1 | 2 | 2 | 2 | 1 | 1 | 4 | 2 | 9 | 0 | 305 |
| | Upgrade | 0 | 3 | 0 | 0 | 0 | 1 | 0 | 2 | 16 | 1 | 1 | 0 | 1 | 1 | 0 | 0 | 0 | 1 | 0 | 0 | 27 |
| Total Projects | New Generation | 166 | 129 | 0 | 12 | 13 | 33 | 21 | 13 | 243 | 161 | 1 | 5 | 218 | 15 | 8 | 12 | 13 | 31 | 117 | 0 | 1211 |
| | Upgrade | 1 | 4 | 0 | 0 | 0 | 1 | 0 | 2 | 24 | 10 | 1 | 0 | 12 | 1 | 0 | 0 | 0 | 1 | 1 | 0 | 58 |

Table 12-28 shows the status of all solar generation project MW that have entered the PJM generation queue from January 1, 1997 through December 31, 2017, by zone. Of a total of 34,144.4 MW of solar nameplate capacity ever to enter the PJM generation queue, 4,260.6 MW, or 12.5 percent, have been located in JCPL, AECO and PSEG, all of which are zones in New Jersey. Solar projects in Dominion have accounted for 14,291.2 MW or 41.9 percent of all solar project nameplate capacity in the PJM queue from January 1, 1997 through December 31, 2017. Solar projects in DPL have accounted for 2,891.0 MW or 8.5 percent of all solar project nameplate capacity in the PJM queue from January 1, 1997 through December 31, 2017.

### Table 12-28 Current status of all solar generation capacity (MW) in the PJM generation queue: 1997 through 2017

| | Project | Project MW | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Project Status | Classification | AECO | AEP | APS | ATSI | BGE | ComEd | DAY | DEOK | Dominion | DPL | DLCO |
| In Service | New Generation | 57.3 | 14.7 | 0.0 | 0.0 | 1.1 | 9.0 | 2.5 | 0.0 | 409.2 | 118.4 | 0.0 |
| | Upgrade | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 3.1 | 0.0 | 0.0 |
| Under Construction | New Generation | 0.0 | 30.0 | 0.0 | 0.0 | 22.0 | 0.0 | 3.4 | 0.0 | 238.5 | 43.0 | 0.0 |
| | Upgrade | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 4.5 | 0.0 | 0.0 |
| Suspended | New Generation | 0.0 | 59.9 | 0.0 | 0.0 | 0.0 | 0.0 | 20.0 | 0.0 | 5.0 | 6.0 | 0.0 |
| | Upgrade | 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 | 1,664.3 | 2,592.9 | 0.0 | 116.1 | 31.3 | 176.8 | 250.5 | 159.4 | 4,236.4 | 1,385.9 | 0.0 |
| | Upgrade | 10.0 | 6.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 128.0 | 0.0 | 0.0 |
| Active | New Generation | 24.2 | 4,663.6 | 0.0 | 646.0 | 0.0 | 1,025.5 | 739.5 | 215.0 | 8,296.0 | 1,317.7 | 11.7 |
| | Upgrade | 0.0 | 210.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 85.0 | 970.5 | 20.0 | 8.3 |
| Total Projects | New Generation | 1,745.8 | 7,361.2 | 0.0 | 762.1 | 54.4 | 1,211.3 | 1,015.9 | 374.4 | 13,185.1 | 2,871.0 | 11.7 |
| | Upgrade | 10.0 | 216.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 85.0 | 1,106.1 | 20.0 | 8.3 |

| | Project | Project MW | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Project Status | Classification | EKPC | JCPL | Met-Ed | PECO | PENELEC | Pepco | PPL | PSEG | RECO | TOTAL |
| In Service | New Generation | 0.0 | 266.9 | 0.0 | 3.3 | 0.0 | 0.0 | 15.0 | 191.0 | 0.0 | 1,088.4 |
| | Upgrade | 0.0 | 16.3 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 19.4 |
| Under Construction | New Generation | 0.0 | 127.4 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 36.6 | 0.0 | 500.8 |
| | Upgrade | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 4.5 |
| Suspended | New Generation | 0.0 | 59.1 | 3.0 | 0.0 | 13.5 | 0.0 | 0.0 | 8.4 | 0.0 | 174.9 |
| | Upgrade | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Withdrawn | New Generation | 189.9 | 1,311.3 | 467.0 | 51.4 | 34.3 | 122.1 | 283.7 | 427.7 | 0.0 | 13,501.0 |
| | Upgrade | 0.0 | 23.8 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 1.3 | 0.0 | 169.1 |
| Active | New Generation | 100.0 | 1.8 | 135.0 | 18.0 | 50.0 | 65.3 | 30.0 | 24.8 | 0.0 | 17,364.0 |
| | Upgrade | 0.0 | 8.5 | 20.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 1,322.3 |
| Total Projects | New Generation | 289.9 | 1,766.4 | 605.0 | 72.7 | 97.8 | 187.3 | 328.7 | 688.6 | 0.0 | 32,629.1 |
| | Upgrade | 0.0 | 48.6 | 20.0 | 0.0 | 0.0 | 0.0 | 0.0 | 1.3 | 0.0 | 1,515.3 |

## Relationship Between Project Developer and Transmission Owner

Table 12-29 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 December 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 12-29 Relationship between project developer and Transmission Owner for all interconnection queue projects MW by fuel type: 1997 through 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 | 51 | 0.0 | 3,965.0 | 0.0 | 34.0 | 3.0 | 3,027.0 | 214.0 | 0.0 | 301.7 | 0.0 | 7,544.7 |
| | | Unrelated | 413 | 501.1 | 10,292.0 | 7.5 | 448.4 | 83.8 | 24,300.0 | 0.0 | 66.0 | 7,658.8 | 26,967.0 | 70,324.5 |
| AES | DAY | Related | 17 | 0.0 | 1,347.5 | 0.0 | 0.0 | 0.0 | 51.0 | 0.0 | 0.0 | 74.0 | 0.0 | 1,472.5 |
| | | Unrelated | 39 | 1.9 | 0.0 | 0.0 | 0.0 | 10.0 | 9.0 | 0.0 | 0.0 | 871.9 | 2,128.0 | 3,020.8 |
| 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 | 23 | 0.0 | 2,810.0 | 0.0 | 106.0 | 19.2 | 870.0 | 1,879.0 | 0.0 | 63.3 | 0.0 | 5,747.5 |
| Dominion | Dominion | Related | 86 | 64.0 | 301.0 | 0.0 | 340.0 | 0.0 | 13,215.0 | 1,944.0 | 0.0 | 496.1 | 142.0 | 16,502.1 |
| | | Unrelated | 362 | 343.7 | 20.0 | 10.0 | 35.1 | 184.0 | 12,105.1 | 0.0 | 156.3 | 17,168.7 | 3,067.0 | 33,089.9 |
| 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 | 26 | 0.0 | 120.0 | 0.0 | 112.0 | 4.8 | 154.5 | 0.0 | 0.0 | 509.3 | 0.0 | 900.6 |
| 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 | 10 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 2,216.8 | 0.0 | 0.0 | 240.0 | 150.3 | 2,607.1 |
| 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 | 273 | 29.8 | 15.0 | 13.0 | 0.0 | 31.0 | 9,791.8 | 0.0 | 0.0 | 1,786.3 | 3,808.9 | 15,475.8 |
| | 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 | 277 | 90.0 | 1,926.0 | 42.0 | 22.7 | 112.9 | 15,669.4 | 0.0 | 20.0 | 1,238.3 | 28,784.5 | 47,905.8 |
| | 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 | 267 | 84.0 | 653.0 | 0.0 | 0.0 | 70.0 | 7,373.6 | 0.0 | 30.0 | 2,996.9 | 2,809.6 | 14,017.1 |
| | 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 | 79 | 0.0 | 0.0 | 12.1 | 220.0 | 18.7 | 21,578.8 | 0.0 | 0.0 | 73.4 | 0.0 | 21,903.0 |
| | 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 | 70 | 0.0 | 0.0 | 0.0 | 0.0 | 12.5 | 22,698.9 | 0.0 | 0.0 | 200.3 | 0.0 | 22,911.7 |
| First Energy | APS | 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 | 320 | 177.2 | 4,057.0 | 53.8 | 371.3 | 125.8 | 22,588.4 | 0.0 | 96.0 | 2,095.7 | 5,522.7 | 35,087.8 |
| | 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 | 57 | 0.0 | 0.0 | 0.0 | 0.0 | 35.3 | 9,154.7 | 0.0 | 135.0 | 564.5 | 1,961.7 | 11,851.2 |
| | JCPL | Related | 3 | 0.0 | 0.0 | 0.0 | 20.0 | 0.0 | 100.0 | 0.0 | 0.0 | 8.5 | 0.0 | 128.5 |
| | | Unrelated | 324 | 30.0 | 0.0 | 0.0 | 1.6 | 24.4 | 15,796.0 | 0.0 | 0.0 | 1,828.9 | 90.6 | 17,771.4 |
| | 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 | 90 | 90.4 | 0.0 | 8.0 | 0.0 | 57.9 | 16,839.6 | 93.0 | 11.0 | 625.0 | 70.0 | 17,794.9 |
| | 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 | 223 | 0.0 | 561.0 | 8.0 | 53.3 | 50.9 | 20,796.8 | 0.0 | 621.0 | 177.8 | 6,454.1 | 28,722.8 |
| 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 | 192 | 28.5 | 6,868.6 | 10.4 | 2.6 | 99.5 | 21,726.5 | 0.0 | 152.5 | 329.8 | 3,380.8 | 32,599.2 |
| PSEG | PSEG | Related | 104 | 0.0 | 24.0 | 0.0 | 0.0 | 11.7 | 12,802.1 | 381.0 | 0.0 | 142.2 | 0.0 | 13,361.0 |
| | | Unrelated | 184 | 0.0 | 0.0 | 0.0 | 1,000.0 | 24.4 | 18,676.0 | 0.0 | 45.5 | 567.5 | 20.0 | 20,333.3 |
| 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 | 7.1 | 0.0 | 0.0 | 0.0 | 0.0 | 7.1 |
| Total | | Related | 406 | 64.0 | 9,398.5 | 0.0 | 723.0 | 22.4 | 49,070.1 | 11,179.1 | 0.0 | 1,083.5 | 538.0 | 72,078.5 |
| | | Unrelated | 3,290 | 1,376.6 | 27,322.6 | 193.8 | 2,513.4 | 974.6 | 246,505.8 | 1,972.0 | 1,465.3 | 39,030.6 | 85,215.1 | 406,569.7 |

Table 12-30 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 December 31, 2017, by zone and project status. Of the 1,319.1 solar project MW that have achieved in service or under construction status during this time period, 186.9 MW, or 14.2 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 12-30 Relationship between project developer and transmission owner for all solar projects MW in PJM interconnection queue: 1997 through 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 | 1,046.5 | 5,505.9 | 6,624.1 |
| AES | DAY | Related | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | | Unrelated | 2.5 | 23.4 | 0.0 | 151.5 | 468.5 | 645.9 |
| DLCO | DLCO | Related | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | | Unrelated | 0.0 | 0.0 | 0.0 | 0.0 | 40.0 | 40.0 |
| Dominion | Dominion | Related | 20.0 | 0.0 | 0.0 | 81.9 | 224.4 | 326.3 |
| | | Unrelated | 140.1 | 122.9 | 205.0 | 2,083.5 | 12,996.0 | 15,547.5 |
| Duke | DEOK | Related | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | | Unrelated | 0.0 | 0.0 | 0.0 | 159.4 | 290.0 | 449.4 |
| EKPC | EKPC | Related | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | | Unrelated | 0.0 | 0.0 | 0.0 | 80.0 | 160.0 | 240.0 |
| 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 | 337.0 | 421.8 |
| | DPL | Related | 7.4 | 0.0 | 0.0 | 24.0 | 0.0 | 31.4 |
| | | Unrelated | 21.0 | 159.5 | 0.0 | 1,126.5 | 1,679.9 | 2,986.9 |
| | 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 | 118.1 | 60.0 | 178.1 |
| First Energy | APS | Related | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | | Unrelated | 34.0 | 32.5 | 38.9 | 806.0 | 839.3 | 1,750.7 |
| | ATSI | Related | 0.0 | 0.0 | 0.0 | 0.6 | 0.0 | 0.6 |
| | | Unrelated | 0.0 | 0.0 | 0.0 | 59.5 | 485.0 | 544.5 |
| | JCPL | Related | 0.0 | 0.0 | 0.0 | 0.0 | 8.5 | 8.5 |
| | | Unrelated | 204.1 | 175.5 | 92.9 | 1,266.5 | 89.7 | 1,828.7 |
| | Met-Ed | Related | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | | Unrelated | 0.0 | 0.0 | 3.0 | 367.0 | 255.0 | 625.0 |
| | 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 | 15.2 | 1.2 | 132.2 |
| | | Unrelated | 53.8 | 46.2 | 9.7 | 387.8 | 60.0 | 557.5 |
| 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 | 121.7 | 294.1 | 602.7 |
| | | Unrelated | 513.4 | 618.8 | 414.7 | 9,738.1 | 23,476.6 | 34,761.6 |

Table 12-31 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 December 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 12-31 Relationship between project developer and transmission owner for all natural gas project MW in PJM interconnection queue: 1997 through 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 | 9,008.0 | 10,270.0 | 24,300.0 |
| 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 | 3,949.3 | 5,585.0 | 12,105.1 |
| 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 | 6,325.4 | 1,118.0 | 9,791.8 |
| | 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 | 4,023.0 | 10,055.3 | 15,669.4 |
| | 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 | 1,168.0 | 7,373.6 |
| | 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 | APS | Related | 701.0 | 0.0 | 0.0 | 4,089.0 | 0.0 | 4,790.0 |
| | | Unrelated | 1,796.7 | 962.5 | 70.1 | 13,533.6 | 6,225.5 | 22,588.4 |
| | ATSI | Related | 0.0 | 0.0 | 0.0 | 1,678.0 | 0.0 | 1,678.0 |
| | | Unrelated | 40.0 | 961.0 | 0.0 | 3,833.8 | 4,249.9 | 9,084.7 |
| | JCPL | Related | 0.0 | 0.0 | 0.0 | 100.0 | 0.0 | 100.0 |
| | | Unrelated | 2,294.3 | 440.0 | 200.0 | 10,879.2 | 1,982.5 | 15,796.0 |
| | 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 | 16,426.7 | 2,553.9 | 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 | 12,575.7 | 2,805.9 | 21,726.5 |
| 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 | 14,906.0 | 2,554.6 | 18,676.0 |
| Consolidated Edison, Inc. | RECO | Related | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | | Unrelated | 0.0 | 0.0 | 0.0 | 6.9 | 0.2 | 7.1 |
| Total | | Related | 8,634.0 | 1,748.0 | 0.0 | 35,200.1 | 3,437.0 | 49,019.1 |
| | | Unrelated | 19,947.7 | 15,868.3 | 1,751.8 | 156,912.0 | 51,369.1 | 245,848.8 |

Table 12-32 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 December 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 12-32 Relationship between project developer and transmission owner for all wind project MW in PJM interconnection queue: 1997 through 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 | 6,831.4 | 25,883.8 |
| 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 | 1,880.9 | 212.2 | 3,067.0 |
| 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 | 747.8 | 5,362.7 |
| | 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 | 610.5 | 3,380.8 |
| 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 | 56,063.7 | 12,461.9 | 82,066.8 |

# Regional Transmission Expansion Plan (RTEP)

## Authorized TEAC Transmission Upgrades

The Transmission Expansion Advisory Committee (TEAC) regularly reviews internal and external proposals to improve transmission reliability throughout PJM. These proposals are periodically presented to the PJM Board of Managers for authorization.

- On July 26, 2017, the PJM Board of Managers authorized more than $417 million in electric transmission projects for reliability. The approved projects include a large substation that serves critical infrastructure customers in Newark, N.J., a $275 million PSEG Newark Switch substation project to replace aging equipment, and additional equipment upgrades and improvements in areas served by: American Electric Power; Dominion; Atlantic City Electric Company; PECO Energy Company; Pennsylvania Electric Company; American Transmission Systems, Inc.; East Kentucky Power Cooperative, Inc. and Dayton Power & Light. Most of the individual projects cost less than $5 million.[29]
- On October 18, 2017, the PJM Board of Managers authorized $1 billion in various electric transmission projects including reliability and market efficiency improvements. The approved projects include approximately $300 million in reliability reinforcements to several 69 kV transmission lines in New Jersey. The PJM Board approved upgrades in areas served by American Electric Power; American Transmission Systems, Inc.; Commonwealth Edison; Dominion; East Kentucky Power Cooperative, Inc.; Pennsylvania Electric Company; and Public Service Electric & Gas. Many of the individual projects cost less than $5 million.[30]
- On December 6, 2017, the PJM Board of Managers authorized $318 million in electric transmission projects for reliability. The approved projects include a new $20 million 138 kV transmission line substation project in the ComEd Zone, a $16.5 million rebuild of a 161 kV line in the AEP Zone, and additional projects designed to alleviate reliability issues in northern New Jersey. Many of the individual projects cost less than $5 million.[31]

## 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, and the conversion of the Marion-Bayonne and Bayway-Linden lines from 138 kV to 345 kV.[32]

## Market Efficiency Process[33]

PJM's Regional Transmission Expansion Plan (RTEP) process includes a market efficiency analysis. The purpose of the market efficiency analysis is: to determine which reliability based enhancements have economic benefit if accelerated; to identify new transmission enhancements that result in economic benefits; and to identify economic benefits associated with modification to existing RTEP reliability based enhancements that when modified would relieve one or more economic constraints. PJM identifies the economic benefit of proposed transmission projects by conducting production cost analyses.[34]

PJM presents all of the RTEP market efficiency enhancements to the TEAC Committee for review and comment. Subsequent to TEAC review, PJM addresses the TEAC review and presents the final RTEP market efficiency plan to the PJM Board, along with the advice, comments, and recommendations of the TEAC Committee, for Board approval.

To be included in the RTEP recommended to the PJM Board of Managers for approval, the relative benefits and costs of the economic based enhancement or

29 See PJM. "*PJM Board approves $417 million investment in transmission improvements*," <http://www.pjm.com/-/media/about-pjm/newsroom/2017-releases/20170726-pjm-board-approves-417-million-investment-in-transmission-improvements.ashx> (July 26, 2017).

30 See PJM. "PJM Board authorizes $1 billion in transmission upgrades," <http://www.pjm.com/-/media/about-pjm/newsroom/2017-releases/20171018-pjm-board-authorizes-1-billion-in-transmission-upgrades.ashx> (October 18, 2017).

31 See PJM. "PJM Board authorizes $317 million in transmission upgrades," <http://www.pjm.com/-/media/about-pjm/newsroom/2017-releases/20171206-pjm-board-approves-rtep-updates-news-release.ashx> (December 6, 2017).

32 See PJM. "*2017 RTEP Process Scope and Input Assumptions White Paper*," P 25. <http://www.pjm.com/-/media/library/reports-notices/2017-rtep/20170731-rtep-input-assumptions-and-scope-whitepaper.ashx?la=en>.

33 The material in this section is based in part on the PJM Manual 14B: PJM Region Transmission Planning Process. See PJM. "*PJM Manual 14B: PJM Region Transmission Planning Process*," Rev. 40 (Oct. 26, 2017) <http://www.pjm.com/-/media/documents/manuals/m14b.ashx?la=en>.

34 See PJM. "*PJM Regional Transmission Expansion Plan: 2016*," (February 28, 2017). <http://www.pjm.com/-/media/library/reports-notices/2016-rtep/2016-rtep-books-1-3.ashx?la=en>.

expansion must meet a benefit/cost ratio threshold of at least 1.25:1. The benefit/cost ratio is the ratio of the present value of the total annual benefit for 15 years by the present value of the total annual cost for each of the first 15 years of the life of the enhancement or expansion.

The market efficiency process is comprised of a 12 month cycle and a 24 month cycle, both of which begin and end on the calendar year. The 12 month cycle is used for analysis of modifications and accelerations to approved RTEP projects only. The 24 month cycle is used for analysis of new economic transmission upgrades for years five through 15. This long-term proposal window takes place concurrent with the long-term proposal window for reliability projects. [35]

Through December 31, 2017, PJM has completed two market efficiency cycles. In the first cycle, PJM received 92 proposals for 11 identified issues. In the second market efficiency cycle, PJM received 96 proposals for four identified issues.

## Supplemental Projects

Supplemental projects are "transmission expansions or enhancements that are not required for compliance with PJM criteria and are not state public policy projects according to the PJM Operating Agreement. These projects are used as inputs to RTEP models, but are not required for reliability, economic efficiency or operational performance criteria, as determined by PJM."[36] Supplemental projects are funded wholly by the Transmission Owner and no PJM approval is needed. Supplemental projects addressed two of the four issues identified in the most recent market efficiency cycle. Because supplemental projects are considered by transmission owners to be outside the scope of FERC Order No. 1000, supplemental projects may be considered noncompetitive.

The MMU is concerned with the impact of supplemental projects on the market efficiency process. It is not clear how a supplemental project can be used to resolve market efficiency projects that have been identified based on a cost/benefit analysis and why such a project should not be subject to competition. The MMU recommends that PJM limit the scope of supplemental projects that can obtain exceptions to the Order No. 1000 process to ensure maximum competition.

## PJM MISO Interregional Targeted Market Efficiency Process (TMEP)

PJM and MISO developed a process to facilitate the construction of interregional projects in response to the Commissions concerns about interregional coordination along the PJM-MISO seam, called the Targeted Market Efficiency Process (TMEP).[37]

The allocation of costs to each RTO for TMEPs will be in proportion to the benefits received.[38]

On November 2, 2017, PJM submitted a compliance filing including additional revisions the MISO-PJM JOA to include stakeholder feedback in the TMEP project selection process.[39] [40]

The first TMEP analysis included the investigation of congestion on 50 market to market flowgates. The study resulted in the evaluation of 13 potential upgrades, resulting in the recommendation of five TMEP projects. The five projects address $59 million in historical congestion, with a TMEP benefit of $99.6 million. The projects have a total cost of $20 million, with a 5.0 average benefit/cost ratio. PJM and MISO presented the five recommended projects to their boards in December, 2017, and both boards approved all five projects.[41]

## Artificial Island

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

35 See PJM. "*PJM Market Efficiency Modeling Practices*," (February 2, 2017). <http://www.pjm.com/-/media/planning/rtep-dev/market-efficiency/pjm-market-efficiency-modeling-practices.ashx?la=en>.

36 See PJM. "*Transmission Construction Status*," (January 23, 2018) <http://www.pjm.com/planning/rtep-upgrades-status/construct-status.aspx>.

37 See *PJM Interconnection, L.L.C*, Docket No. ER17-718-000 (December 30, 2016).

38 See *PJM Interconnection, L.L.C*, Docket No. ER17-729-000 (December 30, 2016).

39 See *PJM Interconnection, L.L.C*, Docket No. ER17-718-000, ER17-721-000 and ER17-729-000 (Not Consolidated) (November 2, 2017).

40 161 FERC ¶ 61,005 (2017). *Order accepting filings subject to condition.*

41 See PJM. "*MISO PJM IPSAC*," (January 12, 2018) <http://www.pjm.com/-/media/committees-groups/stakeholder-meetings/ipsac/20180112/20180112-ipsac-presentation.ashx>.

to LS Power, a merchant developer, PSEG, and PHI with a total cost estimate between $263M and $283M.[42] [43] 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, $140 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 FERC despite repeated challenges.[44]

# Transmission Facility Outages

## Scheduling Transmission Facility Outage Requests

A transmission facility is designated as reportable by PJM if a change in its status can affect a transmission constraint on any Monitored Transmission Facility or could impede free flowing ties within the PJM RTO and/or adjacent areas.[45] When one of the reportable transmission facilities needs to be taken out of service, the TO is required to submit an outage request as early as possible. The specific timeline is shown in Table 12-34.[46]

Transmission outages have significant impacts on PJM markets. There are impacts on FTR auctions, on congestion, and on expected market outcomes in the day-ahead and real-time markets. It is important for the efficient functioning of the markets that there be clear, enforceable rules governing transmission outages.

Transmission outages are categorized by duration: greater than 30 calendar days; less than or equal to 30 calendar days and greater than five calendar days; or less than or equal to five calendar days.[47] Table 12-33 shows that 73.4 percent of the requested outages were planned for less than or equal to five days and 8.5 percent of requested outages were planned for greater than 30 days in the 2017/2018 planning period. It also shows that 76.9 percent of the requested outages were planned for less than or equal to five days and 7.0 percent of requested outages were planned for greater than 30 days in the 2016/2017 planning period.

All of the outage data in this section except in the analysis for the day-ahead market are for outages scheduled to occur in the planning periods 2016/2017 and 2017/2018, regardless of when they were initially submitted.[48] The outage data in the analysis for the day-ahead market are for outages scheduled to occur from January 1, 2015, through December 31, 2017.

### Table 12-33 Transmission facility outage request summary by planned duration: planning periods 2016/2017 and 2017/2018

| | 2016/2017 | | 2017/2018 | |
|---|---|---|---|---|
| Planned Duration (Days) | Outage Requests | Percent | Outage Requests | Percent |
| <=5 | 16,440 | 76.9% | 11,465 | 73.4% |
| >5 & <=30 | 3,448 | 16.1% | 2,817 | 18.0% |
| >30 | 1,489 | 7.0% | 1,331 | 8.5% |
| Total | 21,377 | 100.0% | 15,613 | 100.0% |

42 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>.

43 See letter from Terry Boston concerning the Artificial Island Project at <http://www.pjm.com/-/media/library/reports-notices/special-reports/board-statement-on-artificial-island-project.ashx?la=en>.

44 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).

45 If a transmission facility is not modeled in the PJM EMS or the facility is not expected to significantly impact PJM system security or congestion management, it is not reportable. See PJM. "Manual 3A: Energy Management System (EMS) Model Updates and Quality Assurance (QA), Rev. 13 (September 29, 2017).

46 See PJM. "Manual 3: Transmission Operations," Rev. 52 (Dec. 22, 2017), p.69.

47 *Id.* p.70.

48 The hotline tickets, EMS tripping tickets or test outage tickets were excluded. We only included all the transmission outage tickets submitted by PJM internal companies which are currently active.

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 12-34.[49]

The purpose of the rules defined in Table 12-34 is to require the TOs to submit transmission facility outages prior to the Financial Transmission Right (FTR) auctions so that market participants have complete information about market conditions on which to base their FTR bids and so that PJM can accurately model market conditions.[50]

### Table 12-34 PJM transmission facility outage request received status definition

| Planned Duration (Calendar Days) | Request Submitted | Received Status |
|---|---|---|
| <=5 | Before the first of the month one month prior to the starting month of the outage | On Time |
| | After or on the first of the month one month prior to the starting month of the outage | Late |
| > 5 & <=30 | Before the first of the month six months prior to the starting month of the outage | On Time |
| | After or on the first of the month six months prior to the starting month of the outage | Late |
| >30 | The earlier of 1) February 1, 2) the first of the month six months prior to the starting month of the outage | On Time |
| | After or on the earlier of 1) February 1, 2) the first of the month six months prior to the starting month of the outage | Late |

### Table 12-35 Transmission facility outage request summary by received status: planning periods 2016/2017 and 2017/2018

| | 2016/2017 | | | | 2017/2018 | | | |
|---|---|---|---|---|---|---|---|---|
| Planned Duration (Days) | On Time | Late | Total | Percent Late | On Time | Late | Total | Percent Late |
| <=5 | 8,471 | 7,969 | 16,440 | 48.5% | 6,598 | 4,867 | 11,465 | 42.5% |
| >5 & <=30 | 1,667 | 1,781 | 3,448 | 51.7% | 1,636 | 1,181 | 2,817 | 41.9% |
| >30 | 515 | 974 | 1,489 | 65.4% | 554 | 777 | 1,331 | 58.4% |
| Total | 10,653 | 10,724 | 21,377 | 50.2% | 8,788 | 6,825 | 15,613 | 43.7% |

### Table 12-36 Transmission facility outage request summary by emergency: planning periods 2016/2017 and 2017/2018

| | 2016/2017 | | | | 2017/2018 | | | |
|---|---|---|---|---|---|---|---|---|
| Planned Duration (Days) | Emergency | Non Emergency | Total | Percent Emergency | Emergency | Non Emergency | Total | Percent Emergency |
| <=5 | 2,186 | 14,254 | 16,440 | 13.3% | 1,301 | 10,164 | 11,465 | 11.3% |
| >5 & <=30 | 433 | 3,015 | 3,448 | 12.6% | 254 | 2,563 | 2,817 | 9.0% |
| >30 | 199 | 1,290 | 1,489 | 13.4% | 153 | 1,178 | 1,331 | 11.5% |
| Total | 2,818 | 18,559 | 21,377 | 13.2% | 1,708 | 13,905 | 15,613 | 10.9% |

Table 12-35 shows a summary of requests by received status. In the 2017/2018 planning period, 43.7 percent of outage requests received were late. In the 2016/2017 planning period, 50.2 percent of outage requests received were late.

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.[51] Table 12-36 is a summary of outage requests by emergency status. Of all outage requests scheduled to occur in the 2017/2018 planning period, 10.9 percent were for emergency outages. Of all outage requests scheduled to occur in the 2016/2017 planning period, 13.2 percent were for emergency outages.

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."[52]

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

49 See PJM. "Manual 3: Transmission Operations," Rev. 52 (Dec. 22, 2017), at 69–70.
50 See "Report of PJM Interconnection, L.L.C. on Transmission Oversight Procedures," Docket No. EL01-122-000 (November 2, 2001).
51 PJM. "Manual 3: Transmission Operations," Rev. 52 (Dec. 22, 2017) at 81.
52 PJM added this definition to Manual 38 in February 2017. PJM. "Manual 38: Operations Planning," Rev. 11 (Feb. 1, 2018) at 20.

Owner defer the outage. If no solutions are available, PJM may require the Transmission Owner to reschedule or cancel the outage.

Table 12-37 is a summary of outage requests by congestion status. Of all outage requests submitted to occur in the 2017/2018 planning period, 8.1 percent were expected to cause congestion. Of all the outage requests that were expected to cause congestion, 3.0 percent (38 out of 1,264) were denied by PJM in the 2017/2018 planning period and 16.4 percent (207 out of 1,264) were cancelled (Table 12-39). Of all outage requests submitted to occur in the 2016/2017 planning period, 8.9 percent were expected to cause congestion. Of all the outage requests that were expected to cause congestion, 4.1 percent (77 out of 1,893) were denied by PJM in the 2016/2017 planning period and 18.9 percent (357 out of 1,893) were cancelled (Table 12-39).

### Table 12-37 Transmission facility outage request summary by congestion: planning periods 2016/2017 and 2017/2018

| | 2016/2017 | | | | 2017/2018 | | | |
|---|---|---|---|---|---|---|---|---|
| Planned Duration (Days) | Congestion Expected | No Congestion Expected | Total | Percent Congestion Expected | Congestion Expected | No Congestion Expected | Total | Percent Congestion Expected |
| <=5 | 1,389 | 15,051 | 16,440 | 8.4% | 807 | 10,658 | 11,465 | 7.0% |
| >5 & <=30 | 373 | 3,075 | 3,448 | 10.8% | 317 | 2,500 | 2,817 | 11.3% |
| >30 | 131 | 1,358 | 1,489 | 8.8% | 140 | 1,191 | 1,331 | 10.5% |
| Total | 1,893 | 19,484 | 21,377 | 8.9% | 1,264 | 14,349 | 15,613 | 8.1% |

Table 12-38 shows the outage requests summary by received status, congestion status and emergency status. In the 2017/2018 planning period, 32.9 percent of requests were submitted late and were nonemergency while 1.3 percent of requests (205 out of 15,613) were late, nonemergency, and expected to cause congestion. In the 2016/2017 planning period, 37.1 percent of request were submitted late and were nonemergency while 1.9 percent of requests (403 out of 21,377) were late, nonemergency, and expected to cause congestion.

### Table 12-38 Transmission facility outage request summary by received status, emergency and congestion: planning periods 2016/2017 and 2017/2018

| | | 2016/2017 | | | | 2017/2018 | | | |
|---|---|---|---|---|---|---|---|---|---|
| Received Status | | Congestion Expected | No Congestion Expected | Total | Percent | Congestion Expected | No Congestion Expected | Total | Percent |
| Late | Emergency | 114 | 2,687 | 2,801 | 13.1% | 71 | 1,615 | 1,686 | 10.8% |
| | Non Emergency | 403 | 7,520 | 7,923 | 37.1% | 205 | 4,934 | 5,139 | 32.9% |
| On Time | Emergency | 2 | 15 | 17 | 0.1% | 3 | 19 | 22 | 0.1% |
| | Non Emergency | 1,374 | 9,262 | 10,636 | 49.8% | 985 | 7,781 | 8,766 | 56.1% |
| Total | | 1,893 | 19,484 | 21,377 | 100.0% | 1,264 | 14,349 | 15,613 | 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.[53] Table 12-39 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 12-39. Table 12-39 shows that of all the outage requests that were expected to cause congestion, 3.0 percent (38 out of 1,264) were denied by PJM in the 2017/2018 planning period, 56.9 percent were complete and 16.4 percent (207 out of 1,264) were cancelled. Of all the outage requests that were expected to cause congestion, 4.1 percent (77 out of 1,893) were denied by PJM in the 2016/2017 planning period, 72.0 percent were complete and 18.9 percent (357 out of 1,893) were cancelled.

53 See PJM Markets & Operations, PJM Tools "Outage Information," <http://www.pjm.com/markets-and-operations/etools/oasis/system-information/outage-info.aspx> (2017).

Table 12-39 Transmission facility outage requests that might cause congestion status summary: planning periods 2016/2017 and 2017/2018

| | | 2016/2017 | | | | | | 2017/2018 | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Submission Status | | Cancelled | Complete | In Process | Denied | Congestion Expected | Percent Complete | Cancelled | Complete | In Process | Denied | Congestion Expected | Percent Complete |
| Late | Emergency | 10 | 103 | 0 | 1 | 114 | 90.4% | 10 | 59 | 2 | 0 | 71 | 83.1% |
| | Non Emergency | 69 | 280 | 10 | 44 | 403 | 69.5% | 29 | 129 | 32 | 13 | 205 | 62.9% |
| On Time | Emergency | 0 | 1 | 0 | 0 | 2 | 50.0% | 2 | 1 | 0 | 0 | 3 | 33.3% |
| | Non Emergency | 278 | 979 | 75 | 32 | 1,374 | 71.3% | 166 | 530 | 257 | 25 | 985 | 53.8% |
| Total | | 357 | 1,363 | 85 | 77 | 1,893 | 72.0% | 207 | 719 | 291 | 38 | 1,264 | 56.9% |

There are clear rules defined for assigning On Time or Late status for submitted outage requests in both the PJM Tariff and PJM Manuals.[54] However, the On Time or Late status only affects the priority that PJM assigns for processing the outage request. Table 12-39 shows that in the 2016/2017 planning period, many (69.5 percent or 280 out of 403) outages that were nonemergency, expected to cause congestion, and late transmission outages were approved and completed compared to (62.9 percent or 129 out of 205) in the 2017/2018 planning period. The expected impact on congestion is the basis for PJM's treatment of late outage requests. But there is no rule or clear definition of this congestion analysis in the PJM Manuals. The MMU recommends that PJM draft a clear definition of the congestion analysis required for transmission outage requests to include in Manual 3 after appropriate review.

## Rescheduling Transmission Facility Outage Requests

A TO can reschedule or cancel an outage after initial submission. Table 12-40 is a summary of all the outage requests planned for the planning periods 2016/2017 and 2017/2018 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 2017/2018 planning period, 24.2 percent of transmission outage requests were approved by PJM and then rescheduled by the TOs, and 9.2 percent of the transmission outages were approved by PJM and subsequently cancelled by the TOs. In the 2016/2017 planning period, 30.2 percent of transmission outage requests were approved by PJM and then rescheduled by the TO, and 10.8 percent of the transmission outages were approved by PJM and subsequently cancelled by the TO.

Table 12-40 Rescheduled and cancelled transmission outage request summary: planning periods 2016/2017 and 2017/2018

| | 2016/2017 | | | | | 2017/2018 | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| 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 | 16,440 | 3,460 | 21.0% | 2,048 | 12.5% | 11,465 | 1,922 | 16.8% | 1,252 | 10.9% |
| >5 & <=30 | 3,448 | 2,008 | 58.2% | 211 | 6.1% | 2,817 | 1,192 | 42.3% | 135 | 4.8% |
| >30 | 1,489 | 990 | 66.5% | 50 | 3.4% | 1,331 | 668 | 50.2% | 44 | 3.3% |
| Total | 21,377 | 6,458 | 30.2% | 2,309 | 10.8% | 15,613 | 3,782 | 24.2% | 1,431 | 9.2% |

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.[55] This rule allows a TO to reschedule within the same month with very little notice.

54 OA Schedule 1 § 1.9.2.

55 PJM. "Manual 3: Transmission Operations," Rev. 52 (Dec. 22, 2017) at 70.

A transmission outage ticket with a duration exceeding five days with an On Time status can retain its On Time status if the outage is rescheduled to a future month, and the revision is submitted by the first of the month prior to the revised month in which the outage will occur.[56] This rescheduling rule is much less strict than the rule that applies to the first submission of outage requests with similar duration. When first submitted, the outage request with a duration exceeding five days needs to be submitted before the first of the month 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 12-34) 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 12-41 shows that there were 10,063 transmission equipment planned outages in the 2017/2018 planning period, of which 1,374 were planned outages longer than 30 days, and of which 200 or 2.0 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.

56 *Id.*

### Table 12-41 Transmission outage summary: planning periods 2016/2017 and 2017/2018

| | | 2016/2017 | | 2017/2018 | |
|---|---|---|---|---|---|
| Duration | Divided into Shorter Periods | Number of Outages | Percent | Number of Outages | Percent |
| > 30 Days | No | 1,287 | 10.1% | 1,174 | 11.7% |
| | Yes | 247 | 1.9% | 200 | 2.0% |
| <= 30 Days | | 11,238 | 88.0% | 8,689 | 86.3% |
| Total | | 12,772 | 100.0% | 10,063 | 100.0% |

Table 12-42 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 2017/2018 planning period, there would have been 25 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 12-42 Summary of potentially long duration (> 30 days) outages: planning periods 2016/2017 and 2017/2018

| | 2016/2017 | | 2017/2018 | |
|---|---|---|---|---|
| Days | Number of Outages | Percent | Number of Outages | Percent |
| <=31 | 4 | 1.6% | 4 | 2.0% |
| >31 & <=62 | 28 | 11.3% | 25 | 12.5% |
| >62 & <=93 | 14 | 5.7% | 20 | 10.0% |
| >93 | 201 | 81.4% | 151 | 75.5% |
| Total | 247 | 100.0% | 200 | 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 governing outage reporting 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.

There are Long Term, Annual and Monthly Balance of Planning Period auctions in the FTR Market. For each type of auction, PJM includes a set of outages to be modeled.

## Annual FTR Market

The Annual FTR Market includes the Annual ARR Allocation and the Annual FTR Auction. When determining transmission outages to be modeled in the simultaneous feasibility test used in the Annual FTR Market, PJM considers all outages with planned duration longer than or equal to two months and may consider outages with planned durations shorter than 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.[57]

In the 2017/2018 planning period, 250 outage requests were included in the annual FTR market outage list and 15,363 outage requests were not included. In the 2016/2017 planning period, 249 outage requests were included in the annual FTR market outage list and 21,128 outage requests were not included. Table 12-43, Table 12-44, Table 12-45 and Table 12-46 show the summary information on the modeled outage requests and Table 12-47 and Table 12-48 show the summary information on outages that were not included in the Annual FTR Market.

### Table 12-43 Annual FTR market modeled transmission facility outage requests by received status: planning periods 2016/2017 and 2017/2018

| | 2016/2017 | | | | 2017/2018 | | | |
|---|---|---|---|---|---|---|---|---|
| Planned Duration | On Time | Late | Total | Percent | On Time | Late | Total | Percent |
| <2 weeks | 10 | 1 | 11 | 4.4% | 4 | 2 | 6 | 2.4% |
| >=2 weeks & <2 months | 88 | 2 | 90 | 36.1% | 87 | 9 | 96 | 38.4% |
| >=2 months | 125 | 23 | 148 | 59.4% | 126 | 22 | 148 | 59.2% |
| Total | 223 | 26 | 249 | 100.0% | 217 | 33 | 250 | 100.0% |

### Table 12-44 Annual FTR market modeled transmission facility outage requests by emergency and received status: planning periods 2016/2017 and 2017/2018

| | | 2016/2017 | | | | 2017/2018 | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Planned Duration | Emergency | Non Emergency | Total | Percent Non Emergency | Emergency | Non Emergency | Total | Percent Non Emergency |
| On Time | <2 weeks | 0 | 10 | 10 | 100.0% | 0 | 4 | 4 | 100.0% |
| | >=2 weeks & <2 months | 0 | 88 | 88 | 100.0% | 0 | 87 | 87 | 100.0% |
| | >=2 months | 0 | 125 | 125 | 100.0% | 0 | 126 | 126 | 100.0% |
| | Total | 0 | 223 | 223 | 100.0% | 0 | 217 | 217 | 100.0% |
| Late | <2 weeks | 0 | 1 | 1 | 100.0% | 0 | 2 | 2 | 100.0% |
| | >=2 weeks & <2 months | 0 | 2 | 2 | 100.0% | 0 | 9 | 9 | 100.0% |
| | >=2 months | 2 | 21 | 23 | 91.3% | 0 | 22 | 22 | 100.0% |
| | Total | 2 | 24 | 26 | 92.3% | 0 | 33 | 33 | 100.0% |

Table 12-43 shows that 2.4 percent of the outage requests modeled in the Annual FTR Market for the 2017/2018 planning period had a planned duration of less than two weeks and that 13.2 percent of the outage requests (33 out of 250) modeled in the Annual FTR Market for the planning period were submitted late according to outage submission rules. It also shows that 4.4 percent of the outage requests modeled in the Annual FTR Market for the 2016/2017 planning period had a planned duration of less than two weeks and that 10.4 percent of the outage requests (26 out of 249) modeled in the Annual FTR Market for the planning period were submitted late according to outage submission rules.

Table 12-44 shows the annual FTR market modeled outage requests summary by emergency status and received status. All the annual FTR market modeled outages expected to occur in the 2017/2018 planning period were nonemergency outages. Two of the modeled outages expected to occur in the 2016/2017 planning period were emergency outages.

PJM determines 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 12-45 shows a summary of requests by expected congestion and received status. Overall, 12.1 percent (4 out of 33) of all the annual FTR market modeled outages expected to occur in the 2017/2018 planning period and submitted late were expected to cause congestion. Of all the annual FTR market modeled outages expected to occur in the 2016/2017 planning period and submitted late, 11.5 percent (3 out of 26) were expected to cause congestion.

57 PJM Financial Transmission Rights, "Annual ARR Allocation and FTR Auction Transmission Outage Modeling," <http://www.pjm.com/~/media/markets-ops/ftr/annual-ftr-auction/2017-2018/2017-2018-annual-outage-modeling.ashx> (February 21, 2017).

### Table 12-45 Annual FTR market modeled transmission facility outage requests by congestion and received status: planning periods 2016/2017 and 2017/2018

| | | 2016/2017 | | | | 2017/2018 | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Planned Duration | Congestion Expected | No Congestion Expected | Total | Percent Congestion Expected | Congestion Expected | No Congestion Expected | Total | Percent Congestion Expected |
| On Time | <2 weeks | 2 | 8 | 10 | 20.0% | 1 | 3 | 4 | 25.0% |
| | >=2 weeks & <2 months | 19 | 69 | 88 | 21.6% | 20 | 67 | 87 | 23.0% |
| | >=2 months | 29 | 96 | 125 | 23.2% | 34 | 92 | 126 | 27.0% |
| | Total | 50 | 173 | 223 | 22.4% | 55 | 162 | 217 | 25.3% |
| Late | <2 weeks | 0 | 1 | 1 | 0.0% | 0 | 2 | 2 | 0.0% |
| | >=2 weeks & <2 months | 0 | 2 | 2 | 0.0% | 1 | 8 | 9 | 11.1% |
| | >=2 months | 3 | 20 | 23 | 13.0% | 3 | 19 | 22 | 13.6% |
| | Total | 3 | 23 | 26 | 11.5% | 4 | 29 | 33 | 12.1% |

Table 12-46 shows that 27.1 percent of outage requests modeled in the annual FTR market for the 2017/2018 planning period and with a duration of two weeks or longer but shorter than two months were cancelled, compared to 35.6 percent for the 2016/2017 planning period. Table 12-46 also shows that 10.8 percent of outages requests modeled in the Annual FTR Market for the 2017/2018 planning period and with a duration of two months or longer were cancelled, compared to 20.9 percent for the 2016/2017 planning period.

### Table 12-46 Annual FTR market modeled transmission facility outage requests by processed status: planning periods 2016/2017 and 2017/2018

| | | 2016/2017 | | 2017/2018 | |
|---|---|---|---|---|---|
| Planned Duration | Processed Status | Outage Requests | Percent | Outage Requests | Percent |
| <2 weeks | In Progress | 0 | 0.0% | 1 | 16.7% |
| | Denied | 0 | 0.0% | 0 | 0.0% |
| | Approved | 0 | 0.0% | 0 | 0.0% |
| | Cancelled | 1 | 9.1% | 2 | 33.3% |
| | Revised | 0 | 0.0% | 0 | 0.0% |
| | Active | 0 | 0.0% | 0 | 0.0% |
| | Completed | 10 | 90.9% | 3 | 50.0% |
| | Total | 11 | 100.0% | 6 | 100.0% |
| >=2 weeks & <2 months | In Progress | 10 | 11.1% | 31 | 32.3% |
| | Denied | 0 | 0.0% | 2 | 2.1% |
| | Approved | 0 | 0.0% | 0 | 0.0% |
| | Cancelled | 32 | 35.6% | 26 | 27.1% |
| | Revised | 0 | 0.0% | 2 | 2.1% |
| | Active | 0 | 0.0% | 1 | 1.0% |
| | Completed | 48 | 53.3% | 34 | 35.4% |
| | Total | 90 | 100.0% | 96 | 100.0% |
| >=2 months | In Progress | 23 | 15.5% | 49 | 33.1% |
| | Denied | 0 | 0.0% | 0 | 0.0% |
| | Approved | 0 | 0.0% | 1 | 0.7% |
| | Cancelled | 31 | 20.9% | 16 | 10.8% |
| | Revised | 0 | 0.0% | 2 | 1.4% |
| | Active | 3 | 2.0% | 31 | 20.9% |
| | Completed | 91 | 61.5% | 49 | 33.1% |
| | Total | 148 | 100.0% | 148 | 100.0% |

More outage requests were not modeled in the Annual FTR Market than were modeled in the Annual FTR Market. In the 2017/2018 planning period, 250 outage requests were modeled and 15,363 outage requests were not modeled in the Annual FTR Market. In the 2016/2017 planning period, 249 outage requests were modeled and 21,128 outage requests were not modeled in the Annual FTR Market.

Table 12-47 shows that 12.3 percent of outage requests not modeled in the Annual FTR Auction with duration longer than or equal to two months, labelled On Time according to the rules, were submitted after the Annual FTR Auction bidding opening date for the 2017/2018 planning period compared to 17.5 percent in the 2016/2017 planning period.

Table 12-47 Transmission facility outage requests not modeled in Annual FTR Auction: planning periods 2016/2017 and 2017/2018

| | 2016/2017 | | | | | | 2017/2018 | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 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 | 1,486 | 7,988 | 84.3% | 261 | 8,802 | 97.1% | 1,405 | 6,056 | 81.2% | 231 | 5,306 | 95.8% |
| >=2 weeks & <2 months | 460 | 376 | 45.0% | 152 | 953 | 86.2% | 603 | 352 | 36.9% | 107 | 715 | 87.0% |
| >=2 months | 99 | 21 | 17.5% | 185 | 345 | 65.1% | 136 | 19 | 12.3% | 197 | 236 | 54.5% |
| Total | 2,045 | 8,385 | 80.4% | 598 | 10,100 | 94.4% | 2,144 | 6,427 | 75.0% | 535 | 6,257 | 92.1% |

Table 12-48 shows that 42.8 percent of late outage requests which were not modeled in the Annual FTR Auction with duration longer than or equal to two months and submitted after the Annual FTR Auction bidding opening date were approved and completed in the 2017/2018 planning period. It also shows that 78.0 percent of late outage requests which were not modeled in the Annual FTR Auction with duration longer than or equal to two months and submitted after the Annual FTR Auction bidding opening date were approved and completed in the 2016/2017 planning period.

Table 12-48 Late transmission facility outage requests not modeled in Annual FTR Auction and submitted after annual bidding opening date: planning periods 2016/2017 and 2017/2018

| | 2016/2017 | | | 2017/2018 | | |
|---|---|---|---|---|---|---|
| Planned Duration | Completed Outages | Total | Percent | Completed Outages | Total | Percent |
| <2 weeks | 7,385 | 8,802 | 83.9% | 4,128 | 5,306 | 77.8% |
| >=2 weeks & <2 months | 834 | 953 | 87.5% | 485 | 715 | 67.8% |
| >=2 months | 269 | 345 | 78.0% | 101 | 236 | 42.8% |
| Total | 8,488 | 10,100 | 84.0% | 4,714 | 6,257 | 75.3% |

Although the definition of late outages was developed in order to prevent outages for the planning period being submitted after the opening of bidding in the Annual FTR Auction, the rules have not functioned effectively because the rule has no direct connection to the date on which bidding opens for the Annual FTR Auction. 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. There is no rule to address the situation in which short-duration outages (duration <= 5 days) are submitted on time, but are changed to long-duration transmission outages after the outages are approved and active. 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 outages but also include outages shorter than 30 days. In those cases, PJM outage submission rules failed to prevent long duration transmission outages from being submitted late. The MMU recommends that PJM modify the rules to eliminate the approval of outage requests submitted or rescheduled after the opening of bidding in the Annual FTR Auction.

## Monthly FTR Market

When determining transmission outages to be modeled in the simultaneous feasibility test used in the Monthly Balance of Planning Period FTR Auction, PJM considers all outages with planned duration longer than five days and may consider outages with planned durations shorter than or equal to five days. PJM may exercise significant discretion in selecting outages to be modeled. PJM posts an FTR outage list to the FTR webpage usually at least one week before the auction bidding opening day.[58] Table 12-49 and Table 12-50 show the summary information on outage requests modeled in the Monthly Balance of Planning Period FTR Auction and Table 12-51 and Table 12-52 show the summary information on outage requests not modeled in the Monthly Balance of Planning Period FTR Auction.

Table 12-49 shows that on average, 29.3 percent of the outage requests modeled in the Monthly Balance of Planning Period FTR Auction were submitted late according to outage submission rules in the 2017/2018

58 PJM Financial Transmission Rights, "2015/2016 Monthly FTR Auction Transmission Outage Modeling," <http://www.pjm.com/-/media/markets-ops/ftr/ftr-allocation/monthly-ftr-auctions/2015-2016-monthly-transmission-outages-that-may-cause-infeasibilities.ashx?la=en> (December 9, 2015).

planning period. On average, 30.8 percent of the outage requests modeled in the Monthly Balance of Planning Period FTR Auction were submitted late according to outage submission rules in the 2016/2017 planning period.

### Table 12-49 Monthly Balance of Planning Period FTR Auction modeled transmission facility outage requests by received status: planning periods 2016/2017 and 2017/2018

| | 2016/2017 | | | | 2017/2018 | | | |
|---|---|---|---|---|---|---|---|---|
| Month | On Time | Late | Total | Late Percent | On Time | Late | Total | Late Percent |
| Jun | 170 | 94 | 264 | 35.6% | 134 | 116 | 250 | 46.4% |
| Jul | 67 | 57 | 124 | 46.0% | 83 | 72 | 155 | 46.5% |
| Aug | 77 | 63 | 140 | 45.0% | 100 | 73 | 173 | 42.2% |
| Sep | 367 | 129 | 496 | 26.0% | 394 | 125 | 519 | 24.1% |
| Oct | 542 | 195 | 737 | 26.5% | 598 | 162 | 760 | 21.3% |
| Nov | 365 | 172 | 537 | 32.0% | 453 | 177 | 630 | 28.1% |
| Dec | 289 | 130 | 419 | 31.0% | 330 | 142 | 472 | 30.1% |
| Jan | 162 | 90 | 252 | 35.7% | | | | |
| Feb | 162 | 89 | 251 | 35.5% | | | | |
| Mar | 310 | 132 | 442 | 29.9% | | | | |
| Apr | 395 | 162 | 557 | 29.1% | | | | |
| May | 411 | 165 | 576 | 28.6% | | | | |
| Avg | 276 | 123 | 400 | 30.8% | 299 | 124 | 423 | 29.3% |

Table 12-50 shows that on average, 18.6 percent of outage requests modeled in the Monthly Balance of Planning Period FTR Auction were cancelled in the 2017/2018 planning period. On average, 20.4 percent of outage requests modeled in the Monthly Balance of Planning Period FTR Auction were cancelled in the 2016/2017 planning period.

### Table 12-50 Monthly Balance of Planning Period FTR Auction modeled transmission facility outage requests by processed status: planning periods 2016/2017 and 2017/2018

| Planning Year | Month | In Process | Denied | Approved | Cancelled | Revised | Active | Complete | Total | Cancelled Percent |
|---|---|---|---|---|---|---|---|---|---|---|
| 2016/2017 | Jun | 18 | 3 | 5 | 51 | 1 | 53 | 133 | 264 | 19.3% |
| | Jul | 10 | 12 | 2 | 19 | 0 | 41 | 40 | 124 | 15.3% |
| | Aug | 9 | 1 | 2 | 31 | 0 | 52 | 45 | 140 | 22.1% |
| | Sep | 47 | 4 | 11 | 85 | 0 | 165 | 184 | 496 | 17.1% |
| | Oct | 75 | 5 | 19 | 172 | 0 | 196 | 270 | 737 | 23.3% |
| | Nov | 46 | 1 | 10 | 104 | 0 | 162 | 214 | 537 | 19.4% |
| | Dec | 25 | 4 | 11 | 87 | 0 | 66 | 226 | 419 | 20.8% |
| | Jan | 35 | 0 | 7 | 60 | 0 | 75 | 75 | 252 | 23.8% |
| | Feb | 22 | 2 | 4 | 42 | 1 | 87 | 93 | 251 | 16.7% |
| | Mar | 48 | 2 | 9 | 94 | 0 | 120 | 169 | 442 | 21.3% |
| | Apr | 55 | 2 | 7 | 101 | 1 | 154 | 237 | 557 | 18.1% |
| | May | 26 | 1 | 18 | 134 | 0 | 119 | 278 | 576 | 23.3% |
| | Avg | 35 | 3 | 9 | 82 | 0 | 108 | 164 | 400 | 20.4% |
| 2017/2018 | Jun | 19 | 5 | 5 | 52 | 0 | 64 | 105 | 250 | 20.8% |
| | Jul | 11 | 2 | 8 | 25 | 0 | 54 | 55 | 155 | 16.1% |
| | Aug | 10 | 0 | 1 | 27 | 0 | 64 | 71 | 173 | 15.6% |
| | Sep | 67 | 8 | 13 | 100 | 3 | 161 | 167 | 519 | 19.3% |
| | Oct | 77 | 2 | 27 | 142 | 0 | 201 | 311 | 760 | 18.7% |
| | Nov | 39 | 5 | 10 | 121 | 2 | 177 | 276 | 630 | 19.2% |
| | Dec | 42 | 4 | 9 | 97 | 0 | 74 | 246 | 472 | 20.6% |
| | Avg | 38 | 4 | 10 | 81 | 1 | 114 | 176 | 423 | 18.6% |

Table 12-51 shows that on average, 8.9 percent of outage requests not modeled in the Monthly Balance of Planning Period FTR Auction, labeled On Time according to the rules, were submitted after the monthly FTR auction bidding opening dates in the 2017/2018 planning period, compared to 10.1 percent in the 2016/2017 planning period. On average, 71.0 percent of outage requests not modeled in the Monthly Balance of Planning Period FTR Auction, labeled Late according to the rules, were submitted after the Monthly Balance of Planning Period FTR Auction bidding opening dates in the 2017/2018 planning period, compared to 70.7 percent in the 2016/2017 planning period.

**Table 12-51 Transmission facility outage requests that are not modeled in Monthly Balance of Planning Period FTR Auction: planning periods 2016/2017 and 2017/2018**

| | 2016/2017 | | | | | | 2017/2018 | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | On Time | | | Late | | | On Time | | | Late | | |
| | 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 |
| Jun | 694 | 103 | 12.9% | 336 | 894 | 72.7% | 642 | 96 | 13.0% | 306 | 851 | 73.6% |
| Jul | 274 | 74 | 21.3% | 251 | 698 | 73.6% | 294 | 48 | 14.0% | 245 | 608 | 71.3% |
| Aug | 413 | 92 | 18.2% | 259 | 733 | 73.9% | 344 | 25 | 6.8% | 211 | 651 | 75.5% |
| Sep | 964 | 156 | 13.9% | 292 | 772 | 72.6% | 862 | 81 | 8.6% | 257 | 598 | 69.9% |
| Oct | 1,092 | 89 | 7.5% | 430 | 901 | 67.7% | 1,000 | 75 | 7.0% | 347 | 866 | 71.4% |
| Nov | 887 | 57 | 6.0% | 389 | 832 | 68.1% | 829 | 69 | 7.7% | 367 | 789 | 68.3% |
| Dec | 601 | 47 | 7.3% | 340 | 723 | 68.0% | 623 | 55 | 8.1% | 330 | 687 | 67.6% |
| Jan | 432 | 35 | 7.5% | 243 | 592 | 70.9% | | | | | | |
| Feb | 462 | 25 | 5.1% | 301 | 674 | 69.1% | | | | | | |
| Mar | 1,068 | 94 | 8.1% | 357 | 806 | 69.3% | | | | | | |
| Apr | 1,140 | 103 | 8.3% | 340 | 789 | 69.9% | | | | | | |
| May | 1,143 | 154 | 11.9% | 356 | 966 | 73.1% | | | | | | |
| Avg | 764 | 86 | 10.1% | 325 | 782 | 70.7% | 656 | 64 | 8.9% | 295 | 721 | 71.0% |

Table 12-52 shows that on average, 69.5 percent of late outage requests which were not modeled in the Monthly Balance of Planning Period FTR Auction, submitted after the Monthly Balance of Planning Period FTR Auction bidding opening dates, were approved and complete in the 2017/2018 planning period, compared to 69.5 percent in the 2016/2017 planning period.

**Table 12-52 Late transmission facility outage requests that are not modeled in Monthly Balance of Planning Period FTR Auction and submitted after monthly bidding opening date: planning periods 2016/2017 and 2017/2018**

| | 2016/2017 | | | 2017/2018 | | |
|---|---|---|---|---|---|---|
| | Completed Outages | Total | Percent | Completed Outages | Total | Percent |
| Jun | 639 | 894 | 71.5% | 627 | 851 | 73.7% |
| Jul | 476 | 698 | 68.2% | 410 | 608 | 67.4% |
| Aug | 523 | 733 | 71.4% | 473 | 651 | 72.7% |
| Sep | 495 | 772 | 64.1% | 406 | 598 | 67.9% |
| Oct | 644 | 901 | 71.5% | 595 | 866 | 68.7% |
| Nov | 536 | 832 | 64.4% | 490 | 789 | 62.1% |
| Dec | 534 | 723 | 73.9% | 508 | 687 | 73.9% |
| Jan | 401 | 592 | 67.7% | | | |
| Feb | 447 | 674 | 66.3% | | | |
| Mar | 580 | 806 | 72.0% | | | |
| Apr | 575 | 789 | 72.9% | | | |
| May | 668 | 966 | 69.2% | | | |
| Avg | 543 | 782 | 69.5% | 501 | 721 | 69.5% |

## 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. [59]

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

59 PJM. "Manual 3: Transmission Operations," Rev. 52 (Dec. 22, 2017) at 74

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 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 nine 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: November 22, 2016

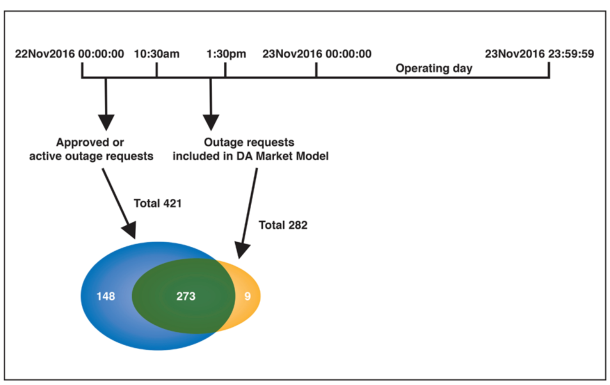



Figure 12-5 compares the weekly average number of active or approved outages available to market participants prior to the close of the day-ahead market with the outages included as inputs to the day-ahead market by PJM.

### Figure 12-5 Approved or active outage requests: 2015 through 2017

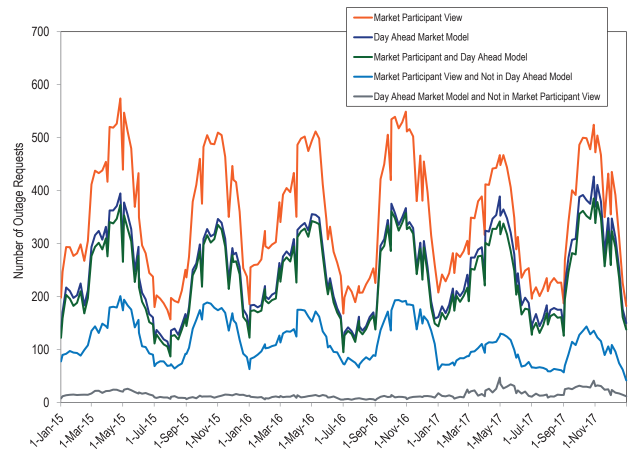



Figure 12-6 compares the weekly average number of outages included as inputs to the day-ahead market by PJM with the outages that actually occurred during the operating day.

### Figure 12-6 Day-ahead market model outages: 2015 through 2017

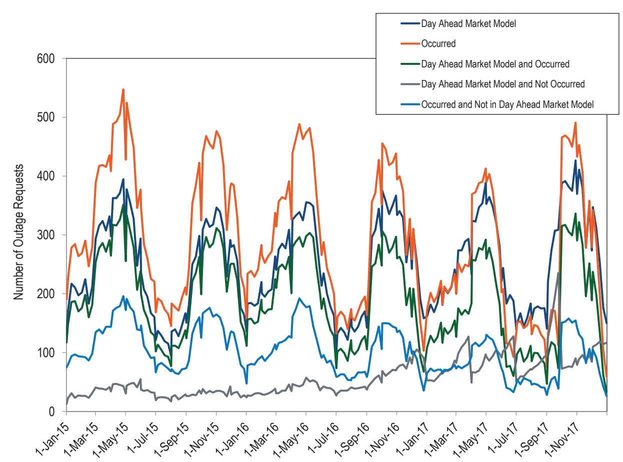


Figure 12-7 compares the weekly average number of active or approved outages available to market participants prior to the close of the day-ahead market with the outages that actually occurred during the operating day.

**Figure 12-7 Approved or active outage requests: 2015 through 2017**

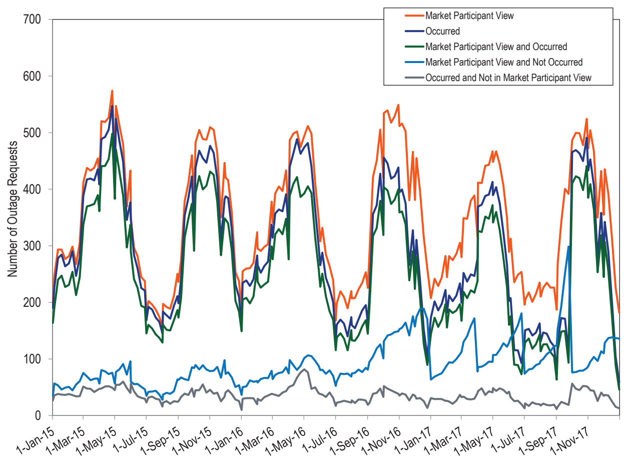



Figure 12-5, Figure 12-6, and Figure 12-7 show that on a weekly average basis, the active or approved outages available to day-ahead market participants, the outages included as inputs in the day-ahead market model and the outages that actually occurred in real time are not consistent. The active or 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 or through bilateral contracts 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 the benefits of access to remote low cost generation in the form of revenues which offset congestion to the extent permitted by the transmission system.[1] Financial transmission rights and the associated revenues were directly provided to loads in recognition of the fact that loads pay for the transmission system which permits low cost generation to be delivered to load. 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, as a result of LMP, load pays too much for generation. The excess payments are defined to be congestion. Under LMP, load pays locational prices which result in load payments in excess of generation revenues. These excess payments are congestion revenues. Congestion revenues are 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. FTRs were the mechanism selected in PJM to pay congestion revenues back to load. 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). Under the ARR construct, the load still owns the rights to congestion revenue, but the ARR construct allows load to either claim the FTRs directly (through a process called self scheduling), or to sell the rights to congestion revenue in the FTR auction in exchange for a revenue stream based on the auction clearing prices of the FTRs. Under the ARR construct, all 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 rights to all the potential congestion revenues. Total ARR and self scheduled FTR revenue offset 98.1 percent of total congestion costs including congestion in the Day-Ahead Energy Market and the balancing energy market for the 2016/2017 planning period, before the allocation of balancing congestion and M2M payments to load. For the first seven months of the 2017/2018 planning period, after the reallocation of balancing congestion and M2M payments, ARR and self scheduled FTR revenue offset 79.4 percent of total congestion. One of the reasons for this inefficiency is the link, established by PJM member companies in their initial FTR filings prior to the opening of the PJM market, 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 contract path based view of congestion rooted in physical transmission rights. In

1 *See* 81 FERC ¶ 61,257, at 62,241 (1997).
2 *See Id.* at 62, 259–62,260 & n. 123.

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 but it served as a reasonable approximation in the early years, although that is no longer true. 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.

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.[4] Under the order, PJM allocates the costs of balancing congestion and market to market payments to load and exports effective June 1, 2017, for the 2017/2018 planning period. Under the order, PJM allocates all excess congestion revenue from the day-ahead market to FTR Holders and allocates excess auction revenue 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. The design should simply have provided for the return of all congestion revenues to load. 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 State of the Market Report for PJM* focuses on the 2017/2020 Long Term FTR Auction, the 2017/2018 Annual FTR Auction and the 2016/2017 and 2017/2018 Monthly Balance of Planning Period FTR Auctions for the 2016/2017 and 2017/2018 planning periods, specifically covering January 1, 2017, through December 31, 2017.

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).

### Table 13-1 The FTR auction markets results were competitive

| Market Element | Evaluation | Market Design |
|---|---|---|
| Market Structure | Competitive | |
| Participant Behavior | Competitive | |
| Market Performance | Competitive | Flawed |

- Market structure was evaluated as competitive because the FTR Auction is voluntary and the ownership positions resulted from the distribution of ARRs and voluntary participation. But it is not clear, in a competitive market, why the ownership structure of Long Term FTRs is so highly concentrated.
- Participant behavior was evaluated as competitive because there was no evidence of anticompetitive 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 or effective way to ensure that all congestion revenues are returned to load. ARR holders' rights to congestion revenues are not defined clearly enough. ARR holders cannot determine the price at which they are willing to sell rights to congestion revenue. PJM defines the share of system capability made available for sale as FTRs.

# 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. Residual ARRs with negative target allocations are not allocated to participants. Instead they are removed and the model is rerun.

In the first seven months of the 2017/2018 planning period, PJM allocated a total of 23,506.1 MW of residual ARRs, up from 21,600.4 MW in the first seven months of the 2016/2017 planning period, with a total target allocation of $7.9 million for the first seven months of the 2017/2018 planning period, up from $4.2 million for the first seven months of the 2016/2017 planning period.

- **ARR Reassignment for Retail Load Switching.** There were 33,771 MW of ARRs associated with $245,600 of revenue that were reassigned in the first seven months of the 2017/2018 planning period. There were 27,920 MW of ARRs associated with $315,900 of revenue that were reassigned for the first seven months of the 2016/2017 planning period.

### Market Performance

- **Revenue Adequacy.** For the first seven months of the 2017/2018 planning period, the ARR target allocations, which are based on the nodal price differences from the Annual FTR Auction, were $555.5 million, while PJM collected $568.6 million from the combined Annual and Monthly Balance of Planning Period FTR Auctions, making ARRs revenue adequate. ARRs have historically been fully funded by the revenue collected from the Annual FTR Auction. As a result, ARRs do not receive revenue collected from the long term or monthly auctions. For the 2016/2017 planning period, the ARR target allocations were $914.2 million while PJM collected $941.5 million from the combined 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 74.5 percent of total congestion costs, which include congestion in the Day-Ahead Energy Market and the balancing energy market, for the 2011/2012 planning period through the 2017/2018 planning period. In the first seven months of the 2017/2018 planning period, in which balancing congestion and M2M payments were directly assigned to load, total ARR and self scheduled FTR revenues offset 79.4 percent of total congestion costs. Without the allocation of balancing congestion to load, the total offset offered by ARRs and FTRs would have been 90.5 percent. The goal of the FTR market design should be to ensure that load has the rights to 100 percent of the congestion revenues.

## Financial Transmission Rights

### Market Structure

- **Supply.** The principal binding constraints limiting the supply of FTRs in the 2017/2020 Long Term FTR Auction include the St. John's Transformer in Dominion and the Elliott-Rosewood Line in AEP. The principal binding constraints limiting the supply of FTRs in the Annual FTR Auction for the 2017/2018 planning period include the Bunsonville Flowgate in MISO and the Silver Lake-Silver Lake Line in ComEd.

In a given auction round, market participants can sell FTRs that they have acquired in preceding auction rounds. In the 2017/2020 Long Term FTR Auction, total participant FTR sell offers were 208,405 MW, down from 327,980 in the 2016/2017 Long Term FTR Auction. In the 2017/2018 Annual FTR Auction, total participant sell offers were 276,844 MW, down from 378,431 MW in the 2016/2017 Annual FTR Auction. In the Monthly Balance of Planning Period FTR Auctions for the first seven months of the 2017/2018 planning period, total participant FTR sell offers were 3,228,291 MW, up from 3,173,126 MW for the same period during the 2016/2017 planning period.

- **Demand.** In the 2017/2020 Long Term FTR Auction, total FTR buy bids were 2,176,871 MW, down 11.5 percent from 2,459,946 MW the previous planning period. There were 2,306,063 MW of buy and self scheduled bids in the 2017/2018 Annual FTR Auction, down 11.0 percent from 2,592,183 MW the previous planning period. The total FTR buy bids from the Monthly Balance of Planning Period FTR Auctions for the first seven months of the 2017/2018 planning period decreased 8.9 percent from 14,971,267 MW for the same time period of the prior planning period, to 13,631,502 MW.
- **Patterns of Ownership.** For the 2017/2020 Long Term FTR Auction, financial entities purchased 77.5 percent of prevailing flow FTRs and 84.9 percent of counter flow FTRs. For the 2017/2018 Annual FTR Auction, financial participants purchased 60.1 percent of all prevailing flow FTRs and 76.7 percent of all counter flow FTRs. For the Monthly Balance of Planning Period Auctions, financial entities purchased 74.3 percent of prevailing flow and 82.7 percent of counter flow FTRs January through December of 2017. Financial entities owned 59.6 percent of all prevailing and counter flow FTRs, including 50.4 percent of all prevailing flow FTRs and 71.9 percent of all counter flow FTRs during the period from January through December, 2017.

## Market Behavior

- **FTR Forfeitures.** FTR forfeitures were not billed after January 19, 2017, pending retroactive implementation of a new FTR forfeiture rule. As of the September bill, PJM has begun retroactive billing under the new FTR forfeiture rule. In the period without FTR forfeiture bills, no information on forfeitures was provided to participants and behavior could not be adjusted.
- **Credit Issues.** There were two collateral defaults in 2017, for a total of $318,746. Both defaults were cured reasonably promptly.

## Market Performance

- **Volume.** The 2017/2020 Long Term FTR Auction cleared 297,083 MW (13.6 percent) of FTR buy bids, up 7.1 percent from 277,397 MW (11.3 percent) in the 2016/2019 Long Term FTR Auction. The Long Term FTR Auction also cleared 36,782 MW (17.6 percent) of FTR sell offers, compared to 61,210 (18.7 percent), a 40.0 percent decrease.

  In the Annual FTR Auction for the 2017/2018 planning period 513,263 MW (22.3 percent) of buy and self schedule bids cleared, up 22.1 percent from 420,198 MW (16.2 percent) for the previous planning period. In the first seven months of the 2017/2018 planning period Monthly Balance of Planning Period FTR Auctions cleared 1,933,854 MW (14.2 percent) of FTR buy bids and 791,546 MW (24.5 percent) of FTR sell offers.
- **Price.** The weighted average buy bid FTR price in the 2017/2020 Long Term FTR Auction was $0.04 per MW, down from $0.05 per MW for the 2016/2019 planning period. The weighted average buy bid FTR price in the Annual FTR Auction for the 2017/2018 planning period was $0.51 per MW, up from $0.49 per MW in the 2016/2017 planning period. The weighted average buy bid cleared FTR price in the Monthly Balance of Planning Period FTR Auctions for the first seven months of the 2017/2018 planning period was $0.12, down from $0.13 per MW for the same period in the 2016/2017 planning period.
- **Revenue.** The 2017/2020 Long Term FTR Auction generated $26.7 million of net revenue for all FTRs, up from $23.2 million for the 2016/2019 Long Term FTR Auction. The 2017/2018 Annual FTR Auction generated $542.2 million in net revenue, down from $909.0 million for the 2016/2017 Annual FTR Auction. The Monthly Balance of Planning Period FTR Auctions generated $26.4 million in net revenue for all FTRs for the first seven months of the 2017/2018 planning period, down from $26.7 million for the same time period in the 2016/2017 planning period.
- **Revenue Adequacy.** FTRs were paid at 100 percent of the target allocation level for the first seven months of the 2017/2018 planning period. This high level of revenue adequacy was at least partially a result of FERC redefining the FTR congestion calculation to exclude balancing congestion and M2M payments.
- **Profitability.** FTR profitability is the difference between the revenue received for an FTR and the cost of the FTR. In the first seven months of the 2017/2018 planning period, physical entities made $32.1 million in profits, while receiving $85.5 million in returned congestion from self scheduled FTRs, and financial entities made $87.7 million in profits.

## 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 |
|---|---|---|
| 2018/2021 Long Term | 6/2/2017 | 12/12/2017 |
| 2018/2019 ARR | 3/5/2018 | 4/6/2018 |
| 2018/2019 Annual | 4/10/2018 | 5/7/2018 |

## 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 Long Term FTRs be modified to include only a one year ahead FTR. (Priority: High. First reported Q2, 2017. Status: Not adopted.)
- The MMU recommends that the full transmission capacity of the system be allocated as ARRs prior to sale as FTRs. (The MMU recommends that all requested ARR rights for each delivery year be reserved for ARR holders during the Long Term FTR Auction.) (Priority: High. New recommendation. Status: Not adopted.)
- The MMU recommends that all FTR auction revenue, including auction revenue from the sale of Long Term FTRs, 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 market 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 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: Adopted 2017)
- 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, including the use of probabilistic outage modeling. (Priority: Low. First reported 2013. Status: Not adopted.)
- 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: Partially adopted, 2014/2015 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

5 See "PJM Manual 6: Financial Transmission Rights," Rev. 18 (Sep. 1, 2017) at 55.

fixed charges paid for firm transmission services result in the transmission system which provides physically firm transmission service which results in the delivery of low cost generation which results, in an LMP system, 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 of congestion revenues in an LMP market. In other words, load payments in excess of generation revenues are the source of the funds used 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. With the creation of ARRs and the creation of FTRs as a derivative product, the purchasers of FTRs do not pay for firm transmission service, do not have the right to financially firm transmission service and 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 63.8, 86.5 and 98.1 percent of total congestion costs including congestion in the Day-Ahead Energy Market and the balancing energy market for the 2014/2015, 2015/2016 and 2016/2017 planning periods. The results for 2016/2017 resulted from the FTR Market expecting higher congestion than was realized. Day-ahead congestion was down 19.3 percent and balancing congestion was down 41.9 percent between the 2015/2016 and 2016/2017 planning periods. The FTR auction cleared, relative to realized congestion, at a higher relative price in 2016/2017 than in 2014/2015.

In the 2014/2015, 2015/2016 and 2016/2017 planning periods, PJM limited the allocation of ARR capacity, and FTRs, through outage selection to manage FTR funding. This resulted in a surplus of congestion revenue relative to FTR target allocations. This also resulted in a significant redistribution of ARRs among ARR holders based on differences in allocations between Stage 1A and Stage 1B ARRs.

As of the 2017/2018 planning period, as a result of the FERC order, balancing congestion and M2M payments are assigned to load, rather than to FTR Holders. Load is significantly worse off as a result of the changes made to the FTR/ARR process by PJM based on the FERC order of September 15, 2016. ARR holders can expect a decrease in ARR revenues and an increase in the volatility of ARR revenues under the new rules. ARR revenues were significantly reduced for the 2017/2018 FTR Auction, the first auction under the new rules. ARRs and self scheduled FTRs offset 79.4 percent of total congestion costs for the first seven months of the 2017/2018 planning period rather than the 90.5 percent offset that would have occurred under the prior rules. The increase in ARR value from the reassignment of balancing congestion and M2M payments to load, as predicted by proponents of the reassignment, did not occur.

Load should never be required to subsidize payments to FTR Holders, regardless of the reason. Such subsidies have been suggested repeatedly.[6] The FERC order of September 15, 2016, introduced a subsidy to FTR Holders at the expense of ARR holders.[7] The order requires PJM to ignore balancing congestion when calculating total congestion dollars available to fund FTRs. This approach ignores the fact that loads must pay both day-ahead and

6 See FERC Dockets Nos. EL13-47-000 and EL12-19-000.

7 See 156 FERC ¶ 61,180.

balancing congestion and that congestion is defined, in an accounting sense, to equal the sum of day-ahead and balancing congestion. Eliminating balancing congestion from the FTR revenue calculation requires load to pay twice for congestion. Load will have to continue paying for the physical transmission system, will have to continue paying in excess of generator revenues and load will not have balancing congestion included in the calculation of congestion. These changes were made in order to increase the payout to holders of FTRs who are not loads. In other words, load will continue to be the source of all the funding for 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 shifts substantial revenue from load to the holders of FTRs and reduces the ability of load to offset congestion. Under the old allocation rule ARR holders would have had an effective offset of 90.5 percent of congestion in the first seven months of the 2017/2018 planning period rather than the 79.4 percent effective offset that resulted from the new rule, a loss of $36.5 million.

If these allocation rules had been in place beginning with the 2011/2012 planning period, ARR holders would have received a total of $1,034.2 million less in congestion offsets from the 2011/2012 through the 2016/2017 planning period. The total overpayment to FTR Holders for the 2011/2012 through 2016/2017 planning period would have been $944.4 million. The underpayment to load and the overpayment to FTR Holders is a result of several factors in the 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 while degrading the ability of ARRs to provide a predictable offset to congestion costs. PJM will continue to clear counter flow FTRs using auction revenues greater than the ARR target allocations in order to make it possible to sell more prevailing flow FTRs. FTR Holders will also receive day-ahead congestion revenues in excess of target allocations. FTR Holders will also receive additional auction revenue, which is what FTR Holders were willing to pay for FTRs above what is provided to ARR holders through ARR target allocations on defined paths.

Revenue adequacy has received a lot of attention in the PJM FTR Market. There are several factors that can affect the reporting, distribution of and quantity of funding in the FTR Market. Revenue adequacy is misunderstood. FTR Holders, with the creation of ARRs, do not have the right to financially firm transmission service and FTR Holders do not have the right to revenue adequacy 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.

PJM used a more conservative approach to modeling the transmission capability for the 2014/2015 through 2016/2017 planning periods compared to the 2013/2014 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, an increase in ARR target allocations and an increase in congestion revenues not assigned to ARRs. The market response to the reduced supply of FTRs was increased bid prices, increased clearing prices and reduced clearing quantities. For the 2017/2018 planning period PJM assigned all balancing congestion and M2M payments to load and exports. As a result, PJM also reversed course and increased the availability of Stage 1B and Stage 2 FTRs. The market response to the increased supply of FTRs was lower bid prices and clearing prices.

Clearing prices fell and cleared quantities increased from the 2010/2011 planning period through the 2013/2014 planning period. The market response to lower revenue adequacy was to reduce bid prices and to increase bid volumes and offer volumes. In the 2014/2015, 2015/2016 and 2016/2017 planning periods, due to reduced ARR allocations resulting from PJM's actions to manage FTR revenue, FTR volume decreased relative to the 2013/2014 planning period. The reduction in ARR allocations and resulting FTR volume caused, by definition, an improvement in revenue adequacy, and also resulted in an increase in the prices of FTRs. Increased FTR prices resulted in increased ARR target allocations, because ARR target allocations are based on the Annual FTR Auction nodal prices. In the 2017/2018 planning period, based on the reallocation of balancing congestion and M2M payments to load, PJM reduced outages in the Annual FTR Auction model. This increased

FTR capability, but decreased ARR target allocations resulting from lower FTR clearing prices.

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

If netting within portfolios were eliminated and the payout ratio were calculated correctly, the payout ratio in the 2013/2014 planning period would have been 87.5 percent instead of the reported 72.8 percent. The MMU recommends that netting of positive and negative target allocations within portfolios be eliminated.

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

There is no reason to treat counter flow FTRs more favorably than prevailing flow FTRs. Counter flow FTRs should also be affected when the payout ratio is less than 100 percent. This would mean that counter flow FTRs would pay back an increased amount that mirrors the decreased payments to prevailing flow FTRs. The adjusted payout ratio would evenly divide the impact of lower payouts among counter flow FTR Holders and prevailing flow FTR Holders by increasing negative counter flow target allocations by the same amount it decreases positive target allocations. The FTR Market cannot work efficiently if FTR buyers do not receive payments consistent with the performance of their FTRs. Eliminating the counter flow subsidy would be another good step in that direction.

The result of removing portfolio netting and applying a payout ratio to counter flow FTRs would have increased the calculated payout ratio in the 2013/2014 planning period from the reported 72.8 percent to 91.0 percent. For the 2014/2015, 2015/2016 and 2016/2017 planning periods 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 reduced revenue and cross subsidy.

The MMU recommends that the basis for the Stage 1A assignments be reviewed and made explicit and that the role of out of date generation to load paths be reviewed beyond the replacement of retired generation that was implemented. 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.

In addition to addressing these issues, the approach to the question of FTR funding should also examine 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 annual and long term FTR auction models; 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; 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 FTR target allocations 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. It is also not clear, in a competitive market, why the ownership structure of long term FTRs is so highly concentrated for the three year product and why participation in the Long Term FTR Auction continues to be very low for the second and third year long term product. The apparent lack of competition to purchase Long Term FTRs (three year product), results in low prices when compared to the resale prices in Annual FTR Auctions. In a competitive market the price of Long Term FTRs would be expected to converge with the prices of Annual FTRs, but there has been a persistent, wide divergence that has made the purchase of Long Term FTRs persistently very profitable.

It has become increasingly clear that the long term FTR auction structure should be significantly modified. The value of congestion rights sold in the long term FTR auction are not available to load via ARRs. The Long Term FTR auction sells congestion rights that are not allocated to ARR holders. These congestion rights are not available to ARR holders in the annual ARR allocation because the outages included in the annual auction are not included in the long term FTR auction model and because scheduled system upgrades are not included in the annual FTR auction model but are included in the long term FTR auction model. Even the additional revenue from the sale of these congestion rights are not returned to ARR holders. Auction revenue from the sale of FTRs in the Long Term FTR Auction is not returned to ARR holders. An estimate of the value of these congestion rights is based on the difference in price for congestion rights between the annual auction and the long term auction for the same years. The prices in the Long Term FTR Auction are much lower than those in the Annual FTR Auction. The difference in revenue over the previous four planning periods was $337.2 million. There is no reason to continue to fail to assign congestion rights to load and to make it available solely to the purchasers of long term FTRs.

## 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 in the FTR Auction.[8] 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 and their assessment of competitive conditions in the FTR Market.

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 would receive based on the FTR auction price differences. ARR credits can be positive or negative

8 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.

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 auction revenues greater than the ARR target allocations, the revenue is currently incorrectly treated as surplus and given to FTR Holders. ARR revenues result from the sale of congestion rights that belong to ARR holders. All ARR revenues should therefore be allocated to ARR holders and not used to fund FTRs.

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 congestion revenues whether through self scheduling or selling the rights to FTR Holders. 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.[9] Each network service customer within a zone is allocated a share of the IARRs in the zone based on their share of the network service peak load of the zone.

## Market Structure

ARRs have been available to network service and firm, point to point transmission service customers since June 1, 2003, when the annual ARR allocation was first implemented for the 2003/2004 planning period. The initial allocation covered the Mid-Atlantic Region and the APS Control Zone. For the 2006/2007 planning period, the choice of ARRs or direct allocation FTRs was available to eligible market participants in the AEP, DAY, DLCO and Dominion control zones. For the 2007/2008 and subsequent planning periods through the present, all eligible market participants were allocated ARRs.

### Supply and Demand

System capability available to ARR holders is limited by the system capability made available in PJM's annual FTR transmission system market model. PJM's annual FTR transmission market model represents annual, expected system capability, modified by PJM to achieve PJM's goal of guaranteeing revenue equal to target allocations for FTRs, and subject to the requirement that all Stage1A ARR requests must be allocated. Stage 1A ARR right requests are guaranteed and system capability necessary to accommodate the rights must be included in PJM's annual FTR transmission system market model.

### ARR Allocation

For the 2007/2008 planning period, the annual ARR allocation process was revised to include Long Term ARRs that would be in effect for 10 consecutive planning periods.[10] Stage 1A ARRs can give LSEs the ability to offset their congestion costs, through the return of congestion revenues, on a long-term basis. Stage 1B and Stage 2 ARRs provide a method for ARR holders to have more congestion revenues returned to them in the planning period, but may be prorated. ARR holders

9 "PJM Manual 6: Financial Transmission Rights," Rev. 18 (Sep. 1, 2017) 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>.

10 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.

can self schedule ARRs as FTRs during the Annual FTR Auction.

Each March, PJM allocates annual 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, which is the lowest daily peak load in the prior twelve month period increased by load growth projections. The amount of Stage 1A ARRs a participant can request is based on generation to load paths that reflect generation resources that had historically served load, or their qualified replacements if the resource has retired, in the historical reference year for the zone. The historical reference year is the year prior to the creation of PJM markets, which is 1999 for the original zones, or the year in which a zone joined PJM. Firm, point to point transmission service customers can obtain Stage 1A ARRs, up to 50 percent of the MW of 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.[11]
- **Stage 1B.** Transmission capacity unallocated in Stage 1A is available in the Stage 1B allocation for the planning period. Network transmission service customers can obtain ARRs up to their share of zonal peak load, which is the highest daily peak load in the prior twelve month period increased by load growth projections, based on generation to load paths and up to the difference between their share of zonal peak load and Stage 1A allocations. 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.
- **Stage 2.** Stage 2 of the annual ARR allocation allocates the remaining system capability equally in three steps. 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 up to their total peak network load in that zone. 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.[12] Participants may seek additional ARRs in the Stage 2 allocation.

Effective for the 2015/2016 planning period, when residual zone pricing was introduced, an ARR will default to sinking at the load settlement point if different than the zone, but the ARR holder may elect to sink their ARR at the zone instead.[13]

ARRs can be traded between LSEs prior to the first round of the Annual FTR Auction. Traded ARRs are effective for the full 12 month planning period.

When ARRs are allocated after Stage 1A, all ARRs must be simultaneously feasible, meaning 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 based on assumptions about generation and transmission outages.[14] PJM adjusts outages, line limits and closed loop interfaces to achieve target revenues. The simultaneous feasibility requirement is intended to ensure that there are adequate revenues collected from the FTR auction to satisfy all 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:

11 See "PJM Manual 6: Financial Transmission Rights," Rev. 18 (Sep. 1, 2017) at 22.

12 Id. at 21.

13 *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>.

14 "PJM Manual 6: Financial Transmission Rights," Rev. 18 (Sep. 1, 2017) at 55–56.

### Equation 13-1 Calculation of prorated ARRs[15]

$$MW = Constraint\ Capability\ x\ \left(\frac{Individual\ Requested\ MW}{Total\ Requested\ MW}\right) x \left(\frac{1}{MW\ impact\ on\ line}\right)$$

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 ARR MW that would have a power flow on the binding constraint. The PJM method prorates ARR requests in proportion to their MW value and the impact on the binding constraint. The PJM method prorates only ARRs that cause the greatest flows on the binding constraint. Were all ARR requests prorated equally, regardless of their impact on the binding constraints, the result would reduce allocated ARRs below actually available ARRs.

### FERC Order EL16-121: Stage 1A ARR Allocation

FERC ordered PJM to remove retired resources from the generation to load paths used to allocate Stage 1A ARRs.[16] PJM replaced retired units with operating generators, termed qualified replacement resources (QRRs).[17]

The method PJM implemented continues to rely on a contract path based approach. PJM only replaced retired generators, so over allocations may persist due to inaccurate generation to load paths. Existing Stage 1A resources will 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 ARRs after existing resources are allocated. As a result of this proration, the new ARRs will have lower priority than the preexisting 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 2014/2015, 2015/2016 and 2016/2017 planning periods, FTR revenue adequacy was over 100 percent. Not every month was revenue adequate, but there was additional 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 2009/2010 planning period.

This high level of revenue adequacy was primarily a result of PJM actions. PJM's actions included the arbitrary use of higher outage levels and the 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 and therefore a reduction in available FTRs.

While PJM's approach to outages in the ARR allocation and in the Annual FTR Auction reduces revenue inadequacy, it does not address the Stage 1A ARR overallocation issue directly because Stage 1A ARR allocations cannot be prorated. PJM's actions have resulted in decreased Stage 1B ARR allocations, decreased Stage 2 ARR allocations and decreased FTR capability for the 2014/2015 through 2016/2017 planning periods. Over these three planning periods PJM modeled fewer outages each subsequent planning period, resulting in more ARR and FTR availability. Following the assignment of balancing congestion and M2M payments to load beginning in the 2017/2018 planning period, PJM further reduced the number of outages taken in the ARR allocation and in the Annual FTR Auction, increasing ARR allocations and FTR availability.

Figure 13-1 shows the historic allocations for Stage 1B and Stage 2 ARRs from the 2011/2012 to 2017/2018 planning periods. There was an 84.9 percent decrease in Stage 1B ARRs allocated and an 88.1 percent decrease in total Stage 2 ARR allocations from the 2013/2014 planning period to the 2014/2015 planning period. Total Stage 1B and Stage 2 ARR allocations increased slightly in the 2015/2016 planning year over the 2014/2015 planning year allocations, from 3,497.6 MW to 5,219.6 MW. But the ARR allocations for the 2015/2016 planning year were still 78.8 percent below 2013/2014 planning period volumes of 34,444.0 MW. For the 2016/2017 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 2013/2014 planning period volumes. For the 2017/2018 planning period, Stage 1B and Stage 2 ARRs returned to 2013/2014 volumes.

15 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>.
16 156 FERC ¶ 61,180 (2016).
17 See FERC Docket No. EL16-6-003.

Figure 13-1 Historic Stage 1B and Stage 2 ARR Allocations from the 2011/2012 through 2017/2018 planning periods

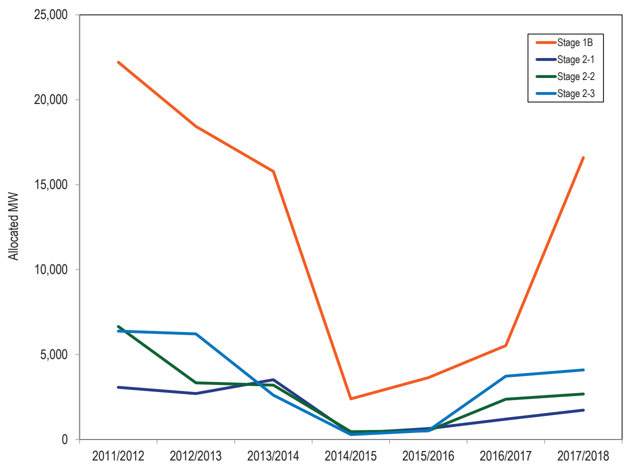



Table 13-3 shows the ARR allocations for the 2011/2012 through 2017/2018 planning periods.

Table 13-3 Historic Stage 1B and Stage 2 ARR Allocations from the 2011/2012 through 2017/2018 planning periods

| Stage | 2011/2012 | 2012/2013 | 2013/2014 | 2014/2015 | 2015/2016 | 2016/2017 | 2017/2018 |
|---|---|---|---|---|---|---|---|
| Stage 1A | 64,159.9 | 67,299.6 | 67,861.4 | 68,837.7 | 71,874.0 | 69,089.1 | 70,874.7 |
| Stage 1B | 22,208.3 | 18,431.7 | 15,782.0 | 2,389.6 | 3,643.1 | 5,525.7 | 16,592.3 |
| Stage 2-1 | 3,072.5 | 2,700.6 | 3,519.2 | 360.9 | 643.8 | 1,197.1 | 1,725.0 |
| Stage 2-2 | 6,652.6 | 3,334.3 | 3,200.0 | 455.9 | 511.2 | 2,368.8 | 2,675.0 |
| Stage 2-3 | 6,382.6 | 6,218.7 | 2,611.8 | 291.2 | 521.5 | 3,730.0 | 4,093.0 |
| Total Stage 2 | 16,107.7 | 12,253.6 | 9,331.0 | 1,108.0 | 1,676.5 | 7,295.9 | 8,493.0 |
| Total Allocations | 102,475.9 | 97,984.9 | 92,974.4 | 72,335.3 | 77,193.6 | 81,910.7 | 95,960.0 |

## ARR Reassignment for Retail Load Switching

PJM rules provide that when load switches between LSEs during the planning period, a proportional share of associated ARRs that sink in a given control or load aggregation zone is automatically reassigned to follow that load.[18] ARR reassignment occurs daily only if the LSE losing load has ARRs with a net positive economic value. 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 may be reassigned multiple times over a planning period. Residual ARRs are also subject to 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, the 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 44,056 MW of ARRs associated with $492,500 of revenue that were reassigned in the 2016/2017 planning period. There were 33,771 MW of ARRs associated with $245,600 of revenue that were reassigned for the first seven months of the 2017/2018 planning period.

Table 13-4 summarizes ARR MW and associated revenue reassigned for network load in each control zone where changes occurred between June 2016 and December 2017.

18 See "PJM Manual 6: Financial Transmission Rights," Rev. 18 (Sep. 1, 2017) at 28.

Table 13-4 ARRs and ARR revenue automatically reassigned for network load changes by control zone: June 1, 2016 through December 31, 2017

| | ARRs Reassigned (MW-day) | | ARR Revenue Reassigned [Dollars (Thousands) per MW-day] | |
|---|---|---|---|---|
| Control Zone | 2016/2017 (12 months) | 2017/2018 (7 months) | 2016/2017 (12 months) | 2017/2018 (7 months) |
| AECO | 451 | 286 | $4.0 | $1.9 |
| AEP | 1,952 | 1,613 | $11.8 | $9.0 |
| APS | 1,617 | 1,303 | $33.4 | $14.7 |
| ATSI | 8,415 | 4,290 | $45.8 | $13.8 |
| BGE | 2,213 | 2,082 | $131.5 | $43.9 |
| ComEd | 3,468 | 3,477 | $113.9 | $58.4 |
| DAY | 821 | 1,314 | $2.4 | $2.4 |
| DEOK | 3,335 | 3,194 | $19.1 | $16.7 |
| DLCO | 5,464 | 5,031 | $12.9 | $15.3 |
| DPL | 1,538 | 1,266 | $31.3 | $23.7 |
| Dominion | 55 | 2 | $0.2 | $0.0 |
| EKPC | 0 | 0 | $0.0 | $0.0 |
| JCPL | 1,105 | 782 | $3.7 | $1.6 |
| Met-Ed | 825 | 444 | $6.8 | $3.6 |
| PECO | 3,468 | 2,559 | $8.8 | $7.3 |
| PENELEC | 1,150 | 451 | $17.3 | $4.5 |
| PPL | 4,055 | 2,657 | $5.0 | $2.6 |
| PSEG | 1,640 | 983 | $23.0 | $11.8 |
| Pepco | 2,419 | 1,938 | $21.3 | $14.3 |
| RECO | 65 | 101 | $0.1 | $0.0 |
| Total | 44,056 | 33,771 | $492.5 | $245.6 |

## Residual ARRs

Residual ARRs are available if transmission system capability is added during the planning period after the annual ARR allocation if the additional transmission system capability was not accounted for in the annual ARR allocation. Residual ARRs are effective on the first day of the month in which the additional transmission system capability is available and through the end of the planning period. For the following planning period, these Residual ARRs are available as ARRs in the annual ARR allocation. Residual ARRs are a separate product from incremental ARRs.

Stage 1 ARR holders have a priority right to Residual ARRs, which cannot be declined. Beginning with the June 2017 monthly auction, Residual ARRs that would have cleared with a negative target allocation are not assigned to participants.[19] 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. Residual ARR target allocations are based on the clearing prices from FTR obligations in the relevant 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 (cleared volume) allocated to participants, along with the target allocations (bid and requested) from the effective month. In the first seven months of the 2017/2018 planning period, PJM allocated a total of 36,940.6 MW of residual ARRs with a target allocation of $10.6 million. In the 2016/2017 planning period planning period, PJM allocated a total of 35,034.9 MW of residual ARRs, up from 30,118.1 MW for the 2015/2016 planning period. Residual ARRs had a total target allocation of $7.0 million for the 2016/2017 planning period, down from $7.7 million for the 2015/2016 planning period. In prior planning years, PJM's modeling of excess outages resulted in the allocation of some ARRs that could have been allocated in Stage 1B 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 |
| Apr-17 | 8,334.5 | 3,313.8 | 39.8% | $347,694 |
| May-17 | 6,312.2 | 3,268.7 | 51.8% | $55,180 |
| Jun-17 | 4,241.0 | 3,666.1 | 86.4% | $805,206 |
| Jul-17 | 6,018.8 | 3,850.9 | 64.0% | $1,773,770 |
| Aug-17 | 4,714.5 | 3,421.9 | 72.6% | $872,879 |
| Sep-17 | 6,835.2 | 3,284.5 | 48.1% | $1,303,420 |
| Oct-17 | 6,987.3 | 2,773.9 | 39.7% | $431,097 |
| Nov-17 | 4,077.7 | 3,098.7 | 76.0% | $1,115,536 |
| Dec-17 | 6,505.6 | 3,410.1 | 52.4% | $1,564,094 |
| Total | 72,470.2 | 36,940.6 | 51.0% | $10,610,089 |

# 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. The rules provide that if a simultaneous feasibility test violation occurs in any year, PJM will identify or accelerate any

19 See FERC Letter Order, "Revisions to cease awarding negative Residual Auction Revenue Rights," Docket No. ER17-1057 (April 5, 2017).

transmission upgrades to resolve the violation and these upgrades will be recommended for inclusion in the PJM RTEP process.[20] But such transmission upgrades are not actually built.

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 associated with Stage 1A overallocations 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. This continues to be true even with the replacement of retired generating units.

For the 2017/2018 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.

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.

Table 13-6 shows the value of 2016/2017 and 2017/2018 allocated ARRs at FTR prices from both planning periods. For example, in the 2017/2018 planning period, ARRs allocated in that planning period are expected to be worth a total of $545.2 million. The MMU calculates that the same allocated ARRs, but at 2016/2017 planning period prices, would have been worth $1,139.8 million. This substantial reduction in expected revenue from the same set of ARRs is a result of a significant reduction in FTR prices, and therefore ARR revenue, resulting from PJM's modeling decisions following the allocation of balancing congestion to load and exports. The predicted increased in value to ARR holders from shifting balancing congestion out of FTR funding did not occur, and in fact ARR holders can expect to receive less total revenue and more volatility while FTR Holders experience increased profits and revenue stability.[21]

### Table 13-6 ARR Revenue at 2016/2017 and 2017/2018 planning period FTR prices

| | 2016/2017 ARRs | 2017/2018 ARRs |
|---|---|---|
| 2016/2017 Value | $907,756,156 | $454,527,372 |
| 2017/2018 Value | $1,139,824,163 | $545,229,437 |

## Revenue Adequacy

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.

Total net FTR auction revenue for the 2016/2017 planning period, before accounting for self scheduling, load shifts or residual ARRs, was $941.5 million. The FTR auction revenue collected pays ARR holders' credits. During the 2017/2018 planning period, total net FTR auction revenue was $568.6 million.

Table 13-7 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 2016/2017 planning period and the first seven months of the 2017/2018 planning periods.

20 "PJM Manual 6: Financial Transmission Rights," Rev. 18 (Sep.1, 2017) at 22.

21 *See* "Post-Technical Conference Comments of DC Energy, LLC; Inertia Power, LP; Saracen Energy East LP; and Vitol Inc.," Docket No. EL16-6 (March 15, 2016) at 28.

Table 13-7 Projected ARR revenue adequacy (Dollars (Millions)): Planning periods 2016/2017 and 2017/2018

| | 2016/2017* | 2017/2018** |
|---|---|---|
| Total FTR auction net revenue | $941.5 | $568.6 |
| Annual FTR Auction net revenue | $909.0 | $542.2 |
| Monthly Balance of Planning Period FTR Auction net revenue* | $32.5 | $26.4 |
| ARR target allocations | $914.2 | $555.5 |
| ARR credits | $914.2 | $555.5 |
| Surplus auction revenue | $27.4 | $13.2 |
| ARR payout ratio | 100% | 100% |
| FTR payout ratio* | 100% | 100% |

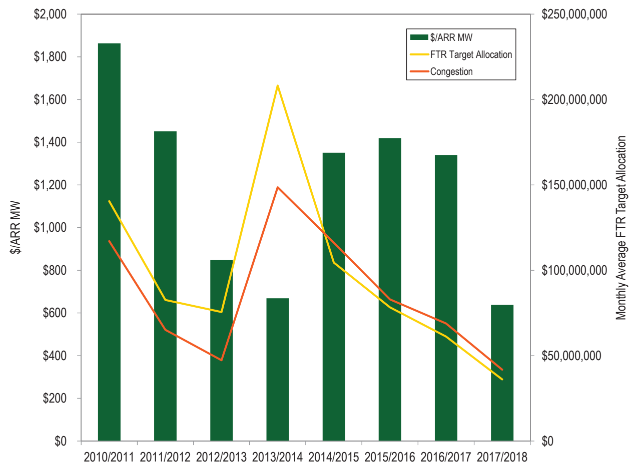
* Shows twelve months for 2016/2017

** Shows seven months for 2017/2018

Figure 13-2 shows the dollars per ARR MW held for each month of the 2010/2011 planning period through the first seven months of the 2017/2018 planning period. The ARR MW held do not include self scheduled FTRs but do include Residual ARRs starting in August 2012. FTR prices increased in the 2014/2015 Annual FTR Auction as a result of reduced supply caused by PJM's assumption of more outages in the model used to allocate Stage 1B and Stage 2 ARRs. The increased FTR prices resulted in an increase in dollars paid per ARR MW. For the 2014/2015 planning period, the total dollars per MW of ARR allocation was $11,279, while the previous planning period resulted in a dollars per MW of $6,692, a 68.5 percent increase in payment per allocated ARR MW. Some of the ARR MW lost from proration were provided in the Residual ARR process, but the residual allocations are not comparable to the ARRs awarded in the annual process because residual ARR allocations change each month and cannot be self scheduled as FTRs. For the 2015/2016 planning period, the dollars per MW of ARR allocation was $10,641.54. For the 2016/2017 planning period, the dollars per MW of ARR allocation were $10,411.

The dollar per MW value of ARRs in the first seven months of the 2017/2018 planning period decreased 51.0 percent from the previous planning period. ARR value was expected to increase in the 2017/2018 planning period from higher FTR prices paid in expectation of increased revenue with no balancing congestion offset, but this increased value did not materialize. FTRs buyers paid less. Figure 13-2 shows that the total congestion and FTR target allocations did not change significantly from the 2016/2017 to the 2017/2018 planning period, but that ARR value was significantly lower. Load is now paying balancing congestion costs, not accounted for in this figure, reducing revenue received by ARR holders.

Figure 13-2 Dollars per ARR MW paid to ARR holders compared to congestion and FTR target allocations: 2010/2011 through 2017/2018




## Auction Revenue

Figure 13-3 shows the monthly auction revenue collected each month from FTR auctions above ARR target allocations from the 2011/2012 through 2017/2018 planning periods.

Beginning with the 2014/2015 planning period, market rules allow PJM to decrease prevailing flow target allocations by clearing counter flow FTRs, without making the opposite prevailing flow FTR available, as long as ARRs remain revenue adequate.[22] This allows PJM to use 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 ARR revenue over ARR target allocations beginning in June 2014. The extra auction revenue is allocated pro rata to FTR Holders at the end of the

22 *See* "PJM Manual 6: Financial Transmission Rights," Rev. 18 (Sep. 1, 2017) at 55.

planning period. All FTR auction revenue should be distributed to ARR holders.

### Figure 13-3 Monthly additional ARR revenue: Planning periods 2011/2012 through 2017/2018

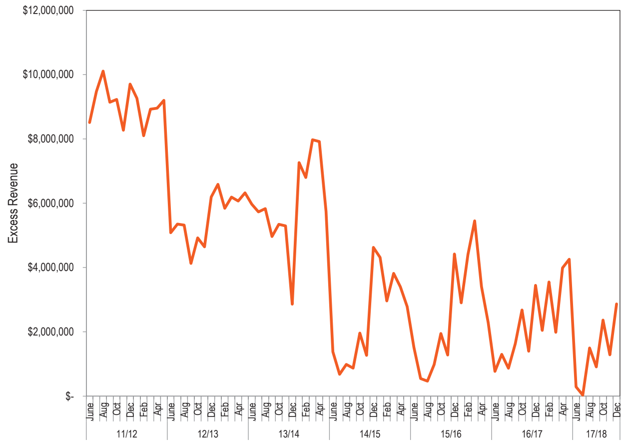



Table 13-8 shows the auction revenue over ARR target allocations, by planning period, for planning periods 2010/2011 through 2017/2018.

### Table 13-8 Additional Auction Revenue: Planning periods 2010/2011 through 2017/2018

| Planning Period | Excess Auction Revenue |
|---|---|
| 2010/2011 | $29,704,562 |
| 2011/2012 | $108,874,342 |
| 2012/2013 | $66,652,822 |
| 2013/2014 | $71,687,937 |
| 2014/2015* | $29,045,590 |
| 2015/2016 | $29,612,591 |
| 2016/2017 | $27,917,175 |
| 2017/2018** | $9,246,362 |
| Total | $372,741,381 |

*Start of counter flow "buy back"

**Through December 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, but without guarantee. 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 congestion, payments by holders of negatively valued FTRs, Market to Market payments, additional auction revenues available at the end of a month over ARR target allocations 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 a level greater than their target allocations.

FTR funding is not on a path specific basis or on an hour to hour 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. Self scheduled FTRs represent a direct return of day-ahead congestion revenue to load serving entities but not a complete return of congestion revenue to load.

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 for the 24 hour product and only in the Annual FTR Auction.

## Market Structure

### Supply and Demand

PJM oversees the process of selling and buying FTRs through FTR Auctions. Market participants purchase FTRs by participating in Long Term, Annual and Monthly Balance of Planning Period FTR Auctions.[23] FTRs can also be traded between market participants through bilateral transactions. ARRs may be self scheduled as FTRs in the Annual FTR Auction.

Total annual FTR supply is limited by the capability of the transmission system, included in the PJM FTR market model as modified, for example, by PJM assumptions about outages. PJM assumptions are a key factor in determining the supply of ARRs and the related supply of FTRs. In general, the supply of FTRs is consistent with the supply of ARRs, for example in the annual auction. But there is a very significant exception and this exception is inconsistent with the basic logic of the ARR/FTR approach. There is transmission system capability made available in the Long Term FTR Auction to FTR buyers that is not available to ARR holders and ARR holders do not receive the proceeds for the sale of these rights. The result is that the revenues made available to load to offset congestion are understated. The supply of FTRs in the Long Term FTR Auction includes transmission system capability that is not available as ARRs. PJM expands the available transmission capacity for the Long Term FTR Auction above what can be allocated to ARRs by removing all the transmission outages included in the model when allocating ARRs. Total Monthly FTR Auction capacity is based on the residual capacity available after the long term and annual FTR auctions are conducted.

The MMU recommends that the full transmission capacity of the system be allocated as ARRs prior to sale as FTRs.

23 See "PJM Manual 6: Financial Transmission Rights," Rev. 18 (Sep. 1, 2017) at 38.

Stage 1A ARR requests must be granted, which, as a result of the use of generation to load paths, artificially increases the transmission capacity in the model on affected facilities. The capacity modeled in the Annual ARR Allocation is used as the capacity for the Annual FTR Auction. 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 artificially increased, contributing to FTR revenue inadequacy. Where FTR supply is less than system capability, FTR target allocations will be lower, consistent with an FTR revenue surplus.

PJM can also make further adjustments to the auction model to manage FTR revenues. 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 very significant adjustments starting in the 2014/2015 planning period auction model through the 2016/2017 planning period.

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.[24] 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. None of these outages are included in the transmission market model used for the Long Term FTR Auction.

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.[25] 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 to better align the supply of ARRs and FTRs with actual system capabilities.

## Long Term FTR Auctions

In July 2006, FERC issued a Final Rule mandating the creation of long term firm transmission rights in transmission organizations with organized electricity markets (FERC Docket No. RM06-8-000; Order No. 681).[26] FERC's goal was that "load serving entities be able to request and obtain transmission rights up to a reasonable amount on a long-term firm basis, instead of being limited to obtaining exclusively annual rights." Despite that order and inconsistent with the directive in that order, LSEs are not able to request ARRs nor are LSEs guaranteed rights to the revenue from Long Term FTR Auctions in PJM's long term FTR auction market design.

PJM conducts a Long Term FTR Auction for the next three consecutive planning periods. The capacity offered for sale in Long Term FTR Auctions is the residual system capability assuming that all allocated ARRs are self scheduled as FTRs. In addition, PJM expands the available transmission capacity for the Long Term FTR Auction above what can be allocated to ARRs by removing all the transmission outages included in the model when allocating ARRs.

The 2009/2012 and 2010/2013 Long Term FTR Auctions consisted of two rounds.[27] Subsequent Long Term FTR Auctions consist of three rounds. FTRs purchased in prior rounds may be offered for sale in subsequent rounds. FTRs obtained in the Long Term Auctions may

24 See "PJM Manual 6: Financial Transmission Rights," Rev. 18 (Sep. 1, 2017) at 55.

25 See 2017 Quarterly State of the Market Report for PJM: January through September, Section 12B: Transmission Facility Outages.

26 116 FERC ¶ 61,077 (2006).

27 FERC approved, on December 7, 2009, the addition of a third round to the Long Term FTR Auction. FERC letter order accepting PJM Interconnection, L.L.C.'s revisions to Long-Term Financial Transmission Rights Auctions to its Amended and Restated Operating Agreement and Open Access Transmission Tariff, Docket No. ER10-82-000 (December 7, 2009).

have terms of any one year or a single term of all three years. FTR products available in the Long Term Auction include 24 hour, on peak and off peak FTR obligations. FTR option products are not available in Long Term FTR Auctions.

- **Round 1.** The first round is conducted in the June prior to the start of the term covered by the Long Term FTR Auction and uses PJM's Summer Model build. Market participants make offers for FTRs between any source and sink.
- **Round 2.** The second round is conducted in September, uses the Summer Model build and follows the same rules as Round 1.
- **Round 3.** The third round is conducted in December, uses the Fall Model build and follows the same rules as Round 1.

Table 13-10 shows the top 10 binding constraints for the 2017 to 2020 Long Term FTR Auction based on the marginal value of on peak hours. The severity ranking is based on the marginal value of the constraint in the simultaneous feasibility test.

PJM includes a three year FTR product in the Long Term FTR Auction design. The market for the three year FTR product is highly concentrated. More than 99 percent of the three year FTRs sold in the last five FTR Long Term FTR auctions were purchased by two or three financial participants in each planning period. Table 13-9 shows the HHI for three year FTRs sold in the last five long term FTR auctions, by On Peak or Off Peak and Prevailing or counter flow.

### Table 13-9 HHIs for Three-year FTRs

| Class Type | Direction | 2014/2017 | 2015/2018 | 2016/2019 | 2017/2020 |
|---|---|---|---|---|---|
| On Peak | Prevailing | 9489 | 9778 | 4646 | 8863 |
| | Counter | 10000 | 10000 | 4524 | 6760 |
| Off Peak | Prevailing | 9708 | 9816 | 5749 | 9324 |
| | Counter | 10000 | 10000 | 5671 | 9522 |

### Table 13-10 Top 10 principal binding transmission constraints limiting the 2017/2020 Long Term FTR Auction

| | | | Severity Ranking by Auction Round | | |
|---|---|---|---|---|---|
| Constraint | Type | Control Zone | 1 | 2 | 3 |
| St. Johns | Transformer | Dominion | 1 | NA | 5 |
| Elliott - Rosewood | Line | AEP | NA | 1 | NA |
| Brown Jct. - Gates Hill | Line | APS | NA | NA | 1 |
| Mercer IP - Galesburg | Flowgate | MISO | 2 | NA | NA |
| Gore Jct. - Rolling Meadow | Line | Penelec | 3 | NA | 6 |
| Greenfield - Visteaon-Ford | Line | ATSI | NA | 2 | NA |
| Erie South - French Road | Line | Penelec | NA | 3 | NA |
| Worcester - Ocean Pines | Line | DPL | 27 | 4 | 13 |
| Gainesville | Transformer | Dominion | NA | 5 | NA |

## Annual FTR Auctions

Annual FTRs are effective beginning June 1 of the planning period through May 31. Outages expected to last two or more months are included in the determination of the simultaneous feasibility for the Annual FTR Auction. ARR holders who wish to self schedule must inform PJM prior to round one of this auction. Any self scheduled ARR requests clear 25 percent of the requested volume in each round of the Annual FTR Auction as price takers. This auction consists of four rounds that allow any transmission service customers or PJM members to bid for any FTR or to offer for sale any FTR that they currently hold. FTRs in this auction can be obligations or options for peak, off peak or 24 hour periods. FTRs purchased in one round of the Annual FTR Auction can be sold in later rounds or in the Monthly Balance of Planning Period FTR Auctions.

The FTRs sold in the Long Term FTR Auction for a future delivery year may conflict with the ARRs assigned to load in the ARR allocation process when that delivery year is the next one if the ARRs are self scheduled.

Table 13-11 shows the top 10 binding constraints for the 2017/2018 Annual FTR Auction based on the marginal value of on peak hours.

Table 13-11 Top 10 principal binding transmission constraints limiting the Annual FTR Auction: Planning period 2017/2018

| | | | Severity Ranking by Auction Round | | | |
|---|---|---|---|---|---|---|
| Constraint | Type | Control Zone | 1 | 2 | 3 | 4 |
| Bunsonville | Flowgate | MISO | 2 | 1 | 1 | 1 |
| Silver Lake - Silver Lake | Line | ComEd | 1 | 2 | 2 | 2 |
| Reynolds - Magnetation | Flowgate | MISO | 3 | 3 | 3 | 3 |
| Cherry Valley | Transformer | ComEd | 5 | 6 | 5 | 4 |
| Harbor - University | Line | ComEd | 4 | 4 | 4 | 6 |
| Garden Plain | Flowgate | MISO | 6 | 5 | 6 | 5 |
| Sheperdstown - Sleepy Hollow | Line | APS | 8 | 9 | 7 | 7 |
| State Line | Transformer | ComEd | 7 | 7 | 8 | 8 |
| Roxbury - Shade Gap | Line | Penelec | 18 | 8 | 14 | 20 |
| Bush - Lafayette | Flowgate | MISO | 9 | 14 | 23 | 29 |

## 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. 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.[28]

## Secondary Bilateral Market

Market participants can buy and sell existing FTRs through the PJM administered, bilateral market, or market participants can trade FTRs among themselves without PJM involvement. Bilateral transactions that are not done through PJM can involve parties that are not PJM members. PJM has no knowledge of bilateral transactions that are done outside of PJM's bilateral market system.

For bilateral trades done through PJM, the FTR transmission path must remain the same, FTR obligations must remain obligations, and FTR options must remain options. However, an individual FTR may be split up into multiple, smaller FTRs, down to increments of 0.1 MW. FTRs can also be given different start and end times, but the start time cannot be earlier than the original FTR start time and the end time cannot be later than the original FTR end time.

## Patterns of Ownership

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, trading firms 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 13-12 presents the 2017/2020 long term FTR auction market cleared FTRs by trade type, organization type and FTR direction. The results show that financial entities purchased 77.5 percent of prevailing flow buy bid FTRs and 84.9 percent of counter flow buy bid FTRs with the result that financial entities purchased 80.8 percent of all long term FTR auction cleared buy bids for the 2017/2020 Long Term FTR Auction. Physical entities purchased only 19.2 percent of all available long term FTRs in the 2017/2020 Long Term FTR Auction.

Table 13-12 Long term FTR auction patterns of ownership by FTR direction: Planning periods 2017/2020

| | | FTR Direction | | |
|---|---|---|---|---|
| Trade Type | Organization Type | Prevailing Flow | Counter Flow | All |
| Buy Bids | Physical | 22.5% | 15.1% | 19.2% |
| | Financial | 77.5% | 84.9% | 80.8% |
| | Total | 100.0% | 100.0% | 100.0% |
| Sell Offers | Physical | 36.9% | 26.6% | 33.3% |
| | Financial | 63.1% | 73.4% | 66.7% |
| | Total | 100.0% | 100.0% | 100.0% |

Table 13-13 presents the annual FTR auction cleared FTRs for the 2017/2018 planning period by trade type, organization type and FTR direction. In the Annual FTR Auction for the 2017/2018 planning period, financial entities purchased 77.5 percent of prevailing flow FTRs, up 20.6 percentage points, and 79.7 percent of counter flow FTRs, down 5.2 percentage points, with the results that financial entities purchased 66.6 percent, up one

28 See "PJM Manual 6: Financial Transmission Rights," Rev. 18 (Sep. 1, 2017) at 39.

percentage point, of all annual FTR auction cleared buy bids for the 2017/2018 planning period.

### Table 13-13 Annual FTR Auction patterns of ownership by FTR direction: Planning period 2017/2018

| | | | FTR Direction | | |
|---|---|---|---|---|---|
| Trade Type | Organization Type | Self-Scheduled FTRs | Prevailing Flow | Counter Flow | All |
| Buy Bids | Physical | Yes | 7.2% | 1.0% | 4.8% |
| | | No | 32.7% | 22.3% | 28.6% |
| | | Total | 39.9% | 23.3% | 33.4% |
| | Financial | No | 60.1% | 76.7% | 66.6% |
| | Total | | 100.0% | 100.0% | 100.0% |
| Sell Offers | Physical | | 21.3% | 17.6% | 20.0% |
| | Financial | | 78.7% | 82.4% | 80.0% |
| | Total | | 100.0% | 100.0% | 100.0% |

Table 13-14 presents the monthly balance of planning period FTR auction cleared FTRs for 2017 by trade type, organization type and FTR direction. Financial entities purchased 74.3 percent of prevailing flow FTRs, up 1.7 percent, and 82.7 percent of counter flow FTRs, up 0.6 percent, for the year, with the result that financial entities purchased 78.3 percent, up 1.3 percent, of all prevailing and counter flow FTR buy bids in the monthly balance of planning period FTR auction cleared FTRs for 2017.

### Table 13-14 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 | 25.7% | 17.3% | 21.7% |
| | Financial | 74.3% | 82.7% | 78.3% |
| | Total | 100.0% | 100.0% | 100.0% |
| Sell Offers | Physical | 16.7% | 17.0% | 16.8% |
| | Financial | 83.3% | 83.0% | 83.2% |
| | Total | 100.0% | 100.0% | 100.0% |

Table 13-15 presents the average daily net position ownership for all FTRs for 2017, by FTR direction.

### Table 13-15 Daily FTR net position ownership by FTR direction: 2017

| | FTR Direction | | |
|---|---|---|---|
| Organization Type | Prevailing Flow | Counter Flow | All |
| Physical | 49.6% | 28.1% | 40.4% |
| Financial | 50.4% | 71.9% | 59.6% |
| Total | 100.0% | 100.0% | 100.0% |

## Market Performance

### Volume

In an effort to manage FTR revenues, PJM may use normal transmission limits (rather than the inflated limits used in Stage 1A) in the FTR auction model. These capability limits may be reduced if ARR funding is not affected, 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 auction bids for counter flow FTRs.[29]

In another effort to manage FTR revenues, PJM implemented a rule stating that PJM may model normal capability limits (rather than the inflated limits used in Stage 1A) 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.[30]

In the 2017/2020 Long Term FTR Auction, 133,153 MW (26.8 percent of demand; 44.8 percent of total FTR volume) of counter flow FTR buy bids cleared, an increase from 120,650 MW and 43.5 percent of total FTR volume. In the same auction, prevailing flow FTR buy bids cleared 163,931 MW (9.8 percent of demand; 55.2 percent of total FTR volume) an increase from 156,746 MW and 55.2 percent of total FTR volume. In the 2017/2020 Long Term FTR Auction, there were 12,853 MW (13.5 percent) of counter flow sell offers and 23,929 MW (21.1 percent) of prevailing flow sell offers cleared.

29 See "PJM Manual 6: Financial Transmission Rights," Rev. 18 (Sep. 1, 2017) at 56.
30 See *id.*

### Table 13-16 Long Term FTR Auction market volume: Planning period 2017/2020

| Trade Type | FTR Direction | Period Type | Bid and Requested Count | Bid and Requested Volume (MW) | Cleared Volume (MW) | Cleared Volume | Uncleared Volume (MW) | Uncleared Volume |
|---|---|---|---|---|---|---|---|---|
| Buy bids | Counter Flow | Year 1 | 71,013 | 188,872 | 48,984 | 25.9% | 139,887 | 74.1% |
| | | Year 2 | 55,813 | 167,917 | 47,150 | 28.1% | 120,767 | 71.9% |
| | | Year 3 | 49,332 | 137,540 | 36,330 | 26.4% | 101,210 | 73.6% |
| | | Year All | 266 | 1,627 | 688 | 42.3% | 938 | 57.7% |
| | | Total | 176,424 | 495,955 | 133,153 | 26.8% | 362,802 | 73.2% |
| | Prevailing Flow | Year 1 | 167,750 | 646,060 | 58,233 | 9.0% | 587,826 | 91.0% |
| | | Year 2 | 129,840 | 510,387 | 61,768 | 12.1% | 448,618 | 87.9% |
| | | Year 3 | 127,220 | 508,133 | 43,709 | 8.6% | 464,425 | 91.4% |
| | | Year All | 2,760 | 16,336 | 220 | 1.3% | 16,116 | 98.7% |
| | | Total | 427,570 | 1,680,916 | 163,931 | 9.8% | 1,516,986 | 90.2% |
| | Total | | 603,994 | 2,176,871 | 297,083 | 13.6% | 1,879,788 | 86.4% |
| Sell offers | Counter Flow | Year 1 | 26,109 | 59,201 | 8,744 | 14.8% | 50,457 | 85.2% |
| | | Year 2 | 12,347 | 28,722 | 3,582 | 12.5% | 25,140 | 87.5% |
| | | Year 3 | 3,192 | 7,167 | 527 | 7.3% | 6,640 | 92.7% |
| | | Year All | NA | NA | NA | NA | NA | NA |
| | | Total | 41,648 | 95,089 | 12,853 | 13.5% | 82,237 | 86.5% |
| | Prevailing Flow | Year 1 | 29,991 | 62,737 | 14,093 | 22.5% | 48,644 | 77.5% |
| | | Year 2 | 17,866 | 40,390 | 8,575 | 21.2% | 31,814 | 78.8% |
| | | Year 3 | 4,555 | 10,189 | 1,261 | 12.4% | 8,928 | 87.6% |
| | | Year All | NA | NA | NA | NA | NA | NA |
| | | Total | 52,412 | 113,316 | 23,929 | 21.1% | 89,386 | 78.9% |
| | Total | | 94,060 | 208,405 | 36,782 | 17.6% | 171,623 | 82.4% |

### Table 13-17 Long Term FTR Auction quoted and cleared volume

| | | Physical | | | | | Financial | | | | | HHI | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Quoted Participants | Quoted MW | Cleared Participants | Cleared MW | % of Cleared | Quoted Participants | Quoted MW | Cleared Participants | Cleared MW | % of Cleared | Quoted HHI | Cleared HHI |
| 2014/2017 | YR1 | 47 | 601,036.1 | 41 | 68,000.7 | 47.0% | 23 | 771,694.9 | 23 | 76,578.9 | 53.0% | 716 | 583 |
| | YR2 | 41 | 517,206.4 | 35 | 55,761.1 | 52.1% | 18 | 523,921.7 | 17 | 51,263.5 | 47.9% | 936 | 748 |
| | YR3 | 34 | 417,715.1 | 29 | 47,902.9 | 51.4% | 16 | 487,618.8 | 15 | 45,279.0 | 48.6% | 990 | 788 |
| | YRALL | 0 | 0.0 | 0 | 0.0 | 0.0% | 3 | 69,759.9 | 2 | 7,091.9 | 100.0% | 9949 | 8263 |
| 2015/2018 | YR1 | 52 | 615,257.6 | 36 | 58,692.3 | 42.1% | 26 | 783,139.0 | 26 | 80,703.3 | 57.9% | 744 | 599 |
| | YR2 | 47 | 446,105.6 | 33 | 40,642.9 | 39.4% | 22 | 576,745.2 | 22 | 62,474.6 | 60.6% | 1061 | 856 |
| | YR3 | 34 | 422,956.7 | 28 | 32,791.8 | 50.7% | 20 | 459,985.1 | 20 | 31,945.7 | 49.3% | 927 | 621 |
| | YRALL | 0 | 0.0 | 0 | 0.0 | 0.0% | 2 | 60,982.7 | 2 | 5,191.9 | 100.0% | 9521 | 6321 |
| 2016/2019 | YR1 | 61 | 362,172.9 | 51 | 56,493.3 | 38.4% | 30 | 753,910.9 | 30 | 90,436.5 | 61.6% | 639 | 546 |
| | YR2 | 48 | 268,949.2 | 44 | 38,465.5 | 37.6% | 26 | 584,749.7 | 25 | 63,856.5 | 62.4% | 792 | 643 |
| | YR3 | 38 | 231,232.8 | 36 | 26,153.5 | 29.8% | 20 | 546,418.7 | 19 | 61,532.1 | 70.2% | 1290 | 697 |
| | YRALL | 13 | 420.0 | 10 | 31.7 | 1.9% | 3 | 40,071.6 | 3 | 1,637.9 | 98.1% | 5591 | 4349 |
| 2017/2020 | YR1 | 63 | 330,839.2 | 55 | 53,657.9 | 41.3% | 37 | 626,029.6 | 36 | 76,396.4 | 58.7% | 429 | 353 |
| | YR2 | 54 | 168,326.8 | 51 | 30,212.2 | 25.0% | 30 | 579,089.0 | 30 | 90,864.2 | 75.0% | 1635 | 1069 |
| | YR3 | 45 | 187,635.2 | 40 | 23,301.2 | 28.5% | 27 | 475,393.6 | 26 | 58,524.7 | 71.5% | 1303 | 898 |
| | YRALL | 3 | 367.0 | 2 | 72.0 | 7.9% | 3 | 17,596.0 | 1 | 836.7 | 92.1% | 8696 | 5638 |

Table 13-17 shows the quoted and cleared participant count and volume for the Long Term FTR Auctions by period type, along with the HHI. Quoted and cleared participant counts are the unique participants for that period type, not for the entire auction. The percent of cleared calculates the percentage of cleared volume held by a physical or financial participant. The calculated HHIs provide a measure of market concentration both at the quoted, to indicate participant interest, and cleared levels.

The HHI for the product including all three years (YRALL) is highly concentrated, meaning only a small number of participants hold all YRALL long term FTRs. For example, for the YRALL product auctioned in the 2017/2020 Long Term FTR Auction, three participants held all of the volume, with the single financial participant holding 92.1 percent of the YRALL product. The YR1, YR2 and YR3 cleared volume is not concentrated, but all the volume is held by approximately half the number of participants that cleared FTRs in the 2017/2018 Annual FTR Auction. In other words, the concentration of held long term FTRs is not high, but all the volume is held by only around half of FTR participants.

Financial participants purchase an increasingly large volume of long term FTRs. Financial participants held 51.2, 57.7, 64.2 and 67.9 percent of all long term FTRs for the 2014/2017, 2015/2018, 2016/2019 and 2017/2020 Long Term FTR Auctions.

Table 13-18 provides a comparison of cleared FTR obligations (not options) acquired in the Long Term FTR Auctions versus the Annual FTR Auction, for FTRs in the 2014/2015 through 2017/2018 planning periods. A three year FTR is distributed to each individual planning period during its three year effective period. Long term FTRs that are effective in a single planning period were an average of 42.6 percent of total FTR volume in the 2014/2015 through 2017/2018 planning periods.

### Table 13-18 Long Term and Annual Auction total cleared FTR MW

| | Long Term FTR Product | | | | | |
|---|---|---|---|---|---|---|
| Planning Period | Year 3 | Year 2 | Year 1 | Total Long Term | Annual (including self scheduled) | Long Term Percent of Total Cleared |
| 2014/2015 | 81,666 | 86,754 | 131,911 | 300,330 | 356,522 | 45.7% |
| 2015/2016 | 89,419 | 99,329 | 123,400 | 312,148 | 355,682 | 46.7% |
| 2016/2017 | 97,837 | 95,637 | 107,182 | 300,656 | 397,258 | 43.1% |
| 2017/2018 | 69,161 | 86,323 | 108,126 | 263,609 | 493,683 | 34.8% |

Table 13-19 provides the annual FTR auction market volume for the 2016/2017 planning period. Total FTR buy bids were 2,306,063 MW, down 11.0 percent from 2,592,183 MW for the previous planning period. For the 2016/2017 planning period 488,734 MW (21.4 percent) of buy bids cleared, up 6.1 percentage points from 393,509 MW for the previous planning period. There were 276,844 MW of sell offers with 37,990 MW (13.7 percent) clearing for the 2016/2017 planning period. The total volume of cleared buy and self scheduled bids was 513,263 MW, up 22.1 percent from 420,198 MW in the previous Annual FTR Auction.

### Table 13-19 Annual FTR Auction market volume: 2017/2018 planning period

| Trade Type | Type | FTR Direction | Bid and Requested Count | Bid and Requested Volume (MW) | Cleared Volume (MW) | Cleared Volume | Uncleared Volume (MW) | Uncleared Volume |
|---|---|---|---|---|---|---|---|---|
| Buy bids | Obligations | Counter Flow | 200,749 | 638,840 | 198,853 | 31.1% | 439,987 | 68.9% |
| | | Prevailing Flow | 366,221 | 1,446,952 | 270,302 | 18.7% | 1,176,650 | 81.3% |
| | | Total | 566,970 | 2,085,792 | 469,154 | 22.5% | 1,616,638 | 77.5% |
| | Options | Counter Flow | 51 | 5,897 | 0 | 0.0% | 5,897 | 100.0% |
| | | Prevailing Flow | 15,807 | 189,845 | 19,580 | 10.3% | 170,265 | 89.7% |
| | | Total | 15,858 | 195,742 | 19,580 | 10.0% | 176,162 | 90.0% |
| | Total | Counter Flow | 200,800 | 644,737 | 198,853 | 30.8% | 445,884 | 69.2% |
| | | Prevailing Flow | 382,028 | 1,636,797 | 289,882 | 17.7% | 1,346,916 | 82.3% |
| | | Total | 582,828 | 2,281,534 | 488,734 | 21.4% | 1,792,800 | 78.6% |
| Self-scheduled bids | Obligations | Counter Flow | 127 | 1,941 | 1,941 | 100.0% | 0 | 0.0% |
| | | Prevailing Flow | 2,401 | 22,588 | 22,588 | 100.0% | 0 | 0.0% |
| | | Total | 2,528 | 24,529 | 24,529 | 100.0% | 0 | 0.0% |
| Buy and self-scheduled bids | Obligations | Counter Flow | 200,876 | 640,780 | 200,793 | 31.3% | 439,987 | 68.7% |
| | | Prevailing Flow | 368,622 | 1,469,540 | 292,890 | 19.9% | 1,176,650 | 80.1% |
| | | Total | 569,498 | 2,110,321 | 493,683 | 23.4% | 1,616,638 | 76.6% |
| | Options | Counter Flow | 51 | 5,897 | 0 | 0.0% | 5,897 | 100.0% |
| | | Prevailing Flow | 15,807 | 189,845 | 19,580 | 10.3% | 170,265 | 89.7% |
| | | Total | 15,858 | 195,742 | 19,580 | 10.0% | 176,162 | 90.0% |
| | Total | Counter Flow | 200,927 | 646,677 | 200,793 | 31.0% | 445,884 | 69.0% |
| | | Prevailing Flow | 384,429 | 1,659,385 | 312,470 | 18.8% | 1,346,916 | 81.2% |
| | | Total | 585,356 | 2,306,063 | 513,263 | 22.3% | 1,792,800 | 77.7% |
| Sell offers | Obligations | Counter Flow | 57,427 | 112,108 | 13,909 | 12.4% | 98,200 | 87.6% |
| | | Prevailing Flow | 68,535 | 158,210 | 23,555 | 14.9% | 134,655 | 85.1% |
| | | Total | 125,962 | 270,318 | 37,464 | 13.9% | 232,854 | 86.1% |
| | Options | Counter Flow | 2 | 100 | 0 | 0.0% | 100 | 100.0% |
| | | Prevailing Flow | 1,226 | 6,426 | 527 | 8.2% | 5,899 | 91.8% |
| | | Total | 1,228 | 6,526 | 527 | 8.1% | 5,999 | 91.9% |
| | Total | Counter Flow | 57,429 | 112,208 | 13,909 | 12.4% | 98,300 | 87.6% |
| | | Prevailing Flow | 69,761 | 164,635 | 24,081 | 14.6% | 140,554 | 85.4% |
| | | Total | 127,190 | 276,844 | 37,990 | 13.7% | 238,853 | 86.3% |

Figure 13-4 shows the bid volumes of the Annual FTR Auctions from the 2009/2010 planning period through the 2017/2018 planning period and the associated planning period payout ratios, represented by the background bars. The payout ratio for the 2017/2018 planning period is shown as dotted background because it is not yet final. Bid volume has not changed significantly with the payout ratio. For on and off peak prevailing flow products, the bid volume in the 2012/2013 planning period decreased 24.3 percent from the 2011/2012 planning period, but then increased 30.5 percent for the 2013/2014 planning period despite an only slightly improved payout ratio. Bid volume for the 2016/2017 planning period was down 15.4 percent from the 2015/2016 planning period. Bid volume for the 2017/2018 planning period was only up 4.4 percent over the previous planning period, despite a less conservative FTR annual model.

### Figure 13-4 Annual bid FTR auction volume: Planning period 2009/2010 through 2017/2018

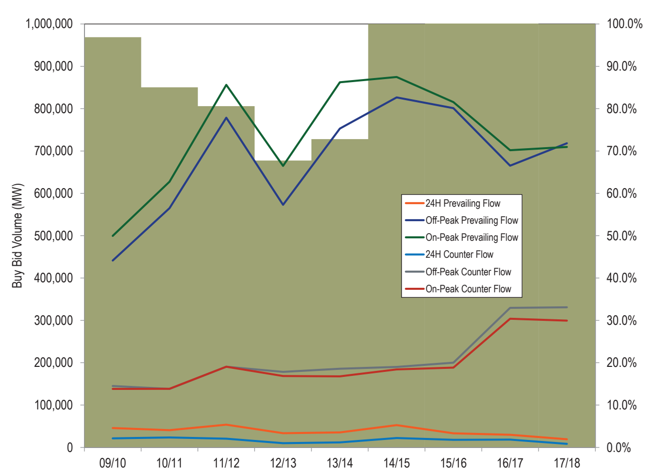


Figure 13-5 shows the cleared volumes of the Annual FTR Auctions from the 2009/2010 planning period through the 2017/2018 planning period and the associated planning period payout ratios, represented by the background bars. The payout ratio for the 2017/2018 planning period is shown as dotted background because it is not yet final. The cleared MW increased from the 2009/2010 planning period through the 2013/2014 planning period, as a market response to lower payout ratios. The 2014/2015, 2015/2016 and 2016/2017 planning period volumes were 19.1 percent, 16.3 percent and 7.0 percent lower than the 2013/2014 volume, as a result of PJM's more restrictive modeling of Stage 1B and Stage 2 ARRs starting in the 2014/2015 planning period which lead to fewer available FTRs in the Annual FTR Auction and higher prices. In the planning periods since 2014/2015, PJM has allowed more Stage 1B and Stage 2 ARRs to clear, resulting in higher slightly higher cleared volume and increasing prices in the Annual FTR Auction. In the 2017/2018 planning period, PJM ended their conservative outage modeling practices and assigned balancing congestion and M2M payments to load and exports. This created more FTR volume, and allowed for a 13.6 percent increase in cleared volume over the 2013/2014 planning period and a 40.3 percent increase in cleared volume over the 2014/2015 planning period.

### Figure 13-5 Annual Cleared FTR Auction volume: Planning period 2009/2010 through 2017/2018

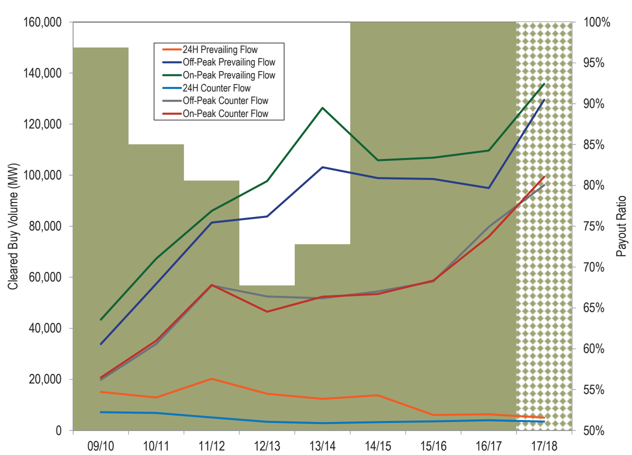



Table 13-20 shows the proportion of ARRs self scheduled as FTRs for the last seven planning periods. The maximum possible level of self scheduled FTRs includes all ARRs. Eligible participants self scheduled 24,529 MW (25.4 percent) of ARRs as FTRs for the 2017/2018 planning period, down from 26,689 MW (32.5 percent) in the previous planning period.

### Table 13-20 Comparison of self scheduled FTRs: Planning periods 2009/2010 through 2017/2018

| Planning Period | Self-Scheduled FTRs (MW) | Maximum Possible Self-Scheduled FTRs (MW) | Percent of ARRs Self-Scheduled as FTRs |
|---|---|---|---|
| 2009/2010 | 68,589 | 109,613 | 62.6% |
| 2010/2011 | 55,669 | 102,046 | 54.6% |
| 2011/2012 | 46,017 | 103,660 | 44.4% |
| 2012/2013 | 41,351 | 99,115 | 41.7% |
| 2013/2014 | 29,289 | 94,097 | 31.1% |
| 2014/2015 | 26,964 | 73,504 | 36.7% |
| 2015/2016 | 23,699 | 77,872 | 30.4% |
| 2016/2017 | 26,689 | 82,229 | 32.5% |
| 2017/2018 | 24,529 | 96,638 | 25.4% |

Table 13-21 provides the monthly balance of planning period FTR auction market volume for the entire 2016/2017 and the first seven months of the 2017/2018 planning periods. There were 11,139,129 MW of FTR obligation buy bids and 1,895,480 MW of FTR obligation sell offers for all bidding periods in the first seven months of the 2017/2018 planning period. The monthly balance of planning period FTR auction cleared 1,895,480 MW (17.0 percent) of FTR obligation buy bids and 681,194 MW (23.9 percent) of FTR obligation sell offers.

There were 2,492,373 MW of FTR option buy bids and 380,225 MW of FTR option sell offers for all bidding periods in the Monthly Balance of Planning Period FTR Auctions for the first seven months of the 2017/2018 planning period. The monthly auctions cleared 38,374 MW (1.5 percent) of FTR option buy bids, and 110,352 MW (29.0 percent) of FTR option sell offers.

## Table 13-21 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% |
| Apr-17 | Obligations | Buy bids | 215,326 | 826,778 | 136,306 | 16.5% | 690,472 | 83.5% |
| | | Sell offers | 111,753 | 219,164 | 58,063 | 26.5% | 161,102 | 73.5% |
| | Options | Buy bids | 1,734 | 71,002 | 2,431 | 3.4% | 68,571 | 96.6% |
| | | Sell offers | 4,938 | 25,045 | 9,789 | 39.1% | 15,255 | 60.9% |
| May-17 | Obligations | Buy bids | 144,990 | 554,023 | 96,709 | 17.5% | 457,314 | 82.5% |
| | | Sell offers | 67,250 | 119,645 | 33,324 | 27.9% | 86,320 | 72.1% |
| | Options | Buy bids | 875 | 41,671 | 1,970 | 4.7% | 39,701 | 95.3% |
| | | Sell offers | 2,325 | 12,564 | 6,287 | 50.0% | 6,277 | 50.0% |
| Jun-17 | Obligations | Buy bids | 424,924 | 1,890,242 | 261,153 | 13.8% | 1,629,089 | 86.2% |
| | | Sell offers | 245,103 | 441,623 | 103,552 | 23.4% | 338,071 | 76.6% |
| | Options | Buy bids | 2,850 | 95,975 | 3,466 | 3.6% | 92,509 | 96.4% |
| | | Sell offers | 13,125 | 87,201 | 24,446 | 28.0% | 62,754 | 72.0% |
| Jul-17 | Obligations | Buy bids | 462,676 | 2,004,974 | 365,860 | 18.2% | 1,639,114 | 81.8% |
| | | Sell offers | 270,091 | 467,185 | 99,257 | 21.2% | 367,928 | 78.8% |
| | Options | Buy bids | 4,839 | 526,023 | 6,728 | 1.3% | 519,295 | 98.7% |
| | | Sell offers | 9,090 | 60,642 | 16,226 | 26.8% | 44,416 | 73.2% |
| Aug-17 | Obligations | Buy bids | 404,905 | 1,719,427 | 287,275 | 16.7% | 1,432,152 | 83.3% |
| | | Sell offers | 250,573 | 488,090 | 104,763 | 21.5% | 383,327 | 78.5% |
| | Options | Buy bids | 3,918 | 521,524 | 10,630 | 2.0% | 510,894 | 98.0% |
| | | Sell offers | 7,694 | 48,901 | 14,652 | 30.0% | 34,249 | 70.0% |
| Sep-17 | Obligations | Buy bids | 368,917 | 1,528,610 | 292,194 | 19.1% | 1,236,416 | 80.9% |
| | | Sell offers | 217,010 | 424,349 | 98,165 | 23.1% | 326,184 | 76.9% |
| | Options | Buy bids | 2,893 | 334,962 | 5,033 | 1.5% | 329,929 | 98.5% |
| | | Sell offers | 8,035 | 66,839 | 17,520 | 26.2% | 49,319 | 73.8% |
| Oct-17 | Obligations | Buy bids | 347,963 | 1,368,991 | 266,038 | 19.4% | 1,102,954 | 80.6% |
| | | Sell offers | 195,048 | 428,713 | 106,535 | 24.8% | 322,179 | 75.2% |
| | Options | Buy bids | 2,987 | 280,576 | 5,168 | 1.8% | 275,407 | 98.2% |
| | | Sell offers | 6,477 | 48,563 | 13,897 | 28.6% | 34,666 | 71.4% |
| Nov-17 | Obligations | Buy bids | 287,727 | 1,290,729 | 212,008 | 16.4% | 1,078,721 | 83.6% |
| | | Sell offers | 129,084 | 332,818 | 96,308 | 28.9% | 236,510 | 71.1% |
| | Options | Buy bids | 3,396 | 406,810 | 4,119 | 1.0% | 402,691 | 99.0% |
| | | Sell offers | 5,195 | 37,004 | 14,003 | 37.8% | 23,001 | 62.2% |
| Dec-17 | Obligations | Buy bids | 283,257 | 1,336,156 | 210,956 | 15.8% | 1,125,200 | 84.2% |
| | | Sell offers | 132,789 | 265,288 | 72,615 | 27.4% | 192,673 | 72.6% |
| | Options | Buy bids | 3,237 | 326,504 | 3,231 | 1.0% | 323,272 | 99.0% |
| | | Sell offers | 3,750 | 31,076 | 9,609 | 30.9% | 21,467 | 69.1% |
| 2016/2017* | Obligations | Buy bids | 3,910,604 | 16,452,696 | 2,250,750 | 13.7% | 14,201,947 | 86.3% |
| | | Sell offers | 1,888,130 | 3,845,238 | 843,507 | 21.9% | 3,001,731 | 78.1% |
| | Options | Buy bids | 83,045 | 3,692,188 | 61,247 | 1.7% | 3,630,941 | 98.3% |
| | | Sell offers | 119,139 | 497,083 | 161,155 | 32.4% | 335,928 | 67.6% |
| 2017/2018** | Obligations | Buy bids | 2,580,369 | 11,139,129 | 1,895,480 | 17.0% | 9,243,649 | 83.0% |
| | | Sell offers | 1,439,698 | 2,848,066 | 681,194 | 23.9% | 2,166,872 | 76.1% |
| | Options | Buy bids | 24,120 | 2,492,373 | 38,374 | 1.5% | 2,453,998 | 98.5% |
| | | Sell offers | 53,366 | 380,225 | 110,352 | 29.0% | 269,873 | 71.0% |

* Shows twelve months for 2016/2017; ** Shows seven months ended Dec 31 for 2017/2018

Table 13-22 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 216,931.5 MW. The average monthly cleared volume for 2016 was 219,630.6 MW.

### Table 13-22 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 |
| Apr-17 | Bid | 641,003 | 256,777 | | | | | | 897,780 |
| | Cleared | 100,962 | 37,775 | | | | | | 138,737 |
| May-17 | Bid | 595,694 | | | | | | | 595,694 |
| | Cleared | 98,679 | | | | | | | 98,679 |
| Jun-17 | Bid | 694,826 | 242,835 | 225,724 | 140,632 | 249,241 | 220,255 | 212,703 | 1,986,217 |
| | Cleared | 115,341 | 32,654 | 26,230 | 15,601 | 28,384 | 24,559 | 21,850 | 264,619 |
| Jul-17 | Bid | 848,864 | 393,988 | 263,694 | | 342,147 | 337,546 | 344,757 | 2,530,997 |
| | Cleared | 157,587 | 63,616 | 19,649 | | 42,089 | 46,476 | 43,197 | 372,615 |
| Aug-17 | Bid | 819,359 | 303,118 | 269,085 | | 233,292 | 300,527 | 315,570 | 2,240,951 |
| | Cleared | 137,299 | 43,044 | 25,896 | | 20,256 | 37,199 | 34,210 | 297,904 |
| Sep-17 | Bid | 698,343 | 258,610 | 248,071 | | 142,865 | 255,214 | 260,469 | 1,863,571 |
| | Cleared | 136,468 | 44,276 | 33,029 | | 11,932 | 38,125 | 33,427 | 297,258 |
| Oct-17 | Bid | 708,469 | 267,126 | 191,295 | | | 233,286 | 249,391 | 1,649,567 |
| | Cleared | 125,719 | 50,518 | 17,271 | | | 40,025 | 37,673 | 271,206 |
| Nov-17 | Bid | 708,746 | 267,037 | 222,029 | | | 216,879 | 282,848 | 1,697,539 |
| | Cleared | 111,483 | 33,002 | 22,211 | | | 20,888 | 28,542 | 216,127 |
| Dec-17 | Bid | 689,513 | 282,979 | 262,442 | | | 130,678 | 297,047 | 1,662,660 |
| | Cleared | 102,888 | 42,326 | 31,819 | | | 11,109 | 26,045 | 214,188 |

Figure 13-6 shows cleared auction volumes as a percent of the total FTR cleared volume by calendar months for June 2004 through December 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 13-6 Cleared auction volume (MW) as a percent of total FTR cleared volume by calendar month: June 1, 2004 through December 31, 2017

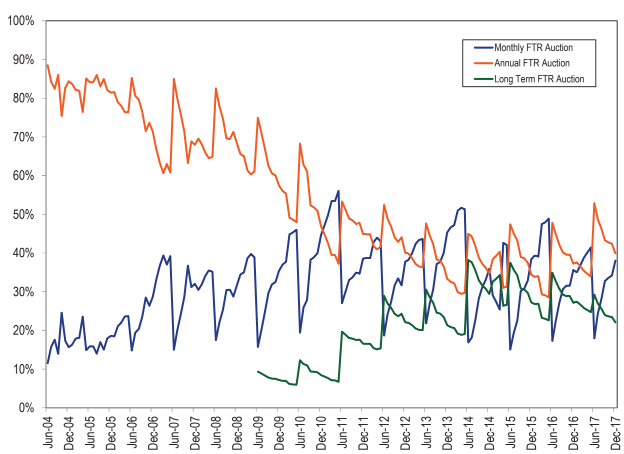


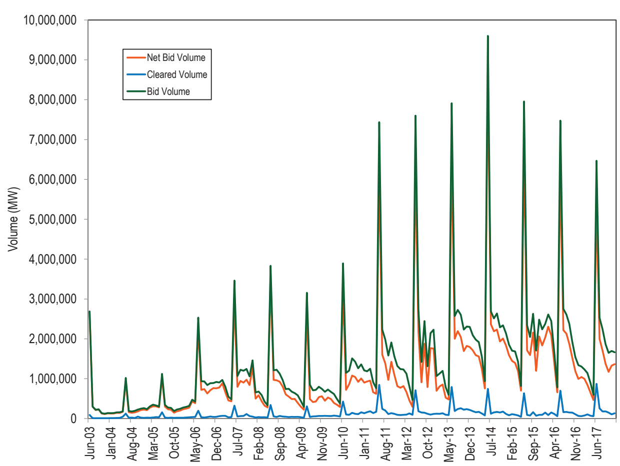
Table 13-23 provides the secondary bilateral FTR market volume for the entire 2016/2017 and 2017/2018 planning periods.

### Table 13-23 Secondary bilateral FTR market volume: Planning periods 2016/2017 and 2017/2018[31]

| Planning Period | Type | Class Type | Volume (MW) |
|---|---|---|---|
| 2016/2017 | Obligation | 24-Hour | 538.5 |
| | | On Peak | 7,414.4 |
| | | Off Peak | 13,955.7 |
| | | Total | 21,908.6 |
| | Option | 24-Hour | 0.0 |
| | | On Peak | 678.0 |
| | | Off Peak | 104.5 |
| | | Total | 782.5 |
| 2017/2018 | Obligation | 24-Hour | 167.4 |
| | | On Peak | 7,288.1 |
| | | Off Peak | 4,833.7 |
| | | Total | 12,289.2 |
| | Option | 24-Hour | 0.0 |
| | | On Peak | 0.0 |
| | | Off Peak | 0.0 |
| | | Total | 0.0 |

Figure 13-7 shows the FTR bid, cleared and net bid volume from June 2003 through December 2017 for Long Term, Annual and Monthly Balance of Planning Period Auctions.[32] 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.

### Figure 13-7 Long Term, Annual and Monthly FTR Auction bid and cleared volume: June 1, 2003 through December 31, 2017




31 The 2016/2017 planning period covers bilateral FTRs that are effective for any time between June 1, 2016 through May 31, 2017, which originally had been purchased in a Long Term FTR Auction, Annual FTR Auction or Monthly Balance of Planning Period FTR Auction.

32 The data for this table are available in *2017 State of the Market Report for PJM*, Volume 2, Appendix H.

## Price

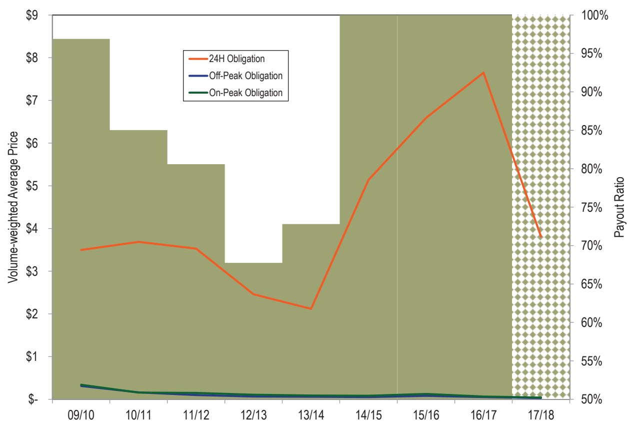
Table 13-24 shows the cleared, weighted-average prices by trade type, FTR direction, period type and class type for the 2017/2020 Long Term FTR Auction. Only FTR obligation products (no options) are available in the Long Term FTR Auctions. In this auction, weighted average buy bid counter flow and prevailing flow FTR prices were -\$0.42 and \$0.41, compared to -\$0.47 and \$0.45 from the 2016 to 2019 Long Term FTR Auction. Weighted average sell bid counter flow and prevailing flow FTR prices were -\$0.43 and \$0.44, compared to -\$0.37 for counter flow FTRs and \$0.43 for prevailing flow FTRs.

### Table 13-24 Long Term FTR Auction weighted-average cleared prices (Dollars per MW): Planning periods 2017/2020

| | | | Class Type | | | |
|---|---|---|---|---|---|---|
| Trade Type | FTR Direction | Period Type | 24-Hour | On Peak | Off Peak | All |
| Buy bids | Counter Flow | Year 1 | (\$1.55) | (\$0.33) | (\$0.55) | (\$0.47) |
| | | Year 2 | (\$1.19) | (\$0.31) | (\$0.52) | (\$0.42) |
| | | Year 3 | (\$0.71) | (\$0.27) | (\$0.44) | (\$0.36) |
| | | Year All | NA | (\$0.03) | (\$0.09) | (\$0.05) |
| | | Total | (\$1.18) | (\$0.30) | (\$0.50) | (\$0.42) |
| | Prevailing Flow | Year 1 | \$0.81 | \$0.35 | \$0.55 | \$0.46 |
| | | Year 2 | \$0.78 | \$0.32 | \$0.50 | \$0.41 |
| | | Year 3 | \$0.61 | \$0.27 | \$0.44 | \$0.35 |
| | | Year All | NA | \$0.01 | \$0.01 | \$0.01 |
| | | Total | \$0.75 | \$0.32 | \$0.50 | \$0.41 |
| | Total | | (\$0.26) | \$0.03 | \$0.06 | \$0.04 |
| Sell offers | Counter Flow | Year 1 | (\$1.46) | (\$0.35) | (\$0.50) | (\$0.46) |
| | | Year 2 | NA | (\$0.32) | (\$0.45) | (\$0.40) |
| | | Year 3 | NA | (\$0.10) | (\$0.18) | (\$0.13) |
| | | Year All | NA | NA | NA | NA |
| | | Total | (\$1.17) | (\$0.33) | (\$0.48) | (\$0.43) |
| | Prevailing Flow | Year 1 | \$0.55 | \$0.27 | \$0.48 | \$0.38 |
| | | Year 2 | \$0.62 | \$0.47 | \$0.65 | \$0.55 |
| | | Year 3 | NA | \$0.26 | \$0.49 | \$0.36 |
| | | Year All | NA | NA | NA | NA |
| | | Total | \$0.57 | \$0.34 | \$0.54 | \$0.44 |
| | Total | | (\$0.26) | \$0.11 | \$0.19 | \$0.13 |

Figure 13-8 shows the volume-weighted average buy bid price for the Annual FTR Auctions from the 2009/2010 through the 2017/2018 planning periods and the associated planning period payout ratios, represented by the background bars. The payout ratio for the 2017/2018 planning period is shown as dotted background because it is not yet final. From the 2010/2011 planning period to the 2013/2014 planning period FTR prices decreased. The 2014/2015, 2015/2016 and 2016/2017 planning periods 24 hour obligation prices increased 142.5 percent, 210.8 and 260.8 percent from the 2013/2014 planning period. These large price increases were a result of the significant decrease in FTR supply volume during the Annual FTR Auctions which was a result of PJM's decisions to use a more constrained model and its impact on Stage 1B and Stage 2 ARR allocations. The increased prices led to an increase in ARR target allocations for the 2014/2015, 2015/2016 and 2016/2017 planning periods. Prices dropped for the 2017/2018 planning period as a result of PJM's change in FTR auction modeling which led to an increase in available capacity in the Annual FTR Auction. The reduced prices reflect in the ARR values.

### Figure 13-8 Annual FTR Auction volume-weighted average buy bid price: Planning period 2009/2010 through 2017/2018




### Table 13-25 Annual FTR Auction weighted-average cleared prices (Dollars per MW): Planning period 2017/2018

| | | | Class Type | | | |
|---|---|---|---|---|---|---|
| Trade Type | Type | FTR Direction | 24-Hour | On Peak | Off Peak | All |
| Buy bids | Obligations | Counter Flow | ($0.27) | ($0.35) | ($0.21) | ($0.28) |
| | | Prevailing Flow | $1.14 | $0.62 | $0.38 | $0.52 |
| | | Total | $0.57 | $0.21 | $0.13 | $0.18 |
| | Options | Counter Flow | $0.00 | $0.00 | $0.00 | $0.00 |
| | | Prevailing Flow | $0.71 | $0.43 | $0.25 | $0.35 |
| | | Total | $0.71 | $0.43 | $0.25 | $0.35 |
| Self-scheduled bids | Obligations | Counter Flow | ($0.04) | NA | NA | ($0.04) |
| | | Prevailing Flow | $0.76 | NA | NA | $0.76 |
| | | Total | $0.69 | NA | NA | $0.69 |
| Buy and self-scheduled bids | Obligations | Counter Flow | ($0.19) | ($0.35) | ($0.21) | ($0.28) |
| | | Prevailing Flow | $0.83 | $0.62 | $0.38 | $0.55 |
| | | Total | $0.66 | $0.21 | $0.13 | $0.23 |
| | Options | Counter Flow | $0.00 | $0.00 | $0.00 | $0.00 |
| | | Prevailing Flow | $0.71 | $0.43 | $0.25 | $0.35 |
| | | Total | $0.71 | $0.43 | $0.25 | $0.35 |
| Sell offers | Obligations | Counter Flow | ($0.59) | ($0.52) | ($0.33) | ($0.43) |
| | | Prevailing Flow | $1.36 | $0.40 | $0.27 | $0.35 |
| | | Total | $0.26 | $0.07 | $0.06 | $0.07 |
| | Options | Counter Flow | NA | NA | NA | NA |
| | | Prevailing Flow | $0.00 | $0.47 | $0.35 | $0.41 |
| | | Total | $0.00 | $0.47 | $0.35 | $0.41 |

Table 13-25 shows the weighted-average cleared buy bid prices by trade type, FTR product, FTR direction and class type for the Annual FTR Auction for the 2017/2018 planning period. The weighted-average cleared buy bid price in the 2017/2018 Annual FTR Auction was $0.24 per MW, down from $0.35 per MW in the 2016/2017 planning period.

Table 13-26 compiles the buy bid, buy bid revenue and $/MW of buy bids for the six latest planning periods. In the 2014/2015 planning period the $/MW increased significantly from the 2013/2014 planning period due to PJM's decisions to limit capacity through conservative modeling. In the 2017/2018 Annual FTR Auction, the $/MW decreased to lower than 2013/2014 levels, due in part to the partial relaxation of PJM's conservative modeling practices due to the reassignment of balancing congestion and M2M payments to load and exports.

### Table 13-26 Cleared Volume, revenue and $/MW for planning periods 2012/2013 through 2017/2018 Annual FTR Auction

| | Cleared Buy Bid Volume | % Cleared | Buy Bid Revenue | Buy Bid Revenue ($/MW) |
|---|---|---|---|---|
| 2012/2013 | 371,295 | 14.5% | $627.3 | $1,689 |
| 2013/2014 | 420,489 | 12.8% | $567.6 | $1,350 |
| 2014/2015 | 365,843 | 11.2% | $789.7 | $2,159 |
| 2015/2016 | 378,328 | 15.4% | $948.6 | $2,507 |
| 2016/2017 | 420,198 | 16.2% | $918.0 | $2,185 |
| 2017/2018 | 513,263 | 22.3% | $555.2 | $1,082 |

Table 13-27 shows the weighted average cleared buy bid price in the Monthly Balance of Planning Period FTR Auctions by bidding period for January through December 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 December 2017 was $0.11 per MW, down from $0.13 per MW in the same time last year, a 15.4 percent decrease in FTR prices. The cleared weighted-average price for the current planning period was $0.12, down 7.7 percent from $0.13 for the previous planning period.

Table 13-27 Monthly balance of planning period FTR auction cleared, weighted-average, buy bid price per period (Dollars per MW): 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 |
| Apr-17 | $0.09 | $0.10 | | | | | $0.00 | $0.10 |
| May-17 | $0.06 | | | | | | $0.00 | $0.06 |
| Jun-17 | $0.07 | $0.14 | $0.11 | $0.15 | $0.11 | $0.20 | $0.11 | $0.12 |
| Jul-17 | $0.08 | $0.10 | $0.06 | | $0.11 | $0.12 | $0.08 | $0.10 |
| Aug-17 | $0.09 | $0.09 | $0.12 | | $0.18 | $0.12 | $0.12 | $0.12 |
| Sep-17 | $0.08 | $0.11 | $0.08 | | $0.04 | $0.08 | $0.06 | $0.08 |
| Oct-17 | $0.10 | $0.08 | ($0.01) | | | $0.16 | $0.13 | $0.12 |
| Nov-17 | $0.12 | $0.09 | $0.11 | | | $0.49 | $0.19 | $0.21 |
| Dec-17 | $0.07 | $0.02 | $0.01 | | | $0.33 | $0.14 | $0.11 |

## Profitability

FTR profitability is the difference between the revenue received for an FTR and the cost of the FTR for entities that purchase FTRs. 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. ARR holders that self schedule FTRs do not receive a profit on the transaction. ARR holders that self schedule are trading rights to congestion revenues for a fixed payment. 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. Accounting for direct profitability and the distribution of excess congestion, FTR purchases by financial entities were not profitable in 2012/2013 and were profitable in every planning year from 2013/2014 through 2016/2017, and were profitable if summed over the entire period (Table 13-30). 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.

Table 13-28 lists FTR profits by organization type and FTR direction for the first four months of the 2017/2018 planning period. 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 are in the Physical category, while any entity that is eligible for ARRs and holds ARRs are in the Physical ARR Holder category. FTR profits are the sum of the daily FTR target allocations, adjusted by the payout ratio minus the daily FTR auction costs for each FTR (not self scheduled) held by an organization. Self scheduled FTRs can have a negative value, depending on the congestion on the FTR path. 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 for entities that purchase FTRs and do not self schedule the FTRs. In the first seven months of the 2017/2018 planning period, companies made profits of $119.8 million. ARR holders who self scheduled FTRs received $85.5 million in congestion revenues. Revenues from self scheduled FTRs are more accurately described as a return of congestion rather than profits.

### Table 13-28 FTR profits and revenues by organization type and FTR direction for the 2017/2018 planning period

| | FTR Direction | | | | |
|---|---|---|---|---|---|
| Organization Type | Prevailing Flow | Self Scheduled Prevailing Flow | Counter Flow | Self Scheduled Counter Flow | All |
| Financial | $40,811,499 | | $46,900,257 | | $87,711,756 |
| Physical | ($9,369,683) | | $10,028,710 | | $659,026 |
| Physical ARR Holder | $17,192,244 | $87,292,443 | $14,251,815 | ($1,834,752) | $31,444,059 |
| Total | $48,634,060 | $87,292,443 | $71,180,781 | ($1,834,752) | $119,814,841 |

Table 13-29 lists the monthly FTR profits for the 2016/2017 and 2017/2018 planning periods by organization type. FTR revenues for ARR holders who self schedule are not included. FTR profits for ARR holders who purchase FTRs in auctions are included.

### Table 13-29 Monthly FTR profits by organization type for the 2016/2017 and 2017/2018 planning periods

| | Organization Type | | | |
|---|---|---|---|---|
| Month | Physical | Physical ARR Holders (no self scheduled) | Financial | Total |
| Jun-16 | ($2,861,362) | $803,936 | ($6,163,265) | ($8,220,691) |
| Jul-16 | $289,899 | $14,377,883 | $570,363 | $15,238,146 |
| Aug-16 | $3,152,454 | ($134,167) | $9,898,169 | $12,916,455 |
| Sep-16 | $5,595,192 | $21,054,353 | $12,909,228 | $39,558,772 |
| Oct-16 | $4,111,015 | $27,910,195 | ($3,486,077) | $28,535,133 |
| Nov-16 | ($3,395,815) | ($13,060,493) | ($8,477,147) | ($24,933,455) |
| Dec-16 | ($540,576) | ($21,651,681) | ($6,540,942) | ($28,733,199) |
| Jan-17 | ($1,748,872) | ($23,130,635) | $82,092 | ($24,797,415) |
| Feb-17 | ($2,264,649) | ($9,401,312) | $3,282,949 | ($8,383,013) |
| Mar-17 | ($3,884,155) | ($17,055,619) | ($673,693) | ($21,613,466) |
| Apr-17 | ($5,227,387) | ($48,799,438) | ($7,180,585) | ($61,207,410) |
| May-17 | ($4,464,887) | ($48,041,208) | ($7,740,915) | ($60,247,010) |
| | Summary for Planning Period 2016/2017 | | | |
| Total | ($11,239,145) | ($117,128,185) | ($13,519,824) | ($141,887,154) |
| Jun-17 | $764,708 | $14,045,076 | $14,019,198 | $28,828,982 |
| Jul-17 | ($2,987,829) | ($2,386,369) | $7,306,611 | $1,932,413 |
| Aug-17 | ($3,234,012) | ($8,540,404) | $2,414,244 | ($9,360,171) |
| Sep-17 | $2,168,231 | $21,312,733 | $22,644,485 | $46,125,449 |
| Oct-17 | $777,230 | $6,839,934 | $14,400,509 | $22,017,673 |
| Nov-17 | $2,350,616 | $2,340,485 | $3,244,972 | $7,936,074 |
| Dec-17 | $820,082 | ($2,167,396) | $23,681,735 | $22,334,421 |
| | Summary for Planning Period 2017/2018 | | | |
| Total | $659,026 | $31,444,059 | $87,711,756 | $119,814,841 |

Table 13-30 lists the historical profits by calendar year by organization type beginning in the 2012/2013 planning period, excluding revenue returned through self scheduled FTRs for Physical ARR holding participants. The profits include any end of planning period excess distribution or uplift that will impact total profitability. The excess or uplift is distributed prorata based on positive target allocations.

### Table 13-30 Planning period FTR profits by organization type: 2012/2013 through 2017/2018 planning periods

| | | 2012/2013 | 2013/2014 | 2014/2015 | 2015/2016 | 2016/2017 | 2017/2018* |
|---|---|---|---|---|---|---|---|
| Financial | Profit | $63,457,511 | $557,583,317 | $236,692,290 | $41,264,165 | ($13,519,824) | $87,711,756 |
| | Excess | ($80,450,357) | ($256,820,253) | $44,410,625 | $11,897,525 | $20,968,663 | |
| | Total | ($16,992,846) | $300,763,064 | $281,102,915 | $53,161,690 | $7,448,839 | $87,711,756 |
| Physical | Profit | ($25,069,434) | $217,693,500 | $65,085,246 | ($16,904,899) | ($11,239,145) | $659,026 |
| | Excess | ($83,332,665) | ($104,947,376) | $14,485,066 | $5,072,985 | $10,533,444 | |
| | Total | ($108,402,099) | $112,746,125 | $79,570,312 | ($11,831,914) | ($705,701) | $659,026 |
| Physical ARR | Profit | ($40,633,441) | $183,450,850 | $95,609,153 | $39,490,527 | ($117,128,185) | $31,444,059 |
| | Excess | ($128,497,763) | ($316,929,138) | $80,692,482 | $25,484,394 | $44,883,161 | |
| | Total | ($169,131,204) | ($133,478,288) | $176,301,636 | $64,974,921 | ($72,245,025) | $31,444,059 |
| Total | | ($294,526,149) | $280,030,900 | $536,974,863 | $106,304,698 | ($65,501,886) | $119,814,841 |

* Seven months of the 2017/2018 planning period

# Revenue

## Long Term FTR Auction Revenue

Table 13-31 shows the long term FTR auction revenue data by trade type, FTR direction, period type and class type. The 2017/2020 Long Term FTR Auction netted $26.7 million in revenue, $3.5 million more than the previous Long Term FTR Auction. Buyers paid $48.4 million and sellers received $21.7 million, down $12.0 million and $15.4 million over the previous Long Term FTR Auction. In general, revenue increased $3.5 million over the previous Long Term FTR Auction, with counter flow buy bid revenue decreasing 3.9 percent and prevailing flow buy bid revenue decreasing 6.9 percent.

### Table 13-31 Long Term FTR Auction Revenue: Planning periods 2017/2020

| | | | Class Type | | | |
|---|---|---|---|---|---|---|
| Trade Type | FTR Direction | Period Type | 24-Hour | On Peak | Off Peak | All |
| Buy bids | Counter Flow | Year 1 | ($13,865,196) | ($52,361,573) | ($37,364,286) | ($103,591,055) |
| | | Year 2 | ($7,761,389) | ($43,553,743) | ($37,548,472) | ($88,863,605) |
| | | Year 3 | ($5,005,407) | ($28,000,602) | ($25,397,031) | ($58,403,039) |
| | | Year All | $0 | ($319,141) | ($176,332) | ($495,473) |
| | | Total | ($26,631,992) | ($124,235,058) | ($100,486,121) | ($251,353,171) |
| | Prevailing Flow | Year 1 | $6,795,665 | $67,652,677 | $44,562,449 | $119,010,791 |
| | | Year 2 | $5,662,333 | $57,741,990 | $49,101,454 | $112,505,777 |
| | | Year 3 | $2,860,593 | $35,206,352 | $30,170,444 | $68,237,390 |
| | | Year All | $6,961 | $10,816 | $15,524 | $33,301 |
| | | Total | $15,325,553 | $160,611,835 | $123,849,872 | $299,787,259 |
| | Total | | ($11,306,439) | $36,376,777 | $23,363,751 | $48,434,088 |
| Sell offers | Counter Flow | Year 1 | ($2,553,051) | ($8,658,617) | ($7,007,072) | ($18,218,739) |
| | | Year 2 | ($666,560) | ($3,101,121) | ($2,656,749) | ($6,424,429) |
| | | Year 3 | 0 | ($158,053) | ($142,046) | ($300,099) |
| | | Year All | NA | NA | NA | NA |
| | | Total | ($3,219,610) | ($11,917,790) | ($9,805,868) | ($24,943,268) |
| | Prevailing Flow | Year 1 | $1,026,067 | $14,286,980 | $8,408,061 | $23,721,107 |
| | | Year 2 | $699,642 | $10,531,252 | $9,695,363 | $20,926,257 |
| | | Year 3 | 11,648 | $1,206,188 | $792,342 | $2,010,177 |
| | | Year All | NA | NA | NA | NA |
| | | Total | $1,737,356 | $26,024,420 | $18,895,765 | $46,657,541 |
| | Total | | ($1,482,254) | $14,106,630 | $9,089,897 | $21,714,273 |
| Total | | | ($9,824,185) | $22,270,147 | $14,273,853 | $26,719,815 |

## Annual FTR Auction Revenue

Table 13-32 shows the Annual FTR Auction revenue by trade type, type, FTR direction and class type. The Annual FTR Auction for the 2017/2018 planning period generated $542.2 million, down 40.4 percent from $909.0 million in the 2016/2017 planning period, and down 42.3 percent from $936.3 million in the 2015/2016 planning period. Counter flow FTR Holders received $233.0 million, down 8.9 percent from the previous planning period and prevailing flow FTR Holders paid $765.3 million, down 34.3 percent from the previous planning period.

## Table 13-32 Annual FTR auction revenue: Planning period 2017/2018

| | | | Class Type | | | |
|---|---|---|---|---|---|---|
| Trade Type | Type | FTR Direction | 24-Hour | On Peak | Off Peak | All |
| Buy bids | Obligations | Counter Flow | ($8,029,201) | ($145,788,774) | ($94,420,672) | ($248,238,646) |
| | | Prevailing Flow | $50,055,711 | $351,302,730 | $223,789,478 | $625,147,919 |
| | | Total | $42,026,509 | $205,513,957 | $129,368,807 | $376,909,273 |
| | Options | Counter Flow | $0 | $0 | $0 | $0 |
| | | Prevailing Flow | $76,728 | $19,194,704 | $10,307,477 | $29,578,910 |
| | | Total | $76,728 | $19,194,704 | $10,307,477 | $29,578,910 |
| | Total | Counter Flow | ($8,029,201) | ($145,788,774) | ($94,420,672) | ($248,238,646) |
| | | Prevailing Flow | $50,132,439 | $370,497,434 | $234,096,956 | $654,726,829 |
| | | Total | $42,103,238 | $224,708,661 | $139,676,284 | $406,488,182 |
| Self-scheduled bids | Obligations | Counter Flow | ($750,762) | NA | NA | ($750,762) |
| | | Prevailing Flow | $149,488,947 | NA | NA | $149,488,947 |
| | | Total | $148,738,185 | NA | NA | $148,738,185 |
| Buy and self-scheduled bids | Obligations | Counter Flow | ($8,779,963) | ($145,788,774) | ($94,420,672) | ($248,989,408) |
| | | Prevailing Flow | $199,544,657 | $351,302,730 | $223,789,478 | $774,636,866 |
| | | Total | $190,764,694 | $205,513,957 | $129,368,807 | $525,647,458 |
| | Options | Counter Flow | $0 | $0 | $0 | $0 |
| | | Prevailing Flow | $76,728 | $19,194,704 | $10,307,477 | $29,578,910 |
| | | Total | $76,728 | $19,194,704 | $10,307,477 | $29,578,910 |
| | Total | Counter Flow | ($8,779,963) | ($145,788,774) | ($94,420,672) | ($248,989,408) |
| | | Prevailing Flow | $199,621,386 | $370,497,434 | $234,096,956 | $804,215,776 |
| | | Total | $190,841,423 | $224,708,661 | $139,676,284 | $555,226,367 |
| Sell offers | Obligations | Counter Flow | ($1,992,236) | ($14,801,307) | ($9,158,120) | ($25,951,663) |
| | | Prevailing Flow | $3,519,716 | $20,025,225 | $14,466,957 | $38,011,899 |
| | | Total | $1,527,480 | $5,223,918 | $5,308,838 | $12,060,235 |
| | Options | Counter Flow | $0 | $0 | $0 | $0 |
| | | Prevailing Flow | $0 | $572,540 | $373,021 | $945,560 |
| | | Total | $0 | $572,540 | $373,021 | $945,560 |
| | Total | Counter Flow | ($1,992,236) | ($14,801,307) | ($9,158,120) | ($25,951,663) |
| | | Prevailing Flow | $3,519,716 | $20,597,765 | $14,839,978 | $38,957,459 |
| | | Total | $1,527,480 | $5,796,458 | $5,681,858 | $13,005,796 |
| Total | | | $189,313,943 | $218,912,203 | $133,994,426 | $542,220,572 |

The total net of all buy and sell offers in the Annual FTR Auction, not including self scheduled FTRs, was $606.8 million for the 2016/2017 planning period and $393.5 million for the 2017/2018 planning period, a 35.2 percent reduction in revenue. The total buy bids were 393,509.0 MW for the 2016/2017 planning period and 488,734.1 MW for the 2017/2018 planning period. The value of FTRs per MW decreased from $1,564.83 for the 2016/2017 planning period to $831.72 for the 2017/2018 planning period, a 46.8 percent decrease. The expected return to load from the redefinition of balancing congestion did not occur. Load receives lower ARR revenues in addition to the fact that load has to bear 100 percent of the costs of balancing congestion.

Table 13-33 provides a comparison of FTR auction net revenue from Long Term FTR Auctions and the Annual FTR Auction for the 2014/2015 through 2017/2018 planning periods. Despite the fact that the volume of FTRs traded in Long Term FTR Auctions is similar to the volume in Annual FTR Auctions, average buy bid long term FTR auction revenue was only 3.0 percent of the buy bid annual FTR auction revenue. In a competitive market, it would be expected that the long term FTR auction revenue should be comparable to the annual FTR auction revenue on a dollar per MW basis. If the full transmission capability made available in the Long Term FTR Auction were provided to ARR holders, the volume of long term FTRs would be significantly reduced.

## Table 13-33 FTR Auction net revenue: Long Term FTR Auction compared to Annual FTR Auction

| | Long Term FTR Product | | | | | |
|---|---|---|---|---|---|---|
| Planning Period | Year 3 | Year 2 | Year 1 | Total Long Term | Annual (including self scheduled) | Long Term Percent of Total Net Revenue |
| 2014/2015 | $13,016,512 | $7,176,209 | $6,863,135 | $27,055,856 | $735,998,448 | 3.5% |
| 2015/2016 | $12,479,874 | $7,378,550 | $5,156,206 | $25,014,630 | $893,043,415 | 2.7% |
| 2016/2017 | $7,624,149 | $2,105,984 | $11,087,250 | $20,817,382 | $861,031,182 | 2.4% |
| 2017/2018 | $1,670,521 | $7,210,445 | $9,763,312 | $18,644,279 | $513,587,222 | 3.5% |

FTRs sold in Long Term FTR Auctions are sold at a substantial discount to the same FTR sold in Annual FTR Auctions. Table 13-34 shows the increase in total auction revenue that would have resulted for the 2014/2015 through 2017/2018 planning periods if long term FTRs were sold at annual auction clearing prices. This $337 million is a good estimate of the value of the transmission capability made available in the Long Term FTR Auction that is not made available to ARR holders. This capability should be made available to ARR holders.

### Table 13-34 Estimated additional long term FTR auction revenue at Annual FTR Auction prices

| | Long Term FTR Product | | | | |
|---|---|---|---|---|---|
| Planning Period | Year 3 | Year 2 | Year 1 | Three Year | Total Difference |
| 2014/2015 | $59,598,642 | $30,284,173 | $52,030,909 | $926,989 | $142,840,713 |
| 2015/2016 | $67,896,588 | $40,975,278 | $9,936,078 | $303,082 | $119,111,026 |
| 2016/2017 | $42,378,048 | $3,854,373 | $11,055,824 | $1,079,901 | $58,368,147 |
| 2017/2018 | $6,134,076 | ($1,841,715) | $12,396,817 | $227,524 | $16,916,702 |
| Total | $176,007,354 | $73,272,109 | $85,419,628 | $2,537,496 | $337,236,587 |

## Monthly Balance of Planning Period FTR Auction Revenue

Table 13-35 shows monthly balance of planning period FTR auction revenue by trade type, type and class type for January through December 2017. The Monthly Balance of Planning Period FTR Auctions for the first seven months of the 2017/2018 planning period netted $26.4 million in revenue, the difference between buyers paying $132.8 million and sellers receiving $106.4. For the entire 2016/2017 planning period, the Monthly Balance of Planning Period FTR Auctions netted $32.5 million in revenue with buyers paying $158.3 million and sellers receiving $125.7 million.

Table 13-35 Monthly Balance of Planning Period FTR Auction revenue: 2017

| Monthly Auction | Type | Trade Type | Class 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 |
| Apr-17 | Obligations | Buy bids | $56,196 | $2,794,792 | $1,942,194 | $4,793,183 |
| | | Sell offers | ($424,330) | $1,893,838 | $1,219,145 | $2,688,653 |
| | Options | Buy bids | $1 | $170,667 | $70,317 | $240,985 |
| | | Sell offers | $5,510 | $837,677 | $642,171 | $1,485,359 |
| May-17 | Obligations | Buy bids | ($148,725) | $1,298,130 | $954,626 | $2,104,031 |
| | | Sell offers | ($18,257) | $596,555 | $356,062 | $934,361 |
| | Options | Buy bids | $0 | $10,894 | $10,626 | $21,520 |
| | | Sell offers | $1,172 | $470,594 | $320,693 | $792,459 |
| Jun-17 | Obligations | Buy bids | $1,449,554 | $12,156,206 | $5,881,196 | $19,486,956 |
| | | Sell offers | $263,150 | $6,840,938 | $3,132,765 | $10,236,854 |
| | Options | Buy bids | $189 | $308,906 | $167,990 | $477,085 |
| | | Sell offers | $20,477 | $3,257,891 | $1,572,561 | $4,850,929 |
| Jul-17 | Obligations | Buy bids | $2,661,155 | $11,806,212 | $7,534,773 | $22,002,140 |
| | | Sell offers | $264,884 | $8,580,489 | $6,077,539 | $14,922,913 |
| | Options | Buy bids | $14 | $267,280 | $179,853 | $447,146 |
| | | Sell offers | $17,257 | $2,116,842 | $1,188,629 | $3,322,728 |
| Aug-17 | Obligations | Buy bids | $2,899,252 | $11,362,501 | $5,698,898 | $19,960,651 |
| | | Sell offers | $92,888 | $8,936,893 | $4,916,782 | $13,946,563 |
| | Options | Buy bids | $0 | $569,359 | $268,821 | $838,180 |
| | | Sell offers | $6,894 | $2,058,782 | $964,953 | $3,030,629 |
| Sep-17 | Obligations | Buy bids | $5,672,712 | $4,859,316 | $1,891,283 | $12,423,312 |
| | | Sell offers | $113,479 | $4,342,957 | $2,203,121 | $6,659,556 |
| | Options | Buy bids | $0 | $430,151 | $265,489 | $695,640 |
| | | Sell offers | $7,008 | $1,992,795 | $1,134,426 | $3,134,229 |
| Oct-17 | Obligations | Buy bids | $7,865,651 | $6,383,764 | $3,387,972 | $17,637,388 |
| | | Sell offers | $378,594 | $7,515,784 | $4,482,298 | $12,376,676 |
| | Options | Buy bids | $81 | $579,960 | $422,026 | $1,002,067 |
| | | Sell offers | $14,102 | $1,838,236 | $1,040,427 | $2,892,766 |
| Nov-17 | Obligations | Buy bids | $12,875,618 | $7,924,690 | $4,111,243 | $24,911,551 |
| | | Sell offers | $658,341 | $11,415,328 | $7,195,936 | $19,269,605 |
| | Options | Buy bids | $0 | $628,435 | $305,805 | $934,241 |
| | | Sell offers | $9,015 | $1,882,930 | $1,295,208 | $3,187,153 |
| Dec-17 | Obligations | Buy bids | $8,114,015 | $1,280,590 | $2,029,296 | $11,423,901 |
| | | Sell offers | $537,321 | $3,062,580 | $2,793,126 | $6,393,027 |
| | Options | Buy bids | $618 | $346,819 | $211,945 | $559,382 |
| | | Sell offers | $7,225 | $1,191,345 | $961,134 | $2,159,704 |
| 2016/2017* | Obligations | Buy bids | $33,300,850 | $74,471,786 | $35,210,649 | $142,983,284 |
| | | Sell offers | $1,054,010 | $54,037,503 | $22,053,221 | $77,144,734 |
| | Options | Buy bids | $370,193 | $9,383,661 | $5,521,874 | $15,275,728 |
| | | Sell offers | $587,564 | $29,503,924 | $18,494,976 | $48,586,464 |
| | Net Total | | $32,029,469 | $314,020 | $184,325 | $32,527,815 |
| 2017/2018** | Obligations | Buy bids | $41,537,958 | $55,773,279 | $30,534,662 | $127,845,899 |
| | | Sell offers | $2,308,656 | $50,694,969 | $30,801,568 | $83,805,193 |
| | Options | Buy bids | $902 | $3,130,911 | $1,821,929 | $4,953,741 |
| | | Sell offers | $81,978 | $14,338,822 | $8,157,337 | $22,578,137 |
| | Net Total | | $39,148,225 | ($6,129,601) | ($6,602,314) | $26,416,310 |

* Shows Twelve Months; ** Shows Seven Months

## FTR Target Allocations

FTR target allocations were examined separately by source and sink contribution. Hourly FTR target allocations were divided into those that were benefits and liabilities and summed by sink and by source for the first seven months of the 2017/2018 planning period. Figure 13-9 shows the 10 largest positive and negative FTR target allocations, summed by sink, for the first seven months of the 2017/2018 planning period. The top 10 sinks that produced financial benefit accounted for 34.4 percent of total positive target allocations during the 2017/2018 planning period with the Northern Illinois Hub accounting for 9.3 percent of all positive target allocations. The top 10 sinks that created liability accounted for 17.8 percent of total negative target allocations with the PECO Zone accounting for 4.8 percent of all negative target allocations.

Figure 13-9 Ten largest positive and negative FTR target allocations summed by sink: 2017/2018 planning period

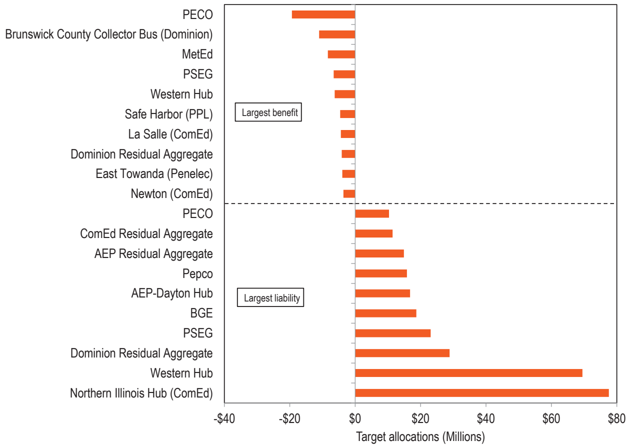
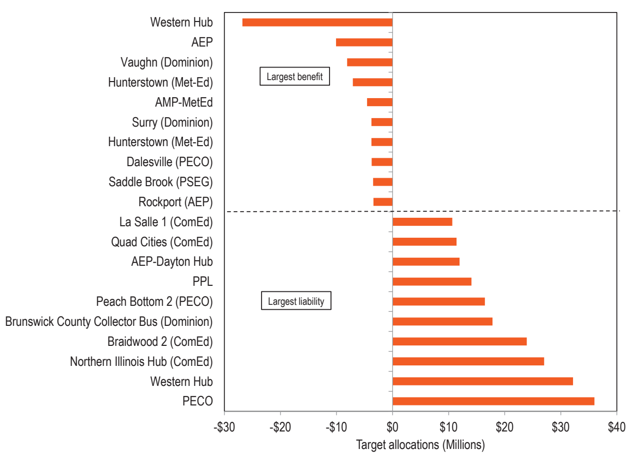



Figure 13-10 shows the 10 largest positive and negative FTR target allocations, summed by source, for the first seven months of the 2017/2018 planning period. The top 10 sources with a positive target allocation accounted for 24.2 percent of total positive target allocations with the PECO Zone accounting for 4.3 percent of total positive target allocations. The top 10 sources with a negative target allocation accounted for 18.4 percent of all negative target allocations, with the Western Hub accounting for 6.6 percent.

Figure 13-10 Ten largest positive and negative FTR target allocations summed by source: 2017/2018 planning period




## Revenue Adequacy

Congestion revenue is created in an LMP system when all loads pay their LMP and all generators receive their LMP. 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.[33] That is the source of the congestion revenue to pay holders of ARRs and FTRs.

FTR revenue adequacy must be distinguished from the adequacy of ARRs/FTRs as an offset for load against total congestion. FTR revenue adequacy, under current PJM rules, is a narrower concept that compares day-ahead congestion revenue to the sum of the target allocations across the specific paths for which FTRs were purchased. A path specific target allocation is not a guarantee of payment. The adequacy of ARRs/FTRs as an offset for load against total congestion compares ARR and self scheduled FTR revenues, minus balancing congestion and M2M payments, to total congestion on the system.

FTRs are paid from day-ahead congestion revenues. Day-ahead congestion revenues in excess of FTR payments 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 that was carried forward 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 Holders 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

33 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."

FTR position for the planning year. For example, the 2013/2014 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 2014/2015 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 market.[34] FTR revenues also include additional auction revenue over ARR target allocations, which equal the difference between ARR target allocations and the sum of FTR auction revenues and negative FTR target allocations which are a source of revenue from FTRs with a negative target allocation.

For the 2014/2015, 2015/2016 and the 2016/2017 planning periods, PJM paid MISO and NYISO a combined \$33.2 million, \$41.5 million and \$43.5 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.

FTRs were paid at 100 percent of the target allocation level for the 2014/2015, 2015/2016 and 2016/2017 planning periods. PJM collected \$1,457.1 million, \$1,003.3 million and \$828.7 million of FTR revenues during the 2014/2015, 2015/2016 and the 2016/2017 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.

This step change to high levels of revenue adequacy was primarily a result of actions taken by PJM to address prior low levels of revenue adequacy. PJM's actions included PJM's assumption of higher outage levels and PJM's decision to include additional constraints (closed loop interfaces) both of which reduced system capability in the FTR auction model. PJM's actions led to a significant reduction in the allocation of Stage 1B and Stage 2 ARRs. For the 2014/2015 planning period, Stage 1B and Stage 2 ARR allocations were reduced by 84.9 percent and 88.1 percent from the 2013/2014 planning period. For the 2015/2016 planning period, Stage 1B and Stage 2 ARR allocations were reduced by 76.9 percent and 82.0 percent from the 2013/2014 planning period. The result of this change in modeling was also that available FTR capacity decreased for the planning period. This decrease resulted in an increase in FTR nodal prices for the Annual FTR Auction. The result was fewer available ARRs, but an increased dollar per MW value for those ARRs.

Beginning in the 2017/2018 planning period PJM allocated balancing congestion and M2M payments to load, allowing FTR Holders to have more reliable revenue adequacy. The result was to support FTR revenue adequacy with an increased supply of FTRs. The result was lower prices paid for FTRs and therefore a lower dollar per MW value of ARRs.

Table 13-36 presents the PJM FTR revenue detail for the 2016/2017 planning period and the 2017/2018 planning period. In this table, under the new balancing congestion and M2M payment rules, any negative congestion is from day-ahead balancing congestion and does not include balancing. For the 2017/2018 planning period there was \$0.5 million and \$0.7 million in negative day-ahead congestion in October and November 2017 for a total of \$1.2 million in negative day-ahead congestion charged to FTR Holders.

34 When hourly congestion revenues are negative, it is defined as a net negative congestion hour.

Table 13-36 Total annual PJM FTR revenue detail (Dollars (Millions)): Planning periods 2016/2017 and 2017/2018

| Accounting Element | 2016/2017 | 2017/2018* |
|---|---|---|
| **ARR information** | | |
| ARR target allocations | $934.3 | $334.0 |
| FTR auction revenue | $962.2 | $343.3 |
| ARR excess | $27.9 | $9.2 |
| **FTR targets** | | |
| Positive target allocations | $929.1 | $588.1 |
| Negative target allocations | ($194.1) | ($154.8) |
| FTR target allocations | $735.0 | $433.3 |
| **Adjustments:** | | |
| Adjustments to FTR target allocations | ($0.4) | $2.4 |
| Total FTR targets | $734.6 | $430.9 |
| **FTR revenues** | | |
| ARR excess | $27.9 | $9.2 |
| **Congestion** | | |
| Net Negative Congestion (enter as negative) | ($16.9) | ($1.2) |
| Hourly congestion revenue | $843.6 | $502.0 |
| Midwest ISO M2M (credit to PJM minus credit to Midwest ISO) | ($43.5) | ($6.3) |
| **Adjustments:** | | |
| Excess revenues carried forward into future months | $20.4 | $15.7 |
| Excess revenues distributed back to previous months | $0.0 | $0.0 |
| Other adjustments to FTR revenues | $0.0 | $0.0 |
| **Total FTR revenues** | | |
| Excess revenues distributed to other months | $20.4 | $15.7 |
| Net Negative Congestion charged to DA Operating Reserves | $0.0 | $0.0 |
| Total FTR congestion credits | $831.4 | $525.5 |
| Total congestion credits on bill (includes CEPSW and end-of-year distribution) | $831.4 | $525.5 |
| **Remaining deficiency** | ($76.4) | ($94.6) |

* Seven months of 2017/2018 planning period

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 13-37 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 13-37 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 13-37 Monthly FTR accounting summary (Dollars (Millions)): Planning period 2016/2017 and 2017/2018

| 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-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% | $4.4 |
| Mar-17 | $44.4 | $48.9 | 90.8% | $48.9 | 100.0% | $4.6 |
| Apr-17 | $28.0 | $25.3 | 100.0% | $28.0 | 100.0% | ($2.6) |
| May-17 | $25.6 | $28.4 | 90.3% | $28.4 | 100.0% | $2.7 |
| | | | Summary for Planning Period 2016/2017 | | | |
| Total | $811.3 | $734.5 | | $831.5 | | ($76.4) |
| Jun-17 | $64.8 | $60.1 | 100.0% | $64.8 | 100.0% | ($4.7) |
| Jul-17 | $51.8 | $45.4 | 100.0% | $51.8 | 100.0% | ($6.3) |
| Aug-17 | $35.7 | $31.0 | 100.0% | $35.7 | 100.0% | ($4.7) |
| Sep-17 | $100.5 | $93.0 | 100.0% | $100.5 | 100.0% | ($7.5) |
| Oct-17 | $53.2 | $68.8 | 77.2% | $68.8 | 100.0% | $15.7 |
| Nov-17 | $61.2 | $51.0 | 100.0% | $61.2 | 100.0% | ($10.1) |
| Dec-17 | $142.7 | $81.4 | 100.0% | $142.7 | 100.0% | ($61.3) |
| | | | Summary for Planning Period 2017/2018 | | | |
| Total | $509.8 | $430.9 | | $525.5 | | ($78.9) |

Figure 13-11 shows the original PJM reported FTR payout ratio by month, excluding excess revenue distribution, for January 2004 through December 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 13-11 also shows the payout ratio after distributing excess day-ahead congestion revenue across months within the planning period. If there are excess day-ahead congestion 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. Congestion in December 2017 was high relative to other months in the planning period, resulting in an extremely high payout ratio.

### Figure 13-11 FTR payout ratio by month, excluding and including excess revenue distribution: January 1, 2004 through December 31, 2017

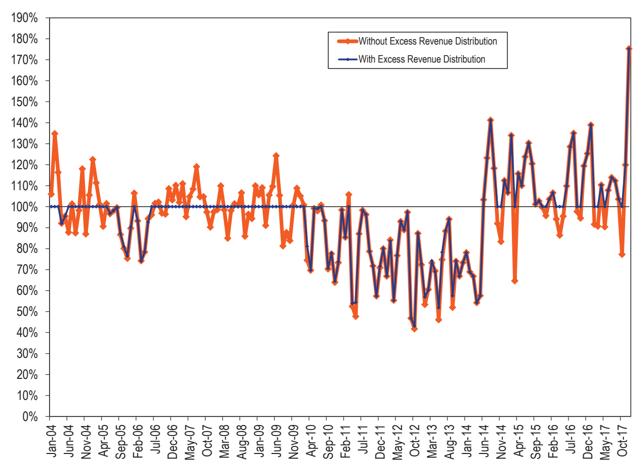



Table 13-38 shows the FTR payout ratio by planning period from the 2003/2004 planning period forward. Planning period 2013/2014 includes the additional revenue from unallocated congestion charges from Balancing Operating Reserves. For the 2014/2015, 2015/2016 and 2016/2017 planning periods, there was excess congestion revenue to pay FTR Holders pro rata in proportion to their net positive target allocations, resulting in a payout ratio of 116.2 percent, 106.8 and 113.1 percent for the planning periods.

### Table 13-38 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% |
| 2017/2018 | 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 13-39 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 13-39 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, the use of generation to load paths rather than a measure of total congestion, and the failure to provide to ARR holders the full system capability that is provided to FTR purchasers in the Long Term FTR Auction.

The issuance of the September 15, 2016, FERC order increased the gap between congestion revenue and ARR/FTR revenue collected. The result of allocating balancing congestion and M2M payments to ARRs, and allocating excess day-ahead congestion revenue and additional FTR auction revenue to FTR Holders solely, increases revenue to FTRs and reduces payments to load. FTR portfolio netting leads to cross subsidies among FTR participants which treat FTRs differently depending on how a participant's portfolio in constructed. 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 generation to load contract path congestion revenue rights rather than on the correct definition of congestion revenues. The 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 modified 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 13-40 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 13-40 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 | - |

## 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 13-41 demonstrates the impact on the payout ratio to positive target allocation FTRs with and without portfolio netting.  In the example the total congestion collected is $4,750 and the total net target allocation is $9,500, resulting in a reported payout ratio of 50.0 percent. With portfolio netting, the net target allocation is simply multiplied by the payout ratio to calculate the congestion revenue a participant receives. For Participant 1, this is $250 multiplied by 0.5 for a total revenue received of $125. The revenue to positive TA column is an indication of how much revenue the positive target allocations, which are the only part of a portfolio receiving available revenue, of a participant need to be paid in order to reach the congestion revenue received. For Participant 1, they are effectively being paid $875 of their $1,000 so that the congestion revenue received can be $125. Another way to state this is the participant is effectively paying themselves their negative target allocations first, and then receiving revenue based on their net target allocation. The result of this is that Participant 1's positive target allocations are effectively granted a payout ratio of 87.5 percent simply because they hold negative target allocations, while Participant 3, who holds no negative target allocations, is only paid at a 50.0 percent payout ratio.

Without portfolio netting all participants are paid at the same effective payout ratio for their positive target allocations. Counting negative target allocations as a source of revenue raises the payout ratio to 54.5 percent. Without portfolio netting, the payout ratio is first applied to positive target allocations, then the participant's negative target allocations are added. The result of this calculation is that each participant is paid an equal 54.5 percent regardless of their portfolio's negative target allocations. In this example Participant 1 pays ends up paying $204.55 into the congestion pot, in net, while Participant 3 is paid 54.5 percent of the positive target allocations, resulting in a payment of $4,745.45. Eliminating portfolio netting is the only way to treat positive target allocations equally across all portfolios, and eliminates the subsidy positive target allocations holders are paying to negative target allocation holders.

Table 13-41 Change in positive target allocation payout ratio given portfolio construction

| | Congestion = $4,750 Net TA = $9,500 | | | | With Netting | | | Without Netting | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Participant | Positive Target Allocations | Negative Target Allocations | Net Target Allocations | Reported Payout Ratio | Congestion Revenue Received | Revenue to Positive TA | Calculated Positive TA Payout Ratio | Congestion Revenue Received | Revenue to Positive TA | Calculated Positive TA Payout Ratio |
| 1 | $1,000.00 | ($750.00) | $250.00 | 50.0% | $125.00 | $875.00 | 87.5% | ($204.55) | $545.45 | 54.5% |
| 2 | $750.00 | ($200.00) | $550.00 | 50.0% | $275.00 | $475.00 | 63.3% | $209.09 | $409.09 | 54.5% |
| 3 | $8,700.00 | $0.00 | $8,700.00 | 50.0% | $4,350.00 | $4,350.00 | 50.0% | $4,745.45 | $4,745.45 | 54.5% |
| Total | $10,450.00 | ($950.00) | $9,500.00 | - | $4,750.00 | $5,700.00 | - | $4,750.00 | $5,700.00 | - |

## Mathematically Equivalent FTRs

A single FTR can be broken into multiple FTRs. The newly formed set of multiple FTRs can have the same net target allocation as long as the start and end points of the constituent end points are, in net, the same as the original. Opponents of the elimination of FTR netting have claimed that without netting this would no longer be true. However, this assertion does not account for revenues from negative target allocation FTR paths in the mathematically equivalent set of FTRs. Appropriately including these revenues results in mathematical equivalence between the single FTR and that same FTR broken into a constituent set of FTRs with the same start and end point.

Table 13-43 shows the effects on a participant with and without portfolio netting under three distinct scenarios. Table 13-42 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 significantly 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 13-42 Nodal day-ahead CLMPs

| Node | DA CLMP |
|---|---|
| A | $20 |
| B | $25 |
| C | $40 |
| D | $100 |
| E | $10 |

Table 13-43 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.[35] FERC did not agree that portfolio netting led to subsidization of portfolios with counterflow positions. The MMU 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. Table 13-40 and Table 13-41 examples demonstrate that portfolio netting in PJM leads to incorrect payments based on participant FTR portfolios. Including portfolio netting in FTR accounting treats FTRs differently depending on the composition of a participant's FTR portfolio.

## Counter Flow FTRs and Revenues

The current rules create an asymmetry between the treatment of counter flow and prevailing flow FTRs. The payout to the holders of counter flow FTRs is not affected when the payout ratio is less than 100 percent. There is no reason for that asymmetric treatment.

For a prevailing flow FTR, the target allocation would be subject to a reduced payout ratio, while a counter flow FTR Holder would not be subject to the reduced payout ratio. The profitability of the prevailing flow FTRs is affected by the payout ratio while the profitability of the counter flow FTRs is not affected by the payout ratio.

Counter flow FTR Holders make payments over the planning period, in the form of negative target allocations. These negative target allocation FTRs are paid at 100 percent regardless of whether positive target allocation FTRs are paid at less than 100 percent.

A counter flow FTR is profitable if the hourly negative target allocation is smaller than the hourly auction payment they received. A prevailing flow FTR is profitable if the hourly positive target allocation is larger than the auction payment they made.

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

Table 13-44 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 13-44 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) |

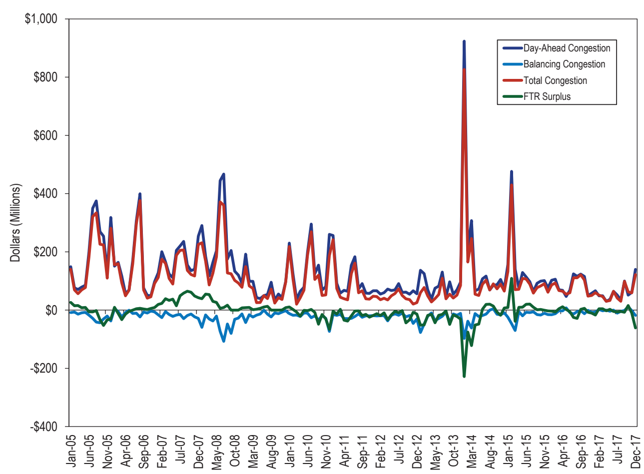
35 See 156 FERC ¶ 61,180 (2016).

Table 13-45 shows the monthly positive, negative and total target allocations.[36] Table 13-45 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 2013/2014 planning period. If this change were implemented after excess planning period revenue was distributed, it would not result in additional revenue for the 2014/2015, 2015/2016, 2016/2017 or 2017/2018 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 $3.8 million in additional revenue generated for the 2016/2017 planning period and an increase of $5.4 million for the 2017/2018 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 2013/2014 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 13-12 shows the FTR surplus, collected day-ahead, balancing and total congestion payments from January 2005 through December 2017. May 2016 had positive total balancing congestion of $7.5 million. March 2015 had balancing congestion of -$70.0 million.

### Figure 13-12 FTR surplus and the collected day-ahead, balancing and total congestion: 2005 through 2017




### Table 13-45 Counter flow FTR payout ratio adjustment impacts: Planning period 2016/2017 and 2017/2018

| | 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 | $47,485,194 | 91.6% | $159,743,326 | 98.2% | 101.8% | $161,202,653 | $1,459,327 |
| Mar-17 | $176,027,074 | ($128,158,531) | $47,868,543 | $44,355,740 | 92.7% | $172,514,271 | 98.7% | 101.3% | $173,686,238 | $1,171,967 |
| Apr-17 | $120,235,925 | ($94,891,539) | $25,344,386 | $27,953,520 | 100.0% | $122,845,060 | 100.0% | 100.0% | $122,845,060 | $0 |
| May-17 | $145,660,505 | ($116,932,244) | $28,728,260 | $25,612,240 | 89.2% | $142,544,484 | 98.6% | 101.4% | $143,609,312 | $1,064,828 |
| Jun-17 | $166,308,515 | ($106,169,103) | $60,139,412 | $64,838,041 | 100.0% | $171,007,144 | 100.0% | 100.0% | $171,007,144 | $0 |
| Jul-17 | $162,370,963 | ($116,930,204) | $45,440,759 | $51,751,599 | 100.0% | $168,681,803 | 100.0% | 100.0% | $168,681,803 | $0 |
| Aug-17 | $111,856,310 | ($80,024,026) | $31,832,284 | $35,736,334 | 100.0% | $115,760,360 | 100.0% | 100.0% | $115,760,360 | $0 |
| Sep-17 | $320,680,546 | ($223,634,276) | $97,046,270 | $100,498,783 | 100.0% | $324,133,059 | 100.0% | 100.0% | $324,133,059 | $0 |
| Oct-17 | $258,051,552 | ($189,205,100) | $68,846,452 | $53,157,210 | 77.2% | $242,362,310 | 96.0% | 104.0% | $247,780,544 | $5,418,234 |
| Nov-17 | $220,121,175 | ($169,092,045) | $51,029,130 | $61,156,211 | 100.0% | $230,248,256 | 100.0% | 100.0% | $230,248,256 | $0 |
| Dec-17 | $380,122,050 | ($298,682,971) | $81,439,079 | $142,692,544 | 100.0% | $441,375,515 | 100.0% | 100.0% | $441,375,515 | $0 |
| Total 2016/2017 | $2,359,360,349 | ($1,624,936,255) | $734,424,094 | $819,886,355 | 100.0% | $2,444,822,610 | 100.0% | 100.0% | $2,351,900,338 | $3,770,798 |
| Total 2017/2018 | $1,619,511,111 | ($369,115,713) | $509,830,721 | $509,830,721 | 100.0% | $878,946,434 | 100.0% | 100.0% | $1,609,240,103 | $5,418,234 |

* Reported payout ratios may vary due to rounding differences when netting

36 Reported payout ratio may differ between Table 13-39 and Table 13-45 due to rounding differences when netting target allocations and considering each FTR individually.

## 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.

### 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.[37] 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.[38] The case has been consolidated with appeals filed by others and is now pending. The Market Monitor and joint petitioners filed an initial brief on July 11, 2017, and a reply brief on October 25, 2017.[39] Oral argument is scheduled for April 23, 2018.

The new rule for calculating congestion revenues went into effect on June 1, 2017, for the 2017/2018 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. Based on the 2011/2012 and subsequent planning periods, load comprises 94.8 percent of all demand. Based on the 2011/2012 and subsequent planning periods, total balancing congestion and M2M payments were $1,537.8 million, so load would have been responsible for an additional $1,034.2 million in charges if the new rules had been place.

37 See 156 FERC ¶ 61,180 (2016), *reh'g denied*, 156 FERC ¶ 61,093 (2017).

38 U.S. Court of Appeals for the District of Columbia Circuit. *NJBPU v. FERC*, Case No. 17-1106 (March 31, 2017).

39 Joint Opening Brief of Petitioners, Case Nos. 17-1106 et al. (D.C. Cir July 11, 2017); Joint Reply Brief of Petitioners (October 25, 2017).

In addition, FERC ordered that all day-ahead congestion revenue in excess of FTR target allocations and additional FTR auction revenue over ARR target allocations, belongs to FTR Holders. This further increased the underlying problem with the FTR design and reduced the probability that congestion revenues will be returned to load.

The reallocation of balancing congestion and M2M payments from FTR Holders to load, and the allocation of additional FTR 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 and increases the uncertainty of holding an ARR to offset congestion charges.

Table 13-46 shows the congestion offset available to load with and without allocating balancing congestion to load. Table 13-46 also shows the congestion offset available to load under the old and current balancing congestion allocation rules, the change in the congestion offset available to load and the overpayment to FTRs under the old and current rules. The current 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 current 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-ahead congestion revenue and additional FTR auction revenue FTR Holders received over their FTR target allocations.

The allocation of balancing congestion and M2M payments to load went into effect in the 2017/2018 planning period. If these rules had been in place beginning with the 2011/2012 planning period, ARR holders would have received a total of $1,034.2 million less in congestion offsets from the 2011/2012 through the 2016/2017 planning period. The total overpayment to FTR Holders for the 2011/2012 through 2016/2017 planning period would have been $944.4 million. The actual underpayment to load in the first seven months of the 2017/2018 planning period was $36.5 million with an $80.4 million overpayment to FTR Holders.

Table 13-46 ARR and FTR total congestion offset (in millions) for ARR holders: Planning periods 2011/2012 through 2017/2018

| | Old | | | | | Current | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Planning Period | ARR Credits | FTR Credits | Total Congestion | Total ARR/ FTR Offset | Percent Offset | New Offset | Old Revenue Received | Current 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 | $640.0 | $169.1 | $824.6 | $809.1 | 98.1% | 89.5% | $809.1 | $727.7 | ($81.4) | $179.0 |
| 2017/2018* | $334.0 | $98.4 | $477.7 | $432.4 | 90.5% | 79.4% | $432.4 | $395.9 | ($36.5) | $80.4 |
| Total | $3,291.2 | $1,783.3 | $6,809.3 | $5,074.4 | 74.5% | 64.6% | $5,074.4 | $4,003.7 | ($1,070.7) | $1,024.7 |

* Seven months of 2017/2018 planning period

Table 13-46 demonstrates the inadequacies of the current ARR/FTR design even before allocating balancing congestion and M2M payments to load. 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.

# Credit Issues

There were two collateral defaults in 2017 for a total of $318,746. Both defaults were cured reasonably promptly.

# 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.[40] 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.

After January 19, 2017, participants will be subject to the new FTR forfeiture rule. PJM began retroactively billing forfeitures back to January 19, 2017, and billing for the prompt month FTR forfeitures, starting with the September bill. PJM will continue billing one retroactive month concurrently with the prompt month until all retroactive months are billed. This rule considers the impact of a participant's net virtual transaction portfolio on all constraints. If a participant's net virtual portfolio impacts a constraint by the greater of 0.1 MW or 10 percent or more of the line limit, and that constraint affects an individual FTR's target allocation by $0.01, the FTR is subject to FTR forfeiture if the net virtual portfolio increased the value of the FTR. FTR forfeitures do not result from net virtual portfolios that decrease the value of their affiliates' FTRs. The forfeiture amount calculation is the hourly profit of the FTR and an FTR cannot forfeit more than once per hour.

40 See 158 FERC ¶ 61,038 (2017).