Q3

State of the Market Report for PJM

January through September

Monitoring Analytics, LLC

Independent
Market Monitor
for PJM

11.14.2019

2019

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 *2019 Quarterly State of the Market Report for PJM: January through September*.[3]

1 PJM Open Access Transmission Tariff (OATT) Attachment M (PJM Market Monitoring Plan) § VI.A. Capitalized terms used herein and not otherwise defined have the meaning provided in the OATT, PJM Operating Agreement, PJM Reliability Assurance Agreement or other tariffs 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: 2019 Quarterly State of the Market Report for PJM: January through September.

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Introduction

2019 Q3 in Review

The goal of competition in PJM is to provide customers wholesale power at the lowest possible price, but no lower. The PJM markets have done that. The PJM markets work, even if not perfectly. The results of the energy market were competitive in the first nine months of 2019. The results of the base capacity auction run in 2018 for 2021/2022 were not competitive and the underlying issues need to be addressed. The PJM markets bring customers the benefits of competition. Inflation adjusted load weighted real-time energy prices were lower in the first nine months of 2019 than in the first nine months of any year since the creation of the PJM energy market on April 1, 1999. But the PJM markets, and wholesale power markets in the U.S., face new challenges that potentially threaten the viability of competitive markets. The value of markets is under attack, from those who think energy prices are too low and from those who think that market outcomes do not favor their preferred technology whether it is nuclear, coal, wind or solar.

The PJM market design has brought significant benefits to participants and the fundamental current design of PJM markets is sustainable. There is no reason to overturn the key components of the PJM capacity and energy markets. There is no reason to create convoluted capacity market rules to exclude any competitive offer from any technology including renewable and nuclear technologies. There is no reason to artificially increase energy prices to benefit nuclear and coal plants. The focus should be on the continued refinement of the market rules in order to ensure that the rules correctly incorporate the fundamentals of the markets, e.g. improved combined cycle modeling, accurate scarcity pricing, and matching dispatch and pricing intervals. Markets are preferred to the integrated resource planning approach that some would reimpose because markets provide technology neutral incentives to all market participants, including those who will introduce technologies not yet in existence. Markets continue to provide the most efficient way to organize the production of power at the lowest possible cost. Markets are also the most efficient way to integrate state supported renewable technologies.

To the extent that there are shared broader goals related to PJM markets, they should also be addressed. If the PJM states decide that carbon is a pollutant with a negative value, a market approach to carbon is preferred to an inefficient technology or unit specific subsidy approach or inconsistent RPS rules. 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. Implementation of a carbon price using RGGI or a similar market mechanism by the states would mean that the states control the carbon price and that no FERC approval would be required and no PJM rule changes would be required. The carbon price would become part of the marginal costs of power plants and the impacts on production and consumption decisions would be market based. States would control the resulting revenues. This is the case regardless of the number of PJM states that join RGGI or a similar market.

In the capacity market, the Commission order on PJM's MOPR filing clarified the dilemma faced by the Commission in choosing between market solutions and potentially inconsistent state policy initiatives. In response, PJM filed a proposed complex and unworkable redesign of the capacity market that would effectively exclude new state subsidized renewable resources from the capacity market and would result in a significant increase in capacity market payments.

The Sustainable Market Rule (SMR) approach to the capacity market design is simple, based in economic logic, based on the PJM competitive market design, and does not require complex rule changes to implement.[1] The SMR would provide a straightforward way to harmonize federal and state approaches to the provision of energy, while respecting the distinction between federal and state authority. The SMR reaffirms the definition of a competitive offer in the PJM capacity market and removes noncompetitive barriers to the participation of renewables.

1 See the "*Summary of the Sustainable Market Rule Proposal of the Independent Market Monitor for PJM*," Docket Nos. ER18-1314-000, EL16-49-000 & EL18-178-000 (October 31, 2018) <http://www.monitoringanalytics.com/Filings/2018/IMM_Summary_of_Position_Docket_No__EL18-178_ER18-1314_EL16-49.pdf>.

The expected impact of the SMR design on the offers and clearing of renewable resources would be from zero to insignificant. The competitive offers of renewables, based on the net ACR of technologies currently operating in PJM, are likely to clear in the capacity market. The expected impact of the SMR design on the offers and clearing of nuclear plants would be from zero to insignificant. The competitive offers of efficient nuclear plants, based on net ACR, are likely to clear in the capacity market. The expected impact of the SMR design on the offers and clearing of cost of service resources would be from zero to insignificant. The competitive offers of these resources, based on net ACR, are likely to clear in the capacity market. In addition, cost of service resources have the option of using the existing FRR rules, which would retain their existing status.

Under the SMR, all nonmarket resources may participate in the energy market without limits. But to ensure the reliable operation of the energy market, the capacity market needs to be the balancing mechanism for required market resources to provide the appropriate incentives for entry and exit. This balancing function requires that all capacity resources offer at competitive levels. If resources offer at competitive levels and clear the capacity market, the resources are paid the market clearing price. If resources do not clear the capacity market, the resources are not paid for capacity. Any nonmarket revenues required to meet the public policy goals associated with these resources would be provided outside the market in whatever manner the supporters of those resources choose.

All capacity has a must offer requirement. All cleared resources are paid the capacity market clearing price. All resources with a must offer requirement or that wish to sell capacity are required to make competitive offers in the capacity market. Competitive offers in the capacity market for resources with nonmarket revenues are defined to be greater than or equal to net going forward costs (ACR), and less than the offer cap. Gross ACR uses unit specific facts, or technology defaults, and net ACR uses unit specific forward looking market net energy revenue. Competitive offers for resources with only market revenues are defined to be less than the offer cap.

Attempts to distinguish between the definition of competitive offers of new entrants and the competitive offers of existing resources are a mistake. A competitive offer is a competitive offer, regardless of whether the resource is new or existing. A competitive offer in the capacity market is the marginal cost of capacity, or net ACR, regardless of whether the resource is planned or existing. ACR includes incremental capital expenditures, termed APIR. Use of higher offers for new resources based on the full cost of entry, as proposed by PJM, would constitute a noncompetitive barrier to entry and would create a noneconomic bias in favor of existing resources and against new resources of all types, including new renewable resources and new gas fired combined cycles. Use of higher offers for new renewable resources creates an issue because most such artificially higher offers are unlikely to clear in the market and would be categorized as subsidized.

Market and nonmarket resources that do not clear the capacity market based on their competitive offers are not paid a capacity price, do not contribute to meeting PJM's reliability requirements, and are not given any special treatment in the wholesale power market. Any revenues required to sustain such resources would come from the energy and ancillary services markets and from nonmarket sources. Nonmarket resources that do not clear the capacity market would be eligible to receive bonus payments under the capacity performance design for performance during performance assessment intervals, similar to energy only resources.

In the energy market, PJM's price formation filing clarified the difference between fundamental changes to the energy market design and the alternative relatively simple solutions to identified problems. The impact of PJM's filing on the energy market would be significantly larger than the impact on the reserve market. PJM's proposal would also guarantee double recovery for generation owners by breaking the tight link between energy and capacity markets that has been essential to the success of the PJM market design. PJM has failed to identify an issue or issues that require the dramatic changes to the energy market design PJM proposes. PJM has failed to explain how PJM's proposed changes would enhance or even maintain the competitiveness of the markets. It is likely that the proposed changes would create significant unintended consequences that PJM cannot foresee or address.

It is reasonable to continue the Commission's efforts to improve price formation in organized wholesale power markets. PJM has not fully implemented or assessed the effects of the changes to the PJM energy market resulting from the Commission's price formation proceedings including the impact of offer flexibility, five minute settlements, cost-based offers over $1,000 per MWh, transmission penalty factors, uplift transparency, and fast start pricing.

As an alternative, there is a set of defined steps that could be implemented immediately and would address identified issues in the energy market design. These defined steps to modify the current energy market design to address legitimate concerns about price formation in the energy and reserves markets, include: the consolidation of the tier 1 and tier 2 synchronized markets; an increase in the scarcity price to reflect the highest generator energy offer allowed; the explicit pricing of defined operator actions; the increased transparency of operator actions; the implementation of clear rules governing real-time pricing through the selection of RT SCED cases and LPC cases; and the consistent definition of energy and reserves products in the day-ahead and real-time markets, including recognition of the appropriate role of demand side resources. Additional steps include the ongoing evolution of market design to improve the granularity and sophistication of price signals with the goal of increased reliance on market prices and less on administrative actions. This should not be the end of the discussion but the beginning of a longer, more complete discussion which would lead to incremental steps to improve markets.

Energy prices in PJM are not too low. Energy prices reflect the short run marginal costs of energy, consistent with a competitive market. There is no evidence to support the asserted need for a significant change to the level of energy market revenues. The objective of efficient short run price signals in the energy market is to minimize system production costs, not to minimize uplift or to ensure a predefined level of revenues in the energy market for any defined set of generation technologies.

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 decreased significantly in the first nine months of 2019 compared to the first nine months of 2018. The load-weighted average real-time LMP was 30.0 percent lower in the first nine months of 2019 than in the first nine months of 2018, $27.60 per MWh versus $39.43 per MWh. Of the $11.83 per MWh decrease, 34.2 percent was a result of lower fuel costs. Other contributors to the decrease were the dispatch of lower cost units, decreased load and lower markups.

The role of gas continued to grow in the first nine months of 2019. The capacity of gas fired units has exceeded the capacity of coal units and nuclear units since 2017. The energy output of gas fired plants exceeded the energy output of coal plants and of nuclear plants in the first nine months of 2019. Gas fired units were almost 70 percent of marginal units, a significant increase over the 37 percent share in 2015.

Net revenue from the energy and capacity markets 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 decreased for all unit types in the first nine months of 2019 compared to the first nine months of 2018 as a result of lower energy prices. For example, in the first nine months of 2019, average energy market net revenues decreased by 52 percent for a new combustion turbine, 36 percent for a new combined cycle, 82 percent for a new coal plant, 32 percent for a new nuclear plant, and 29 percent for a new onshore wind installation.

Changes in forward energy market prices can significantly affect expected profitability of nuclear plants in PJM. The current analysis, based on forward prices for energy and known forward prices for capacity, shows that two plants, Davis Besse and Perry, would not cover their annual avoidable costs. These two plants are single unit sites which have higher operating costs per MWh than multiple unit plants and show an average annual shortfall of $8.12 per MWh. In March 2018, Davis Besse and Perry requested deactivation in 2021 but reversed the decision based on new subsidies in Ohio. Susquehanna shows a shortfall in 2019 and a surplus in 2020 and 2021. Susquehanna has reduced its operating costs and is not operating at a loss when the unit specific information is accounted for.

Net revenues for nuclear power plants increased significantly in 2018 but decreased from that level in the first nine months of 2019. There are currently two nuclear power plants in PJM that are not economic at expected 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 level of potential retirements of coal and nuclear units does not imply a reliability issue in PJM and does not imply a fuel security issue in PJM. A comparison of the total units at risk and the current excess capacity in PJM shows that, ignoring local reliability issues, the current and expected excess capacity is of the same order of magnitude as the units at risk. PJM had excess reserves of more than 11,000 ICAP MW on June 1, 2019, and will have excess reserves of more than 12,000 ICAP MW on June 1, 2020, based on current positions. There are currently 124,399.7 MW in the PJM generator interconnection queues, of which 35,269.3 MW are expected to go into service based on historical completion rates.

The evolution of wholesale power markets is far from complete. The market design can be improved and made more efficient and more competitive. PJM and its market participants will need to continue to work constructively to refine the competitive market design and to ensure the continued effectiveness of PJM markets in providing customers wholesale power at the lowest possible price, but no lower.

PJM Market Summary Statistics

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

Table 1-1 PJM Market Summary Statistics: January through September, 2018 and 2019[2]

	Jan - Sep, 2018	Jan - Sep, 2019	Percent Change
Average Hourly Load (MW)	91,905	89,834	(2.3%)
Average Hourly Generation (MW)	95,561	95,531	(0.0%)
Peak Load (MW)	147,042	148,228	0.8%
Installed Capacity at September 30 (MW)	184,560	186,503	1.1%
Load Weighted Average Real Time LMP ($/MWh)	$39.43	$27.60	(30.0%)
Total Congestion Costs ($ Million)	$1,116.23	$419.07	(62.5%)
Total Uplift Charges ($ Million)	$176.83	$70.63	(60.1%)
Total PJM Billing ($ Billion)	$37.95	$29.98	(21.0%)

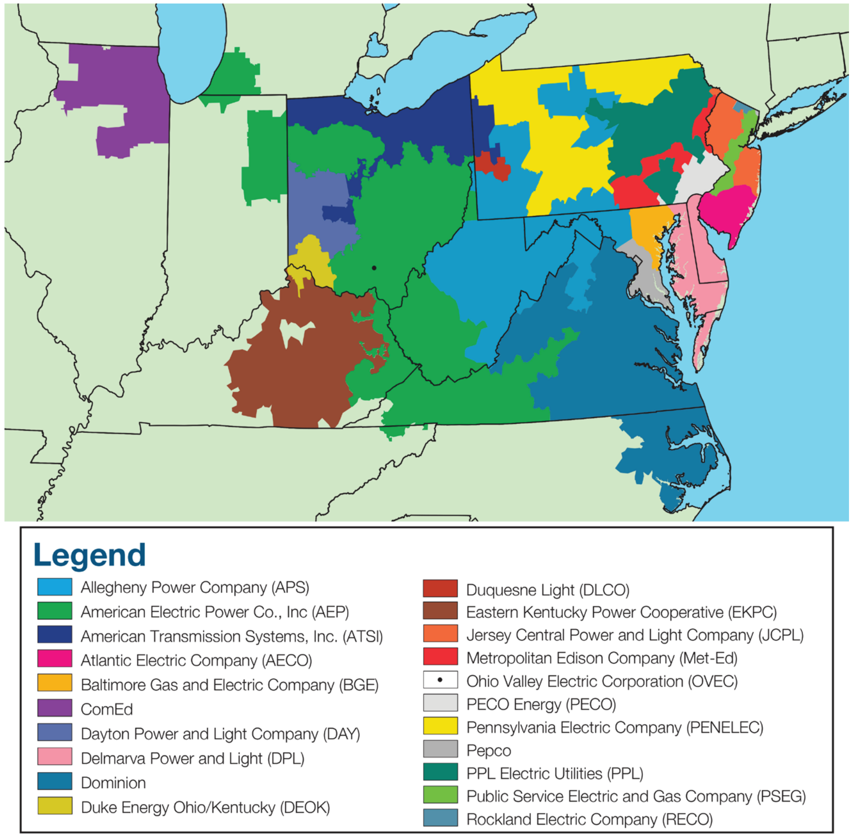
PJM Market Background

The PJM Interconnection, L.L.C. (PJM) operates a centrally dispatched, competitive wholesale electric power market that, as of September 30, 2019, had installed generating capacity of 186,503 megawatts (MW) and 1,044 members including market buyers, sellers and traders of electricity in a region including more than 65 million people in all or parts of 13 states (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.

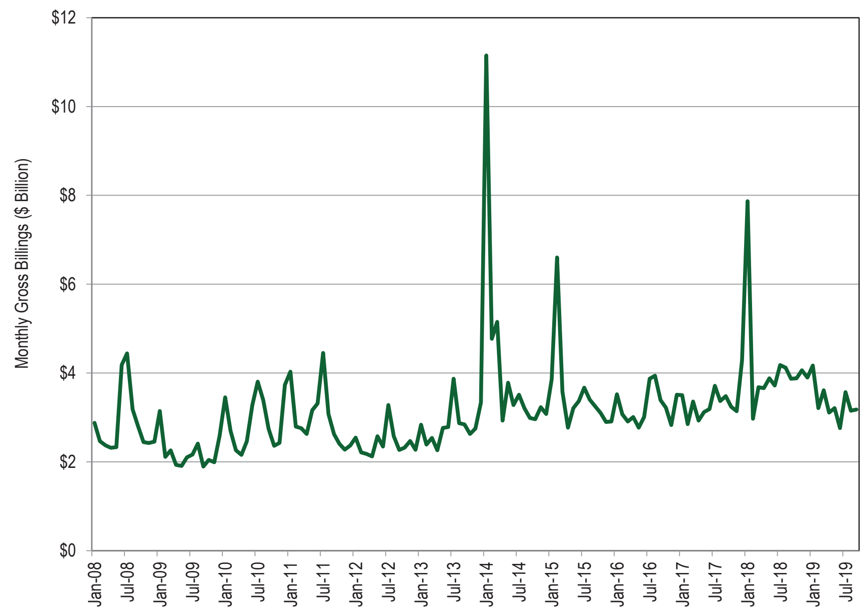
2 The load reported in this table is the accounting load plus net withdrawals at generator buses. The average hourly accounting load is reported in Section 3, "Energy Market."
3 See PJM. "Member List," which can be accessed at: <http://pjm.com/about-pjm/member-services/member-list.aspx>.
4 See PJM. "Who We Are," which can be accessed at: <http://pjm.com/about-pjm/who-we-are.aspx>.
5 See the 2018 State of the Market Report for PJM, Volume II, Appendix A:"PJM Geography" for maps showing the PJM footprint and its evolution prior to 2019.

Figure 1-1 PJM's footprint and its 21 control zones



In the first nine months of 2019, PJM had total billings of \$29.98 billion, a decrease of 21.0 percent from \$37.95 billion in the first nine months of 2018 (Figure 1-2).[6]

Figure 1-2 PJM reported monthly billings (\$ Billion): 2008 through September 2019



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

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

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. PJM introduced the Capacity Performance capacity market design effective on August 10, 2015, with the Base Residual Auction for 2018/2019.[7 8]

Conclusions

This report assesses the competitiveness of the markets managed by PJM in the first nine months of 2019, 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 cost, demand, and ownership structure of the market. The three pivotal supplier (TPS) test is the most relevant measure of market structure because it accounts for the ownership of assets and the relationship among the pattern of ownership, the resource costs, 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 outcomes of the market. Market performance results from 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.

Energy Market Conclusion

The Market Monitoring Unit (MMU) analyzed measures of market structure, participant conduct and market performance, including market size, concentration, pivotal suppliers, offer behavior, and price. The MMU concludes that the PJM energy market results were competitive in the first nine months of 2019.

7 See also the *2018 State of the Market Report for PJM*, Volume 2, Appendix B: "PJM Market Milestones."

8 Analysis of 2019 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, 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). In December 2018, PJM integrated the Ohio Valley Electric Corporation (OVEC.) 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 2019, see *2018 State of the Market Report for PJM*, Volume 2, Appendix A: "PJM Geography."

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 the PJM energy market in the first nine months of 2019 was unconcentrated by FERC HHI standards in 98.2 percent of market hours and moderately concentrated in 1.8 percent of market hours. Average HHI was 773 with a minimum of 572 and a maximum of 1098 in the first nine months of 2019. The PJM energy market intermediate and peaking segments of supply were highly concentrated. 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 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 definition of cost-based offers and 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 they fail the TPS test.
- 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 represents economic withholding and the markups of those participants affected LMP.
- 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 for some marginal units 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. Market design implementation issues, including inaccuracies in modeling of the transmission system and of generator capabilities as well as inefficiencies in real-time dispatch and price formation, undermine market efficiency in the energy market.
- 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 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

The Market Monitoring Unit (MMU) analyzed market structure, participant conduct and market performance in the PJM Capacity Market, including supply, demand, concentration ratios, pivotal suppliers, volumes, prices, outage rates and reliability.[11] The conclusions are a result of the MMU's evaluation of the last Base Residual Auction, for the 2021/2022 Delivery Year.

Table 1-3 The Capacity Market results were not competitive

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

- The aggregate market structure was evaluated as not competitive. For almost all auctions held from 2007 to the present, the PJM region failed the three pivotal supplier test (TPS), which is conducted at the time of the auction.[12] Structural market power is endemic to the capacity market.
- The local market structure was evaluated as not competitive. For almost every auction held, all LDAs have failed the TPS test, which is conducted at the time of the auction.[13]
- Participant behavior was evaluated as not competitive in the 2021/2022 RPM Base Residual Auction. 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. In the 2021/2022 RPM Base Residual Auction, some participants' offers were above the competitive level. The MMU recognizes that these market

11 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.

12 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.

13 In the 2012/2013 RPM Base Residual Auction, six participants included in the incremental supply of EMAAC passed the TPS test. In the 2014/2015 RPM Base Residual Auction, seven participants in the incremental supply in MAAC passed the TPS test. In the 2021/2022 RPM First Incremental Auction, two participants in the incremental supply in EMAAC passed the TPS test.

participants followed the capacity market rules by offering at less than the stated offer cap of Net CONE times B. But Net CONE times B is not a competitive offer when the expected number of performance assessment intervals is zero or a very small number and the non-performance charge rate is defined as Net CONE/30. Under these circumstances, a competitive offer, under the logic defined in PJM's capacity performance filing, is net ACR. That is the way in which most market participants offered in this and prior capacity performance auctions.

- Market performance was evaluated as not competitive based on the 2021/2022 RPM Base Residual Auction. Although structural market power exists in the Capacity Market, a competitive outcome can result from the application of market power mitigation rules. The outcome of the 2021/2022 RPM Base Residual Auction was not competitive as a result of participant behavior which was not competitive, specifically offers which exceeded the competitive level.
- 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, the inclusion of imports which are not substitutes for internal capacity resources, and the definition of the default offer cap.

Tier 2 Synchronized Reserve Market Conclusion

The MMU analyzed measures of market structure, conduct and performance for the PJM Synchronized Reserve Market for the first nine months of 2019.

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

The MMU analyzed measures of market structure, conduct and performance for the PJM DASR Market for the first nine months of 2019.

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 DASR market would have failed a three pivotal supplier test in less than one percent of cleared hours in the first nine months of 2019. The day-ahead scheduling reserve market structure remains evaluated as not competitive based on persistent structural issues.
- 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 were part of the

clearing price in all but three of the 803 hours when the clearing price was above $0.00.

- Market design was evaluated as mixed because the DASR product does not include performance obligations. Offers should be based on opportunity cost only, to ensure competitive outcomes and that market power cannot be exercised.

Regulation Market Conclusion

The MMU analyzed measures of market structure, conduct and performance for the PJM Regulation Market for the first nine months of 2019.

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 because the PJM Regulation Market failed the three pivotal supplier (TPS) test in 93.3 percent of the hours in the first nine months of 2019.
- Participant behavior in the PJM Regulation Market was evaluated as competitive for the first nine months of 2019 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

The Market Monitoring Unit (MMU) analyzed measures of market structure, participant conduct and market performance, including market size, concentration, offer behavior, and price. The MMU concludes that the PJM FTR auction market results were competitive in the first nine months of 2019.

Table 1-7 The FTR auction markets results were competitive

Market Element	Evaluation	Market Design
Market Structure	Partially Competitive	
Participant Behavior	Partially Competitive	
Market Performance	Competitive	Flawed

- Market structure was evaluated as partially competitive because while purchasing FTRs in the FTR Auction is voluntary, issues have been identified with the under assignment of system capability to ARRs and the accuracy of modeling in the Long Term FTR Auctions.
- Participant behavior was evaluated as partially competitive based on the behavior of GreenHat Energy, LLC.
- Market performance was evaluated as competitive because it reflected the interaction between participant demand behavior and the expected system capability that PJM made available for sale as FTRs. It is not clear, in a competitive market, why FTR purchases by financial entities remain persistently profitable. The fact that load is not able to define its willingness to sell FTRs or the prices at which it is willing to sell FTRs also raises questions about the market structure, the market performance and the market design.
- 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. The path based assignment of congestion rights is inadequate and incorrect. ARR holders cannot determine the price at which they are willing to sell rights to congestion revenue. Ongoing PJM subjective

intervention in the FTR market that affects market fundamentals is also an issue.

Role of MMU

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

Reporting

The MMU performs its reporting function primarily by issuing and filing annual and quarterly state of the market reports; regular reports on market 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.

14 18 CFR § 35.28(g)(3)(ii); see also *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, FERC Stats. & Regs. ¶31,281 (2008) ("Order No. 719"), *order on reh'g*, Order No. 719-A, FERC Stats. & Regs. ¶31,292 (2009), *reh'g denied*, Order No. 719-B, 129 FERC ¶ 61,252 (2009).
15 OATT Attachment M § IV; 18 CFR § 1c.2.

Monitoring

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

The MMU monitors market behavior for violations of FERC Market Rules and PJM Market Rules, including the actual or potential exercise of market power.[19] 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…"[20] [21] [22] The MMU also monitors PJM for compliance with the rules, in addition to market participants.[23]

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

16 OATT Attachment M § IV.
17 OATT Attachment M § IV.K.3.
18 OATT Attachment M § IV.H.
19 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.")
20 FERC defines manipulation as engaging "in any act, practice, or course of business that operates or would operate as a fraud or deceit upon any entity." 18 CFR § 1c.2(a)(3). Manipulation may involve behavior that is consistent with the letter of the rules, but violates their spirit. An example is market behavior that is economically meaningless, such as equal and opposite transactions, which may entitle the transacting party to a benefit associated with volume. Unlike market power or rule violations, manipulation must be intentional. The MMU must build its case, including an inference of intent, on the basis of market data.
21 OATT § I.1.
22 The MMU has no prosecutorial or enforcement authority. The MMU notifies 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 FERC, state regulators, stakeholders or other authorities. The MMU may also participate as a party or provide information or testimony in regulatory or other proceedings.
23 OATT Attachment M § IV.C.

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 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.[24]

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.[25] [26] [27] [28]

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 FERC or other regulatory authorities. 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.

24 OATT Attachment M–Appendix § II.E.
25 OATT Attachment M–Appendix § II.B.
26 OATT Attachment M–Appendix § II.C.
27 OATT Attachment M–Appendix § IV.
28 OATT Attachment M–Appendix § VII.

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.[29] [30]

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.[31]

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.[32] The MMU initiates and proposes changes to the design of such markets or the PJM Market Rules in stakeholder or regulatory proceedings.[33] 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.[34] 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.[35] The MMU may provide in its annual, quarterly and other reports "recommendations regarding any matter within its purview."[36]

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,"[37] the MMU recommends specific enhancements to existing market rules and implementation of new rules that are required for

29 OATT Attachment M–Appendix § II(p).
30 OATT Attachment M–Appendix § III.
31 OA Schedule 6 § 1.5.
32 OATT Attachment M § IV.D.
33 *Id.*
34 *Id.*
35 *Id.*
36 OATT Attachment M § VI.A.
37 18 CFR § 35.28(g)(3)(ii)(A); see also OATT Attachment M § IV.D.

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

In this *2019 Quarterly State of the Market Report for PJM: January through September*, the MMU includes six new recommendations.[38]

New Recommendations from Section 3, Energy Market

- The MMU recommends that in order to ensure effective market power mitigation, PJM always enforce parameter limited values by committing units only on parameter limited schedules, when the TPS test is failed or during high load conditions such as cold and hot weather alerts or more severe emergencies. (Priority: High. New recommendation. Status: Not adopted.)
- The MMU recommends that PJM model generators' operating transitions and peak operating modes. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that PJM approve one RT SCED case for each five minute interval to send dispatch signals, and that PJM calculate prices for that five minute interval using the same approved SCED case. (Priority: High. New recommendation. Status: Not adopted.)

New Recommendation from Section 10, Ancillary Services

- The MMU recommends that fleet wide cost of service rates used to compensate resources for reactive capability be eliminated and replaced with compensation based on unit specific costs. (Priority: Low. New recommendation.[39] Status: Not adopted.)

38 New recommendations include all MMU recommendations that were reported for the first time in the *2019 Quarterly State of the Market Report for PJM: January through September.*

39 The MMU has discussed this recommendation in state of the market reports since 2016 but this is the first time it has been reported as a formal MMU recommendation.

New Recommendation from Section 11, Congestion and Marginal Losses

- The MMU recommends that PJM's logic for the calculation of implicit balancing congestion charges revert to the method used prior to April 1, 2018. (Priority: Medium. New recommendation. Not adopted.)

New Recommendation from Section 12, Generation and Transmission Planning

- The MMU recommends that the market efficiency process be eliminated because it is not consistent with a competitive market design. (Priority: Medium. New recommendation. Status: Not adopted.)

Total Price of Wholesale Power

The total price of wholesale power is the total price per MWh of purchasing wholesale electricity from PJM markets. The total price is an average price and actual prices vary by location and time period. The total price includes the price of energy, capacity, ancillary services, and transmission service, administrative fees, regulatory support fees and uplift charges billed through PJM systems. Table 1-8 shows the average price, by component, for the first nine months of 2018 and 2019.

The total billing values shown in Table 1-8 are the total price per MWh multiplied by the total load. This represents the total dollars charged for purchasing wholesale electricity from PJM markets. This total is different from the total billing that PJM reports as shown in Figure 1-2. PJM's reported total billing represents the total dollars that pass through the PJM settlement process. There are issues with the PJM total billing calculations. The PJM total billing calculation includes all billing line item charges including monthly billing adjustments for the month in which PJM makes the adjustment rather than the month to which the adjustment applies. Rather than adding positive and negative spot market and congestion charges, PJM calculates the average of the absolute value of the positive and negative charges. PJM also makes adjustments to eliminate certain transmission owners' network charges and monthly bilateral corrections.

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.[40]
- The Energy Uplift (Operating Reserves) component is the average price per MWh of day-ahead and balancing operating reserves and synchronous condensing charges.[41]
- The Reactive component is the average cost per MWh of reactive supply and voltage control from generation and other sources.[42]
- The Regulation component is the average cost per MWh of regulation procured through the PJM Regulation Market.[43]
- The PJM Administrative Fees component is the average cost per MWh of PJM's monthly expenses for a number of administrative services, including Advanced Control Center (AC^2) and OATT Schedule 9 funding of FERC, OPSI, 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.[44]
- The Capacity (FRR) component is the average cost per MWh under the Fixed Resource Requirement (FRR) Alternative for an eligible LSE to satisfy its Unforced Capacity obligation.[45]
- The Emergency Load Response component is the average cost per MWh of the PJM Emergency Load Response Program.[46]
- The Day-Ahead Scheduling Reserve component is the average cost per MWh of Day-Ahead scheduling reserves procured through the Day-Ahead Scheduling Reserve Market.[47]
- The Transmission Owner (Schedule 1A) component is the average cost per MWh of transmission owner scheduling, system control and dispatch services charged to transmission customers.[48]
- The Synchronized Reserve component is the average cost per MWh of synchronized reserve procured through the Synchronized Reserve Market.[49]
- The Black Start component is the average cost per MWh of black start service.[50]
- The RTO Startup and Expansion component is the average cost per MWh of charges to recover AEP, ComEd and DAY's integration expenses.[51]
- The NERC/RFC component is the average cost per MWh of NERC and RFC charges, plus any reconciliation charges.[52]
- The Economic Load Response component is the average cost per MWh of day-ahead and real-time economic load response program charges to LSEs.[53]
- The Transmission Facility Charges component is the average cost per MWh of Ramapo Phase Angle Regulators charges allocated to PJM Mid-Atlantic transmission owners.[54]

40 OATT §§ 13.7, 14.5, 27A & 34.
41 OA Schedules 1 §§ 3.2.3 & 3.3.3.
42 OATT Schedule 2 and OA Schedule 1 § 3.2.3B. The line item in Table 1-8 includes all reactive services charges.
43 OA Schedules 1 §§ 3.2.2, 3.2.2A, 3.3.2, & 3.3.2A; OATT Schedule 3.
44 OATT Schedule 12.
45 RAA Schedule 8.1.
46 OATT PJM Emergency Load Response Program.
47 OA Schedules 1 §§ 3.2.3A.01 & OATT Schedule 6.
48 OATT Schedule 1A.
49 OA Schedule 1 § 3.2.3A.01; PJM OATT Schedule 6.
50 OATT Schedule 6A. The line item in Table 1-8 includes all Energy Uplift (Operating Reserves) charges for Black Start.
51 OATT Attachments H-13, H-14 and H-15 and Schedule 13.
52 OATT Schedule 10-NERC and OATT Schedule 10-RFC.
53 OA Schedule 1 § 3.6.
54 OA Schedule 1 § 5.3b.

- The nonsynchronized reserve component is the average cost per MWh of non-synchronized reserve procured through the Non-Synchronized Reserve Market.[55]
- The Emergency Energy component is the average cost per MWh of emergency energy.[56]

Table 1-8 shows that Energy, Capacity and Transmission 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 the first nine months of 2019.

Table 1-8 Total price per MWh by category: January through September, 2018 and 2019[57 58]

Category	Jan-Sep 2018 $/MWh	Jan-Sep 2018 ($ Millions)	Jan-Sep 2018 Percent of Total	Jan-Sep 2019 $/MWh	Jan-Sep 2019 ($ Millions)	Jan-Sep 2019 Percent of Total	Percent Change
Load Weighted Energy	$39.43	$23,742	62.8%	$27.60	$16,243	54.2%	(30.0%)
Capacity	$12.44	$7,492	19.8%	$11.79	$6,937	23.1%	(5.3%)
Capacity	$12.40	$7,464	19.7%	$11.77	$6,925	23.1%	(5.1%)
Capacity (FRR)	$0.00	$0	0.0%	$0.00	$0	0.0%	0.0%
Capacity (RMR)	$0.05	$28	0.1%	$0.02	$12	0.0%	(53.9%)
Transmission	$9.29	$5,590	14.8%	$10.19	$5,999	20.0%	9.8%
Transmission Service Charges	$8.62	$5,189	13.7%	$9.55	$5,622	18.8%	10.8%
Transmission Enhancement Cost Recovery	$0.57	$345	0.9%	$0.55	$325	1.1%	(3.8%)
Transmission Owner (Schedule 1A)	$0.09	$56	0.1%	$0.09	$52	0.2%	(4.8%)
Transmission Seams Elimination Cost Assignment (SECA)	$0.00	$0	0.0%	$0.00	$0	0.0%	0.0%
Transmission Facility Charges	$0.00	$0	0.0%	$0.00	$0	0.0%	0.0%
Ancillary	$0.84	$506	1.3%	$0.71	$417	1.4%	(15.7%)
Reactive	$0.42	$250	0.7%	$0.44	$259	0.9%	5.7%
Regulation	$0.20	$121	0.3%	$0.11	$64	0.2%	(45.8%)
Black Start	$0.08	$49	0.1%	$0.08	$48	0.2%	0.7%
Synchronized Reserves	$0.06	$37	0.1%	$0.04	$25	0.1%	(30.6%)
Non-Synchronized Reserves	$0.02	$13	0.0%	$0.01	$8	0.0%	(34.7%)
Day Ahead Scheduling Reserve (DASR)	$0.06	$36	0.1%	$0.02	$13	0.0%	(64.3%)
Administration	$0.51	$308	0.8%	$0.52	$307	1.0%	1.8%
PJM Administrative Fees	$0.48	$289	0.8%	$0.49	$286	1.0%	1.4%
NERC/RFC	$0.03	$18	0.0%	$0.03	$19	0.1%	7.0%
RTO Startup and Expansion	$0.00	$2	0.0%	$0.00	$2	0.0%	3.4%
Energy Uplift (Operating Reserves)	$0.27	$164	0.4%	$0.12	$70	0.2%	(56.4%)
Demand Response	$0.01	$4	0.0%	$0.00	$1	0.0%	(63.2%)
Load Response	$0.01	$4	0.0%	$0.00	$1	0.0%	(63.2%)
Emergency Load Response	$0.00	$0	0.0%	$0.00	$0	0.0%	0.0%
Emergency Energy	$0.00	$0	0.0%	$0.00	$0	0.0%	0.0%
Total Price	$62.80	$37,808	100.0%	$50.93	$29,974	100.0%	(18.9%)
Total Load (GWh)	602,071			588,506			(2.3%)
Total Billing ($ Billions)	$37.81			$29.97			(20.7%)

55 OA Schedule 1 § 3.2.3A.001.
56 OA Schedule 1 § 3.2.6.
57 Note: The totals in this table include after the fact billing adjustments and may not match totals presented in past reports.
58 The total billing in this table does not match the PJM reported total billing due to differences in calculation methods. For example, PJM accounts for all adjustments in the month billed, whereas the totals presented in these tables account for those adjustments in the month for which the adjustment was applied.

Table 1-9 shows the inflation adjusted average price, by component, for January through September, 2018 and 2019. 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).[59]

Table 1-9 Inflation adjusted total price per MWh by category: January through September, 2018 and 2019[60]

Category	Jan-Sep 2018 $/MWh	Jan-Sep 2018 ($ Millions)	Jan-Sep 2018 Percent of Total	Jan-Sep 2019 $/MWh	Jan-Sep 2019 ($ Millions)	Jan-Sep 2019 Percent of Total	Percent Change
Load Weighted Energy	$25.45	$15,323	62.8%	$17.49	$10,293	54.2%	(31.3%)
Capacity	$8.01	$4,825	19.8%	$7.47	$4,398	23.2%	(6.7%)
Capacity	$7.98	$4,807	19.7%	$7.46	$4,390	23.1%	(6.6%)
Capacity (FRR)	$0.00	$0	0.0%	$0.00	$0	0.0%	0.0%
Capacity (RMR)	$0.03	$18	0.1%	$0.01	$8	0.0%	(54.6%)
Transmission	$5.98	$3,602	14.8%	$6.46	$3,799	20.0%	7.9%
Transmission Service Charges	$5.55	$3,343	13.7%	$6.05	$3,560	18.7%	8.9%
Transmission Enhancement Cost Recovery	$0.37	$222	0.9%	$0.35	$206	1.1%	(5.5%)
Transmission Owner (Schedule 1A)	$0.06	$36	0.1%	$0.06	$33	0.2%	(6.5%)
Transmission Seams Elimination Cost Assignment (SECA)	$0.00	$0	0.0%	$0.00	$0	0.0%	0.0%
Transmission Facility Charges	$0.00	$0	0.0%	$0.00	$0	0.0%	0.0%
Ancillary	$0.54	$327	1.3%	$0.45	$264	1.4%	(17.2%)
Reactive	$0.27	$161	0.7%	$0.28	$164	0.9%	3.9%
Regulation	$0.13	$78	0.3%	$0.07	$40	0.2%	(46.9%)
Black Start	$0.05	$32	0.1%	$0.05	$31	0.2%	(1.0%)
Synchronized Reserves	$0.04	$24	0.1%	$0.03	$16	0.1%	(31.9%)
Non-Synchronized Reserves	$0.01	$8	0.0%	$0.01	$5	0.0%	(36.2%)
Day Ahead Scheduling Reserve (DASR)	$0.04	$23	0.1%	$0.01	$8	0.0%	(64.9%)
Administration	$0.33	$199	0.8%	$0.33	$194	1.0%	0.0%
PJM Administrative Fees	$0.31	$186	0.8%	$0.31	$181	1.0%	(0.3%)
NERC/RFC	$0.02	$12	0.0%	$0.02	$12	0.1%	5.7%
RTO Startup and Expansion	$0.00	$1	0.0%	$0.00	$1	0.0%	0.0%
Energy Uplift (Operating Reserves)	$0.18	$106	0.4%	$0.08	$44	0.2%	(57.3%)
Demand Response	$0.00	$3	0.0%	$0.00	$1	0.0%	(62.8%)
Load Response	$0.00	$3	0.0%	$0.00	$1	0.0%	(62.8%)
Emergency Load Response	$0.00	$0	0.0%	$0.00	$0	0.0%	0.0%
Emergency Energy	$0.00	$0	0.0%	$0.00	$0	0.0%	0.0%
Total Price	$40.50	$24,385	100.0%	$32.27	$18,994	100.0%	(20.3%)
Total Load (GWh)	602,071			588,506			(2.3%)
Total Billing ($ Billions)	$24.38			$18.99			(22.1%)

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> (October 10, 2019)
60 Note: The totals in this table include after the fact billing adjustments and may not match totals presented in past reports.

Table 1-10 shows the average price, by component of the total wholesale power price per MWh, for calendar years 1999 through 2018.

Table 1-10 Total price per MWh by category: 1999 through 2018[61]

Category	1999 $/MWh	2000 $/MWh	2001 $/MWh	2002 $/MWh	2003 $ /MWh	2004 $/MWh	2005 $ /MWh	2006 $/MWh	2007 $/MWh	2008 $/MWh	2009 $/MWh	2010 $/MWh	2011 $/MWh	2012 $/MWh	2013 $/MWh	2014 $/MWh	2015 $/MWh	2016 $/MWh	2017 $/MWh	2018 $/MWh
Load Weighted Energy	$34.07	$30.72	$36.65	$31.60	$41.23	$44.34	$63.46	$53.35	$61.66	$71.13	$39.05	$48.35	$45.94	$35.23	$38.66	$53.14	$36.16	$29.23	$30.99	$38.24
Capacity	$0.14	$0.25	$0.27	$0.12	$0.08	$0.09	$0.04	$0.11	$3.58	$7.84	$10.79	$12.17	$10.37	$6.66	$7.29	$9.25	$11.25	$10.96	$11.27	$13.02
Capacity	$0.14	$0.25	$0.27	$0.12	$0.08	$0.09	$0.03	$0.03	$3.53	$7.80	$10.78	$12.15	$9.71	$6.05	$7.13	$9.01	$11.12	$10.96	$11.23	$12.97
Capacity (FRR)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.53	$0.52	$0.11	$0.20	$0.13	$0.00	$0.00	$0.00
Capacity (RMR)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.02	$0.08	$0.05	$0.04	$0.01	$0.02	$0.13	$0.08	$0.06	$0.04	($0.00)	($0.00)	$0.04	$0.05
Transmission	$3.49	$4.13	$3.56	$3.46	$3.64	$3.43	$3.30	$3.34	$3.55	$3.83	$4.22	$4.33	$4.86	$5.32	$5.65	$6.46	$7.69	$8.42	$9.54	$9.47
Transmission Service Charges	$3.41	$4.03	$3.48	$3.39	$3.57	$3.28	$2.71	$3.18	$3.45	$3.68	$4.03	$4.04	$4.49	$4.90	$5.21	$5.96	$7.09	$7.81	$8.83	$8.81
Transmission Enhancement Cost Recovery	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.01	$0.06	$0.11	$0.20	$0.27	$0.34	$0.36	$0.41	$0.51	$0.52	$0.64	$0.57
Transmission Owner (Schedule 1A)	$0.07	$0.09	$0.08	$0.07	$0.07	$0.10	$0.09	$0.09	$0.09	$0.09	$0.09	$0.09	$0.09	$0.08	$0.08	$0.09	$0.09	$0.09	$0.10	$0.09
Transmission Seams Elimination Cost Assignment (SECA)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.05	$0.50	$0.07	$0.00	$0.00	$0.00	$0.00	($0.00)	$0.00	$0.00	$0.00	$0.00	$0.00	($0.03)	$0.00
Transmission Facility Charges	$0.01	$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$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	$0.84	$1.24	$0.99	$0.91	$0.71	$0.77	$0.82
Reactive	$0.26	$0.29	$0.22	$0.20	$0.24	$0.26	$0.26	$0.29	$0.29	$0.34	$0.36	$0.45	$0.41	$0.46	$0.76	$0.40	$0.37	$0.38	$0.43	$0.42
Regulation	$0.15	$0.39	$0.53	$0.42	$0.50	$0.51	$0.80	$0.53	$0.63	$0.70	$0.34	$0.36	$0.32	$0.26	$0.25	$0.33	$0.23	$0.11	$0.14	$0.18
Black Start	$0.00	$0.00	$0.00	$0.00	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.04	$0.14	$0.08	$0.08	$0.09	$0.09	$0.08
Synchronized Reserves	$0.00	$0.00	$0.00	$0.01	$0.15	$0.13	$0.11	$0.08	$0.06	$0.08	$0.05	$0.07	$0.09	$0.04	$0.04	$0.12	$0.11	$0.05	$0.06	$0.06
Non-Synchronized Reserves	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.02	$0.02	$0.01	$0.01	$0.02
Day Ahead Scheduling Reserve (DASR)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.01	$0.00	$0.01	$0.05	$0.05	$0.06	$0.05	$0.10	$0.07	$0.05	$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	$0.46	$0.45	$0.46	$0.47	$0.46	$0.52	$0.50
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	$0.43	$0.42	$0.43	$0.43	$0.43	$0.48	$0.47
NERC/RFC	$0.00	($0.00)	$0.01	$0.01	$0.01	$0.01	$0.01	($0.00)	$0.01	$0.01	$0.02	$0.02	$0.02	$0.02	$0.02	$0.03	$0.03	$0.03	$0.03	$0.03
RTO Startup and Expansion	$0.00	$0.00	$0.00	$0.00	$0.00	$0.06	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.00	$0.00	$0.00
Energy Uplift (Operating Reserves)	$0.52	$0.93	$1.27	$0.72	$0.89	$0.95	$1.07	$0.47	$0.65	$0.64	$0.48	$0.80	$0.78	$0.74	$0.55	$1.11	$0.38	$0.17	$0.14	$0.23
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	$0.03	$0.08	$0.08	$0.02	$0.01	$0.01	$0.01
Load Response	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.03	$0.06	$0.05	$0.01	$0.01	$0.01	$0.02	$0.01	$0.03	$0.02	$0.01	$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	$0.01	$0.06	$0.06	$0.00	$0.00	$0.00	$0.00
Emergency Energy	$0.07	$0.02	$0.00	$0.00	$0.02	$0.00	$0.02	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.01	$0.00	$0.00	$0.00	$0.00
Total Price ($/MWh)	$38.92	$36.98	$43.22	$37.39	$47.83	$50.71	$69.81	$58.97	$71.25	$85.05	$55.66	$66.97	$63.28	$49.28	$53.93	$71.49	$56.87	$49.97	$53.24	$62.29
Total Load (GWh)	259,623	264,510	265,398	312,899	327,533	438,874	684,592	696,165	715,524	698,459	666,069	697,391	723,101	764,300	773,790	780,505	776,093	778,269	758,775	791,094
Total Billing ($ Billions)	$10.10	$9.78	$11.47	$11.70	$15.67	$22.26	$47.79	$41.05	$50.98	$59.40	$37.08	$46.70	$45.76	$37.67	$41.73	$55.80	$44.14	$38.89	$40.39	$49.28

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

Table 1-11 shows the inflation adjusted average price, by component of the total wholesale power price per MWh, for calendar years 1999 through 2018.[62]

Table 1-11 Inflation adjusted total price per MWh by category: 1999 through 2018[63]

Category	1999 $/MWh	2000 $/MWh	2001 $/MWh	2002 $/MWh	2003 $/MWh	2004 $/MWh	2005 $/MWh	2006 $/MWh	2007 $/MWh	2008 $/MWh	2009 $/MWh	2010 $/MWh	2011 $/MWh	2012 $/MWh	2013 $/MWh	2014 $/MWh	2015 $/MWh	2016 $/MWh	2017 $/MWh	2018 $/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	$24.80	$26.82	$36.37	$24.69	$19.68	$20.43	$24.65
Capacity	$0.13	$0.23	$0.24	$0.11	$0.07	$0.08	$0.03	$0.08	$2.77	$5.88	$8.12	$9.02	$7.46	$4.69	$5.06	$6.31	$7.66	$7.38	$7.43	$8.37
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	$4.26	$4.94	$6.15	$7.58	$7.38	$7.40	$8.34
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	$0.37	$0.07	$0.14	$0.09	$0.00	$0.00	$0.00
Capacity (RMR)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.01	$0.06	$0.04	$0.03	$0.01	$0.01	$0.09	$0.06	$0.04	$0.03	($0.00)	($0.00)	$0.02	$0.03
Transmission	$3.38	$3.88	$3.25	$3.10	$3.20	$2.93	$2.73	$2.68	$2.76	$2.87	$3.18	$3.21	$3.49	$3.74	$3.92	$4.41	$5.24	$5.67	$6.29	$6.10
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	$3.45	$3.61	$4.07	$4.84	$5.26	$5.82	$5.67
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	$0.24	$0.25	$0.28	$0.34	$0.35	$0.42	$0.37
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	$0.06	$0.06	$0.06	$0.06	$0.06	$0.06	$0.06
Transmission Seams Elimination Cost Assignment (SECA)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.04	$0.41	$0.06	$0.00	$0.00	$0.00	$0.00	($0.00)	$0.00	$0.00	$0.00	$0.00	$0.00	($0.02)	$0.00
Transmission Facility Charges	$0.01	$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$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	$0.59	$0.86	$0.67	$0.62	$0.48	$0.51	$0.53
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	$0.32	$0.53	$0.27	$0.25	$0.26	$0.28	$0.27
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	$0.18	$0.17	$0.22	$0.16	$0.07	$0.09	$0.12
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	$0.03	$0.10	$0.05	$0.05	$0.06	$0.06	$0.05
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	$0.03	$0.03	$0.08	$0.08	$0.04	$0.04	$0.04
Non-Synchronized Reserves	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.01	$0.01	$0.01	$0.01	$0.01
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	$0.03	$0.04	$0.03	$0.07	$0.05	$0.03	$0.03
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	$0.33	$0.31	$0.32	$0.32	$0.31	$0.34	$0.32
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	$0.30	$0.29	$0.29	$0.29	$0.29	$0.32	$0.30
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	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02
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	$0.01	$0.01	$0.01	$0.00	$0.00	$0.00	$0.00
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	$0.52	$0.38	$0.77	$0.26	$0.12	$0.09	$0.15
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	$0.02	$0.05	$0.05	$0.01	$0.01	$0.00	$0.00
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	$0.01	$0.01	$0.02	$0.01	$0.01	$0.00	$0.00
Emergency Load Response	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.01	$0.01	$0.01	$0.04	$0.04	$0.00	$0.00	$0.00	$0.00
Emergency Energy	$0.07	$0.02	$0.00	$0.00	$0.02	$0.00	$0.02	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total Price ($/MWh)	$37.75	$34.68	$39.44	$33.54	$42.04	$43.36	$57.63	$47.23	$55.51	$63.71	$41.97	$49.63	$45.48	$34.69	$37.41	$48.90	$38.81	$33.64	$35.09	$40.12
Total Load (GWh)	259,623	264,510	265,398	312,899	327,533	438,874	684,592	696,165	715,524	698,459	666,069	697,391	723,101	764,300	773,790	780,505	776,093	778,269	758,775	791,094
Total Billing ($ Billions)	$9.80	$9.17	$10.47	$10.50	$13.77	$19.03	$39.45	$32.88	$39.72	$44.50	$27.95	$34.61	$32.88	$26.52	$28.95	$38.17	$30.12	$26.18	$26.63	$31.74

62 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> (October 10, 2019)

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

Table 1-12 shows the percent of average price, by component of the wholesale power price per MWh, for calendar years 1999 through 2018.

Table 1-12 Percent of total price per MWh by category: 1999 through 2018[64]

Category	Percent of Total Charges 1999	Percent of Total Charges 2000	Percent of Total Charges 2001	Percent of Total Charges 2002	Percent of Total Charges 2003	Percent of Total Charges 2004	Percent of Total Charges 2005	Percent of Total Charges 2006	Percent of Total Charges 2007	Percent of Total Charges 2008	Percent of Total Charges 2009	Percent of Total Charges 2010	Percent of Total Charges 2011	Percent of Total Charges 2012	Percent of Total Charges 2013	Percent of Total Charges 2014	Percent of Total Charges 2015	Percent of Total Charges 2016	Percent of Total Charges 2017	Percent of Total Charges 2018
Load Weighted Energy	87.5%	83.1%	84.8%	84.5%	86.2%	87.4%	90.9%	90.5%	86.5%	83.6%	70.1%	72.2%	72.6%	71.5%	71.7%	74.3%	63.6%	58.5%	58.2%	61.4%
Capacity	0.4%	0.7%	0.6%	0.3%	0.2%	0.2%	0.1%	0.2%	5.0%	9.2%	19.4%	18.2%	16.4%	13.5%	13.5%	12.9%	19.8%	21.9%	21.2%	20.9%
Capacity	0.4%	0.7%	0.6%	0.3%	0.2%	0.2%	0.0%	0.0%	4.9%	9.2%	19.4%	18.1%	15.4%	12.3%	13.2%	12.6%	19.6%	21.9%	21.1%	20.8%
Capacity (FRR)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Capacity (RMR)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.0%	0.0%	0.0%	0.2%	0.2%	0.1%	0.1%	-0.0%	-0.0%	0.1%	0.1%
Transmission	9.0%	11.2%	8.2%	9.3%	7.6%	6.8%	4.7%	5.7%	5.0%	4.5%	7.6%	6.5%	7.7%	10.8%	10.5%	9.0%	13.5%	16.9%	17.9%	15.2%
Transmission Service Charges	8.8%	10.9%	8.0%	9.1%	7.5%	6.5%	3.9%	5.4%	4.8%	4.3%	7.2%	6.0%	7.1%	9.9%	9.7%	8.3%	12.5%	15.6%	16.6%	14.1%
Transmission Enhancement Cost Recovery	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.2%	0.3%	0.4%	0.7%	0.7%	0.6%	0.9%	1.0%	1.2%	0.9%
Transmission Owner (Schedule 1A)	0.2%	0.2%	0.2%	0.2%	0.1%	0.2%	0.1%	0.1%	0.1%	0.1%	0.2%	0.1%	0.1%	0.2%	0.2%	0.1%	0.2%	0.2%	0.2%	0.2%
Transmission Seams Elimination Cost Assignment (SECA)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	-0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	-0.0%	0.0%
Transmission Facility Charges	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	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%	1.3%	1.4%	1.7%	2.3%	1.4%	1.6%	1.4%	1.4%	1.3%
Reactive	0.7%	0.8%	0.5%	0.5%	0.5%	0.5%	0.4%	0.5%	0.4%	0.4%	0.7%	0.7%	0.6%	0.9%	1.4%	0.6%	0.7%	0.8%	0.8%	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%	0.5%	0.5%	0.5%	0.5%	0.5%	0.4%	0.2%	0.3%	0.3%
Black Start	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.3%	0.1%	0.1%	0.2%	0.2%	0.1%
Synchronized Reserves	0.0%	0.0%	0.0%	0.0%	0.3%	0.3%	0.2%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.2%	0.2%	0.1%	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%	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%	0.0%	0.1%	0.1%	0.1%	0.1%	0.2%	0.1%	0.1%	0.1%
Administration	0.6%	0.7%	1.7%	2.3%	2.2%	2.0%	1.1%	1.3%	1.0%	0.5%	0.6%	0.6%	0.6%	0.9%	0.8%	0.6%	0.8%	0.9%	1.0%	0.8%
PJM Administrative Fees	0.6%	0.7%	1.7%	2.3%	2.2%	1.8%	1.0%	1.3%	1.0%	0.5%	0.6%	0.5%	0.6%	0.9%	0.8%	0.6%	0.8%	0.9%	0.9%	0.8%
NERC/RFC	0.0%	-0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	-0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.1%	0.1%
RTO Startup and Expansion	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	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%	1.2%	1.2%	1.5%	1.0%	1.6%	0.7%	0.3%	0.3%	0.4%
Demand Response	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.0%	0.0%	0.0%	0.1%	0.1%	0.1%	0.0%	0.0%	0.0%	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%	0.0%	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%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%
Emergency Energy	0.2%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Total Price	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

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

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

Figure 1-3 Top three components of quarterly total price ($/MWh): January 1999 through September 2019[65]

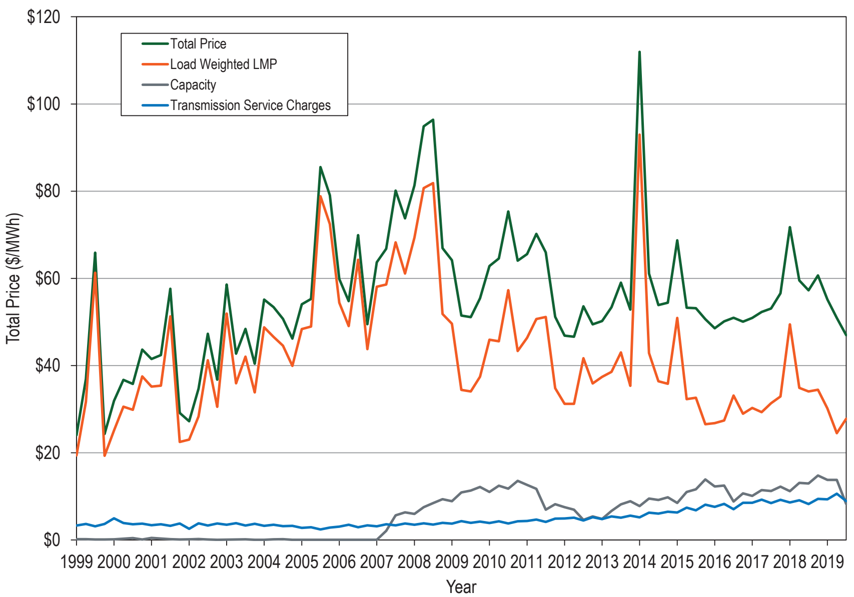
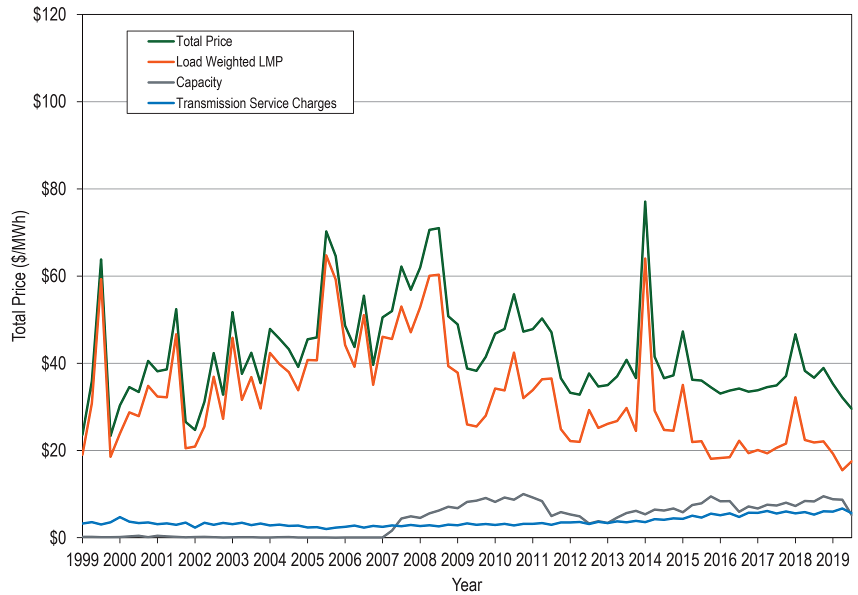


Figure 1-4 shows the inflation adjusted contributions of load-weighted energy, capacity and transmission service charges to the total price of wholesale power for each quarter since 1999.[66]

Figure 1-4 Inflation adjusted top three components of quarterly total price ($/MWh): January 1999 through September 2019[67]



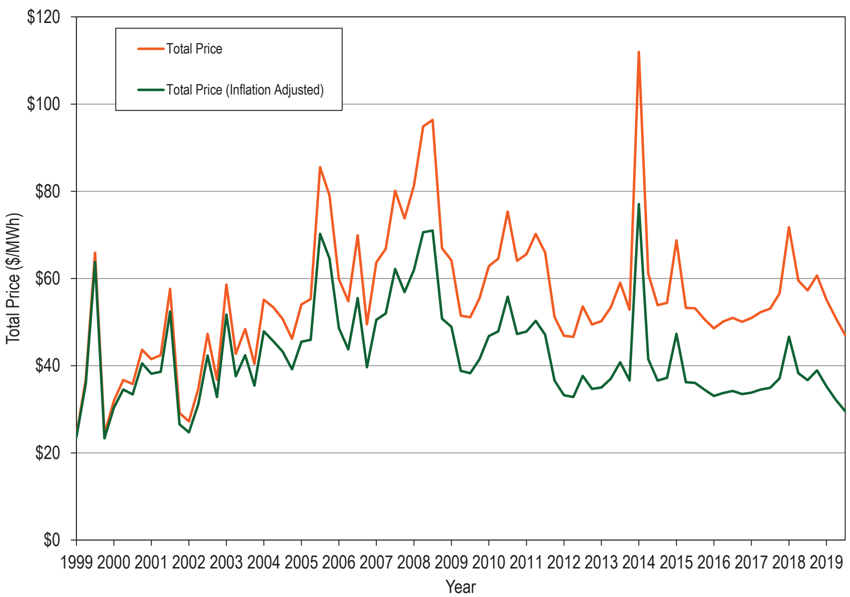
65 Note: The totals presented in this figure include after the fact billing adjustments and may not match totals presented in past reports.

66 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> (October 10, 2019)

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

Figure 1-5 shows the total price of wholesale power and the inflation adjusted total price of wholesale power for each quarter since 1999.[68]

Figure 1-5 Quarterly total price and quarterly inflation adjusted total price ($/MWh): January 1999 through September 2019[69 70]



68 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> (October 10, 2019)

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

70 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> (October 10, 2019)

Section Overviews

Overview: Section 3, Energy Market

Supply and Demand

Market Structure

- **Supply.** Supply includes physical generation, imports and virtual transactions. The maximum average on-peak hourly offered real-time supply was 152,460 MW for summer of 2018 and 152,933 MW for summer of 2019. In the first nine months of 2019, 1,749.6 MW of new resources were added and 4,173.5 MW were retired.

  PJM average real-time cleared generation in the first nine months of 2019 decreased 29 MWh from the first nine months of 2018, from 95,561 MWh to 95,531 MWh.

  PJM average day-ahead cleared supply in the first nine months of 2019, including INCs and up to congestion transactions, increased by 2.5 percent from the first nine months of 2018, from 116,068 MWh to 118,913 MWh.

- **Demand.** Demand includes physical load and exports and virtual transactions. The PJM accounting peak load in the first nine months of 2019 was 148,228 MWh in the HE 1800 on July 19, 2019, which was 1,185 MWh, 0.8 percent, higher than the PJM peak load for the first nine months of 2018, which was 147,042 MWh in the HE 1700 on August 28, 2018.

  PJM average real-time demand in the first nine months of 2019 decreased by 2.3 percent from the first nine months of 2018, from 91,905 MWh to 89,834 MWh. PJM average day-ahead demand in the first nine months of 2019, including DECs and up to congestion transactions, increased by 2.3 percent from the first nine months of 2018, from 111,589 MWh to 114,133 MWh.

Market Behavior

- **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 by MW in the first nine months of 2019, 26.3 percent were offered as available for economic dispatch, 30.4 percent were offered at their economic minimum, 4.2 percent were offered as emergency dispatch, 14.9 percent were offered as self scheduled, and 24.2 percent were offered as self scheduled and dispatchable.

- **Virtual Offers and Bids.** Any market participant in the PJM Day-Ahead Energy Market can use increment offers, decrement bids, up to congestion transactions, import transactions and export transactions as financial instruments that do not require physical generation or load. In the first nine months of 2019, the average hourly increment offers submitted and cleared MW increased by 11.5 percent and 11.6 percent, from 5,725 MW and 2,568 MW in the first nine months of 2018 to 6,382 MW and 2,866 MW in the first nine months of 2019. The hourly average submitted and cleared decrement MW increased by 6.4 percent and 39.7 percent, from 6,854 MW and 2,841 MW in the first nine months of 2018 to 7,293 MW and 3,970 MW in the first nine months of 2019. The average hourly up to congestion submitted and cleared MW increased by 5.8 percent and 15.9 percent, from 60,031 MW and 17,638 MW in the first nine months of 2018 to 63,503 MW and 20,433 MW in the first nine months of 2019.

Market Performance

- **Generation Fuel Mix.** In the first nine months of 2019, coal units provided 24.5 percent, nuclear units 33.2 percent and natural gas units 36.0 percent of total generation. Compared to the first nine months of 2018, generation from coal units decreased 16.4 percent, generation from natural gas units increased 17.2 percent and generation from nuclear units decreased 1.9 percent.
- **Fuel Diversity.** In the first nine months of 2019, the fuel diversity of energy generation, measured by the fuel diversity index for energy (FDI_e), decreased 0.9 percent over the FDI_e for the first nine months of 2018.
- **Marginal Resources.** In the PJM Real-Time Energy Market, in the first nine months of 2019, coal units were 27.2 percent and natural gas units were 69.7 percent of marginal resources. In the first nine months of 2018, coal units were 29.7 percent and natural gas units were 62.1 percent of marginal resources.

  In the PJM Day-Ahead Energy Market, in the first nine months of 2019, up to congestion transactions were 57.7 percent, INCs were 12.9 percent, DECs were 18.4 percent, and generation resources were 10.9 percent of marginal resources. In the first nine months of 2018, up to congestion transactions were 63.9 percent, INCs were 9.2 percent, DECs were 16.1 percent, and generation resources were 10.7 percent of marginal resources.
- **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 decreased in the first nine months of 2019 compared to the first nine months of 2018. The load-weighted, average real-time LMP was 30.0 percent lower in the first nine months of 2019 than in the first nine months of 2018, $27.60 per MWh versus $39.43 per MWh.

  PJM day-ahead energy market prices decreased in the first nine months of 2019 compared to the first nine months of 2018. The load-weighted, average day-ahead LMP was 28.4 percent lower in the first nine months of 2019 than in the first nine months of 2018, $27.70 per MWh versus $38.71 per MWh.
- **Components of LMP.** In the PJM Real-Time Energy Market, in the first nine months of 2019, 26.8 percent of the load-weighted LMP was the result of

coal costs, 42.7 percent was the result of gas costs and 0.9 percent was the result of the cost of emission allowances.

In the PJM Day-Ahead Energy Market, in the first nine months of 2019, 22.2 percent of the load-weighted LMP was the result of coal costs, 19.8 percent was the result of gas costs, 21.3 percent was the result of INC offers, 21.2 percent was the result of DEC bids, and 2.2 percent was the result of up to congestion transaction offers.

- **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 $0.48 per MWh in the first nine months of 2018 and -$0.11 per MWh in the first nine months of 2019. The difference between average day-ahead and real-time prices, by itself, is not a measure of the competitiveness or effectiveness of the Day-Ahead Energy Market.

Scarcity

- There were 27 intervals with five minute shortage pricing on 14 days in the first nine months of 2019. In all 27 intervals, synchronized reserves were short of the extended synchronized reserve requirement in the RTO and MAD reserve zones. In one of the 27 intervals, primary reserves were also short of the extended primary reserve requirement.
- There were 2,307 five minute intervals, or 2.9 percent of all five minute intervals in the first nine months of 2019 for which at least one solved SCED case showed a shortage of reserves, and 1,045 five minute intervals, or 1.3 percent of all five minute intervals in the first nine months of 2019 for which more than one solved SCED case showed a shortage of reserves. PJM operators used only 28 RT SCED cases that showed a shortage of reserves to calculate real-time LMPs and ancillary service prices.
- In the first nine months of 2019, PJM did not declare any emergency actions that triggered Performance Assessment Intervals (PAI).

Competitive Assessment

Market Structure

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

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 increased from 0.1 percent in the first nine months of 2018 to 1.1 percent in the first nine months of 2019. In the Real-Time Energy Market, for units committed to provide energy for local constraint relief, offer-capped unit hours increased from 1.0 percent in the first nine months of 2018 to 1.6 percent in the first nine months of 2019. While overall offer capping levels have been low, there are a significant number of units with persistent structural local market power that would have a significant impact on prices in the absence of local market power mitigation.

  In the first nine months of 2019, 11 control zones experienced congestion resulting from one or more constraints binding for 75 or more hours. The analysis of the application of the TPS test to local markets demonstrates that it is working 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, including for reactive support. In the Day-Ahead

Energy Market, for units committed for reliability reasons, offer-capped unit hours decreased from 0.1 percent in the first nine months of 2018 to 0.0 percent in the first nine months of 2019. In the Real-Time Energy Market, for units committed for reliability reasons, offer-capped unit hours decreased from 0.1 percent in the first nine months of 2018 to 0.0 percent in the first nine months of 2019.

- **Markup Index.** The markup index is a summary measure of participant offer behavior for individual marginal units. In the first nine months of 2019, in the PJM Real-Time Energy Market, 97.6 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 positive ($0.18 per MWh) when using unadjusted cost-based offers. The average dollar markup of units with offer prices between $25 and $50 was positive ($1.77 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, 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 the first nine months of 2019 was more than $400 per MWh while the highest markup in the first nine months of 2018 was more than $500 per MWh. During the period of cold weather and high demand in January 2018, several units in the PJM market were offered with high markups.

  In the first nine months of 2019, in the PJM Day-Ahead Energy Market, 98.4 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 ($0.48 per MWh) when using unadjusted cost-based offers. The average dollar markup of units with offer prices between $25 and $50 was positive ($1.38 per MWh) when using unadjusted cost-based offers. Using the unadjusted cost-based offers, the highest markup for any marginal unit in the first nine months of 2019 was about $90 per MWh, while the highest markup in the first nine months of 2018 was $200 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. Markup for gas fired units decreased in the first nine months of 2019.

- **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 units eligible for an FMU or AU adder for the period between December 2014 and August 2019. One unit qualified for an FMU adder for the month of September 2019.

Market Performance

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

  In the PJM Real-Time Energy Market in the first nine months of 2019, the unadjusted markup component of LMP was $1.95 per MWh or 7.1 percent of the PJM load-weighted, average LMP. June had the highest unadjusted peak markup component, $4.91 per MWh, or 14.1 percent of the real-time, peak hour load-weighted, average LMP. There were 39 hours in the first nine months of 2019 where the positive markup contribution to the PJM system wide, load-weighted, average LMP exceeded $34.39 per MWh.

  In the PJM Day-Ahead Energy Market, INCs, DECs and UTCs have zero markups. In the first nine months of 2019, the unadjusted markup component of LMP resulting from generation resources was $0.67 per MWh or 2.4 percent of the PJM day-ahead load-weighted average LMP. July had the highest unadjusted peak markup component, $4.14 per MWh.

Participant behavior was evaluated as competitive because the analysis of markup shows that marginal units generally make offers at, or close to, their marginal costs in both the Day-Ahead and Real-Time Energy Markets, although the behavior of some participants represents economic withholding.

Section 3 Recommendations

Market Power

- The MMU recommends that the market rules explicitly require that offers in the 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 that all fuel cost policies be algorithmic, verifiable, and systematic, and accurately reflect short run marginal costs. (Priority: Medium. First reported 2016. Status: Not adopted.)
- 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. (Priority: Low. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM change the Fuel Cost Policy requirement to apply only to units that will be offered with non-zero cost-based offers. The PJM market rules should require that the cost-based offers of units without an approved Fuel Cost Policy be set to zero. (Priority: Low. First reported 2018. Status: Not adopted.)
- The MMU recommends that Manual 15 (Cost Development Guidelines) 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: Low. 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: Adopted, 2018.)

- 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. The TPS test application in the Day-Ahead Energy Market is not documented. (Priority: High. First reported 2015. Status: Partially adopted.)
- The MMU recommends that PJM require every market participant to make available at least one cost schedule based on the same hourly fuel type(s) and parameters at least as flexible as their offered price schedule. (Priority: Medium. First reported 2015. 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. (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 in order to ensure effective market power mitigation, PJM always enforce parameter limited values by committing units only on parameter limited schedules, when the TPS test is failed or during high load conditions such as cold and hot weather alerts or more severe emergencies. (Priority: High. New recommendation. 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, 2017.)
- The MMU recommends the elimination of FMU and AU adders. FMU and AU adders no longer serve the purpose for which they were created and interfere with the efficient operation of PJM markets. (Priority: Medium. First reported 2012. Status: Partially adopted, 2014.)
- The MMU recommends that 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.[71] (Priority: Medium. First reported 2012. Status: Not adopted.)

Capacity Performance Resources

- 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 the parameters which determine nonperformance charges and the amounts of uplift payments should reflect the flexibility goals of the capacity performance construct. The operational parameters used by generation owners to indicate to PJM operators what a unit is capable of during the operating day should not determine capacity performance assessment or uplift payments. (Priority: Medium. First reported 2015. Status: Partially adopted.)
- The MMU recommends that PJM not include the balancing ratios calculated for localized Performance Assessment Intervals (PAIs) in the capacity market default offer cap, and only include those events that trigger emergencies for at least a defined sub-zonal or zonal level. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM clearly define the business rules that apply to the unit specific parameter adjustment process, including PJM's implementation of the tariff rules in the PJM manuals to ensure market

71 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. See 151 FERC ¶ 61,208 at P 476 (2015).

sellers know the requirements for their resources. (Priority: Low. First reported 2018. Status: Not adopted.)

- The MMU recommends that PJM update the tariff to clarify that all generation resources are subject to unit specific parameter limits on their cost-based offers using the same standard and process as capacity performance capacity resources. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM institute rules to assess a penalty for resources that choose to submit real-time values that are less flexible than their unit specific parameter limits or approved parameter limit exceptions based on tariff defined reasons. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM not approve temporary exceptions that are based on pipeline tariff terms that are not routinely enforced, and based on inferior transportation service procured by the generator. (Priority: Medium. First reported Q1, 2019. Status: Not adopted.)

Accurate System Modeling

- 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: 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 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 PJM include in the tariff or 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.[72] [73] (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, even if the MW are settled to the generator. 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, even if the injection MW are settled to the load serving entity. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM identify and collect data on available behind the meter generation resources, including nodal location information and relevant operating parameters. (Priority: Low. First reported 2013. Status: Partially adopted.)
- The MMU recommends that PJM document how LMPs are calculated when demand response is marginal. (Priority: Low. First reported 2014. Status: Not Adopted.)
- The MMU recommends that PJM not allow nuclear generators which do not respond to prices or which only respond to manual instructions from the operator to set the LMPs in the real-time market. (Priority: Low. First reported 2016. Status: Not adopted.)
- 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. First reported 2017. Status: Not adopted.)

72 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.

73 There is currently no PJM documentation in the tariff or manuals explaining how hubs are created and how their definitions are changed. 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 model generators' operating transitions and peak operating modes. (Priority: Medium. New recommendation. Status: Not adopted.)

Transparency

- The MMU recommends that PJM market rules require the fuel type be identified for every price and cost schedule on an hourly basis and PJM market rules 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 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 clearly define the criteria for operator approval of RT SCED cases used to send dispatch signals to resources and for pricing, to minimize operator discretion and implement a rule based approach. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM approve one RT SCED case for each five minute interval to send dispatch signals, and that PJM calculate prices for that five minute interval using the same approved SCED case. (Priority: High. New recommendation. Status: Not adopted.)

Section 3 Conclusion

The MMU analyzed key elements of PJM energy market structure, participant conduct and market performance in the first nine months of 2019, including aggregate supply and demand, concentration ratios, aggregate pivotal supplier results, local three pivotal supplier test results, offer capping, participation in demand response programs, virtual bids and offers, loads and prices.

PJM average real-time cleared generation decreased by 29 MWh, and peak load increased by 1,185 MWh, 0.8 percent, in the first nine months of 2019 compared to the first nine months of 2018. 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 both routinely and 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.[74] 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, under the PJM Market Rules, is not currently correct. The definition, that energy costs must be related to electric production,

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

is not clear or correct. All costs and investments for power generation are related to electric production. Under this definition, some unit owners include costs that are not short run marginal costs in offers, especially 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 the first nine months of 2019 generally reflected supply-demand fundamentals, although the behavior of some participants both routinely and during high demand periods represents 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 economically withhold or physically withhold.

Prices in PJM are not too low. Prices in PJM are the result of input prices, consistent with a competitive market. Low natural gas prices have been a primary cause of low PJM energy market prices. 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 reserve 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, because PJM is not implementing scarcity pricing when there is scarcity. 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. Implementing scarcity pricing when there is scarcity is a basic first step. Targeted increases to the demand for reserves when the market is tight would address price formation in the energy market.

When the real-time security constrained economic dispatch (RT SCED) solution indicates a shortage of reserves, it should be used in calculating real-time prices and those prices should be applied to the market interval for which RT SCED calculated the shortage. There are significant issues with operator discretion and reluctance to approve RT SCED cases indicating shortage of reserves, and in using these cases to calculate prices. While it is appropriate for operators to ensure that cases that use erroneous inputs are not approved and not allowed to set prices, it is essential that operator discretion not extend beyond what is necessary and that operator discretion not prevent shortage pricing when there are shortage conditions. There are also issues with the alignment of SCED cases used for resource dispatch and the SCED cases used to calculate real-time prices. PJM should fix its current operating practices and ensure transparency regarding approval of SCED cases for resource dispatch and pricing so that market participants can have confidence in the market design to produce accurate and efficient price signals. These issues are even more critical now that PJM settles real-time energy transactions on a five minute basis.

The PJM defined inputs to the dispatch tools, particularly the real-time SCED, have substantial effects on energy market outcomes. Transmission line ratings, transmission penalty factors, load forecast bias, hydro resource schedules, and unit ramp rate adjustments change the dispatch of the system, affect prices, and can create price spikes through transmission line limit violations or restrictions on the resources available to resolve constraints. The automated adjustment of ramp rates by PJM, called Degree of Generator Performance (DGP), modifies the values offered by generators and limits the MW available to the RT SCED. PJM should evaluate its interventions in the market, consider whether the interventions are appropriate, and provide greater transparency to enhance market efficiency.

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 will be created by PJM's fast start pricing proposal as approved by FERC and would be created in a much more extensive form by PJM's convex hull pricing proposal and reserve pricing proposal.

Units that start in one hour are not fast start units, and their commitment costs are not marginal in a five minute market. The differences between the actual LMP and the fast start LMP will distort the incentive for market participants to behave competitively and to follow PJM's dispatch instructions. PJM will pay new forms of uplift in an attempt to counter the distorted incentives. The magnitude of the new payments and their effects on behavior are not well understood.

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 the 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, as in PJM's ORDC proposal, 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, that scarcity pricing only occurs when scarcity exists, 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. Administrative scarcity pricing that establishes scarcity pricing in about 85 percent of hours, as PJM's ORDC proposal would, is not scarcity pricing but simply a revenue enhancement mechanism. When combined with PJM's failure to address the energy and ancillary services offset in the capacity market, PJM's ORDC filing is not consistent with efficient market design and is even more clearly just a revenue enhancement mechanism.

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 energy pricing net revenue true up mechanism in the capacity market should be addressed if energy revenues are expected to increase as a result of scarcity events, as a result of increased demand for reserves, or as a result of PJM's inappropriate proposals related to fast start pricing and the inclusion of maintenance expenses as short run marginal costs. The true up mechanism must address both cleared auctions and subsequent auctions. 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 the first nine months of 2019 or prior years. In the first nine months of 2019, marginal units were predominantly combined cycle gas generators with low fuel costs. The frequency of combined cycle gas as the marginal unit type has risen rapidly in the last three years, from 29.3 percent in the first nine months of 2016 to 62.2 percent in the first nine months of 2019. Overdue improvements in generator modeling in the energy market would allow PJM to more efficiently commit and dispatch combined cycle plants and to fully reflect the flexibility of these units. New combined cycle units placed competitive pressure on less efficient generators, and the market reliably served load with less congestion, less uplift, and less markup in marginal offers than in the first nine months of 2018. This is evidence of generally competitive behavior and competitive market outcomes, although the behavior of some participants represents economic withholding. Given the structure of the energy market which can permit the exercise of aggregate market power, 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 cost-based offers and a reason for implementing an aggregate market power test. The MMU concludes that the PJM energy market results were competitive in the first nine months of 2019.

Overview: Section 4, Energy Uplift

Energy Uplift Credits

- **Types of credits.** In the first nine months of 2019, energy uplift credits were $70.6 million, including $13.9 million in day-ahead generator credits, $40.8 million in balancing generator credits, $12.6 million in lost opportunity cost credits, and $2.7 million in local constraint control credits.
- **Types of units.** Coal units received 90.9 percent of all day-ahead generator credits. Combustion turbines received 85.5 percent of all balancing generator credits and 94.8 percent of lost opportunity cost credits.
- **Economic and Noneconomic Generation.** In the first nine months of 2019, 82.7 percent of the day-ahead generation eligible for operating reserve credits was economic and 67.0 percent of the real-time generation eligible for operating reserve credits was economic.
- **Day-Ahead Unit Commitment for Reliability.** In the first nine months of 2019, 0.3 percent of the total day-ahead generation MWh was scheduled as must run by PJM, of which 47.8 percent received energy uplift payments.
- **Concentration of Energy Uplift Credits.** The top 10 units receiving energy uplift credits received 23.6 percent of all credits. The top 10 organizations received 73.5 percent of all credits. The HHI for day-ahead operating reserves was 8500, the HHI for balancing operating reserves was 3340 and the HHI for lost opportunity cost was 5789, all of which are classified as highly concentrated.
- **Lost Opportunity Cost Credits.** Lost opportunity cost credits decreased by $36.0 million or 74.1 percent, in the first nine months of 2019 compared to the first nine months of 2018, from $48.3 million to $12.6 million. Generation from combustion turbines and diesels scheduled day-ahead but not requested in real time, receiving lost opportunity cost credits decreased by 428 GWh or 46.8 percent in the first nine months of 2019, compared to the first nine months of 2018, from 915.2 GWh to 487 GWh.

Energy Uplift Charges

- **Energy Uplift Charges.** Total energy uplift charges decreased by $106.3 million, or 60.1 percent, in the first nine months of 2019 compared to the first nine months of 2018, from $176.9 million to $70.6 million.
- **Energy Uplift Charges Categories.** The decrease of $106.3 million in the first nine months of 2019 is comprised of a $17.8 million decrease in day-

ahead operating reserve charges, a $76.4 million decrease in balancing operating reserve charges, and an $11.9 million decrease in reactive services charges.

- **Average Effective Operating Reserve Rates in the Eastern Region.** Day-ahead load paid $0.022 per MWh, real-time load paid $0.029 per MWh, a DEC paid $0.340 per MWh and an INC and any load, generation or interchange transaction deviation paid $0.318 per MWh.
- **Average Effective Operating Reserve Rates in the Western Region.** Day-ahead load paid $0.022 per MWh, real-time load paid $0.027 per MWh, a DEC paid $0.324 per MWh and an INC and any load, generation or interchange transaction deviation paid $0.302 per MWh.
- **Reactive Services Rates.** The PENELEC, DPL, and Dominion control zones were the three zones with the highest local voltage support rate, excluding reactive capability payments: PENELEC had a rate of $0.011 per MWh, DPL had a rate of $0.007 per MWh, and Dominion had a rate of $0.002 per MWh.

Geography of Charges and Credits

- In the first nine months of 2019, 90.3 percent of all uplift charges allocated regionally (day-ahead operating reserves and balancing operating reserves) were paid by transactions at control zones, 3.0 percent by transactions at hubs and aggregates, and 6.8 percent by transactions at interchange interfaces.
- Generators in the Eastern Region received 41.9 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.
- Generators in the Western Region received 56.4 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.
- External generators received 2.1 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.

Section 4 Recommendations

- The MMU recommends that uplift be paid only based on operating parameters that reflect the flexibility of the benchmark new entrant unit (CONE unit) in the PJM Capacity Market. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM not use closed loop interface constraints to artificially override nodal prices 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 CT price setting logic to modify transmission line limits 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 implement CT price setting logic, PJM first initiate a stakeholder process to determine whether such modification is appropriate. PJM should file any proposed changes with FERC to ensure review. Any such changes should be incorporated in the PJM tariff. (Priority: Medium. First Reported 2016. Status: Not adopted.)
- The MMU recommends that PJM initiate an analysis of the reasons why a significant number of 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 eliminating intraday segments from the calculation of uplift payments and returning to calculating the need for uplift based on the entire 24 hour operating day. (Priority: High. First reported 2018. Status: Not adopted.)

- The MMU recommends the elimination of day-ahead operating reserves 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.)
- The MMU recommends enhancing the current energy uplift allocation rules to reflect the recommended elimination of day-ahead operating reserves, the timing of commitment decisions and the commitment reasons. (Priority: High. First reported 2012. Status: Not adopted.)
- 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 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. (Priority: Low. First reported 2013. Status: Not adopted. Stakeholder process.)
- The MMU recommends three modifications to the energy lost opportunity cost calculations:
  - The MMU recommends calculating LOC based on 24 hour daily periods 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 only flexible fast start units (startup plus notification times of 10 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.)
- 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: Adopted 2018.[75])
- 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 balancing operating reserve credit 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, in addition to real-time load. (Priority: Low. First reported 2013. Status: Not adopted.)
- 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). The MMU recommends that PJM allow wind units to request 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.)

75 As of November 1, 2018, internal bilateral transactions are no longer used for the calculation of deviations for purposes of allocating balancing operating reserve charges. See the 2018 State of the Market Report for PJM, Volume 2, Section 3: "Energy Market" at "Internal Bilateral Transactions" for an analysis of the impact of this change on virtual bidding activity.

- 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: Partially adopted.)
- 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.[76])
- The MMU recommends that PJM pay uplift based on the offer at the lower of the actual unit output or the dispatch signal MW. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM develop and implement an accurate metric to define when a unit is following dispatch to determine eligibility to receive balancing operating reserve credits and for assessing generator deviations. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM eliminate the exemption for fast start resources (CTs and diesels) from the requirement to follow dispatch. The performance of these resources should be evaluated in a manner consistent with all other resources (Priority: Medium. First reported 2018. Status: Not adopted.)

Conclusion

Competitive market outcomes result from energy offers equal to short run marginal costs that incorporate flexible operating parameters. 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. The standard for paying uplift should be the maximum achievable flexibility, based on OEM standards for the benchmark new entrant unit (CONE unit) in the PJM Capacity Market. Applying a weaker standard 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.

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 the inflexible 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.

Implementing combined cycle modeling, to permit the energy market model optimization to take advantage of the versatility and flexibility of combined cycle technology in commitment and dispatch, would provide significant flexibility without requiring a distortion of the market rules.

The reduction of uplift payments should not be a goal to be achieved at the expense of the fundamental logic of the 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 CT price setting logic. The same is true of fast start pricing and of convex hull pricing. The same is

76 On September 7, 2018, PJM made a compliance filing for FERC Order No. 844 to publish unit specific uplift credits. The compliance filing was accepted by FERC on March 21, 2019. PJM will begin posting unit-specific uplift reports on May 1, 2019.

true of PJM's proposal to modify the ORDC in order to increase energy prices and reduce uplift.

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 (limited convex hull pricing) and in extensive form by PJM's full convex hull pricing proposal.

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. FERC Order No. 844 authorized the publication of unit specific uplift payments for credits incurred after July 1, 2019.[77]

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.

Up to congestion transactions continue to pay no energy uplift charges, which means that all others who pay these charges are paying too much.[78]

PJM needs to pay substantially more attention to the details of uplift payments including accurately tracking whether units are following dispatch, identifying the actual need for units to be dispatched out of merit and determining whether local reserve zones or better definitions of constraints would be a more market based approach.

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. 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.

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.[79]

Under RPM, capacity obligations are annual. Base Residual Auctions (BRA) are held for delivery years that are three years in the future. Effective with

77 On March 21, 2019 FERC accepted PJM's Order No. 844 compliance filing. The filing stated that PJM would begin posting unit specific uplift reports on May 1, 2019. On April 8, 2019, PJM filed for an extension on the implementation date of the zonal uplift reports and unit specific uplift reports to July 1, 2019. On June 28, 2019, FERC accepted PJM's request for extension of effective dates.

78 On October 17, 2017, PJM filed with FERC a proposed tariff change to allocate uplift to UTC transactions in the same manner in which uplift is currently allocated to other virtual transactions, as a separate injection and withdrawal deviation. FERC rejected the proposed tariff change. The rejection was without prejudice and PJM has the option to submit a new proposal. See FERC Docket No. ER18-86-000. PJM has not filed a new proposal.

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

the 2012/2013 Delivery Year, First, Second and Third Incremental Auctions (IA) are held for each delivery year.[80] 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.[81] 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.[82]

The 2019/2020 RPM Third Incremental Auction, the 2020/2021 RPM Second Incremental Auction, and the 2021/2022 RPM First Incremental Auction were conducted in the first nine months of 2019. FERC granted PJM's request for waiver of its Open Access Transmission Tariff to delay the 2022/2023 RPM Base Residual Auction from May 2019 to August 2019.[83] FERC subsequently denied PJM's motion seeking clarification of the June 29, 2018, Order (163 FERC ¶ 61,236) and directed PJM not to run the 2022/2023 BRA in August 2019.[84]

On June 9, 2015, FERC accepted changes to the PJM capacity market rules proposed in PJM's Capacity Performance (CP) filing.[85] 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.[86] 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.[87] 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. Market power mitigation is effective only when these definitions are up to date and accurate. Demand resources and energy efficiency resources may be offered directly into RPM auctions and receive the clearing price without mitigation.

80 See 126 FERC ¶ 61,275 at P 86 (2009).
81 See Letter Order, FERC Docket No. ER10-366-000 (January 22, 2010).
82 See 126 FERC ¶ 61,275 at P 88 (2009).
83 See 164 FERC ¶ 61,153 (2018).
84 See 168 FERC ¶ 61,051 (2019).
85 See 151 FERC ¶ 61,208 (2015).
86 See "PJM Manual 18: PJM Capacity Market," § 1.5 Transition to Capacity Performance, Rev. 42 (July 25, 2019).
87 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.

Market Structure

- **RPM Installed Capacity.** During the first nine months of 2019, RPM installed capacity increased 6.8 MW or 0.0 percent, from 186,496.1 MW on January 1 to 186,502.9 MW on September 30. Installed capacity includes net capacity imports and exports and can vary on a daily basis.
- **RPM Installed Capacity by Fuel Type.** Of the total installed capacity on September 30, 2019, 42.1 percent was gas; 31.0 percent was coal; 17.3 percent was nuclear; 4.8 percent was hydroelectric; 3.4 percent was oil; 0.6 percent was wind; 0.4 percent was solid waste; and 0.4 percent was solar.
- **Market Concentration.** In the 2020/2021 RPM Second Incremental Auction all participants in the total PJM market as well as the LDA RPM markets failed the three pivotal supplier (TPS) test.[88] In the 2021/2022 RPM First Incremental Auction, two participants in the EMAAC LDA market passed the TPS test. 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.[89] [90] [91]
- **Imports and Exports.** Of the 4,470.4 MW of imports in the 2021/2022 RPM Base Residual Auction, 4,051.8 MW cleared. Of the cleared imports, 1,909.9 MW (47.1 percent) were from MISO.
- **Demand-Side and Energy Efficiency Resources.** Capacity in the RPM load management programs was 11,042.8 MW for June 1, 2019, as a result of cleared capacity for demand resources and energy efficiency resources in RPM auctions for the 2019/2020 Delivery Year (13,231.6 MW) less replacement capacity (2,188.8 MW).

88 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).

89 See OATT Attachment DD § 6.5.

90 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).

91 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).

Market Conduct

- **2020/2021 RPM Second Incremental Auction.** Of the 464 generation resources that submitted Capacity Performance offers, unit specific offer caps were calculated for six generation resources (1.3 percent).
- **2021/2022 RPM First Incremental Auction.** Of the 301 generation resources that submitted Capacity Performance offers, unit specific offer caps were calculated for zero generation resources (0.0 percent).

Market Performance

- The 2019/2020 RPM Third Incremental Auction, the 2020/2021 RPM Second Incremental Auction, and the 2021/2022 RPM First Incremental Auction were conducted in the first nine months of 2019.[92] The weighted average capacity price for the 2018/2019 Delivery Year is $172.09 per MW-day, including all RPM auctions for the 2018/2019 Delivery Year. The weighted average capacity price for the 2019/2020 Delivery Year is $109.82 per MW-day, including all RPM auctions for the 2019/2020 Delivery Year.
- For the 2019/2020 Delivery Year, RPM annual charges to load are $7.0 billion.
- In the 2021/2022 RPM Base Residual Auction, market performance was determined to be not competitive as a result of noncompetitive offers that affected market results.

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.

92 FERC granted PJM's request for waiver of its Open Access Transmission Tariff to delay the 2022/2023 RPM Base Residual Auction from May 2019 to August 2019. See 164 FERC ¶ 61,153 (2018). FERC subsequently denied PJM's motion seeking clarification of the June 29, 2018, Order (163 FERC ¶ 61,236) and directed PJM not to run the 2022/2023 BRA in August 2019. See 168 FERC ¶ 61,051 (2019).

Generator Performance

- **Forced Outage Rates.** The average PJM EFORd for the first nine months of 2019 was 6.8 percent, a decrease from 7.3 percent for the first nine months of 2018.[93]
- **Generator Performance Factors.** The PJM aggregate equivalent availability factor for the first nine months of 2019 was 84.7 percent, a slight increase from 84.6 percent for the first nine months of 2018.

Section 5 Recommendations[94]

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.[95]

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.[96] [97] (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that DR providers be required to have a signed contract with specific customers for specific facilities for specific levels of DR at least six months prior to any capacity auction in which the DR is offered. (Priority: High. First reported 2016. Status: Not adopted.)

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.[98] [99] 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

93 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 November 1, 2019. 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.
94 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.
95 151 FERC ¶ 61,208 (2015).
96 See also Comments of the Independent Market Monitor for PJM, Docket No. ER14-503-000 (December 20, 2013).
97 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2019," <http://www.monitoringanalytics.com/reports/Reports/2019/IMM_Analysis_of_Replacement_Capacity_for_RPM_Commitments_June_1_2007_to_June_1_2019_20190913.pdf> (September 13, 2019).
98 See PJM Interconnection, L.L.C., Docket No. ER12-513-000 (December 1, 2011) ("Triennial Review").
99 See the 2017 State of the Market Report for PJM, Volume 2, Section 7: Net Revenue.

conditional incremental auctions. (Priority: Medium. First reported 2013. 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 2017. Status: Not adopted.)
- 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 2017. Status: Not adopted.)
- The MMU recommends that the maximum price on the VRR curve be defined as net CONE. (Priority: Medium. First reported Q1, 2019. Status: Not adopted.)

Offer Caps, Offer Floors, and Must Offer

- The MMU recommends use of the Sustainable Market Rule (SMR) in order to protect competition in the capacity market from nonmarket revenues.[100] (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.[101] (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 2017. Status: Not adopted.)
- The MMU recommends that the offer cap for capacity resources be defined as the net avoidable cost rate (ACR) of each unit so that the clearing prices are a result of such net ACR offers, consistent with the fundamental economic logic for a competitive offer of a CP resource. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends that PJM develop a process for calculating a forward looking estimate for the expected number of Performance Assessment Intervals (H) to use in calculating the Market Seller Offer Cap (MSOC). The MMU recommends that the Nonperformance Charge Rate be left at its current level. The MMU recommends that PJM develop a forward looking estimate for the Balancing Ratio (B) during Performance Assessment Intervals (PAIs) to use in calculating the MSOC. Both H and B parameters should be included in the annual review of planning parameters for the Base Residual Auction, and should incorporate the actual observed reserve margins, and other assumptions consistent with the annual IRM study. (Priority: High. First reported 2017. Status: Not adopted.)

100 Brief of the Independent Market Monitor for PJM, Docket No. EL16-49, ER18-1314-000,-001; EL18-178 (October 2, 2018).

101 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 capacity market sellers be required to request the use of minimum MW quantities greater than 0 MW (inflexible sell offer segments) and that the requests should only be permitted for defined physical reasons. (Priority: Medium. First reported 2018. 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.)
- The MMU 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 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 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 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: Not 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. First reported 2017. 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. Market power is and will remain endemic to the structure of the PJM Capacity Market. Nonetheless a competitive outcome can be assured by appropriate market power mitigation rules.

The MMU concludes that the 2021/2022 RPM Base Residual Auction results were not competitive as a result of offers above the competitive level by some market participants. The MMU recognizes that these market participants followed the capacity market rules by offering at less than the stated offer cap of Net CONE times B. But Net CONE times B is not a competitive offer when the expected number of performance assessment intervals is zero or a very small number and the non-performance charge rate is defined as Net CONE/30. Under these circumstances, a competitive offer, under the logic defined in PJM's capacity performance filing, is net ACR. That is the way in which most market participants offered in this and prior capacity performance auctions.

FERC approved PJM tariff defines the offer cap as Net CONE times B, rather than including the full logic supporting the definition of the offer cap under the capacity performance paradigm. If the tariff had defined the offer cap consistent with PJM's filing in the capacity performance matter, the offer cap would have been net ACR rather than Net CONE times B.

The MMU is required to identify market issues and to report them to the Commission and to market participants. The Commission decides on any action related to the MMU's findings.

The MMU found serious market structure issues, measured by the three pivotal supplier test results in the PJM Capacity Market in the last BRA and in the first nine months of 2019. Explicit market power mitigation rules in the RPM construct only partially offset the underlying market structure issues in the PJM Capacity Market under RPM. In the 2021/2022 RPM Base Residual Auction, the default offer cap of net CONE times B exceeded the competitive offer for a number of resources. Some seasonal resources were paid additional make whole based on a failure of the market power rules to apply offer capping.

The MMU has identified serious market design issues with RPM and the MMU has made specific recommendations to address those issues.[102] [103] [104] [105] [106] [107] In 2018 and 2019, 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 continue to 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 had excess reserves of more than 11,000 ICAP MW on June 1, 2019, and will have excess reserves of more than 17,000 ICAP MW on June 1, 2020, based on current positions.[108] A majority of capacity investments in PJM were financed by market sources.[109] Of the 36,859.2 MW of additional capacity that cleared in RPM auctions for the 2007/2008 through 2018/2019 delivery years, 27,306.6 MW (74.1 percent) were based on market funding. Of the 7,171.2 MW of additional capacity that cleared in RPM auctions for the 2019/2020 through 2021/2022 delivery years, 7,014.7 MW (97.8 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, particularly for economic nuclear power plants, continued to evolve. The subsidies are not part of the PJM market

102 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).

103 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).

104 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).

105 See "Analysis of the 2021/2022 RPM Base Residual Auction - Revised," <http://www.monitoringanalytics.com/reports/Reports/2018/IMM_Analysis_of_the_20212022_RPM_BRA_Revised_20180824.pdf> (August 24, 2018).

106 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).

107 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2019," <http://www.monitoringanalytics.com/reports/Reports/2019/IMM_Analysis_of_Replacement_Capacity_for_RPM_Commitments_June_1_2007_to_June_1_2019_20190913.pdf> (September 13, 2019).

108 The calculated reserve margin for June 1, 2020, does not account for cleared buy bids that have not been used in replacement capacity transactions.

109 "PJM Generation and Funding Sources 2007/2008 through 2021/2022 Delivery Years," <http://www.monitoringanalytics.com/reports/Reports/2019/IMM_PJM_Generation_Capacity_and_Funding_Sources_20072008_through_20212022_Delivery_Years_20190912.pdf> (September 12, 2019).

design but nonetheless threaten the foundations of the PJM capacity market as well as the competitiveness of PJM markets overall.

The Ohio subsidy legislation to subsidize both nuclear and coal plants and to eliminate the RPS, the Illinois ZEC legislation to subsidize the Quad Cities nuclear power plant and the requests for additional subsidies, the request in Pennsylvania to subsidize the Three Mile Island and other nuclear power plants, the New Jersey legislation to subsidize the Salem and Hope Creek nuclear power plants, the potential U.S. DOE proposal to subsidize coal and nuclear power plants, and the request by FirstEnergy to the U.S. DOE for subsidies consistent with the DOE Grid Resilience Proposal, 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.

Subsidies are contagious. Competition in the markets could be replaced and is now being 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. Competition to receive subsidies is now a reality and is accelerating in PJM.

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 competitive market participants 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. The MMU calls this approach the Sustainable Market Rule (SMR). The SMR is fully consistent with the renewables targets of many states in the PJM footprint. The SMR is also consistent with incorporating economic nuclear power plants in the capacity market.

A sustainable competitive wholesale power market must recognize three salient structural elements: state nonmarket revenues for renewable energy; a significant level of generation resources subject to cost of service regulation; and the structure and performance of the existing market based generation fleet.

Subsidies to specific resources that are uneconomic as a result of competition are an effort to reverse market outcomes with no commitment to a regulatory model and no attempt to mitigate negative impacts on competition. The unit specific subsidy model is inconsistent with the PJM market design and inconsistent with the market paradigm and constitutes a significant threat to both.

The existing FRR approach remains an option for utilities with regulated revenues based on cost of service rates, including both privately and publicly owned (including public power entities and electric cooperatives) utilities. Such regulated utilities have had and continue to have the ability to opt out of the capacity market and provide their own capacity.

Given that states have increasingly aggressive renewable energy targets, a core goal of a competitive market design should be to ensure that the resources required to provide reliability receive appropriate competitive market incentives for entry and for ongoing investment and for exit when uneconomic. A significant level of renewable resources, operating with zero or near zero marginal costs, will result in very low energy prices. Since renewable resources are intermittent, the contribution of renewables to meeting reliability targets must be analyzed carefully to ensure that the capacity value is calculated correctly.

In order to attract and retain adequate resources for the reliable operation of the energy market, revenues from PJM energy, ancillary services and capacity markets must be adequate for those resources. That adequacy requires a capacity market. The capacity market plays the essential role of equilibrating the revenues necessary to incent competitive entry and exit of the resources needed for reliability, with the revenues from the energy market that are directly affected by nonmarket sources.

Price suppression below the competitive level in the capacity market should not be acceptable and is not consistent with a competitive market design. Harmonizing means that the integrity of each paradigm is maintained and respected. Harmonizing permits nonmarket resources to have an unlimited impact on energy markets and energy prices. Harmonizing means designing a capacity market to account for these energy market impacts, clearly limiting the impact of nonmarket revenues on the capacity market and ensuring competitive outcomes in the capacity market and thus in the entire market.

The expected impact of the SMR design on the offers and clearing of renewable resources and nuclear plants would be from zero to insignificant. The competitive offers of renewables, based on the net ACR of current technologies, are likely to clear in the capacity market. The competitive offers of nuclear plants, based on net ACR, are likely to clear in the capacity market.

Cost of service resources have the option of using the existing FRR rules, which would allow regulated utilities to opt out of the capacity market. The expected impact of the SMR design on the offers and clearing of regulated cost of service resources that remained in the capacity market would be from zero to insignificant. The competitive offers of these resources, based on net ACR, are likely to clear in the capacity market.

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/ISO 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

- **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.[110] Demand response resources participate in the Synchronized Reserve Market. Demand response resources participate in the Regulation Market.

  In the first nine months of 2019, total demand response revenue decreased by $41.5 million, 9.5 percent, from $435.1 million in the first nine months of 2018 to $393.7 million in the first nine months of 2019. Emergency demand response revenue accounted for 98.8 percent of all demand

110 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.

response revenue, economic demand response for 0.2 percent, demand response in the Synchronized Reserve Market for 0.3 percent and demand response in the regulation market for 0.3 percent.

Total emergency demand response revenue decreased by $37.3 million, 8.8 percent, from $426.3 million in the first nine months of 2018 to $389.0 million in the first nine months of 2019. This decreased consisted entirely of capacity market revenue.[111]

Economic demand response revenue decreased by $1.5 million, 65.3 percent, from $2.3 million in the first nine months of 2018 to $0.8 million in the first nine months of 2019.[112] Demand response revenue in the Synchronized Reserve Market decreased by $2.1 million, 50.1 percent, from $4.2 million in the first nine months of 2018 to $2.1 million in the first nine months of 2019. Demand response revenue in the regulation market decreased by $0.5 million, 20.9 percent, from $2.3 million in the first nine months of 2018 to $1.8 million in the first nine months of 2019.

- **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.[113]
- **Demand Response Market Concentration.** The ownership of economic demand response resources was highly concentrated in 2018 and the first nine months of 2019. The HHI for economic resource reductions increased by 535 points from 7541 in the first nine months 2018 to 8076 in the first nine months of 2019. The ownership of emergency demand response resources was moderately concentrated in the first nine months of 2019. The HHI for emergency demand response committed MW was 1808 for the 2018/2019 Delivery Year and 1838 for the 2019/2020 Delivery Year. In the 2018/2019 Delivery Year, the four largest companies owned 78.1 percent of all committed demand response UCAP MW. In the 2019/2020 Delivery Year, the four largest companies owned 78.8 percent of all committed demand response UCAP MW.
- **Limited Locational Dispatch of Demand Resources.** Beginning with the 2014/2015 Delivery Year, demand resources that are not Capacity Performance, 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. With full implementation of the Capacity Performance rules in the capacity market starting with the 2020/2021 Delivery Year, PJM will be able to individually dispatch demand resources with no advanced notice, although PJM does not know the nodal location of demand 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 September 30, 2019.

- 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

111 The total credits and MWh numbers for demand resources were calculated as of October 15, 2019 and may change as a result of continued PJM billing updates.

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

113 "PJM Manual 28: Operating Agreement Accounting," § 11.2.2, Rev. 82 (July 25, 2019).

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. First reported 2013. Status: Not adopted.)
- The MMU recommends that the demand resources be treated as economic resources, 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 Interval. (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, if demand resources remain in the capacity market, a daily energy market must offer requirement apply to demand resources, comparable to the rule applicable to generation capacity resources.[114] (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 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 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 operators 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.[115] (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends limited, extended summer and annual demand response event compliance be calculated on an hourly basis for noncapacity performance resources and on a five minute basis for all capacity performance resources and that the penalty structure reflect five minute compliance. (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.)

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

115 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 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 there be only one demand response product in the capacity market, with an obligation to respond when called for any hour of the delivery year. (Priority: High. First reported 2011. Status: Partially adopted.[116])
- 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. First reported 2017. Status: Partially adopted.)
- The MMU recommends that PRD be required to respond during a PAI to be consistent with all CP resources. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends that the limits imposed on the pre-emergency and emergency demand response share of the Synchronized Reserve Market be eliminated. (Priority: Medium. First reported 2018. Status: Not adopted.)

116 PJM's Capacity Performance design requires resources to respond when called for any hour of the delivery year.

- The MMU recommends that 30 minute pre-emergency and emergency demand response be considered to be 30 minute reserves. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that energy efficiency MW not be included in the PJM capacity market and that PJM should ensure that the impact of EE measures on the load forecast is incorporated immediately rather than with the existing lag. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that demand reductions based entirely on behind the meter generation be capped at the lower of economic maximum or actual generation output. (Priority: High. First reported Q2, 2019. Status: Not adopted.)

Section 6 Conclusion

A fully functional demand side of the electricity market means that end use customers or their designated intermediaries will have the ability to see real-time energy price signals in real time, will have the ability to react to real-time prices in real time and will have the ability to receive the direct benefits or costs of changes in real-time energy use. In addition, customers or their designated intermediaries will have the ability to see current capacity prices, will have the ability to react to capacity prices and will have the ability to receive the direct benefits or costs of changes in the demand for capacity in the same year in which demand for capacity changes. A functional demand side of these markets means that customers will have the ability to make decisions about levels of power consumption based both on how customers value 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. Demand resources do not have a must offer requirement into the day-ahead energy market, are able to offer above $1,000 per MWh without providing a fuel cost policy, or any rationale for the offer. PJM automatically triggers a PAI when demand resources are dispatched and demand resources do not have telemetry requirements similar to other Capacity Performance 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 interval (PAI) under the Capacity Performance design, both serve as a significant disincentive to calling on demand resources and mean that demand resources are underused. 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 with 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 Interval (PAI) will be measured on a five-minute 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 MMU peak shaving proposal at the Summer-Only Demand Response Senior Task Force (SODRSTF) is an example of how to create a demand side product that is on the demand side of the market and not on the supply side.[117] The MMU proposal was based on the BGE load forecasting program and Pennsylvania Act 129 Utility Program.[118] [119] Under the MMU proposal, participating load would inform PJM prior to an RPM auction of the MW participating, the months and hours of participation and the temperature humidity index (THI) threshold at which load would be reduced. PJM would reduce the load forecast used in the RPM auction based on the designated reductions. Load would agree to curtail demand to at or below a defined FSL, less than the customer PLC, when the THI exceeds a defined level or load exceeds a specified threshold. By relying on metered load and the PLC, load can reduce its demand for capacity and that reduction can be verified without complicated and inaccurate metrics to estimate load reductions. Under PJM's weakened version of the program, performance will be measured under the current economic demand response CBL rules which means relying on load estimates rather than actual metered load.[120] PJM's proposal includes only a THI curtailment trigger and not an overall load curtailment trigger.

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.

117 See the MMU package within the SODRSTF Matrix, <http://www.pjm.com/-/media/committees-groups/task-forces/sodrstf/20180802/20180802-item-04-sodrstf-matrix.ashx>.

118 Advance signals that can be used to foresee demand response days, BGE, <https://www.pjm.com/-/media/committees-groups/task-forces/sodrstf/20180309/20180309-item-05-bge-load-curtailment-programs.ashx> (Accessed March 6, 2019).

119 Pennsylvania ACT 129 Utility Program, CPower, <https://www.pjm.com/-/media/committees-groups/task-forces/sodrstf/20180413/20180413-item-03-pa-act-129-program.ashx> (Accessed March 6, 2019).

120 The PJM proposal from the SODRSTF weakened the proposal but was approved at the October 25, 2018 Members Committee meeting and PJM filed Tariff changes on December 7, 2018. See "Peak Shaving Adjustment Proposal," Docket No. ER19-511-000 (December 7, 2018).

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 were significantly lower in the first nine months of 2019 than in the first nine months of 2018 largely as a result of lower gas prices.
- In the first nine months of 2019, average energy market net revenues decreased by 52 percent for a new CT, 36 percent for a new CC, 82 percent for a new CP, 32 percent for a new nuclear plant, 74 percent for a new DS, 29 percent for a new onshore wind installation, 29 percent for a new off shore wind installation and 19 percent for a new solar installation compared to the first nine months of 2018.
- The relative prices of fuel varied during the first nine months of 2019. As a result, the marginal cost of the new CC was consistently below that of the new CP in 2019, and the marginal cost of the new CT was above that of the new CP in January.
- Nuclear unit revenue is a combination of energy market revenue and capacity market revenue. Negative prices do not have a significant impact on nuclear unit revenue. Since 2014, negative prices have affected nuclear plants' annual revenues by an average of 0.1 percent.[121]

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 CCs for three representative locations shows that CC units that entered the PJM markets in 2007 have not covered 100 percent of their total costs, including the return on and of capital, on a cumulative basis. The analysis also shows that theoretical new entrant Theoretical new entrant CCs that entered the PJM markets in 2012 have covered their total costs on a cumulative basis in the BGE Zone but have not covered 100 percent of total costs in the PSEG or ComEd zones. Energy market revenues alone were not sufficient to cover total costs in any scenario, which demonstrates the critical role of the capacity market revenue in covering total costs.

121 Analysis is based on actual unit generation and received energy market and capacity market revenues. Negative prices in the DA and RT market were set to zero for the comparison.

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. CC units that entered the PJM markets in 2007 have not covered 100 percent of their total costs, including the return on and of capital, on a cumulative basis. CCs that entered the PJM markets in 2012 have covered their total costs on a cumulative basis in the BGE Zone but have not covered 100 percent of total costs in the PSEG or ComEd zones. Energy market revenues alone were not sufficient to cover total costs in any scenario, which demonstrates the critical role of the capacity market revenue in covering total costs.

Overview: Section 8, Environmental and Renewables

Federal Environmental Regulation

- **MATS.** 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.[122] All coal steam units in PJM are compliant with the state and federal emissions limits established by MATS.
- **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.[123]
- **NSR.** On August 1, 2019, the EPA proposed to reform the New Source Review (NSR) permitting program.[124] NSR requires new projects and existing projects receiving major overhauls that significantly increase emissions to obtain permits under State Implementation Programs.
- **RICE.** Stationary reciprocating internal combustion engines (RICE) are electrical generation facilities like diesel engines typically used for backup, emergency or supplemental power. RICE must be tested annually.[125] Emergency stationary RICE participating in demand response programs are allowed to operate for up to 100 hours/calendar year providing emergency demand response during periods when there is a NERC declared Energy Emergency Alert Level 2 or there is a five percent voltage/frequency deviations, and for an unlimited time during emergency situations.
- **Greenhouse Gas Emissions.** On June 19, 2019, the EPA repealed the Clean Power Plan[126] and replaced it with the Affordable Clean Energy (ACE) rule, which establishes guidelines for states to develop plans to address greenhouse gas emissions from existing coal fired power plants.[127] Under the ACE Rule some states may permit more CO_2 emissions than under the Clean Power Plan.
- **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.[128]
- **Coal Ash.** The EPA administers the Resource Conservation and Recovery Act (RCRA), which governs the disposal of solid and hazardous waste.[129]

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. New Jersey is rejoining.[130] Virginia and Pennsylvania are preparing to join.[131] [132] The auction price in the September 4, 2019, auction for the 2018/2020 compliance period was $5.02 per ton. The clearing price is equivalent to a price of $5.73 per metric tonne, the unit used in other carbon markets. The price decreased by $0.60 per ton, 7.5 percent, from $5.62 per ton from June 5, 2019, to $5.02 per ton for September 4, 2019.
- **Carbon Price.** If the price of carbon were $50.00 per metric tonne, the short run marginal costs would increase by $24.52 per MWh for a new

122 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 (Feb. 16, 2012).
123 CAA § 110(a)(2)(D)(i)(I).
124 Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NNSR): Project Emissions Accounting, EPA Docket No. EPA-HQ-OAR-2018-0048; FRL-9997-95-OAR, 84 Fed. Reg. 39244 (Aug. 9, 2019).
125 See 40 CFR § 63.6640(f).
126 Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, EPA-HQ-OAR-2013-0602, Final Rule mimeo (Aug. 3, 2015) (Clean Power Plan). The Clean Power Plan never took effect because it was subject to a stay issued by the U.S. Supreme Court.
127 See Repeal of the Clean Power Plan; Emission Guidelines for Greenhouse Gas Emissions From Existing Electric Utility Generating Units; Revisions to Emission Guidelines Implementing Regulations, EPA Docket No. EPA-HQ-OAR-2017-0355, et al., 84 Fed. Reg. 32520 (July 8, 2019).
128 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).
129 42 U.S.C. §§ 6901 et seq.
130 Executive Order 7; see Regional Greenhouse Gas Initiative, State of New Jersey Department of Environmental Protection <http://www.state.nj.us/dep/aqes/rggi.html>.
131 See Regulation for Emissions Trading, 9 VAC 5-140. The Virginia Air Pollution Control Board is developing the regulation and considering public comments.
132 Executive Order – 2019-07- Commonwealth Leadership in Addressing Climate Change through Electric Sector Emissions Reductions, Tom Wolf, Governor, October 3, 2019, <https://www.governor.pa.gov/newsroom/executive-order-2019-07-commonwealth-leadership-in-addressing-climate-change-through-electric-sector-emissions-reductions/>.

combustion turbine (CT) unit, $16.71 per MWh for a new combined cycle (CC) unit and $43.15 per MWh for a new coal plant (CP).

State Renewable Portfolio Standards

- **RPS.** In PJM, nine of 14 jurisdictions have enacted legislation requiring 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 September 30, 2019, Delaware, Illinois, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, and Washington D.C. had renewable portfolio standards. Virginia and Indiana had voluntary renewable portfolio standards. Kentucky, Tennessee and West Virginia did not have renewable portfolio standards.
- **RPS Cost.** The cost of complying with RPS, as reported by the states, was $3.4 billion over the four year period from 2014 through 2017, or an average annual RPS compliance cost of $840.4 million.[133]

Emissions Controls in PJM Markets

- **Regulations.** 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.
- **Emissions Controls.** As of September 30, 2019, 93.5 percent of coal steam MW had some type of flue-gas desulfurization (FGD) technology to reduce SO_2 emissions, while 99.6 percent of coal steam MW had some type of particulate control, and 93.6 percent of fossil fuel fired capacity in PJM had NO_x emission control technology. All coal steam units in PJM are compliant with the state and federal emissions limits established by MATS.

133 The actual PJM RPS compliance cost exceeds the reported $3.4 billion since this total does not include a value for Delaware in 2014, a value for Pennsylvania in 2017, does not include any data for 2018 or 2019, and does not include any RPS compliance cost for North Carolina.

Renewable Generation

- **Renewable Generation.** Total wind and solar generation was 3.1 percent of total generation in PJM for the first nine months of 2019. Tier I generation was 4.6 percent of total generation in PJM and Tier II generation was 2.2 percent of total generation in PJM for the first nine months of 2019. Only Tier I generation is renewable.

Section 8 Recommendations

- The MMU recommends that renewable energy credit markets based on state renewable portfolio standards be brought into PJM markets as they are an increasingly important component of the wholesale energy market. (Priority: Medium. First reported 2010. Status: Not adopted.)
- The MMU recommends that the Commission reconsider its disclaimer of jurisdiction over RECs markets because, given market changes since that decision, it is clear that RECs materially affect jurisdictional rates. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that states consider the development of a multistate framework for RECs markets, for potential agreement on carbon pricing including the distribution of carbon revenues, and for coordination with PJM wholesale markets. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that jurisdictions with a renewable portfolio standard make the price and quantity data on supply and demand more transparent. (Priority: Low. First reported 2018. Status: Not adopted.)
- The MMU recommends that load and generation located at separate nodes be treated as separate resources. (Priority: High. First reported Q2, 2019. 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.[134] The MMU recommends that the Commission reconsider its disclaimer of jurisdiction over RECs markets because, given market changes since that decision, it is clear that RECs materially affect jurisdictional rates.

RECs clearly affect prices in the PJM wholesale power market. Some resources are not economic except for the ability to purchase or sell RECs. RECs provide out of market payments to qualifying renewable resources, primarily wind and solar. The credits provide an incentive to make negative energy offers and more generally provide an incentive to enter the market, to remain in the market and 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 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 the PJM RTO 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. The MMU recommends that PJM states consider the development of a multistate framework for REC markets, for potential agreement on carbon pricing, and for coordination with PJM wholesale markets.

REC markets are not consistently or adequately transparent. Data on REC prices, clearing quantities and markets are not publicly available for all PJM states. The provision of more complete data would facilitate competition to provide energy from renewable sources.

The economic logic of RPS programs and the associated REC and SREC prices is not always clear. The price of carbon implied by REC prices ranges from $5.64 per tonne in Washington, D.C. to $31.78 per tonne in Pennsylvania. The price of carbon implied by SREC prices ranges from $48.08 per tonne in Pennsylvania to $789.17 per tonne in Washington, D.C. The effective prices for carbon compare to the RGGI clearing price in September 2019 of $5.73 per tonne and to the social cost of carbon which is estimated in the range of $50 per tonne.[135] The impact on the cost of generation from a new combined cycle unit of an $800 per tonne carbon price would be $267.30 per MWh.[136] The impact of a $50 per tonne carbon price would be $16.71 per MWh. This wide range of implied carbon prices is not consistent with an efficient, competitive, least cost approach to the reduction of emissions.

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 offers 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 ensures 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 to limit carbon output, for example by incorporating a consistent carbon price in unit offers which would be reflected in PJM's economic dispatch. If there is a social decision

134 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.").

135 "Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis – Under Executive Order 12899," Interagency Working Group on the Social Cost of Greenhouse Gases, United States Government, (Aug. 2016), <https://19january2017snapshot.epa.gov/sites/production/files/2016-12/documents/sc_co2_tsd_august_2016.pdf>.

136 The cost impact calculation assumes a heat rate of 6.296 MMBtu per MWh and a carbon emissions rate of 0.053070 tonne per MMBtu. The $800 per tonne carbon price represents an upper bound on the 2019 REC and SREC prices in the PJM jurisdictions with RPS. Additional cost impacts are provided in Table 816.

to limit carbon output, a consistent carbon price would be the most efficient way to implement that decision. The states in PJM could agree, if they decided it was in their interests, with the appropriate information, on a carbon price and on how to allocate the revenues from a carbon price that would make all states better off. The MMU continues to recommend that PJM provide modeling information to the states adequate to inform such a decision making process. A carbon price would also be an alternative to specific subsidies to individual nuclear power plants and to the current wide range of implied carbon prices embedded in RPS programs 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. The use of inconsistent implied carbon prices by state is also inconsistent with an efficient market and inconsistent with the least cost approach to meeting state environmental goals.

The annual average cost of complying with RPS over the four year period from 2014 through 2017 for the eight jurisdictions that had RPS and reported compliance costs was $840.4 million, or a total of $3.4 billion over four years.[137] The RPS compliance cost for 2016, the most recent year for which there is complete data for all jurisdictions except North Carolina, was $986 million. RPS costs are payments by customers to the sellers of qualifying resources.

If all the PJM states participated in a regional carbon market, the estimated revenue returned to the states/customers from selling carbon allowances would be approximately $2.1 billion per year assuming a five percent reduction below 2018 emission levels and a carbon price equal to the latest RGGI auction clearing price. If only the current RPS states participated in a regional carbon market, the estimated revenue returned to the states/customers from selling carbon allowances would be about $1.2 billion. The costs of a carbon price are the impact on energy market prices, net of the revenue returned to states/customers.

Overview: Section 9, Interchange Transactions

Interchange Transaction Activity

- **Aggregate Imports and Exports in the Real-Time Energy Market.** In the first nine months of 2019, PJM was a monthly net exporter of energy in the Real-Time Energy Market in all months.[138] In the first nine months of 2019, the real-time net interchange was -25,916.9 GWh. The real-time net interchange in the first nine months of 2018 was -12,205.8 GWh.
- **Aggregate Imports and Exports in the Day-Ahead Energy Market.** In the first nine months of 2019, PJM was a monthly net exporter of energy in the Day-Ahead Energy Market in February, June, July, August and September, and a net importer of energy in the remaining months. In the first nine months of 2019, the total day-ahead net interchange was -4,540.7 GWh. The day-ahead net interchange in the first nine months of 2018 was 1,810.5.
- **Aggregate Imports and Exports in the Day-Ahead and the Real-Time Energy Market.** In the first nine months of 2019, gross imports in the Day-Ahead Energy Market were 527.0 percent of gross imports in the Real-Time Energy Market (260.8 percent in the first nine months of 2018). In the first nine months of 2019, gross exports in the Day-Ahead Energy Market were 130.5 percent of the gross exports in the Real-Time Energy Market (128.8 percent in the first nine months of 2018).
- **Interface Imports and Exports in the Real-Time Energy Market.** In the first nine months of 2019, there were net scheduled exports at 13 of PJM's 19 interfaces in the Real-Time Energy Market.
- **Interface Pricing Point Imports and Exports in the Real-Time Energy Market.** In the first nine months of 2019, there were net scheduled exports at 10 of PJM's 17 interface pricing points eligible for real-time transactions in the Real-Time Energy Market.[139]

137 The actual PJM RPS compliance cost exceeds the reported $3.4 billion since this total does not include a value for Delaware in 2014, a value for Pennsylvania in 2017, does not include any data for 2018 or 2019, and does not include any RPS compliance cost for North Carolina.

138 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.

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

- **Interface Imports and Exports in the Day-Ahead Energy Market.** In the first nine months of 2019, there were net scheduled exports at 11 of PJM's 19 interfaces in the Day-Ahead Energy Market.
- **Interface Pricing Point Imports and Exports in the Day-Ahead Energy Market.** In the first nine months of 2019, there were net scheduled exports at nine of PJM's 18 interface pricing points eligible for day-ahead transactions in the Day-Ahead Energy Market.
- **Up To Congestion Interface Pricing Point Imports and Exports in the Day-Ahead Energy Market.** In the first nine months of 2019, up to congestion transactions were net exports at three of PJM's 18 interface pricing points eligible for day-ahead transactions in the Day-Ahead Energy Market.
- **Inadvertent Interchange.** In the first nine months of 2019, net scheduled interchange was -25,917 GWh and net actual interchange was -25,870 GWh, a difference of 47 GWh. In the first nine months of 2018, the difference was 8 GWh. This difference is inadvertent interchange.
- **Loop Flows.** In the first nine months of 2019, the Northern Indiana Public Service (NIPS) Interface had the largest loop flows of any interface with -14 GWh of net scheduled interchange and -8,516 GWh of net actual interchange, a difference of 8,502 GWh. In the first nine months of 2019, the SouthIMP interface pricing point had the largest loop flows of any interface pricing point with 3,893 GWh of net scheduled interchange and 20,416 GWh of net actual interchange, a difference of 16,524 GWh.

Interactions with Bordering Areas

PJM Interface Pricing with Organized Markets

- **PJM and MISO Interface Prices.** In the first nine months of 2019, 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 61.5 percent of the hours.
- **PJM and New York ISO Interface Prices.** In the first nine months of 2019, 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 57.9 percent of the hours.
- **Neptune Underwater Transmission Line to Long Island, New York.** In the first nine months of 2019, 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 73.1 percent of the hours.
- **Linden Variable Frequency Transformer (VFT) Facility.** In the first nine months of 2019, 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 68.3 percent of the hours.
- **Hudson DC Line.** In the first nine months of 2019, 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 66.3 percent of the hours.

Interchange Transaction Issues

- **PJM Transmission Loading Relief Procedures (TLRs).** PJM issued two TLRs of level 3a or higher in the first nine months of 2019, compared to four such TLR issued in the first nine months of 2018.
- **Up To Congestion.** The average number of up to congestion bids submitted in the Day-Ahead Energy Market decreased by 24.9 percent, from 68,693 bids per day in the first nine months of 2018 to 51,594 bids per day in the first nine months of 2019. The average cleared volume of up to congestion bids submitted in the Day-Ahead Energy Market increased by 15.9 percent, from 423,268 MWh per day in the first nine months of 2018, to 490,421 MWh per day in the first nine months of 2019.
- **45 Minute Schedule Duration Rule.** Effective May 19, 2014, PJM removed the 45 minute scheduling duration rule in response to FERC Order No. 764.[140] [141] PJM and the MMU issued a statement indicating ongoing concern about market participants' scheduling behavior, and a

140 Order No. 764, 139 FERC ¶ 61,246 (2012), *order on reh'g*, Order No. 764-A, 141 FERC ¶ 61231 (2012).
141 *See* Letter Order, Docket No. ER14-381-000 (June 30, 2014).

commitment to address any scheduling behavior that raises operational or market manipulation concerns.[142]

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 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 PJM Settlement 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

142 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>.

not have the authority to take such steps, PJM should request guidance from FERC. (Priority: Low. 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 the Commission require that the open FFE/FFL freeze date issues be addressed at a Commission technical conference, and that the Commission set a deadline to resolve the significant issues that result from the freeze date. (Priority: Medium. First reported Q2, 2019. Status: Not adopted.)

Section 9 Conclusion

Transactions between PJM and multiple balancing authorities in the Eastern Interconnection are part of a single energy market. While some of these balancing authorities are termed market areas and some are termed 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. Pricing in the market areas is transparent and pricing in the nonmarket areas is 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 across the interfaces.

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.[143]

On April 1, 2018, PJM implemented five minute settlements. PJM determines the primary reserve requirement based on the most severe single contingency every five minutes. The market solution calculates the available tier 1 synchronized reserve every five minutes. In every five minute interval, the required synchronized reserve and nonsynchronized reserve are calculated and dispatched, and there are associated clearing prices (SRMCP and NSRMCP). Scheduled resources are credited based on their five minute assignment and clearing price.

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 most severe single contingency. In the first nine months of 2019, the average primary reserve requirement was 2,474.8 MW in the RTO Zone and 2,530.9 MW in the MAD Subzone.

143 See PJM. "Manual 10: Pre-Scheduling Operations," § 3.1.1 Day-ahead Scheduling (Operating Reserve, Rev. 38 (Aug. 22, 2019).

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 in response to a PJM declared synchronized reserve event. Synchronized reserve consists of tier 1 and tier 2 synchronized reserves.

Tier 1 synchronized reserve 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 reserves. The market solution estimates tier 1 synchronized reserve as available 10 minute ramp from the energy dispatch. In the first nine months of 2019, there was an average hourly supply of 2,185.1 MW of tier 1 available in the RTO Zone. In the first nine months of 2019, there was an average hourly supply of 1,574.7 MW of tier 1 synchronized reserve available within the MAD Subzone.
- **Demand.** The synchronized reserve requirement is calculated for each five minute interval as the most severe single 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 for increasing its output (or reducing load for demand response) at the rate of $50 per MWh in addition to LMP.[144] This is the Synchronized Energy Premium Price.
- **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 synchronized energy premium price of $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 is 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, $2,197,514 in 2017, $4,732,025 in 2018, and $2,295,217 in the first nine months of 2019.

144 See PJM. "Manual 11: Energy & Ancillary Services Market Operations,"§ 4.2.10 Settlements, Rev. 107 (Sep. 26, 2019).

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 may incur costs to be synchronized, and that have an obligation to respond to PJM declared synchronized reserve events. Tier 2 synchronized reserve is penalized for failure to respond to a PJM declared synchronized reserve event. PJM has established a required amount of synchronized reserve as no less than the largest single contingency, and a 10 minute primary reserve at no less than 150 percent of the largest single contingency. This is stricter than the NERC standard of the greater of 80 percent of the largest single contingency or 900 MW.[145]

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 the first nine months 2019, the supply of offered and eligible tier 2 synchronized reserve was 28,609.4 MW in the RTO Zone of which 5,484.6 MW was located in the MAD Subzone.
- **Demand.** The average hourly synchronized reserve requirement was 1,713.8 MW in the RTO Reserve Zone and 1,697.8 MW for the Mid-Atlantic Dominion Reserve Subzone. The hourly average cleared tier 2

145 NERC (August 12, 2019) <NERC Reliability Standard BAL 002-2 Glossary_of_Terms.pdf>.

synchronized reserve was 280.6 MW in the MAD Subzone and 536.9 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 the first nine months 2019.

  The average HHI for tier 2 synchronized reserve in the RTO Zone was 5505 which is classified as highly concentrated.

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. PJM automatically enters an offer of $0 for tier 2 synchronized reserve when an offer is not entered by the owner.

Market Performance

- **Price.** The weighted average price for tier 2 synchronized reserve for all cleared hours/intervals in the Mid-Atlantic Dominion (MAD) Subzone in the first nine months of 2019 was $3.07 per MW, a decrease of $1.85 from the same period in 2018.

  The weighted average price for tier 2 synchronized reserve for all cleared hours/intervals in the RTO Synchronized Reserve Zone was $3.19 per MW in the first nine months of 2019, a decrease of $2.59 from the same period in 2018.

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 for nonsynchronized reserve. 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 the first nine months of 2019, the average hourly supply of eligible nonsynchronized reserve was 3,953.1 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.[146] The actual amount of nonsynchronized reserve scheduled often exceeds the demand and the corresponding price is $0.00. In the RTO Zone, the market scheduled an hourly average of 1,461.9 MW of nonsynchronized reserve in the first nine months of 2019.
- **Market Concentration.** The MMU calculates that the three pivotal supplier test would have been failed in 61.3 percent of hours in the first nine months of 2019.

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

146 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," § $b.2.2 Non-Synchronized Reserve Zones and Levels, Rev. 107 (Sep. 26, 2019). "Because Synchronized Reserve may be utilized to meet the Primary Reserve requirement, there is no explicit requirement for non-synchronized reserves. "

reserve weighted average price for all hours in the RTO Reserve Zone was $0.20 per MW in the first nine months of 2019. The price cleared above $0.00 in 0.9 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.[147] 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 the first nine months of 2019, the average available hourly DASR was 44,547.9 MW.
- **Demand.** The DASR requirement for 2019 is 5.29 percent of peak load forecast, which is up 0.01 percent from in 2018. The average hourly DASR MW purchased in the first nine months of 2019 was 5,511.0 MW. This is a reduction from the 5,625.4 hourly MW in 2018.
- **Concentration.** In the first nine months of 2019, the DASR Market failed the three pivotal supplier test in less than one percent of hours.

147 See PJM, "Manual 11: Energy & Ancillary Services Market Operations," § 11.2.7 Day-Ahead Scheduling Reserve Performance, Rev. 107(Sep. 26, 2019).

Market Conduct

- **Withholding.** Economic withholding remains an issue in the DASR Market. The direct marginal cost of providing DASR is zero. PJM calculates the opportunity cost for each resource. All offers by resource owners greater than zero constitute economic withholding. In the first nine months of 2019, a daily average of 39.6 percent of units offered above $0.00. A daily average of 16.6 percent of units offered above $5.
- **DR.** Demand resources are eligible to participate in the DASR Market. Some demand resources have entered offers for DASR. No demand resources cleared the DASR market in the first nine months of 2019.

Market Performance

- **Price.** In the first nine months of 2019, the weighted average DASR price for all hours when the DASRMCP was above $0.00 was $1.24.

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 rates. 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 technical substitution (MRTS), called a marginal benefit factor (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 the first nine months of 2019, the average hourly eligible supply of regulation for nonramp hours was 1,062.1 performance adjusted MW (801.2 effective MW). This was a decrease of 37.2 performance adjusted MW (a decrease of 56.5 effective MW) from the first nine months of 2018, when the average hourly eligible supply of regulation was 1,099.3 performance adjusted MW (857.7 effective MW). In the first nine months of 2019, the average hourly eligible supply of regulation for ramp hours was 1,357.8 performance adjusted MW (1,127.6 effective MW). This was a decrease of 53.3 performance adjusted MW (a decrease of 64.1 effective MW) from the first nine months of 2018, when the average hourly eligible supply of regulation was 1,411.1 performance adjusted MW (1,191.8 effective MW).
- **Demand.** The hourly regulation demand is 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 470.7 hourly average performance adjusted actual MW in the first nine months of 2019. This is a decrease of 16.1 performance adjusted actual MW from the first nine months of 2018, when the average hourly total regulation cleared performance adjusted actual MW for nonramp hours were 486.8 performance adjusted actual MW. The ramp regulation requirement of 800.0 effective MW was provided by a combination of RegA and RegD resources equal to 722.8 hourly average performance adjusted actual MW in the first nine months of 2019. This is a decrease of 27.1 performance adjusted actual MW from the first nine months of 2018, where the average hourly regulation cleared MW for ramp hours were 750.0 performance adjusted actual MW.

  The ratio of the average hourly eligible supply of regulation to average hourly regulation demand (performance adjusted cleared MW) for ramp hours was 1.88 in the first nine months of 2019 (unchanged from the first nine months of 2018). The ratio of the average hourly eligible supply of regulation to average hourly regulation demand (performance adjusted cleared MW) for nonramp hours was 2.25 in the first nine months of 2019 (2.26 in the first nine months of 2018).
- **Market Concentration.** In the first nine months of 2019, the three pivotal supplier test was failed in 93.3 percent of hours. In the first nine months of 2019, the effective MW weighted average HHI of RegA resources was 2362 which is highly concentrated and the weighted average HHI of RegD resources was 1307 which is moderately concentrated.[148] The weighted average HHI of all resources was 1366, 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.[149] In the first nine months of 2019, there were 213 resources following the RegA signal and 59 resources following the RegD signal.

Market Performance

- **Price and Cost.** The weighted average clearing price for regulation was $14.97 per MW of regulation in the first nine months of 2019. This is a decrease of $13.25 per MW, or 47.0 percent, from the weighted average clearing price of $28.21 per MW in the first nine months of 2018. The weighted average cost of regulation in the first nine months of 2019 was $19.14 per MW of regulation. This is a decrease of $15.91 per MW, or 45.4 percent, from the weighted average cost of $35.05 per MW in the first nine months of 2018.
- **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

148 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.

149 See the 2018 State of the Market Report for PJM, Vol. 2, Appendix F "Ancillary Services Markets."

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.

- **Marginal Benefit Factor.** The marginal benefit factor (MBF) is intended to measure the operational substitutability of RegD resources for RegA resources. The marginal benefit factor is incorrectly defined and applied in the PJM market clearing. Correctly defined, the MBF 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 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 of RegD can also degrade the ability of PJM to control ACE.
- **Changes to the Regulation Market.** The MMU and PJM developed a joint proposal to address the significant flaws in the regulation market design which was approved by the PJM Members Committee on July 27, 2017, and filed with FERC on October 17, 2017. The proposal addresses issues with the inconsistent application of the marginal benefit factor throughout the optimization and settlement process in the PJM Regulation Market. On March 30, 2018, this joint proposal was rejected by FERC.[150] The MMU and PJM filed requests for rehearing.[151]

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).[152]

In the first nine months of 2019, total black start charges were $48.37 million, including $48.21 million in revenue requirement charges and $0.160 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 in the first nine months of 2019 ranged from $0.04 per MW-day in the DLCO Zone (total charges were $33,657) to $4.03 per MW-day in the PENELEC Zone (total charges were $3,299,265).

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 voltage levels on the transmission system and is essential to the flow of real power (measured in MW).

Reactive capability charges are based on FERC approved filings that permit recovery based on a cost of service approach.[153] Reactive service charges are paid to units that operate in real time outside of their normal range at the direction of PJM for the purpose of providing reactive service. Reactive service charges are paid for scheduling in the Day-Ahead Energy Market and committing units in real time that provide reactive service. In the first nine months of 2019, total reactive charges were $258.68 million, a 3.2 percent increase from $250.76 million in the first nine months of 2018. Reactive capability charges increased from $238.35 million in the first nine months of 2018 to $258.23 million in the first nine months of 2019 and reactive service charges decreased from $12.41 million in the first nine months of 2018 to $0.45 million in 2019. Total reactive service charges in the first nine months

150 162 FERC ¶ 61,295.
151 FERC Docket No. ER18-87-002.
152 OATT Schedule 1 § 1.3BB.
153 OATT Schedule 2.

of 2019 ranged from $0 in the RECO and OVEC Zones, to $36.00 million in the AEP Zone.

Frequency Response

On February 15, 2018, the Commission issued Order No. 842, which modified the pro forma large and small generator interconnection agreements and procedures to require newly interconnecting generating facilities, both synchronous and nonsynchronous, to include equipment for primary frequency response capability as a condition to receive interconnection service.[154] PJM filed revisions in compliance with Order No. 842 that substantively incorporated the pro forma agreements into its market rules.[155]

The PJM Tariff requires that all new generator interconnection customers (NRC regulated facilities are exempt from this provision) have hardware and/or software that provides frequency responsive real power control with the ability to sense changes in system frequency and autonomously adjust real power output in a direction to correct for frequency deviations. This includes a governor or equivalent controls capable of operating with a maximum five percent droop and a +/- 0.036 deadband.[156] PJM is currently studying individual unit response to NERC identified frequency events and evaluating compliance.

Section 10 Recommendations

- 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 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. FERC rejected, pending rehearing request before FERC.[157])
- 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.[158] FERC rejected, pending rehearing request before FERC.[159])
- The MMU recommends that the lost opportunity cost 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: Not adopted. FERC rejected, pending rehearing request before FERC.[160])
- 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. FERC rejected, pending rehearing request before FERC.[161])
- The MMU recommends enhanced documentation of the implementation of the Regulation Market design. (Priority: Medium. First reported 2010. Status: Not adopted. FERC rejected, pending rehearing request before FERC.[162])
- 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: Adopted, 2018.)
- 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.)

154 See 157 FERC ¶ 61,122 (2016).
155 See 164 FERC ¶ 61,224 (2018).
156 PJM OATT (ER18-1629-000) October 1, 2018, 4.7.2 Primary Frequency Response, p. 3.
157 FERC Docket No. ER18-87.
158 This recommendation was adopted by PJM for the Energy Market. Lost opportunity costs in the Energy Market are calculated using the schedule on which the unit was scheduled to run. In the Regulation Market, this recommendation has not been adopted, as the LOC continues to be calculated based on the lower of price or cost in the energy market offer.
159 FERC Docket No. ER18-87.
160 Id.
161 Id.
162 Id.

- The MMU recommends that the $7.50 margin be eliminated from the definition of the cost of tier 2 synchronized reserve because it is a markup and not a cost. (Priority: Medium. First reported 2018. Status: Not adopted.)
- 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 on a daily and hourly basis. 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, for calculating the penalty for a tier 2 resource failing to meet its scheduled obligation during a spinning event, the definition of the IPI be changed from the average number of days between events to the actual number of days since the last event greater than 10 minutes. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that aggregation not be permitted to offset unit specific penalties for failure to respond to a synchronized reserve event. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM eliminate the use of Degree of Generator Performance (DGP) in the synchronized reserve market solution and improve the actual tier 1 estimate. If PJM continues to use DGP, DGP should be documented in PJM's manuals. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that a reason code be attached to every hour in which PJM market operations adds additional DASR MW. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that 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 offers in the DASR Market be based on opportunity cost only in order to eliminate market power. (Priority: Low. First reported 2009. Modified, 2018. Status: Not adopted.)
- The MMU recommends that separate cost of service 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 payments for reactive capability, if continued, be based on the 0.90 power factor that PJM has determined is necessary. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that all resources, new and existing, have a requirement to include and maintain equipment for primary frequency response capability as a condition of interconnection service and that compensation is provided through the capacity and energy markets. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends for oil tanks shared with other resources that 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 2017. Status: Not adopted.)

- The MMU recommends that the same capability be required of both new and existing resources. The MMU agrees with Order No. 842 that RTOs not be required to provide additional compensation specifically for frequency response. The current PJM market design provides compensation for all capacity costs, including these, in the capacity market. The current market design provides compensation, through heat rate adjusted energy offers, for any costs associated with providing frequency response. Because the PJM market design already compensates resources for frequency response capability and any costs associated with providing frequency response, any separate filings submitted on behalf of resources for compensation under section 205 of the Federal Power Act should be rejected as double recovery. (Priority: Low. First reported 2017. Status: Not adopted.)
- The MMU recommends that fleet wide cost of service rates used to compensate resources for reactive capability be eliminated and replaced with compensation based on unit specific costs. (Priority: Low. New recommendation.[163] Status: Not adopted.)

Section 10 Conclusion

The current PJM regulation market design that incorporates two signals using two resource types was a result of FERC Order No. 755 and subsequent orders.[164]

The design of the PJM Regulation Market is significantly flawed. The market design does not 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 are the basis for 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.[165] 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. FERC rejected the joint proposal on March 30, 2018, as being noncompliant with Order No. 755.[166] The MMU and PJM separately filed requests for rehearing.[167]

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, the $7.50 margin is not a cost. The margin is effectively a rule-based form of market power and is therefore not consistent with a competitive outcome. The $7.50 margin should be eliminated. Participant performance has not been adequate. Compliance with calls to respond to actual synchronized reserve events remains less than 100 percent. For the 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. For the seven spinning events longer than 10 minutes in 2018, the response was 74.2 percent of scheduled tier 2 MW. There was only one spinning event that lasted longer than 10 minutes in the first nine months of 2019. This one spinning event in the first nine months of 2019 occurred on September 23. In the September 23 event, tier 2 response was 87.4 percent of the amount scheduled and tier 1 response was 71.8 percent of DGP estimated amount. Actual participant performance means that the penalty structure is not adequate to incent performance.

163 The MMU has discussed this recommendation in state of the market reports since 2016 but this is the first time it has been reported as a formal MMU recommendation.
164 Order No. 755, 137 FERC ¶ 61,064 at PP 197–200 (2011).
165 18 CFR § 385,211 (2017)
166 162 FERC ¶ 61,295 (2018).
167 The MMU filed its request for rehearing on April 27, 2018, and PJM filed its request for rehearing on April 30, 2018.

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, $2.2 million in 2017, $4.7 million in 2018, and $2.3 million in the first nine months of 2019.

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 significantly flawed. The MMU concludes that the synchronized reserve market results were competitive, although the $7.50 margin should be removed. 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 $697.2 million or 62.5 percent, from $1,116.2 million in the first nine months of 2018 to $419.1 million in the first nine months of 2019.
- **Day-Ahead Congestion.** Day-ahead congestion costs decreased by $640.3 million or 55.6 percent, from $1,151.7 million in the first nine months of 2018 to $511.4 million in the first nine months of 2019.
- **Balancing Congestion.** Negative balancing congestion costs increased by $56.9 million or 160.3 percent, from -$35.5 million in the first nine months of 2018 to -$92.4 million in the first nine months of 2019. Negative balancing explicit costs increased by $55.8 million, from -$3.6 million in the first nine months of 2018 to -$59.4 million in the first nine months of 2019.
- **Real-Time Congestion.** Real-time congestion costs decreased by $746.4 million or 59.1 percent, from $1,263.6 million in the first nine months of 2018 to $517.2 million in the first nine months of 2019.
- **Monthly Congestion.** Monthly total congestion costs in the first nine months of 2019 ranged from $22.2 million in April to $100.2 million in January.
- **Geographic Differences in CLMP.** Differences in CLMP among eastern, southern and western control zones in PJM were primarily a result of congestion on the Conastone - Peach Bottom Line, the Coolspring – Milford Line, the Tanners Creek - Miami Fort Flowgate, the Siegfried Transformer, and the AP South Interface.
- **Congestion Frequency.** Congestion frequency continued to be significantly higher in the Day-Ahead Energy Market than in the Real-Time Energy Market in the first nine months of 2019. The number of congestion event hours in the Day-Ahead Energy Market was about six times the number of congestion event hours in the Real-Time Energy Market.

Day-ahead congestion frequency decreased by 25.9 percent from 105,437 congestion event hours in the first nine months of 2018 to 78,155 congestion event hours in the first nine months of 2019. The majority (103.1 percent) of the decrease occurred in January and February of 2019. The decrease was largely a result of the decrease in cleared up to congestion (UTC) transactions between January and February, 2018 and January and February, 2019.[168] Day-ahead congestion frequency increased in March, June and July of 2019.

Real-time congestion frequency decreased by 20.2 percent from 16,915 congestion event hours in the first nine months of 2018 to 13,495 congestion event hours in the first nine months of 2019.

- **Congested Facilities.** Day-ahead, congestion event hours decreased on all types of facilities largely as a result of the decrease in cleared up to congestion (UTC) transactions from January and February, 2018, to January and February, 2019.

  The Conastone - Peach Bottom Line was the largest contributor to congestion costs in the first nine months of 2019. With $83.3 million in total congestion costs, it accounted for 19.9 percent of the total PJM congestion costs in the first nine months of 2019.

- **CT Price Setting Logic and Closed Loop Interface Related Congestion.** CT Price Setting Logic caused -$0.2 million of day-ahead congestion in the first nine months of 2019 and -$5.0 million of balancing congestion in the first nine months of 2019. None of the closed loop interfaces was binding in the first nine months of 2019 or 2018.

- **Zonal Congestion.** AEP had the largest zonal congestion costs among all control zones in the first nine months of 2019. AEP had $71.6 million in zonal congestion costs, comprised of $86.7 million in zonal day-ahead congestion costs and -$15.1 million in zonal balancing congestion costs. The Conastone - Peach Bottom Line, the Tanners Creek - Miami Fort Flowgate, the AP South Interface, the Conastone - Northwest Line, and the Coolspring - Milford Line contributed $23.6 million, or 32.9 percent of the AEP zonal congestion costs.

168 162 FERC ¶ 61,139.

Marginal Loss Cost

- **Total Marginal Loss Costs.** Total marginal loss costs decreased by $253.1 million or 33.5 percent, from $755.8 million in the first nine months of 2018 to $502.7 million in the first nine months of 2019. The loss MWh in PJM decreased by 259.6 GWh or 2.2 percent, from 11,860.3 GWh in the first nine months of 2018 to 11,600.8 GWh in the first nine months of 2019. The loss component of real-time LMP in the first nine months of 2019 was $0.02, compared to $0.02 in the first nine months of 2018.
- **Monthly Total Marginal Loss Costs.** Monthly total marginal loss costs in the first nine months of 2019 ranged from $38.8 million in April to $86.5 million in January.
- **Day-Ahead Marginal Loss Costs.** Day-ahead marginal loss costs decreased by $237.2 million or 30.4 percent, from $779.7 million in the first nine months of 2018 to $542.6 million in the first nine months of 2019.
- **Balancing Marginal Loss Costs.** Negative balancing marginal loss costs increased by $16.0 million or 66.7 percent, from -$23.9 million in the first nine months of 2018 to -$39.9 million in the first nine months of 2019.
- **Total Marginal Loss Surplus.** The total marginal loss surplus decreased in the first nine months of 2019 by $93.2 million or 36.5 percent, from $255.3 million in the first nine months of 2018, to $162.1 million in the first nine months of 2019.

Energy Cost

- **Total Energy Costs.** Total energy costs increased by $159.3 million or 32.0 percent, from -$498.7 million in the first nine months of 2018 to -$339.3 million in the first nine months of 2019.
- **Day-Ahead Energy Costs.** Day-ahead energy costs increased by $143.9 million or 26.1 percent, from -$551.4 million in the first nine months of 2018 to -$407.6 million in the first nine months of 2019.

- **Balancing Energy Costs.** Balancing energy costs increased by $20.9 million or 44.5 percent, from $47.1 million in the first nine months of 2018 to $68.0 million in the first nine months of 2019.
- **Monthly Total Energy Costs.** Monthly total energy costs in the first nine months of 2019 ranged from -$59.3 million in January to -$25.7 million in April.

Section 11 Recommendations

- The MMU recommends that PJM's logic for the calculation of implicit balancing congestion charges revert to the method used prior to April 1, 2018. (Priority: Medium. New recommendation. Not adopted.)

Section 11 Conclusion

Congestion is defined to be the total congestion charges 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.

Total congestion in the first nine months of 2019 decreased significantly from the first nine months of 2018. The decrease was a result of high day-ahead congestion in January 2018 which was a result of high gas costs and associated LMPs in the early part of January 2018.

The monthly total congestion costs ranged from $22.2 million in April to $100.2 million in January 2019.

The impact of UTCs on the frequency of day-ahead congestion was illustrated by the significant reduction in day-ahead congestion event hours following the decrease in up to congestion (UTC) transaction activities that resulted from the February 20, 2018, FERC order that limited UTC trading to hubs, residual metered load, and interfaces.

The current ARR/FTR design does not serve as an efficient way to ensure that load receives all the congestion revenues, and 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 only 74.5 percent of total congestion costs including congestion in the Day-Ahead Energy Market and the balancing energy market, for the 2011/2012 planning period through the 2016/2017 planning period, before the FERC decision to allocate balancing congestion and M2M payments to load.[169] For the 2017/2018 planning period, after the implementation of the FERC decision to reallocate balancing congestion and M2M payments to load, ARR and self scheduled FTR revenue offset 50.0 percent of total congestion. For the 2018/2019 planning period, ARR and self scheduled FTR revenue offset 92.1 percent of total congestion. For a number of reasons, the first four months of the 2019/2020 planning period, over 100 percent of total congestion was offset by ARR credit allocations to ARR holders. This reflects the same pattern as the first four months of the 2018/2019 planning period.

Overview: Section 12, Planning

Generation Interconnection Planning

Existing Generation Mix

- As of September 30, 2019, PJM had a total installed capacity of 198,501.1 MW, of which 54,856.6 MW (27.6 percent) are coal fired steam units, 48,641.6 MW (24.5 percent) are combined cycle units and 34,257.6 MW (17.3 percent) are nuclear units. This measure of installed capacity 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.
- The AEP Zone has the most total installed capacity of any PJM zone. Of the 198,501.1 MW of PJM total installed capacity, 30,843.0 MW (15.5 percent) are in the AEP Zone, of which 13,927.8 MW (45.2 percent) are coal fired steam units, 6,990.0 MW (22.7 percent) are combined cycle units and 2,071.0 MW (6.7 percent) are nuclear units.

169 On September 15, 2016, FERC ordered PJM to allocate balancing congestion to load, rather than to FTRs, to modify PJM's Stage 1A ARR allocation process and to continue to use portfolio netting. 153 FERC ¶ 61,180.

- Pennsylvania has the most total installed capacity of any PJM state. Of the 198,501.1 MW of installed capacity, 46,985.4 MW (23.7 percent) are in Pennsylvania, of which 9,324.4 MW (19.8 percent) are coal fired steam units, 16,071.5 MW (34.2 percent) are combined cycle units and 9,648.8 MW (20.5 percent) are nuclear units.
- Of the 198,501.1 MW of installed capacity, 73,586.0 MW (37.1 percent) are from units older than 40 years, of which 38,867.2 MW (52.8 percent) are coal fired steam units, 532.0 MW (0.7 percent) are combined cycle units and 16,044.9 MW (21.8 percent) are nuclear units.

Generation Retirements[170]

- There are 42,955.8 MW of generation that have been, or are planned to be, retired between 2011 and 2022, of which 31,039.2 MW (72.3 percent) are coal fired steam units. Coal unit retirements are primarily a result of the inability of coal units to compete with efficient combined cycle units burning low cost gas.
- In the first nine months of 2019, 4,249.0 MW of generation retired. The largest generators that retired in the first nine months of 2019 were the two 830.0 MW Mansfield coal fired steam units owned by FirstEnergy Corporation and located in the American Transmission Systems Inc. (ATSI) Zone. Of the 4,249.0 MW of generation that retired, 1,660.0 MW (39.1 percent) were located in the ATSI Zone.
- As of September 30, 2019, there are 7,335.7 MW of generation that have requested retirement after September 30, 2019, of which 1,507.0 MW (20.5 percent) are located in the ATSI Zone. Of the ATSI generation requesting retirement, 1,470.0 MW (97.5 percent) are coal fired steam units.

Generation Queue[171]

- There were 114,953.7 total MW in generation queues, in the status of active, under construction or suspended, at the end of 2018. In the first nine months of 2019, the AE2 and AF1 queue windows closed. Combined, these queue windows added 38,172.3 MW to the queue. As projects move through the queue process, projects can be removed from the queue due to incomplete or invalid data, withdrawn by the market participant or placed in service. On September 30, 2019, there were 124,399.7 total MW in generation queues, in the status of active, under construction or suspended, an increase of 9,446.0 MW (8.2 percent).
- 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 September 30, 2019, there were 39,204.9 MW of natural gas fired capacity active, suspended or under construction in PJM queues (including combined cycle units, CTs, RICE units, and natural gas fired steam units).[172] As of September 30, 2019, there were only 132.0 MW of coal fired steam capacity active, suspended or under construction in PJM queues.
- As of September 30, 2019, 4,610 projects, representing 571,957.8 MW, have entered the queue process since its inception in 1998. Of those, 864 projects, representing 67,152.8 MW, went into service. Of the projects that entered the queue process, 2,642 projects, representing 380,405.3 MW (66.5 percent of the MW) withdrew prior to completion. Such projects may create barriers to entry for projects that would otherwise be completed by taking up queue positions, increasing interconnection costs and creating uncertainty.
- As of September 30, 2019, 124,399.7 MW of capacity were in generation request queues in the status of active, under construction or suspended. Of the total 124,399.7 MW in the queue, 64,966.0 MW (52.2 percent) have reached at least the system impact study (SIS) milestone and 59,433.7 MW (47.8 percent) have not received a completed SIS. Based on historical completion rates, (applying the unit type specific completion rates for those projects that have reached the system impact study, facility study agreement or construction service agreement milestone, and using the overall completion rates for those projects that have not yet reached the system impact study milestone), 35,269.3 MW of new generation in the queue are expected to go into service.

170 See PJM. Planning. "Generator Deactivations," at <http://www.pjm.com/planning/services-requests/gen-deactivations.aspx>.
171 See PJM. Planning. "New Services Queue," at <https://www.pjm.com/planning/services-requests/interconnection-queues.aspx>.
172 The unit type RICE refers to Reciprocating Internal Combustion Engines.

Regional Transmission Expansion Plan (RTEP)

Market Efficiency Process

- There are significant issues with PJM's benefit/cost analysis that should be addressed prior to approval of additional projects. PJM's benefit/cost analysis does not correctly account for the costs of increased congestion associated with market efficiency projects.
- Through September 30, 2019, PJM has completed three market efficiency cycles under Order No. 1000. The fourth market efficiency cycle is currently in progress for the 2018/2019 long term window.

PJM MISO Targeted Market Efficiency Process (TMEP) and Interregional Market Efficiency Process (IMEP)

- 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).[173] The allocation of costs to each RTO for TMEPs will be in proportion to the benefits received.[174]

Supplemental Transmission Projects

- Supplemental projects are defined to be "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."[175] Supplemental projects are exempt from the competitive planning process.
- The average number of supplemental projects in each expected in service year increased by 600.0 percent, from 20 for years 1998 through 2007 (pre Order No. 890) to 140 for years 2008 through 2019 (post Order 890).
- The process for designating projects as supplemental projects should be reviewed and modified to ensure that the supplemental project designation is not used to exempt transmission projects from a transparent, robust and clearly defined mechanism to permit competition to build the project or to effectively replace the RTEP process.

173 See PJM Interconnection, L.L.C, Docket No. ER17-718-000 (December 30, 2016).
174 See PJM Interconnection, L.L.C, Docket No. ER17-729-000 (December 30, 2016).
175 See PJM. "Transmission Construction Status," (Accessed on September 30, 2019) <http://www.pjm.com/planning/rtep-upgrades-status/construct-status.aspx>.

End of Life Transmission Projects

- An end of life transmission project is a project submitted for the purpose of replacing existing infrastructure that is at, or is approaching, the end of its useful life. Some Transmission Owners include end of life transmission projects in their Transmission Owner Form 715 Planning Criteria. These projects were exempt from the competitive planning process.[176]
- End of life transmission projects should be included in the RTEP process and should be subject to a transparent, robust and clearly defined mechanism to permit competition to build the project.

Board Authorized Transmission Upgrades

- The Transmission Expansion Advisory Committee (TEAC) reviews internal and external proposals to improve transmission reliability throughout PJM. These proposals, which include reliability baseline, network, market efficiency and targeted market efficiency projects, but exclude supplemental and end of life projects, are periodically presented to the PJM Board of Managers for authorization.[177] In the first nine months of 2019, the PJM Board approved $845.8 million in upgrades. As of September 30, 2019, the PJM Board has approved $39.1 billion in system enhancements since 1999.

Transmission Competition

- The MMU makes several recommendations related to the competitive transmission planning process. The recommendations include improved process transparency, incorporation of competition between transmission and generation alternatives and the removal of barriers to competition from nonincumbent transmission. These recommendations would help ensure that the process is an open and transparent process that results in the most competitive solutions.

176 See PJM. Operating Agreement Schedule 6 § 1.5.8(o).
177 Supplemental Projects, including the end of life subset of supplemental projects, do not require PJM Board of Managers authorization.

- On May 24, 2018, the PJM Markets and Reliability Committee (MRC) approved a motion that required PJM, with input from the MMU, to develop a comparative framework to evaluate the quality and effectiveness of competitive transmission proposals with binding cost containment proposals compared to proposals from incumbent and nonincumbent transmission companies without cost containment provisions.

Qualifying Transmission Upgrades (QTU)

- A Qualifying Transmission Upgrade (QTU) is an upgrade to the transmission system that increases the Capacity Emergency Transfer Limit (CETL) into an LDA and can be offered into capacity auctions as capacity. Once a QTU is in service, the upgrade is eligible to continue to offer the approved incremental import capability into future RPM Auctions. As of September 30, 2019, no QTUs have cleared a BRA.

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.[178]
- There were 6,601 transmission outage requests submitted in the first four months of the 2019/2020 planning period. Of the requested outages, 73.3 percent of the requested outages were planned for less than or equal to five days and 12.5 percent of requested outages were planned for greater than 30 days. Of the requested outages, 50.9 percent were late according to the rules in PJM's Manual 3.

178 See PJM. "PJM Manual 03: Transmission Operations," Rev. 55 (May 31, 2019).

Section 12 Recommendations

Generation Retirements

- The MMU recommends that the question of whether Capacity Injection Rights (CIRs) should persist after the retirement of a unit, or the conversion from Capacity Performance (CP) to energy only status, be addressed. The rules need to ensure that incumbents cannot exploit control of CIRs to block or postpone entry of competitors.[179] (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that rules be implemented to ensure that CIRs are terminated within one year if units cannot qualify to be capacity resources and, if requested, after one CP must offer exception to permit the issue of CP status to be addressed. (Priority: Low. First reported 2018. Status: Not adopted.)

Generation Queue

- 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 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 continuing 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

179 See "Comments of the Independent Market Monitor for PJM," Docket No. ER12-1177-000 (March 12, 2012) <http://www.monitoringanalytics.com/Filings/2012/IMM_Comments_ER12-1177-000_20120312.PDF>.

go into service. (Priority: Medium. First reported 2014. Status: Partially 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.)

Market Efficiency Process

- The MMU recommends that the market efficiency process be eliminated because it is not consistent with a competitive market design. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that, if the market efficiency process is retained, PJM modify the rules governing benefit/cost analysis, the evaluation process for selecting among competing market efficiency projects and cost allocation for economic projects in order to ensure that all costs, including increased congestion costs and the risk of project cost increases, in all zones are included and in order to ensure that the correct metrics are used for defining benefits. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that, if the market efficiency process is retained, PJM modify the rules governing the market efficiency process benefit/cost analysis so that competing projects with different in service dates are evaluated on a symmetric, comparable basis. (Priority: Medium. First reported 2018. Status: Not adopted.)

Transmission Competition

- The MMU recommends, to increase the role of competition, that the exemption of supplemental projects from the Order No. 1000 competitive process be terminated and that the basis for all such exemptions be reviewed and modified to ensure that the supplemental project designation is not used to exempt transmission projects from a transparent, robust and clearly defined mechanism to permit competition to build such projects or to effectively replace the RTEP process. (Priority: Medium. First reported 2017. Status: Not adopted.)
- The MMU recommends, to increase the role of competition, that the exemption of end of life projects from the Order No. 1000 competitive process be terminated and that end of life transmission projects should be included in the RTEP process and should be subject to a transparent, robust and clearly defined mechanism to permit competition to build such projects. (Priority: Medium. First reported Q1, 2019. Status: Not adopted.)
- The MMU recommends that PJM enhance the transparency and queue management process for nonincumbent 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 nonincumbent transmission providers. (Priority: Medium. First reported 2015. Status: Not adopted.)
- 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 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 nonincumbent transmission providers in the RTEP. (Priority: Medium. First reported 2014. 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: Medium. First reported 2015. Status: Not adopted.)

Cost Allocation

- 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.[180] (Priority: Medium. First reported 2015. Status: Not adopted.)

Transmission Facility Outages

- 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.)

180 See the 2015 State of the Market Report for PJM, Volume 2, Section 12: Generation and Transmission Planning, at p. 463, Cost Allocation Issues.

Section 12 Conclusion

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

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

The current market efficiency process does exactly the opposite by permitting transmission projects to be approved without competition from generation. The broader issue is that the market efficiency project approach explicitly allows transmission projects to compete against future generation projects, but without allowing the generation projects to compete. Projecting speculative transmission related benefits for 15 years based on the existing generation fleet and existing patterns of congestion eliminates the potential for new generation to respond to market signals. The market efficiency process allows assets built under the cost of service regulatory paradigm to displace generation assets built under the competitive market paradigm. The MMU recommends that the market efficiency process be eliminated.

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 nonincumbent transmission providers. The ability of transmission owners to block competition for supplemental projects and end of life projects and reasons for that policy should be reevaluated. PJM should enhance the transparency and queue management process for nonincumbent 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 nonincumbent 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, paid for by customers. 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.

The process for determining the reasonableness or purpose of supplemental transmission projects that are asserted to be not needed for reliability, economic efficiency or operational performance as defined under the RTEP process needs additional oversight and transparency. If there is a need for a supplemental project, that need should be clearly defined and there should be a transparent, robust and clearly defined mechanism to permit competition to build the project. If there is no defined need for of a supplemental project for reliability, economic efficiency or operational performance then the project should not be included in rates.

If it is retained, there are significant issues with PJM's benefit/cost analysis that should be addressed prior to approval of additional projects. The current benefit/cost analysis for a regional project, for example, explicitly and incorrectly ignores the increased congestion in zones that results from an RTEP project when calculating the energy market benefits. All costs should be included in all zones and LDAs. The definition of benefits should also be reevaluated.

The benefit/cost analysis should also account for the fact that the transmission project costs are not subject to cost caps and may exceed the estimated costs by a wide margin. When actual costs exceed estimated costs, the cost benefit analysis is effectively meaningless and low estimated costs may result in inappropriately favoring transmission projects over market generation projects. The risk of cost increases for transmission projects should be incorporated in the cost benefit analysis.

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 four months of the 2019/2020 planning period, PJM allocated a total of 11,162.7 MW of residual ARRs, down from 11,961.8 MW in the 2018/2019 planning period, with a total target allocation of $2.7 million for the 2019/2020 planning period, down from $4.1 million for the 2018/2019 planning period.

- **ARR Reassignment for Retail Load Switching.** There were 18,913 MW of ARRs associated with $223,800 of revenue that were reassigned in the 2019/2020 planning period. There were 35,571 MW of ARRs associated with $423,100 of revenue that were reassigned for the 2018/2019 planning period.

Market Performance

- **Revenue Adequacy.** For the first four months of the 2019/2020 planning period, the ARR target allocations, which are based on the nodal price differences from the Annual FTR Auction, were $246.9 million, while PJM collected $956.9 million from the combined Long Term, Annual and Monthly Balance of Planning Period FTR Auctions, making ARRs revenue adequate. The new allocation of surplus congestion revenue provides for revenue adequacy for FTRs first, and any remaining revenues at the end of the planning period are allocated to ARR holders. For the 2018/2019 planning period, the ARR target allocations were $726.8 million while PJM collected $907.6 million from the combined Annual and Monthly Balance of Planning Period FTR Auctions.

- **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 2016/2017 planning period, under the previous allocation of balancing congestion. In 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 50.0 percent of total congestion costs. Under the new rules for surplus congestion revenue allocation beginning in the 2018/2019 planning periods, for the first four months of the 2019/2020 planning period, over 100 percent of total congestion was offset by ARR credit allocations to ARR holders including FTR auction revenues, self scheduled FTR revenue, surplus from the FTR auction, and day-ahead congestion in excess of target allocations. 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.** In a given auction, market participants can sell FTRs that they have acquired in preceding auctions or preceding rounds of auctions. In the Monthly Balance of Planning Period FTR Auctions for the first four months of the 2019/2020 planning period, total participant FTR sell offers were 3,881,264 MW, up from 3,320,461 MW for the same period during the 2018/2019 planning period.

- **Demand.** The total FTR buy bids from the Monthly Balance of Planning Period FTR Auctions for the first four months of the 2019/2020 planning period increased 1.2 percent from 9,443,085 MW for the same time period of the prior planning period, to 9,555,146 MW.

- **Patterns of Ownership.** For the Monthly Balance of Planning Period Auctions, financial entities purchased 79.9 percent of prevailing flow and 71.7 percent of counter flow FTRs for January through September of 2019. Financial entities owned 68.9 percent of all prevailing and counter flow FTRs, including 62.0 percent of all prevailing flow FTRs and 79.1 percent of all counter flow FTRs during the period from January through September 2019.

Market Behavior

- **FTR Forfeitures.** For the period January 19, 2017, through September 30, 2019, total FTR forfeitures were $24.6 million.
- **Credit.** There were no collateral defaults in the first nine months of 2019. There were 58 payment defaults in the first nine months of 2019 not involving GreenHat Energy, LLC for a total of $59,933. GreenHat Energy continued to accrue payment defaults of $53.6 million in the first nine months of 2019, for a total of $130.6 million in defaults to date, which will continue to accrue through May 2021, including the auction liquidation costs.

Market Performance

- **Volume.** In the first four months of the 2019/2020 planning period Monthly Balance of Planning Period FTR Auctions cleared 1,588,345 MW (16.6 percent) of FTR buy bids and 832,832 MW (21.5 percent) of FTR sell offers.
- **Price.** The weighted average buy bid cleared FTR price in the Monthly Balance of Planning Period FTR Auctions for the first four months of the 2019/2020 planning period was $0.17, up from $0.12 per MW for the same period in the 2018/2019 planning period.
- **Revenue.** The Monthly Balance of Planning Period FTR Auctions generated $27.9 million in net revenue for all FTRs of the first four months of the 2019/2020 planning period, down from $33.5 million for the same time period in the 2018/2019 planning period.
- **Revenue Adequacy.** FTRs were paid at 100.0 percent of the target allocation level for the first four months of the 2019/2020 planning period, assuming the distribution of the current (as of September) existing surplus revenue. This level of FTR funding 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 four months of the 2019/2020 planning period, physical entities made -$22.6 million in profits on FTRs purchased directly (not self scheduled), while receiving $39.5 million in returned congestion from self scheduled FTRs, and financial entities made -$3.1 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 the Long Term FTR product be eliminated. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that, if the Long Term FTR product is not eliminated, the Long Term FTR Market be modified so that the supply of prevailing flow FTRs in the Long Term FTR Market is based solely on counter flow offers in the Long Term FTR Market. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends that, under the current FTR design, the full capability of the transmission system be allocated as ARRs prior to sale as FTRs. Reductions for outages and increased system capability should be reserved for ARRs rather than sold in the Long Term FTR Auction. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends that all FTR auction revenue be distributed to ARR holders monthly, regardless of FTR funding levels. (Priority: High. First reported 2015. Status: Not adopted.)

- The MMU recommends that, under the current FTR design, all congestion revenue in excess of FTR target allocations be distributed to ARR holders on a monthly basis. (Priority: High. First reported 2018. 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.[181] (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: Partially 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. Rejected by FERC.)
- The MMU recommends that PJM eliminate subsidies to counter flow FTRs by applying the payout ratio to counter flow FTRs in the same way the payout ratio is applied to prevailing flow FTRs. (Priority: High. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM eliminate geographic cross subsidies. (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM 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 and its members continue to review the management of a defaulted member's FTR portfolio, including options other than immediate liquidation. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM continue to evaluate the bilateral indemnification rules and any asymmetries they may create. (Priority: Low. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM examine the source and sink node combinations available in the FTR market and eliminate generation to generation paths and all other paths that do not represent the delivery of power to load. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that the forfeiture amount from the FTR forfeiture rule be based on the correct hourly cost of an FTR, rather than a simple daily price divided by 24. (Priority: High. First reported 2018. Status: Pending at FERC.)
- The MMU recommends that the direct customer request approach for creating and allocating IARRs be eliminated from PJM's tariff. (Priority: Low. First reported 2018. Status: Not adopted.)

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 inconsistent with the network based delivery of power and the actual way congestion is generated in security constrained 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 load paying congestion revenues, in an LMP market.

Revenue adequacy is misunderstood and generally incorrectly defined. Revenue adequacy has received a lot of attention in the PJM FTR Market and conclusions based on the incorrect definition have led to significant changes in the design of the ARR/FTR market that have distorted the function and purpose of ARRs and FTRs as a means of allocating congestion and congestion

181 See "PJM Manual 6: Financial Transmission Rights," Rev. 23 (Sep. 1, 2019).

rights. Correctly defined, revenue adequacy for ARRs means that ARRs have the rights to 100 percent of congestion revenue. FTR holders, with the creation of ARRs, do not have a right to receive revenues equal to CLMP differentials on individual FTR paths.

The current ARR/FTR design does not serve as an efficient way to ensure that load receives the rights to all the congestion revenues and has the ability to receive the auction revenues associated with all the potential congestion revenues. Total ARR and self scheduled FTR revenue offset only 65.3, 90.3, 103.6, 50.0 and 92.1 percent of total congestion costs including congestion in the Day-Ahead Energy Market and the balancing energy market for the 2014/2015, 2015/2016, 2016/2017, 2017/2018, 2018/2019 planning periods. Within the planning period, surplus monthly revenue can be distributed to achieve revenue adequacy for the planning year to date, but at the end of the planning period any remaining surplus revenue left after paying FTR target allocations is assigned to ARR holders. Distributing surplus to FTR holders first does not preserve ARR's rights to congestion revenue. If the surplus revenue available through September 2019 were distributed to ARR holders, total ARR and self scheduled FTR revenue would offset 116.2 percent, and 94.3 percent without distribution of surplus revenue, of total congestion costs for the first four months of the 2019/2020 planning period.

PJM has persistently and subjectively intervened in the FTR market in order to affect the payments to FTR holders. These interventions are not appropriate. For example, in the 2014/2015, 2015/2016 and 2016/2017 planning periods, PJM significantly reduced the allocation of ARR capacity, and FTRs, in order to guarantee full FTR funding. PJM reduced system capability in the FTR auction model by including more outages, reducing line limits and including additional constraints. PJM's modeling changes resulted in significant reductions in Stage 1B and Stage 2 ARR allocations, a corresponding reduction in the available quantity of FTRs, a reduction in congestion revenues assigned to ARRs, and an associated 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. Starting in the 2017/2018 planning period, with the allocation of balancing congestion and M2M payments to load rather than FTRs, PJM increased system capability allocated to Stage 1B and Stage 2 ARRs, but continued to conservatively select outages to manage FTR funding levels.

PJM has intervened aggressively in the FTR market since its inception in order to meet various subjective objectives. PJM should not intervene in the FTR market to subjectively manage FTR funding. PJM should fix the FTR/ARR design and then should let the market work to return congestion to load and to let FTR values reflect actual congestion.

Load should never be required to subsidize payments to FTR holders, regardless of the reason. Such subsidies have been suggested repeatedly.[182] The FERC order of September 15, 2016, introduced a subsidy to FTR holders at the expense of ARR holders.[183] The order requires PJM to ignore balancing congestion when calculating total congestion dollars available to fund FTRs. 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. The Commission's order shifts substantial revenue from load to the holders of FTRs and reduces the ability of load to offset congestion. 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 pays for the physical transmission system, pays in excess of generator revenues and pays negative balancing congestion again. The result is that load gets back less than total congestion. Based on a recent rule change, balancing congestion is allocated to load on a load ratio share, rather than on the basis of location or source of the balancing congestion. This rule creates inappropriate cross subsidies among loads.

These changes were made in order to increase the payout to holders of FTRs who are not loads. 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. Increasing

182 See FERC Dockets Nos. EL13-47-000 and EL12-19-000.
183 See 156 FERC ¶ 61,180 (2016), reh'g denied, 156 FERC ¶ 61,093 (2017).

the payout to FTR holders at the expense of the load is not a supportable market objective. Under the current FTR design, FTR holders should receive actual congestion on the relevant FTR paths and paths should be limited to actual physical source and sink points to align congestion rights with the paths that generate congestion and to limit cross subsidies. But PJM should implement an FTR design that calculates and assigns congestion rights to load rather than continuing to modify the current design.

Load was made 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 revenues were significantly reduced for the 2017/2018 FTR Auction, the first auction under the new rules. ARRs and self scheduled FTRs offset 50.0 percent of total congestion costs for the 2017/2018 planning period rather than the 60.5 percent offset that would have occurred under the prior rules, a difference of $125.8 million. There was a significant amount of congestion in January 2018 which adversely affected the congestion offset value of ARRs. ARR revenue is fixed at annual auction prices, but congestion revenue varies with market conditions. If these allocation rules had been in place beginning with the 2011/2012 planning period, ARR holders would have received a total of $1,160.0 million less in congestion offsets from the 2011/2012 through the 2017/2018 planning period. The total overpayment to FTR holders for the 2011/2012 through 2018/2019 planning period would have been $1,427.4 million.

The actual underpayment to load and the overpayment to FTR holders was a result of several rules, all of which mean the transfer of revenues to FTR holders and the shifting of costs to load. Load is not assigned rights to all congestion as a result of using generation to load paths. Load is 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. Surplus revenues from the FTR auction are not assigned to ARR holders, but are used by PJM to clear counter flow FTRs in the Monthly FTR Auctions in order to make it possible to sell more prevailing flow FTRs and to insure revenue adequacy for FTRs before distribution to ARR holders. Under the prior rules, surplus revenues in the day-ahead market were assigned directly to FTR holders along with surplus auction revenues.

A rule change was implemented by PJM that offset the more egregious effects of the allocation of balancing congestion to load. Beginning with the 2018/2019 planning period, surplus revenues in the day-ahead market and surplus auction revenue are assigned to FTR holders only up to revenue adequacy, and then distributed to ARR holders. This is consistent with a recognition that PJM's modeling does not assign the full capacity of the system to ARR holders.[184]

All congestion revenue belongs to ARR holders, and PJM's new surplus congestion allocation rule is consistent with that goal. However, under the rules, ARR holders will only be allocated this surplus after full funding of FTRs is accomplished. The new rules do not fully recognize ARR holders' primary rights to surplus congestion revenue. If this rule had been in effect for the 2018/2019 planning period, ARRs and FTRs would have offset 92.1 percent of total congestion rather than 78.1 percent.

The overallocation of Stage 1A ARRs results in FTR overallocations on the same facilities. While Stage 1A overallocation has been reduced, 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 many of the over allocations are due to outages in the FTR model, or are not actual system limitations. Capacity issues do not persist if the modeled outages are removed, so there is no need to expand the transmission system to support them. 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.

184 163 FERC ¶61,165 (2018).

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. The MMU recommends that the transmission modeling in the FTR auction and persistent FTR path overallocation 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 participation in the Long Term FTR Auction continues to be very low for the second and third year long term product. 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. Recent changes to improve the modeling of the next year's auction model and include an offline ARR allocation model are steps in the right direction, but do not do enough to guarantee ARR holders' rights to the congestion being auctioned in the Long Term FTR Auction.

Another issue with the current market design is that there is no effective way for the market to result in price discovery in the long term and annual auctions because the sellers of congestion rights, ARR holders, cannot set a reserve price or otherwise actually participate in what is called the FTR market. ARR holders cannot claim all of the network that serves their load, cannot choose how much of the system they want to sell and cannot set a reserve price on what is made available in the market. PJM, as the system administrator, chooses what is available to sell, including system capability that cannot be claimed by load, and then offers that market model capability as a price taker in the FTR auction. Due to this design, FTR prices are consistently below the value of congestion. When FTR prices begin to converge towards expected congestion levels in near term monthly auctions it is the result of the active participation as sellers by entities who have purchased FTRs in the long term and annual auctions, who set explicit reserve prices reflecting the expected value of congestion.

The MMU recommends that the Long Term FTR product be eliminated. If the Long Term FTR product is not eliminated, the MMU recommends that Long Term FTR Market be modified so that the supply of prevailing flow FTRs in the Long Term FTR Market is based solely on counter flow offers in the Long Term FTR Market. This would ensure ARR holders' rights to congestion while maintaining the ability for participants to purchase congestion offsets for future planning periods.

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.

New Recommendations

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

In this *2019 Quarterly State of the Market Report for PJM: January through September*, the MMU includes six new recommendations.[7]

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

6 18 CFR § 35.28(g)(3)(ii)(A); see also OATT Attachment M § IV.D.
7 New recommendations include all MMU recommendations that were reported for the first time in the *2019 Quarterly State of the Market Report for PJM: January through September.*

New Recommendations from Section 3, Energy Market

- The MMU recommends that in order to ensure effective market power mitigation, PJM always enforce parameter limited values by committing units only on parameter limited schedules, when the TPS test is failed or during high load conditions such as cold and hot weather alerts or more severe emergencies. (Priority: High. New recommendation. Status: Not adopted.)
- The MMU recommends that PJM model generators' operating transitions and peak operating modes. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that PJM approve one RT SCED case for each five minute interval to send dispatch signals, and that PJM calculate prices for that five minute interval using the same approved SCED case. (Priority: High. New recommendation. Status: Not adopted.)

New Recommendation from Section 10, Ancillary Services

- The MMU recommends that fleet wide cost of service rates used to compensate resources for reactive capability be eliminated and replaced with compensation based on unit specific costs. (Priority: Low. New recommendation.[8] Status: Not adopted.)

New Recommendation from Section 11, Congestion and Marginal Losses

- The MMU recommends that PJM's logic for the calculation of implicit balancing congestion charges revert to the method used prior to April 1, 2018. (Priority: Medium. New recommendation. Not adopted.)

8 The MMU has discussed this recommendation in state of the market reports since 2016 but this is the first time it has been reported as a formal MMU recommendation.

New Recommendation from Section 12, Generation and Transmission Planning

- The MMU recommends that the market efficiency process be eliminated because it is not consistent with a competitive market design. (Priority: Medium. New recommendation. Status: Not adopted.)

Complete List of Current MMU Recommendations

The recommendations are explained in each section of the report.

Section 3, Energy Market

Market Power

- The MMU recommends that the market rules explicitly require that offers in the 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 that all fuel cost policies be algorithmic, verifiable, and systematic, and accurately reflect short run marginal costs. (Priority: Medium. First reported 2016. Status: Not adopted.)
- 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. (Priority: Low. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM change the Fuel Cost Policy requirement to apply only to units that will be offered with non-zero cost-based offers. The PJM market rules should require that the cost-based offers of units without an approved Fuel Cost Policy be set to zero. (Priority: Low. First reported 2018. Status: Not adopted.)

- The MMU recommends that Manual 15 (Cost Development Guidelines) 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: Low. 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: Adopted, 2018.)
- 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. The TPS test application in the Day-Ahead Energy Market is not documented. (Priority: High. First reported 2015. Status: Partially adopted.)
- The MMU recommends that PJM require every market participant to make available at least one cost schedule based on the same hourly fuel type(s) and parameters at least as flexible as their offered price schedule. (Priority: Medium. First reported 2015. 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. (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 in order to ensure effective market power mitigation, PJM always enforce parameter limited values by committing units only on parameter limited schedules, when the TPS test is failed or during high load conditions such as cold and hot weather alerts or more severe emergencies. (Priority: High. New recommendation. 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, 2017.)

- The MMU recommends the elimination of FMU and AU adders. FMU and AU adders no longer serve the purpose for which they were created and interfere with the efficient operation of PJM markets. (Priority: Medium. First reported 2012. Status: Partially adopted, 2014.)
- The MMU recommends that 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.)

Capacity Performance Resources

- 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 the parameters which determine nonperformance charges and the amounts of uplift payments should reflect the flexibility goals of the capacity performance construct. The operational parameters used by generation owners to indicate to PJM operators what a unit is capable of during the operating day should not determine capacity performance assessment or uplift payments. (Priority: Medium. First reported 2015. Status: Partially adopted.)
- The MMU recommends that PJM not include the balancing ratios calculated for localized Performance Assessment Intervals (PAIs) in the capacity market default offer cap, and only include those events that trigger emergencies for at least a defined sub-zonal or zonal level. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM clearly define the business rules that apply to the unit specific parameter adjustment process, including PJM's implementation of the tariff rules in the PJM manuals to ensure market sellers know the requirements for their resources. (Priority: Low. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM update the tariff to clarify that all generation resources are subject to unit specific parameter limits on their cost-based offers using the same standard and process as capacity performance capacity resources. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM institute rules to assess a penalty for resources that choose to submit real-time values that are less flexible than their unit specific parameter limits or approved parameter limit exceptions based on tariff defined reasons. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM not approve temporary exceptions that are based on pipeline tariff terms that are not routinely enforced, and based on inferior transportation service procured by the generator. (Priority: Medium. First reported Q1, 2019. Status: Not adopted.)

Accurate System Modeling

- 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: 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 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

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. See 151 FERC ¶ 61,208 at P 476 (2015).

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 PJM include in the tariff or 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] [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, even if the MW are settled to the generator. 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, even if the injection MW are settled to the load serving entity. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM identify and collect data on available behind the meter generation resources, including nodal location information and relevant operating parameters. (Priority: Low. First reported 2013. Status: Partially adopted.)
- The MMU recommends that PJM document how LMPs are calculated when demand response is marginal. (Priority: Low. First reported 2014. Status: Not Adopted.)
- The MMU recommends that PJM not allow nuclear generators which do not respond to prices or which only respond to manual instructions from the operator to set the LMPs in the real-time market. (Priority: Low. First reported 2016. Status: Not adopted.)
- 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. First reported 2017. 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 There is currently no PJM documentation in the tariff or manuals explaining how hubs are created and how their definitions are changed. 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 model generators' operating transitions and peak operating modes. (Priority: Medium. New recommendation. Status: Not adopted.)

Transparency

- The MMU recommends that PJM market rules require the fuel type be identified for every price and cost schedule on an hourly basis and PJM market rules 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 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 clearly define the criteria for operator approval of RT SCED cases used to send dispatch signals to resources and for pricing, to minimize operator discretion and implement a rule based approach. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM approve one RT SCED case for each five minute interval to send dispatch signals, and that PJM calculate prices for that five minute interval using the same approved SCED case. (Priority: High. New recommendation. Status: Not adopted.)

Section 4, Energy Uplift

- The MMU recommends that uplift be paid only based on operating parameters that reflect the flexibility of the benchmark new entrant unit (CONE unit) in the PJM Capacity Market. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM not use closed loop interface constraints to artificially override nodal prices 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 CT price setting logic to modify transmission line limits 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 implement CT price setting logic, PJM first initiate a stakeholder process to determine whether such modification is appropriate. PJM should file any proposed changes with FERC to ensure review. Any such changes should be incorporated in the PJM tariff. (Priority: Medium. First Reported 2016. Status: Not adopted.)
- The MMU recommends that PJM initiate an analysis of the reasons why a significant number of 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 eliminating intraday segments from the calculation of uplift payments and returning to calculating the need for uplift based on the entire 24 hour operating day. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends the elimination of day-ahead operating reserves 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.)
- The MMU recommends enhancing the current energy uplift allocation rules to reflect the recommended elimination of day-ahead operating reserves, the timing of commitment decisions and the commitment reasons. (Priority: High. First reported 2012. Status: Not adopted.)
- 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 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. (Priority: Low. First reported 2013. Status: Not adopted. Stakeholder process.)
- The MMU recommends three modifications to the energy lost opportunity cost calculations:
- The MMU recommends calculating LOC based on 24 hour daily periods 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 only flexible fast start units (startup plus notification times of 10 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.)
- 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: Adopted 2018.[12])
- The MMU recommends allocating the energy uplift payments to units scheduled as must run in the Day-Ahead Energy Market for reasons other

12 As of November 1, 2018, internal bilateral transactions are no longer used for the calculation of deviations for purposes of allocating balancing operating reserve charges. See the 2018 State of the Market Report for PJM, Volume 2, Section 3: "Energy Market" at "Internal Bilateral Transactions" for an analysis of the impact of this change on virtual bidding activity.

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 balancing operating reserve credit 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, in addition to real-time load. (Priority: Low. First reported 2013. Status: Not adopted.)
- 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). The MMU recommends that PJM allow wind units to request 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 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: Partially adopted.)
- 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.[13])
- The MMU recommends that PJM pay uplift based on the offer at the lower of the actual unit output or the dispatch signal MW. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM develop and implement an accurate metric to define when a unit is following dispatch to determine eligibility to receive balancing operating reserve credits and for assessing generator deviations. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM eliminate the exemption for fast start resources (CTs and diesels) from the requirement to follow dispatch. The performance of these resources should be evaluated in a manner consistent with all other resources (Priority: Medium. First reported 2018. Status: Not adopted.)

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.[14]

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

13 On September 7, 2018, PJM made a compliance filing for FERC Order No. 844 to publish unit specific uplift credits. The compliance filing was accepted by FERC on March 21, 2019. PJM will begin posting unit-specific uplift reports on May 1, 2019.
14 151 FERC ¶ 61,208 (2015).

types, including planned generation, demand resources and imports.[15 16] (Priority: High. First reported 2013. Status: Not adopted.)

- The MMU recommends that DR providers be required to have a signed contract with specific customers for specific facilities for specific levels of DR at least six months prior to any capacity auction in which the DR is offered. (Priority: High. First reported 2016. Status: Not adopted.)

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.[17 18] 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. 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 2017. Status: Not adopted.)
- 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 2017. Status: Not adopted.)
- The MMU recommends that the maximum price on the VRR curve be defined as net CONE. (Priority: Medium. First reported Q1, 2019. Status: Not adopted.)

15 See also Comments of the Independent Market Monitor for PJM, Docket No. ER14-503-000 (December 20, 2013).
16 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2019," <http://www.monitoringanalytics.com/reports/Reports/2019/IMM_Analysis_of_Replacement_Capacity_for_RPM_Commitments_June_1_2007_to_June_1_2019_20190913.pdf> (September 13, 2019).
17 See PJM Interconnection, L.L.C., Docket No. ER12-513-000 (December 1, 2011) ("Triennial Review").
18 See the *2017 State of the Market Report for PJM*, Volume 2, Section 7: Net Revenue.

Offer Caps, Offer Floors, and Must Offer

- The MMU recommends use of the Sustainable Market Rule (SMR) in order to protect competition in the capacity market from nonmarket revenues.[19] (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.[20] (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 2017. Status: Not adopted.)
- The MMU recommends that the offer cap for capacity resources be defined as the net avoidable cost rate (ACR) of each unit so that the clearing prices are a result of such net ACR offers, consistent with the fundamental economic logic for a competitive offer of a CP resource. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends that PJM develop a process for calculating a forward looking estimate for the expected number of Performance Assessment Intervals (H) to use in calculating the Market Seller Offer Cap (MSOC). The MMU recommends that the Nonperformance Charge Rate be left at its current level. The MMU recommends that PJM develop a forward looking estimate for the Balancing Ratio (B) during Performance Assessment Intervals (PAIs) to use in calculating the MSOC. Both H and B parameters should be included in the annual review of planning parameters for the Base Residual Auction, and should incorporate the actual observed reserve margins, and other assumptions consistent with the annual IRM study. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends that capacity market sellers be required to request the use of minimum MW quantities greater than 0 MW (inflexible sell offer segments) and that the requests should only be permitted for defined physical reasons. (Priority: Medium. First reported 2018. 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.)
- The MMU 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 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 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.)

19 Brief of the Independent Market Monitor for PJM, Docket No. EL16-49, ER18-1314-000,-001; EL18-178 (October 2, 2018).

20 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 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 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: Not 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. First reported 2017. 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 September 30, 2019.

- 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. First reported 2013. Status: Not adopted.)
- The MMU recommends that the demand resources be treated as economic resources, 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 Interval. (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, if demand resources remain in the capacity market, a daily energy market must offer requirement apply to demand

resources, comparable to the rule applicable to generation capacity resources.[21] (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 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 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 operators have the necessary information for reliability and that market payments to demand resources be calculated based on interval meter data at the site of the demand reductions.[22] (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends limited, extended summer and annual demand response event compliance be calculated on an hourly basis for noncapacity performance resources and on a five minute basis for all capacity performance resources and that the penalty structure reflect five minute compliance. (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 there be only one demand response product in the capacity market, with an obligation to respond when called for any hour of the delivery year. (Priority: High. First reported 2011. Status: Partially adopted.[23])

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

22 See ISO-NE Tariff, Section III, Market Rule 1, Appendix E1 and Appendix E2, "Demand Response," <http://www.iso-ne.com/regulatory/tariff/sect_3/mr1_append-e.pdf>. (Accessed 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.

23 PJM's Capacity Performance design requires resources to respond when called for any hour of the delivery year.

- 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. First reported 2017. Status: Partially adopted.)
- The MMU recommends that PRD be required to respond during a PAI to be consistent with all CP resources. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends that the limits imposed on the pre-emergency and emergency demand response share of the Synchronized Reserve Market be eliminated. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that 30 minute pre-emergency and emergency demand response be considered to be 30 minute reserves. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that energy efficiency MW not be included in the PJM capacity market and that PJM should ensure that the impact of EE measures on the load forecast is incorporated immediately rather than with the existing lag. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that demand reductions based entirely on behind the meter generation be capped at the lower of economic maximum or actual generation output. (Priority: High. First reported Q2, 2019. Status: Not adopted.)

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.)
- The MMU recommends that the Commission reconsider its disclaimer of jurisdiction over RECs markets because, given market changes since that decision, it is clear that RECs materially affect jurisdictional rates. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that states consider the development of a multistate framework for RECs markets, for potential agreement on carbon pricing including the distribution of carbon revenues, and for coordination with PJM wholesale markets. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that jurisdictions with a renewable portfolio standard make the price and quantity data on supply and demand more transparent. (Priority: Low. First reported 2018. Status: Not adopted.)
- The MMU recommends that load and generation located at separate nodes be treated as separate resources. (Priority: High. First reported Q2, 2019. Status: Not adopted.)

Section 9, Interchange Transactions

- The MMU recommends that PJM implement rules to prevent sham scheduling. The MMU recommends that PJM apply after the fact market settlement adjustments to identified sham scheduling segments to ensure 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 PJM Settlement 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: Low. 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 the Commission require that the open FFE/FFL freeze date issues be addressed at a Commission technical conference, and that the Commission set a deadline to resolve the significant issues

that result from the freeze date. (Priority: Medium. First reported Q2, 2019. Status: Not adopted.)

Section 10, Ancillary Services

- 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 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. FERC rejected, pending rehearing request before FERC.[24])
- 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.[25] FERC rejected, pending rehearing request before FERC.[26])
- The MMU recommends that the lost opportunity cost 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: Not adopted. FERC rejected, pending rehearing request before FERC.[27])
- 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. FERC rejected, pending rehearing request before FERC.[28])
- The MMU recommends enhanced documentation of the implementation of the Regulation Market design. (Priority: Medium. First reported 2010. Status: Not adopted. FERC rejected, pending rehearing request before FERC.[29])
- 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: Adopted, 2018.)
- 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 that the $7.50 margin be eliminated from the definition of the cost of tier 2 synchronized reserve because it is a markup and not a cost. (Priority: Medium. First reported 2018. Status: Not adopted.)
- 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 on a daily and hourly basis. 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

24 FERC Docket No. ER18-87.
25 This recommendation was adopted by PJM for the Energy Market. Lost opportunity costs in the Energy Market are calculated using the schedule on which the unit was scheduled to run. In the Regulation Market, this recommendation has not been adopted, as the LOC continues to be calculated based on the lower of price or cost in the energy market offer.
26 FERC Docket No. ER18-87.
27 Id.
28 Id.
29 Id.

and identify the rule based reasons for each instance of biasing. (Priority: Medium. First reported 2012. Status: Not adopted.)

- The MMU recommends that, for calculating the penalty for a tier 2 resource failing to meet its scheduled obligation during a spinning event, the definition of the IPI be changed from the average number of days between events to the actual number of days since the last event greater than 10 minutes. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that aggregation not be permitted to offset unit specific penalties for failure to respond to a synchronized reserve event. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM eliminate the use of Degree of Generator Performance (DGP) in the synchronized reserve market solution and improve the actual tier 1 estimate. If PJM continues to use DGP, DGP should be documented in PJM's manuals. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that a reason code be attached to every hour in which PJM market operations adds additional DASR MW. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that 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 offers in the DASR Market be based on opportunity cost only in order to eliminate market power. (Priority: Low. First reported 2009. Modified, 2018. Status: Not adopted.)
- The MMU recommends that separate cost of service 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 payments for reactive capability, if continued, be based on the 0.90 power factor that PJM has determined is necessary. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that all resources, new and existing, have a requirement to include and maintain equipment for primary frequency response capability as a condition of interconnection service and that compensation is provided through the capacity and energy markets. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends for oil tanks shared with other resources that 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 2017. Status: Not adopted.)
- The MMU recommends that the same capability be required of both new and existing resources. The MMU agrees with Order No. 842 that RTOs not be required to provide additional compensation specifically for frequency response. The current PJM market design provides compensation for all capacity costs, including these, in the capacity market. The current market design provides compensation, through heat rate adjusted energy offers, for any costs associated with providing frequency response. Because the PJM market design already compensates resources for frequency response capability and any costs associated with providing frequency response, any separate filings submitted on behalf of resources for compensation under section 205 of the Federal Power Act should be rejected as double recovery. (Priority: Low. First reported 2017. Status: Not adopted.)
- The MMU recommends that fleet wide cost of service rates used to compensate resources for reactive capability be eliminated and replaced with compensation based on unit specific costs. (Priority: Low. New recommendation.[30] Status: Not adopted.)

Section 11, Congestion and Marginal Losses

- The MMU recommends that PJM's logic for the calculation of implicit balancing congestion charges revert to the method used prior to April 1, 2018. (Priority: Medium. New recommendation. Not adopted.)

30 The MMU has discussed this recommendation in state of the market reports since 2016 but this is the first time it has been reported as a formal MMU recommendation.

Section 12, Planning

Generation Retirements

- The MMU recommends that the question of whether Capacity Injection Rights (CIRs) should persist after the retirement of a unit, or the conversion from Capacity Performance (CP) to energy only status, be addressed. The rules need to ensure that incumbents cannot exploit control of CIRs to block or postpone entry of competitors.[31] (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that rules be implemented to ensure that CIRs are terminated within one year if units cannot qualify to be capacity resources and, if requested, after one CP must offer exception to permit the issue of CP status to be addressed. (Priority: Low. First reported 2018. Status: Not adopted.)

Generation Queue

- 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 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 continuing 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 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.)

Market Efficiency Process

- The MMU recommends that the market efficiency process be eliminated because it is not consistent with a competitive market design. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that, if the market efficiency process is retained, PJM modify the rules governing benefit/cost analysis, the evaluation process for selecting among competing market efficiency projects and cost allocation for economic projects in order to ensure that all costs, including increased congestion costs and the risk of project cost increases, in all zones are included and in order to ensure that the correct metrics are used for defining benefits. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that, if the market efficiency process is retained, PJM modify the rules governing the market efficiency process benefit/cost analysis so that competing projects with different in service dates are evaluated on a symmetric, comparable basis. (Priority: Medium. First reported 2018. Status: Not adopted.)

Transmission Competition

- The MMU recommends, to increase the role of competition, that the exemption of supplemental projects from the Order No. 1000 competitive process be terminated and that the basis for all such exemptions be reviewed and modified to ensure that the supplemental project designation

31 See "Comments of the Independent Market Monitor for PJM," Docket No. ER12-1177-000 (March 12, 2012) <http://www.monitoringanalytics.com/Filings/2012/IMM_Comments_ER12-1177-000_20120312.PDF>.

is not used to exempt transmission projects from a transparent, robust and clearly defined mechanism to permit competition to build such projects or to effectively replace the RTEP process. (Priority: Medium. First reported 2017. Status: Not adopted.)

- The MMU recommends, to increase the role of competition, that the exemption of end of life projects from the Order No. 1000 competitive process be terminated and that end of life transmission projects should be included in the RTEP process and should be subject to a transparent, robust and clearly defined mechanism to permit competition to build such projects. (Priority: Medium. First reported Q1, 2019. Status: Not adopted.)
- The MMU recommends that PJM enhance the transparency and queue management process for nonincumbent 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 nonincumbent transmission providers. (Priority: Medium. First reported 2015. Status: Not adopted.)
- 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 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 nonincumbent transmission providers in the RTEP. (Priority: Medium. First reported 2014. 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: Medium. First reported 2015. Status: Not adopted.)

Cost Allocation

- 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.[32] (Priority: Medium. First reported 2015. Status: Not adopted.)

Transmission Facility Outages

- 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.)

32 See the 2015 State of the Market Report for PJM, Volume 2, Section 12: Generation and Transmission Planning, at p. 463, Cost Allocation Issues.

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 the Long Term FTR product be eliminated. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that, if the Long Term FTR product is not eliminated, the Long Term FTR Market be modified so that the supply of prevailing flow FTRs in the Long Term FTR Market is based solely on counter flow offers in the Long Term FTR Market. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends that, under the current FTR design, the full capability of the transmission system be allocated as ARRs prior to sale as FTRs. Reductions for outages and increased system capability should be reserved for ARRs rather than sold in the Long Term FTR Auction. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends that all FTR auction revenue be distributed to ARR holders monthly, regardless of FTR funding levels. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that, under the current FTR design, all congestion revenue in excess of FTR target allocations be distributed to ARR holders on a monthly basis. (Priority: High. First reported 2018. 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.[33] (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: Partially 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. Rejected by FERC.)
- The MMU recommends that PJM eliminate subsidies to counter flow FTRs by applying the payout ratio to counter flow FTRs in the same way the payout ratio is applied to prevailing flow FTRs. (Priority: High. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM eliminate geographic cross subsidies. (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM 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 and its members continue to review the management of a defaulted member's FTR portfolio, including options other than immediate liquidation. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM continue to evaluate the bilateral indemnification rules and any asymmetries they may create. (Priority: Low. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM examine the source and sink node combinations available in the FTR market and eliminate generation to generation paths and all other paths that do not represent the delivery of power to load. (Priority: High. First reported 2018. Status: Not adopted.)

33 See "PJM Manual 6: Financial Transmission Rights," Rev. 23 (Sep. 1, 2019).

- The MMU recommends that the forfeiture amount from the FTR forfeiture rule be based on the correct hourly cost of an FTR, rather than a simple daily price divided by 24. (Priority: High. First reported 2018. Status: Pending at FERC.)
- The MMU recommends that the direct customer request approach for creating and allocating IARRs be eliminated from PJM's tariff. (Priority: Low. First reported 2018. Status: Not adopted.)

Energy Market

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

The Market Monitoring Unit (MMU) analyzed measures of market structure, participant conduct and market performance, including market size, concentration, pivotal suppliers, offer behavior, and price.[1] The MMU concludes that the PJM energy market results were competitive in the first nine months of 2019.

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 the PJM energy market in the first nine months of 2019 was unconcentrated by FERC HHI standards in 98.2 percent of market hours and moderately concentrated in 1.8 percent of market hours. Average HHI was 773 with a minimum of 572 and a maximum of 1098 in the first nine months of 2019. The PJM energy market intermediate and peaking segments of supply were highly concentrated. 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 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 definition of cost-based offers and 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 they fail the TPS test.
- 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 represents economic withholding and the markups of those participants affected LMP.
- 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,

1 Analysis of 2019 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). In December 2018, PJM integrated the Ohio Valley Electric Corporation (OVEC). 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 2018 State of the Market Report for PJM, Appendix A, "PJM Geography."

their marginal costs in both Day-Ahead and Real-Time Energy Markets, although high markups for some marginal units 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. Market design implementation issues, including inaccuracies in modeling of the transmission system and of generator capabilities as well as inefficiencies in real-time dispatch and price formation, undermine market efficiency in the energy market.

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 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.

2 OATT Attachment M (PJM Market Monitoring Plan).

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

Overview

Supply and Demand

Market Structure

- **Supply.** Supply includes physical generation, imports and virtual transactions. The maximum average on-peak hourly offered real-time supply was 152,460 MW for summer of 2018 and 152,933 MW for summer of 2019. In the first nine months of 2019, 1,749.6 MW of new resources were added and 4,173.5 MW were retired.

  PJM average real-time cleared generation in the first nine months of 2019 decreased 29 MWh from the first nine months of 2018, from 95,561 MWh to 95,531 MWh.

  PJM average day-ahead cleared supply in the first nine months of 2019, including INCs and up to congestion transactions, increased by 2.5 percent from the first nine months of 2018, from 116,068 MWh to 118,913 MWh.

- **Demand.** Demand includes physical load and exports and virtual transactions. The PJM accounting peak load in the first nine months of 2019 was 148,228 MWh in the HE 1800 on July 19, 2019, which was 1,185 MWh, 0.8 percent, higher than the PJM peak load for the first nine months of 2018, which was 147,042 MWh in the HE 1700 on August 28, 2018.

PJM average real-time demand in the first nine months of 2019 decreased by 2.3 percent from the first nine months of 2018, from 91,905 MWh to 89,834 MWh. PJM average day-ahead demand in the first nine months of 2019, including DECs and up to congestion transactions, increased by 2.3 percent from the first nine months of 2018, from 111,589 MWh to 114,133 MWh.

Market Behavior

- **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 by MW in the first nine months of 2019, 26.3 percent were offered as available for economic dispatch, 30.4 percent were offered at their economic minimum, 4.2 percent were offered as emergency dispatch, 14.9 percent were offered as self scheduled, and 24.2 percent were offered as self scheduled and dispatchable.
- **Virtual Offers and Bids.** Any market participant in the PJM Day-Ahead Energy Market can use increment offers, decrement bids, up to congestion transactions, import transactions and export transactions as financial instruments that do not require physical generation or load. In the first nine months of 2019, the average hourly increment offers submitted and cleared MW increased by 11.5 percent and 11.6 percent, from 5,725 MW and 2,568 MW in the first nine months of 2018 to 6,382 MW and 2,866 MW in the first nine months of 2019. The hourly average submitted and cleared decrement MW increased by 6.4 percent and 39.7 percent, from 6,854 MW and 2,841 MW in the first nine months of 2018 to 7,293 MW and 3,970 MW in the first nine months of 2019. The average hourly up to congestion submitted and cleared MW increased by 5.8 percent and 15.9 percent, from 60,031 MW and 17,638 MW in the first nine months of 2018 to 63,503 MW and 20,433 MW in the first nine months of 2019.

Market Performance

- **Generation Fuel Mix.** In the first nine months of 2019, coal units provided 24.5 percent, nuclear units 33.2 percent and natural gas units 36.0 percent of total generation. Compared to the first nine months of 2018, generation from coal units decreased 16.4 percent, generation from natural gas units increased 17.2 percent and generation from nuclear units decreased 1.9 percent.
- **Fuel Diversity.** In the first nine months of 2019, the fuel diversity of energy generation, measured by the fuel diversity index for energy (FDI_e), decreased 0.9 percent over the FDI_e for the first nine months of 2018.
- **Marginal Resources.** In the PJM Real-Time Energy Market, in the first nine months of 2019, coal units were 27.2 percent and natural gas units were 69.7 percent of marginal resources. In the first nine months of 2018, coal units were 29.7 percent and natural gas units were 62.1 percent of marginal resources.

  In the PJM Day-Ahead Energy Market, in the first nine months of 2019, up to congestion transactions were 57.7 percent, INCs were 12.9 percent, DECs were 18.4 percent, and generation resources were 10.9 percent of marginal resources. In the first nine months of 2018, up to congestion transactions were 63.9 percent, INCs were 9.2 percent, DECs were 16.1 percent, and generation resources were 10.7 percent of marginal resources.
- **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 decreased in the first nine months of 2019 compared to the first nine months of 2018. The load-weighted, average real-time LMP was 30.0 percent lower in the first nine months of 2019 than in the first nine months of 2018, $27.60 per MWh versus $39.43 per MWh.

PJM day-ahead energy market prices decreased in the first nine months of 2019 compared to the first nine months of 2018. The load-weighted, average day-ahead LMP was 28.4 percent lower in the first nine months of 2019 than in the first nine months of 2018, $27.70 per MWh versus $38.71 per MWh.

- **Components of LMP.** In the PJM Real-Time Energy Market, in the first nine months of 2019, 26.8 percent of the load-weighted LMP was the result of coal costs, 42.7 percent was the result of gas costs and 0.9 percent was the result of the cost of emission allowances.

  In the PJM Day-Ahead Energy Market, in the first nine months of 2019, 22.2 percent of the load-weighted LMP was the result of coal costs, 19.8 percent was the result of gas costs, 21.3 percent was the result of INC offers, 21.2 percent was the result of DEC bids, and 2.2 percent was the result of up to congestion transaction offers.

- **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 $0.48 per MWh in the first nine months of 2018 and -$0.11 per MWh in the first nine months of 2019. The difference between average day-ahead and real-time prices, by itself, is not a measure of the competitiveness or effectiveness of the Day-Ahead Energy Market.

Scarcity

- There were 27 intervals with five minute shortage pricing on 14 days in the first nine months of 2019. In all 27 intervals, synchronized reserves were short of the extended synchronized reserve requirement in the RTO and MAD reserve zones. In one of the 27 intervals, primary reserves were also short of the extended primary reserve requirement.
- There were 2,307 five minute intervals, or 2.9 percent of all five minute intervals in the first nine months of 2019 for which at least one solved SCED case showed a shortage of reserves, and 1,045 five minute intervals, or 1.3 percent of all five minute intervals in the first nine months of 2019 for which more than one solved SCED case showed a shortage of reserves. PJM operators used only 28 RT SCED cases that showed a shortage of reserves to calculate real-time LMPs and ancillary service prices.
- In the first nine months of 2019, PJM did not declare any emergency actions that triggered Performance Assessment Intervals (PAI).

Competitive Assessment

Market Structure

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

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 increased from 0.1 percent in the first nine months of 2018 to 1.1 percent in the first nine months of 2019. In the Real-Time Energy Market, for units committed to provide energy for local constraint relief, offer-capped unit hours increased from 1.0 percent in the first nine months of 2018 to 1.6 percent in the first nine months of 2019. While overall offer capping levels have been low, there are a significant number of units with persistent structural local market power that would have a significant impact on prices in the absence of local market power mitigation.

In the first nine months of 2019, 11 control zones experienced congestion resulting from one or more constraints binding for 75 or more hours. The analysis of the application of the TPS test to local markets demonstrates that it is working 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, including for reactive support. In the Day-Ahead Energy Market, for units committed for reliability reasons, offer-capped unit hours decreased from 0.1 percent in the first nine months of 2018 to 0.0 percent in the first nine months of 2019. In the Real-Time Energy Market, for units committed for reliability reasons, offer-capped unit hours decreased from 0.1 percent in the first nine months of 2018 to 0.0 percent in the first nine months of 2019.

- **Markup Index.** The markup index is a summary measure of participant offer behavior for individual marginal units. In the first nine months of 2019, in the PJM Real-Time Energy Market, 97.6 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 positive ($0.18 per MWh) when using unadjusted cost-based offers. The average dollar markup of units with offer prices between $25 and $50 was positive ($1.77 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, 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 the first nine months of 2019 was more than $400 per MWh while the highest markup in the first nine months of 2018 was more than $500 per MWh. During the period of cold weather and high demand in January 2018, several units in the PJM market were offered with high markups.

  In the first nine months of 2019, in the PJM Day-Ahead Energy Market, 98.4 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 ($0.48 per MWh) when using unadjusted cost-based offers. The average dollar markup of units with offer prices between $25 and $50 was positive ($1.38 per MWh) when using unadjusted cost-based offers. Using the unadjusted cost-based offers, the highest markup for any marginal unit in the first nine months of 2019 was about $90 per MWh, while the highest markup in the first nine months of 2018 was $200 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. Markup for gas fired units decreased in the first nine months of 2019.

- **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 units eligible for an FMU or AU adder for the period between December 2014 and August 2019. One unit qualified for an FMU adder for the month of September 2019.

Market Performance

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

  In the PJM Real-Time Energy Market in the first nine months of 2019, the unadjusted markup component of LMP was $1.95 per MWh or 7.1 percent of the PJM load-weighted, average LMP. June had the highest unadjusted peak markup component, $4.91 per MWh, or 14.1 percent of the real-time, peak hour load-weighted, average LMP. There were 39 hours in the first nine months of 2019 where the positive markup contribution to the PJM system wide, load-weighted, average LMP exceeded $34.39 per MWh.

  In the PJM Day-Ahead Energy Market, INCs, DECs and UTCs have zero markups. In the first nine months of 2019, the unadjusted markup component of LMP resulting from generation resources was $0.67 per MWh or 2.4 percent of the PJM day-ahead load-weighted average LMP. July had the highest unadjusted peak markup component, $4.14 per MWh.

  Participant behavior was evaluated as competitive because the analysis of markup shows that marginal units generally make offers at, or close to, their marginal costs in both the Day-Ahead and Real-Time Energy Markets, although the behavior of some participants represents economic withholding.

Recommendations

Market Power

- The MMU recommends that the market rules explicitly require that offers in the 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 that all fuel cost policies be algorithmic, verifiable, and systematic, and accurately reflect short run marginal costs. (Priority: Medium. First reported 2016. Status: Not adopted.)
- 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. (Priority: Low. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM change the Fuel Cost Policy requirement to apply only to units that will be offered with non-zero cost-based offers. The PJM market rules should require that the cost-based offers of units without an approved Fuel Cost Policy be set to zero. (Priority: Low. First reported 2018. Status: Not adopted.)
- The MMU recommends that Manual 15 (Cost Development Guidelines) 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: Low. 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: Adopted, 2018.)
- 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. The TPS test application in the Day-Ahead Energy Market is not documented. (Priority: High. First reported 2015. Status: Partially adopted.)
- The MMU recommends that PJM require every market participant to make available at least one cost schedule based on the same hourly fuel type(s) and parameters at least as flexible as their offered price schedule. (Priority: Medium. First reported 2015. 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. (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 in order to ensure effective market power mitigation, PJM always enforce parameter limited values by committing units only on parameter limited schedules, when the TPS test is failed or during high load conditions such as cold and hot weather alerts or more severe emergencies. (Priority: High. New recommendation. 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, 2017.)
- The MMU recommends the elimination of FMU and AU adders. FMU and AU adders no longer serve the purpose for which they were created and interfere with the efficient operation of PJM markets. (Priority: Medium. First reported 2012. Status: Partially adopted, 2014.)
- The MMU recommends that 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.)

Capacity Performance Resources

- 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.)

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. See 151 FERC ¶ 61,208 at P 476 (2015).

- The MMU recommends that the parameters which determine nonperformance charges and the amounts of uplift payments should reflect the flexibility goals of the capacity performance construct. The operational parameters used by generation owners to indicate to PJM operators what a unit is capable of during the operating day should not determine capacity performance assessment or uplift payments. (Priority: Medium. First reported 2015. Status: Partially adopted.)
- The MMU recommends that PJM not include the balancing ratios calculated for localized Performance Assessment Intervals (PAIs) in the capacity market default offer cap, and only include those events that trigger emergencies for at least a defined sub-zonal or zonal level. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM clearly define the business rules that apply to the unit specific parameter adjustment process, including PJM's implementation of the tariff rules in the PJM manuals to ensure market sellers know the requirements for their resources. (Priority: Low. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM update the tariff to clarify that all generation resources are subject to unit specific parameter limits on their cost-based offers using the same standard and process as capacity performance capacity resources. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM institute rules to assess a penalty for resources that choose to submit real-time values that are less flexible than their unit specific parameter limits or approved parameter limit exceptions based on tariff defined reasons. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM not approve temporary exceptions that are based on pipeline tariff terms that are not routinely enforced, and based on inferior transportation service procured by the generator. (Priority: Medium. First reported Q1, 2019. Status: Not adopted.)

Accurate System Modeling

- 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: 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 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 PJM include in the tariff or 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] [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, even if the MW are settled to the generator. 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, even if the injection MW are settled to the load serving entity. (Priority: Low. First reported 2013. Status: Not adopted.)

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 There is currently no PJM documentation in the tariff or manuals explaining how hubs are created and how their definitions are changed. 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 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 document how LMPs are calculated when demand response is marginal. (Priority: Low. First reported 2014. Status: Not Adopted.)
- The MMU recommends that PJM not allow nuclear generators which do not respond to prices or which only respond to manual instructions from the operator to set the LMPs in the real-time market. (Priority: Low. First reported 2016. Status: Not adopted.)
- 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. First reported 2017. Status: Not adopted.)
- The MMU recommends that PJM model generators' operating transitions and peak operating modes. (Priority: Medium. New recommendation. Status: Not adopted.)

Transparency

- The MMU recommends that PJM market rules require the fuel type be identified for every price and cost schedule on an hourly basis and PJM market rules 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 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 clearly define the criteria for operator approval of RT SCED cases used to send dispatch signals to resources and for pricing, to minimize operator discretion and implement a rule based approach. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM approve one RT SCED case for each five minute interval to send dispatch signals, and that PJM calculate prices for that five minute interval using the same approved SCED case. (Priority: High. New recommendation. Status: Not adopted.)

Conclusion

The MMU analyzed key elements of PJM energy market structure, participant conduct and market performance in the first nine months of 2019, including aggregate supply and demand, concentration ratios, aggregate pivotal supplier results, local three pivotal supplier test results, offer capping, participation in demand response programs, virtual bids and offers, loads and prices.

PJM average real-time cleared generation decreased by 29 MWh, and peak load increased by 1,185 MWh, 0.8 percent, in the first nine months of 2019 compared to the first nine months of 2018. 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 both routinely and 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, under the PJM Market Rules, is not currently correct. The definition, that energy costs must be related to electric production, is not clear or correct. All costs and investments for power generation are related to electric production. Under this definition, some unit owners include costs that are not short run marginal costs in offers, especially 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 the first nine months of 2019 generally reflected supply-demand fundamentals, although the behavior of some participants both routinely and during high demand periods represents 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 economically withhold or physically withhold.

Prices in PJM are not too low. Prices in PJM are the result of input prices, consistent with a competitive market. Low natural gas prices have been a primary cause of low PJM energy market prices. 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 reserve 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, because PJM is not implementing scarcity pricing when there is scarcity. 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. Implementing scarcity pricing when there is scarcity is a basic first step. Targeted increases to the demand for reserves when the market is tight would address price formation in the energy market.

When the real-time security constrained economic dispatch (RT SCED) solution indicates a shortage of reserves, it should be used in calculating real-time prices and those prices should be applied to the market interval for which RT SCED calculated the shortage. There are significant issues with operator discretion and reluctance to approve RT SCED cases indicating shortage of reserves, and in using these cases to calculate prices. While it is appropriate for operators to ensure that cases that use erroneous inputs are not approved and not allowed to set prices, it is essential that operator discretion not extend beyond what is necessary and that operator discretion not prevent shortage pricing when there are shortage conditions. There are also issues with the alignment of SCED cases used for resource dispatch and the SCED cases used to calculate real-time prices. PJM should fix its current operating practices and ensure transparency regarding approval of SCED cases for resource dispatch and pricing so that market participants can have confidence in the market design to produce accurate and efficient price signals. These issues are even more critical now that PJM settles real-time energy transactions on a five minute basis.

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

The PJM defined inputs to the dispatch tools, particularly the real-time SCED, have substantial effects on energy market outcomes. Transmission line ratings, transmission penalty factors, load forecast bias, hydro resource schedules, and unit ramp rate adjustments change the dispatch of the system, affect prices, and can create price spikes through transmission line limit violations or restrictions on the resources available to resolve constraints. The automated adjustment of ramp rates by PJM, called Degree of Generator Performance (DGP), modifies the values offered by generators and limits the MW available to the RT SCED. PJM should evaluate its interventions in the market, consider whether the interventions are appropriate, and provide greater transparency to enhance market efficiency.

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 will be created by PJM's fast start pricing proposal as approved by FERC and would be created in a much more extensive form by PJM's convex hull pricing proposal and reserve pricing proposal.

Units that start in one hour are not fast start units, and their commitment costs are not marginal in a five minute market. The differences between the actual LMP and the fast start LMP will distort the incentive for market participants to behave competitively and to follow PJM's dispatch instructions. PJM will pay new forms of uplift in an attempt to counter the distorted incentives. The magnitude of the new payments and their effects on behavior are not well understood.

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 the 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, as in PJM's ORDC proposal, 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, that scarcity pricing only occurs when scarcity exists, 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. Administrative scarcity pricing that establishes scarcity pricing in about 85 percent of hours, as PJM's ORDC proposal would, is not scarcity pricing but simply a revenue enhancement mechanism. When combined with PJM's failure to address the energy and ancillary services offset in the capacity market, PJM's ORDC filing is not consistent with efficient market design and is even more clearly just a revenue enhancement mechanism.

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 energy pricing net revenue true up mechanism in the capacity market should be addressed if energy revenues are expected to increase as a result of scarcity events, as a result of increased demand for reserves, or as a result of PJM's inappropriate proposals related to fast start pricing and the inclusion of maintenance expenses as short run marginal costs. The true up mechanism must address both cleared auctions and subsequent auctions. 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 the first nine months of 2019 or prior years. In the first nine months of 2019, marginal units were predominantly combined cycle gas generators with low fuel costs. The frequency of combined cycle gas as the marginal unit type has risen rapidly in the last three years, from 29.3 percent in the first nine months of 2016 to 62.2 percent in the first nine months of 2019. Overdue improvements in generator modeling in the energy market would allow PJM to more efficiently commit and dispatch combined cycle plants and to fully reflect the flexibility of these units. New combined cycle units placed competitive pressure on less efficient generators, and the market reliably served load with less congestion, less uplift, and less markup in marginal offers than in the first nine months of 2018. This is evidence of generally competitive behavior and competitive market outcomes, although the behavior of some participants represents economic withholding. Given the structure of the energy market which can permit the exercise of aggregate market power, 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 cost-based offers and a reason for implementing an aggregate market power test. The MMU concludes that the PJM energy market results were competitive in the first nine months of 2019.

Supply and Demand

Market Structure

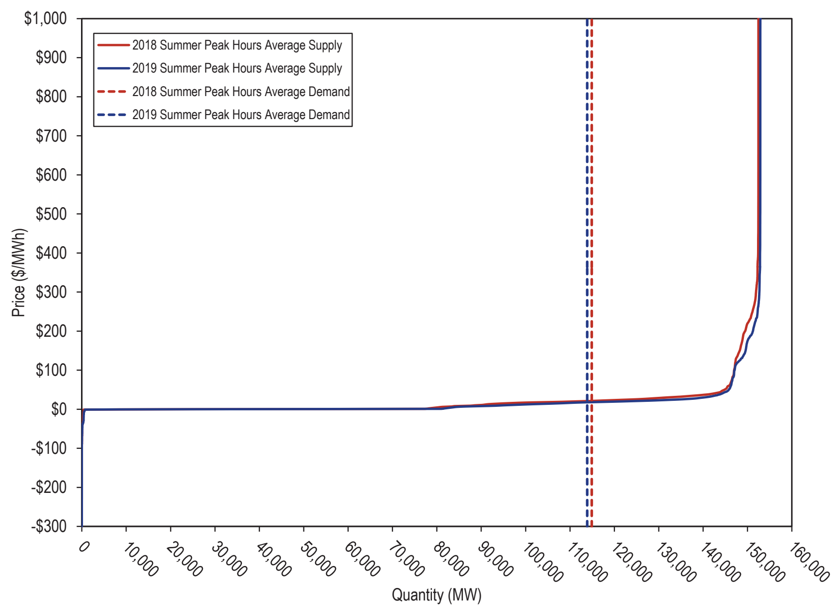
Supply

Supply includes physical generation, imports and virtual transactions.

In the first nine months of 2019, 1,749.6 MW of new resources were added and 4,173.5 MW were retired.

Figure 3-1 shows the average hourly real-time supply and demand for the on peak hours of summer of 2018 and 2019. [8] [9] [10] This figure reflects actual available MW from units that are online or offline and available to generate power in one hour, restricted by ramping capabilities.

Figure 3-1 Average hourly summer real-time supply curve comparison



8 Real-time generation offers and real-time import MWh are included.
9 Real-time load and export MWh are included.
10 The summer supply curve period is from June 1, to August 31.

Average hourly real-time supply curves are weather sensitive. Figure 3-2 shows the typical dispatch range curve.

Figure 3-2 Typical dispatch range of average hourly summer real-time supply curves

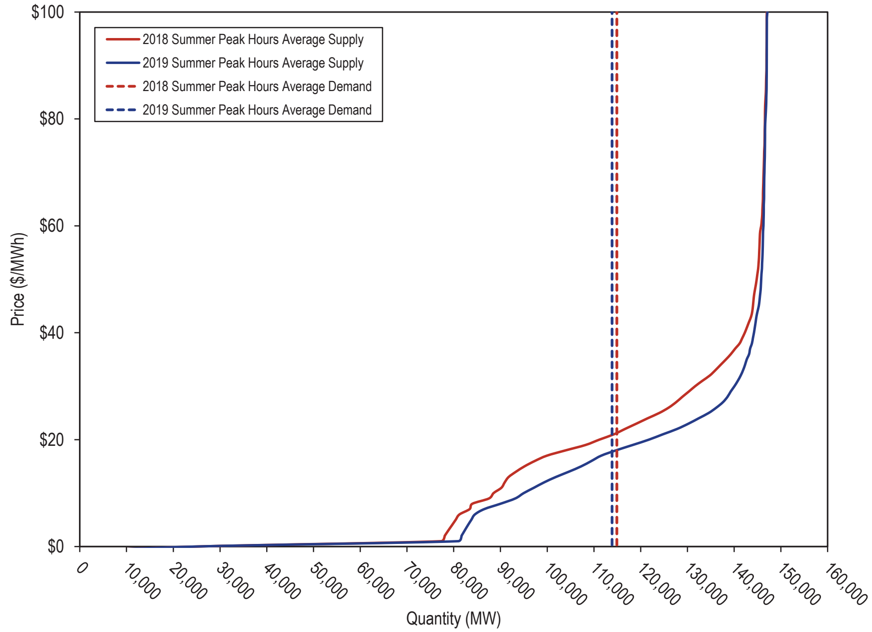


Table 3-2 shows the price elasticity of supply for the on peak summer hours of 2018 and 2019 by load level. The price elasticity of supply measures the responsiveness of the quantity supplied (MWh) to a change in price:

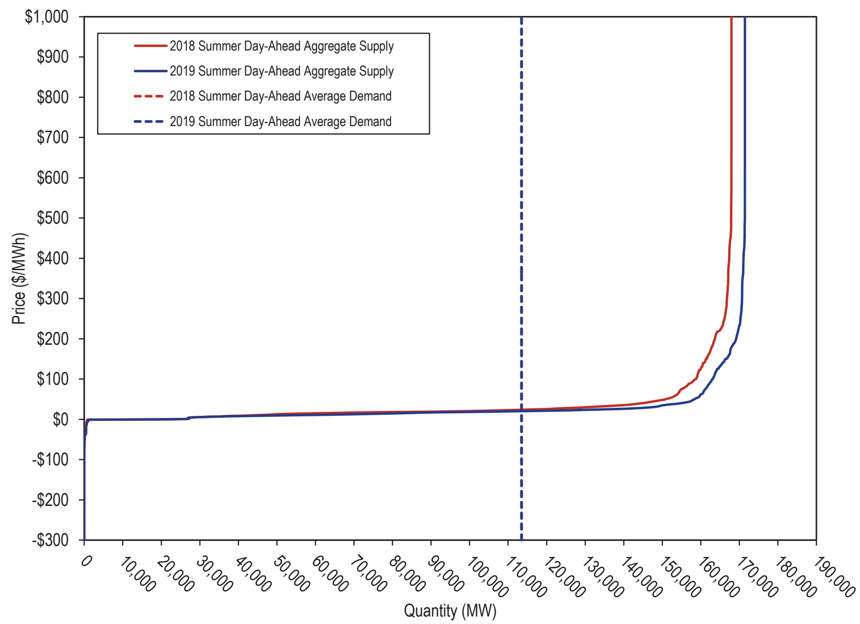
Elasticity of Supply = Percent change in quantity supplied / Percent change in price.

Table 3-2 Price Elasticity of Supply

	Elasticity of Supply	
GWh	2018 Summer	2019 Summer
75-95	0.018	0.020
95-115	0.538	0.302
115-135	0.326	0.414
135-Max	0.004	0.003

Figure 3-3 is the PJM day-ahead generation aggregate supply curve, which includes all day-ahead hourly supply for the peak summer hours of 2018 and 2019.[11]

Figure 3-3 PJM day-ahead generation aggregate supply curve: 2018 summer and 2019 summer



11 Day-ahead generation offers, INC bid MWh, Day-ahead import MWh are included. UTCs are not included due to lack of pricing point.

Real-Time Supply

The maximum of average on-peak hourly offered real-time supply was 152,460 MWh for the summer of 2018, and 152,933 MWh for the summer of 2019. Real-time supply at a defined time is restricted by unit ramp limits and start times. Therefore, the available supply at a defined time is less than the total capacity of the PJM system.

PJM average real-time cleared generation in the first nine months of 2019 decreased from the first nine months of 2018, from 95,561 MWh to 95,531 MWh.[12]

PJM average real-time cleared supply including imports in the first nine months of 2019 decreased by 1.0 percent from the first nine months of 2018, from 97,588 MWh to 96,659 MWh.

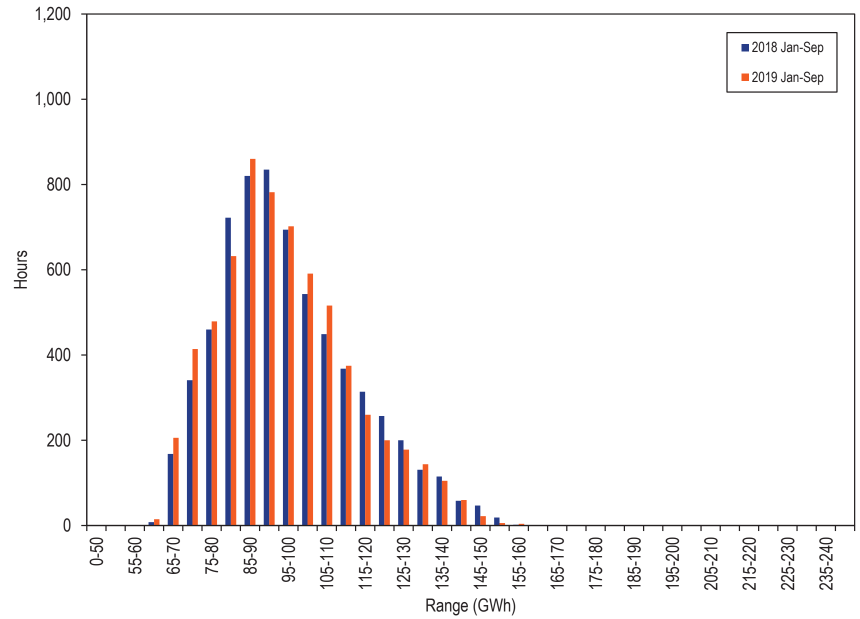
In the PJM Real-Time Energy Market, there are three types of supply offers:

- **Self Scheduled Generation Offer.** Offer to supply a fixed block of MW, 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 MW 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 Frequency

Figure 3-4 shows the hourly distribution of PJM real-time generation plus imports for the first nine months of 2018 and 2019.

Figure 3-4 Distribution of real-time generation plus imports: January through September, 2018 and 2019[13]



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

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

PJM Real-Time, Average Supply

Table 3-3 presents real-time hourly supply summary statistics for the first nine months of each year in the 19 year period from 2001 through 2019.

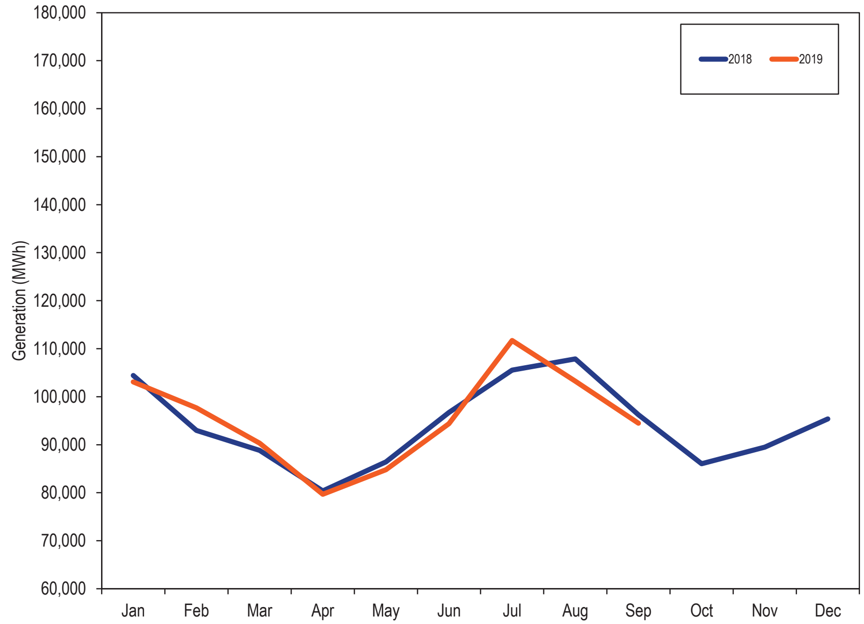
Table 3-3 Average hourly real-time generation and real-time generation plus imports: January through September, 2001 through 2019

	PJM Real-Time Supply (MWh)				Year-to-Year Change			
	Generation		Generation Plus Imports		Generation		Generation Plus Imports	
Jan-Sep	Generation	Standard Deviation	Supply	Standard Deviation	Generation	Standard Deviation	Supply	Standard Deviation
2001	30,304	5,216	33,299	5,571	NA	NA	NA	NA
2002	34,467	8,217	38,207	8,540	13.7%	57.5%	14.7%	53.3%
2003	37,211	6,556	40,815	6,526	8.0%	(20.2%)	6.8%	(23.6%)
2004	45,888	11,035	49,990	11,185	23.3%	68.3%	22.5%	71.4%
2005	81,095	16,710	86,330	17,216	76.7%	51.4%	72.7%	53.9%
2006	84,260	14,696	88,621	15,399	3.9%	(12.1%)	2.7%	(10.5%)
2007	87,297	14,853	91,647	15,668	3.6%	1.1%	3.4%	1.7%
2008	85,241	14,203	90,621	14,646	(2.4%)	(4.4%)	(1.1%)	(6.5%)
2009	78,850	14,242	83,986	14,728	(7.5%)	0.3%	(7.3%)	0.6%
2010	84,086	16,346	88,876	17,001	6.6%	14.8%	5.8%	15.4%
2011	86,966	17,369	91,746	18,276	3.4%	6.3%	3.2%	7.5%
2012	90,367	16,893	95,726	17,810	3.9%	(2.7%)	4.3%	(2.5%)
2013	90,432	15,792	95,639	16,729	0.1%	(6.5%)	(0.1%)	(6.1%)
2014	92,449	16,002	97,922	17,064	2.2%	1.3%	2.4%	2.0%
2015	91,901	16,711	97,896	17,863	(0.6%)	4.4%	(0.0%)	4.7%
2016	92,799	19,003	96,907	19,067	1.0%	13.7%	(1.0%)	6.7%
2017	91,658	15,964	93,639	16,216	(1.2%)	(16.0%)	(3.4%)	(15.0%)
2018	95,561	17,506	97,588	17,747	4.3%	9.7%	4.2%	9.4%
2019	95,531	17,206	96,659	17,378	(0.0%)	(1.7%)	(1.0%)	(2.1%)

PJM Real-Time, Monthly Average Generation

Figure 3-5 compares the real-time, monthly average hourly generation in 2018 and the first nine months of 2019.

Figure 3-5 Real-time monthly average hourly generation: January 2018 through September 2019



Day-Ahead Supply

PJM average hourly, day-ahead cleared supply in the first nine months of 2019, including INCs and up to congestion transactions, increased by 2.5 percent from the first nine months of 2018, from 116,068 MWh to 118,913 MWh.

PJM average hourly, day-ahead cleared supply in the first nine months of 2019, including INCs, up to congestion transactions, and imports, increased by 2.4 percent from the first nine months of 2018, from 116,471 MWh to 119,249 MWh.

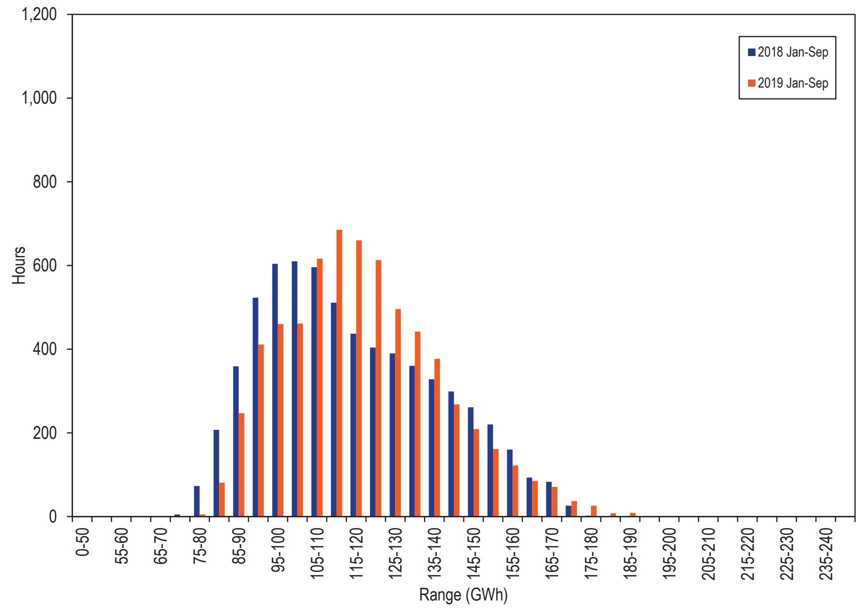
In the PJM Day-Ahead Energy Market, there are five types of financially binding supply offers:

- **Self Scheduled Generation Offer.** Offer to supply a fixed block of MW, 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 MW and corresponding offer prices from a unit.
- **Increment Offer (INC).** Financial offer to supply MW 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 for a specific amount of MW between the transaction source and sink. An up to congestion transaction is a matched pair of an injection and a withdrawal.
- **Import.** An import is an external energy transaction for a specific MW amount 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 3-6 shows the hourly distribution of PJM day-ahead supply, including increment offers, up to congestion transactions, and imports for first nine months of 2018 and 2019.

Figure 3-6 Distribution of day-ahead supply plus imports: January through September, 2018 and 2019[14]



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

PJM Day-Ahead, Average Supply

Table 3-4 presents day-ahead hourly supply summary statistics for the first nine months of the 19-year period from 2001 through 2019.

Table 3-4 Average hourly day-ahead supply and day-ahead supply plus imports: January through September, 2001 through 2019

	PJM Day-Ahead Supply (MWh)				Year-to-Year Change			
	Supply		Supply Plus Imports		Supply		Supply Plus Imports	
Jan-Sep	Supply	Standard Deviation	Supply	Standard Deviation	Supply	Standard Deviation	Supply	Standard Deviation
2001	27,519	4,839	28,279	4,911	NA	NA	NA	NA
2002	30,080	10,982	30,629	10,992	9.3%	126.9%	8.3%	123.8%
2003	40,024	9,079	40,556	9,066	33.1%	(17.3%)	32.4%	(17.5%)
2004	56,103	13,380	56,799	13,349	40.2%	47.4%	40.0%	47.2%
2005	94,437	18,671	96,315	18,963	68.3%	39.5%	69.6%	42.1%
2006	100,888	18,061	103,029	18,071	6.8%	(3.3%)	7.0%	(4.7%)
2007	110,300	17,561	112,575	17,752	9.3%	(2.8%)	9.3%	(1.8%)
2008	107,367	16,601	109,811	16,717	(2.7%)	(5.5%)	(2.5%)	(5.8%)
2009	98,527	17,462	101,123	17,526	(8.2%)	5.2%	(7.9%)	4.8%
2010	108,309	23,295	111,059	23,464	9.9%	33.4%	9.8%	33.9%
2011	116,988	22,722	119,488	23,015	8.0%	(2.5%)	7.6%	(1.9%)
2012	135,213	18,553	137,670	18,788	15.6%	(18.3%)	15.2%	(18.4%)
2013	148,489	18,858	150,785	19,073	9.8%	1.6%	9.5%	1.5%
2014	161,137	23,922	163,431	24,080	8.5%	26.9%	8.4%	26.2%
2015	116,975	20,289	119,349	20,502	(27.4%)	(15.2%)	(27.0%)	(14.9%)
2016	133,089	23,414	134,881	23,403	13.8%	15.4%	13.0%	14.1%
2017	133,377	20,602	134,000	20,710	0.2%	(12.0%)	(0.7%)	(11.5%)
2018	116,068	21,950	116,471	21,939	(13.0%)	6.5%	(13.1%)	5.9%
2019	118,913	20,009	119,249	19,989	2.5%	(8.8%)	2.4%	(8.9%)

PJM Day-Ahead, Monthly Average Supply

Figure 3-7 compares the day-ahead, monthly average hourly supply, including increment offers and up to congestion transactions for 2018 and first nine months of 2019.

Figure 3-7 Day-ahead monthly average hourly supply: January 2018 through September 2019

Real-Time and Day-Ahead Supply

Table 3-5 presents summary statistics for the first nine months of 2018 and 2019, for day-ahead and real-time supply. All data are cleared MWh. The last two columns of Table 3-5 are the day-ahead supply minus the real-time supply. The first of these columns is the total physical day-ahead generation less the total physical real-time generation and the second of these columns is the total day-ahead supply less the total real-time supply. In the first nine months of 2019, up to congestion transactions were 17.1 percent of the total day-ahead supply compared to 15.1 percent in the first nine months of 2018.

Table 3-5 Day-ahead and real-time supply (MWh): January through September, 2018 and 2019

		Day-Ahead					Real-Time		Day-Ahead Less Real-Time	
	Jan-Sep	Generation	INC Offers	Up to Congestion	Imports	Total Supply	Generation	Total Supply	Total Supply	Total Generation
Average	2018	95,852	2,577	17,639	403	116,471	95,561	97,588	18,883	291
	2019	95,616	2,866	20,430	337	119,249	95,531	96,659	22,590	85
Median	2018	93,293	2,470	15,754	362	112,889	92,551	94,608	18,281	742
	2019	93,534	2,735	20,316	295	117,016	93,083	94,316	22,700	451
Standard Deviation	2018	17,680	1,084	8,143	246	21,939	17,506	17,747	4,192	174
	2019	17,824	1,018	4,442	228	19,989	17,206	17,378	2,611	619
Peak Average	2018	105,389	3,137	18,713	383	127,622	104,480	106,732	20,891	910
	2019	105,288	3,357	21,849	289	130,783	104,446	105,631	25,153	842
Peak Median	2018	102,804	3,108	16,630	333	126,398	101,231	103,411	22,988	1,573
	2019	103,456	3,300	21,695	223	128,196	102,364	103,558	24,638	1,091
Peak Standard Deviation	2018	15,532	1,086	8,633	266	19,750	15,968	15,996	3,754	(436)
	2019	15,486	996	4,249	225	17,004	15,492	15,648	1,356	(6)
Off-Peak Average	2018	87,512	2,088	16,700	420	106,720	87,762	89,592	17,128	(250)
	2019	87,159	2,436	19,190	378	109,164	87,737	88,814	20,350	(578)
Off-Peak Median	2018	84,670	2,020	14,967	380	102,006	84,785	86,452	15,554	(115)
	2019	84,599	2,337	19,038	345	106,758	85,398	86,319	20,439	(799)
Off-Peak Standard Deviation	2018	15,030	811	7,566	225	18,904	14,872	15,153	3,752	158
	2019	15,249	824	4,231	223	16,678	14,657	14,834	1,843	592

Figure 3-8 shows the average hourly cleared volumes of day-ahead supply and real-time supply for the first nine months of 2019. The day-ahead supply consists of cleared MW of day-ahead generation, imports, increment offers and up to congestion transactions. The real-time generation includes generation and imports.

Figure 3-8 Day-ahead and real-time supply (Average hourly volumes): January through September, 2019

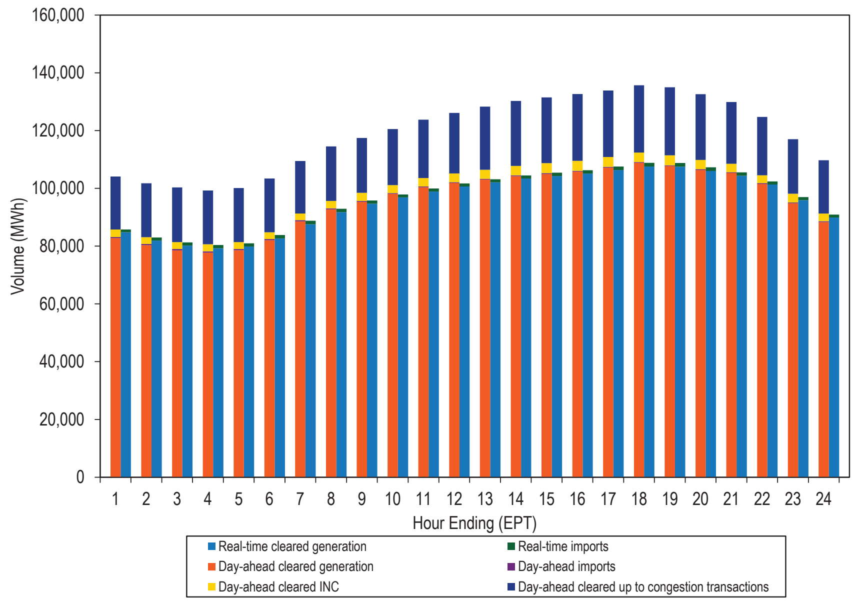
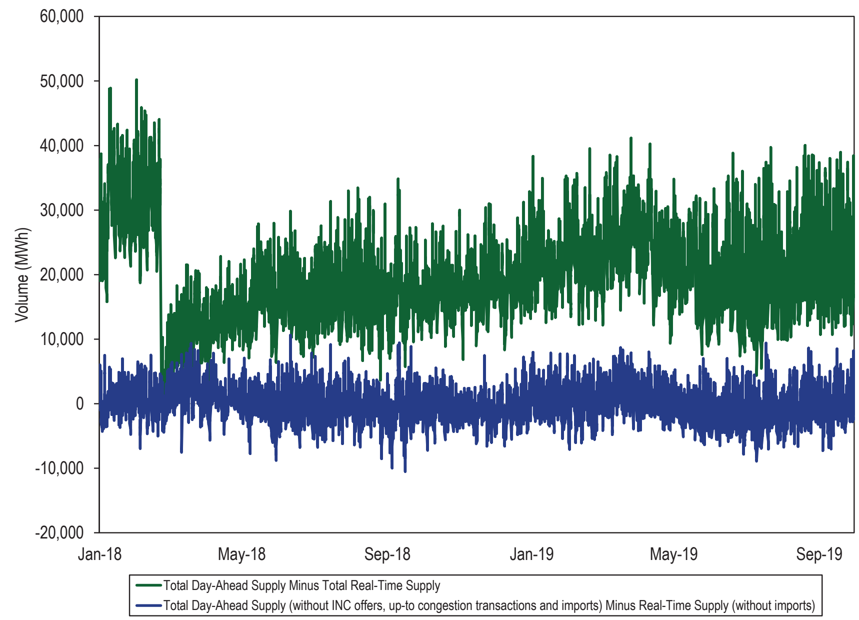


Figure 3-9 shows the difference between the day-ahead and real-time average daily supply for 2018 and the first nine months of 2019.

Figure 3-9 Difference between day-ahead and real-time supply (Average daily volumes): January 2018 through September 2019



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.[15]

The PJM system real-time hourly peak load in the first nine months of 2019 was 148,228 MWh in the HE 1800 on July 19, 2019, which was 1,185 MWh, or 0.8 percent, more than the peak load in the first nine months of 2018, which was 147,042 MWh in the HE 1700 on August 28, 2018.

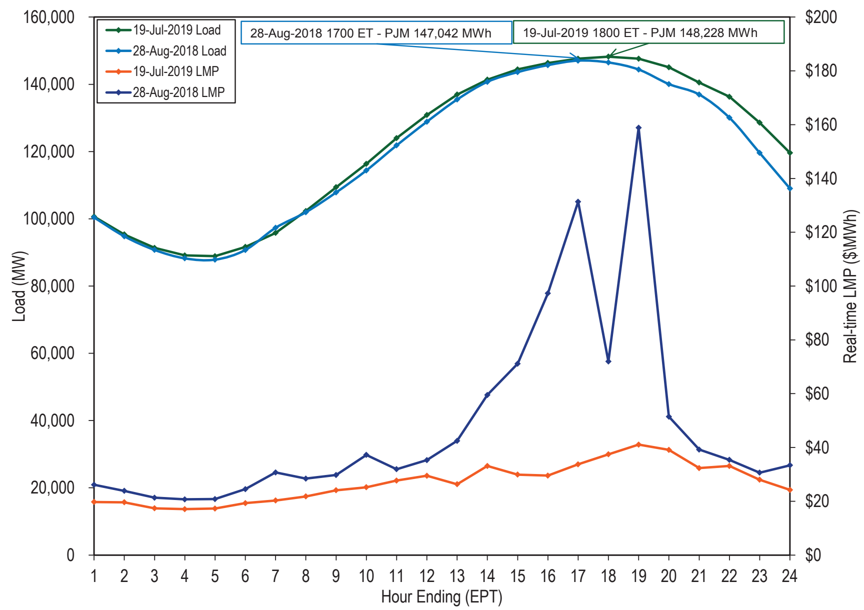
Table 3-6 shows the peak loads for the first nine months of 2009 through 2019.

Table 3-6 Actual footprint peak loads: January through September, 2009 to 2019[16 17]

(Jan - Sep)	Date	Hour Ending (EPT)	PJM Load (MW)	Annual Change (MW)	Annual Change (%)
2009	Mon, August 10	17	123,900	NA	NA
2010	Tue, July 06	17	133,297	9,397	7.6%
2011	Thu, July 21	17	154,095	20,798	15.6%
2012	Tue, July 17	17	150,879	(3,216)	(2.1%)
2013	Thu, July 18	17	153,790	2,911	1.9%
2014	Tue, June 17	18	138,448	(15,341)	(10.0%)
2015	Tue, July 28	17	140,266	1,818	1.3%
2016	Thu, August 11	16	148,577	8,311	5.9%
2017	Wed, July 19	18	142,387	(6,190)	(4.2%)
2018	Tue, August 28	17	147,042	4,656	3.3%
2019	Fri, July 19	18	148,228	1,185	0.8%

Figure 3-10 compares the peak load days during the first nine months of 2018 and 2019. The average real-time LMP for the July 19, 2019 peak load hour was $37.47 and for the August 28, 2018 peak load hour was $131.36.

Figure 3-10 Peak-load comparison Tuesday, August 28, 2018 and Friday, July 19, 2019



15 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 on PJM Manual 19: Load Forecasting and Analysis," Attachment A: Load Drop Estimate Guidelines.

16 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>.

17 Peak loads shown have been corrected to reflect the accounting load value excluding PJM loss adjustment. The values presented in this table do not include settlement adjustments made prior to January 1, 2017.

Real-Time Demand

PJM average hourly real-time demand in the first nine months of 2019 decreased by 2.3 percent from the first nine months of 2018, from 91,905 MWh to 89,834 MWh.[18]

PJM average hourly real-time demand including exports in the first nine months of 2019 decreased by 0.9 percent from the first nine months of 2018, from 95,795 MWh to 94,918 MWh.

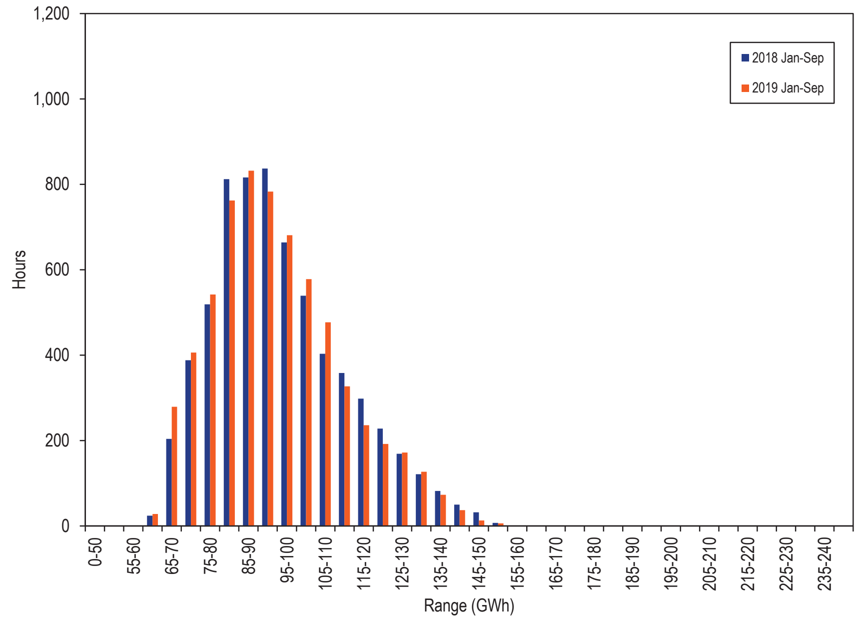
In the PJM Real-Time Energy Market, there are two types of demand:

- **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 3-11 shows the hourly distribution of PJM real-time load plus exports for the first nine months of 2018 and 2019.[19]

Figure 3-11 Distribution of real-time accounting load plus exports: January through September, 2018 and 2019[20]



18 Load data are the net MWh injections and withdrawals MWh at every load bus in PJM.
19 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>.

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

PJM Real-Time, Average Load

Table 3-7 presents real-time hourly demand summary statistics for the first nine months of 2001 to 2019. 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.[21]

Table 3-7 Real-time load and real-time load plus exports: January through September, 2001 through 2019

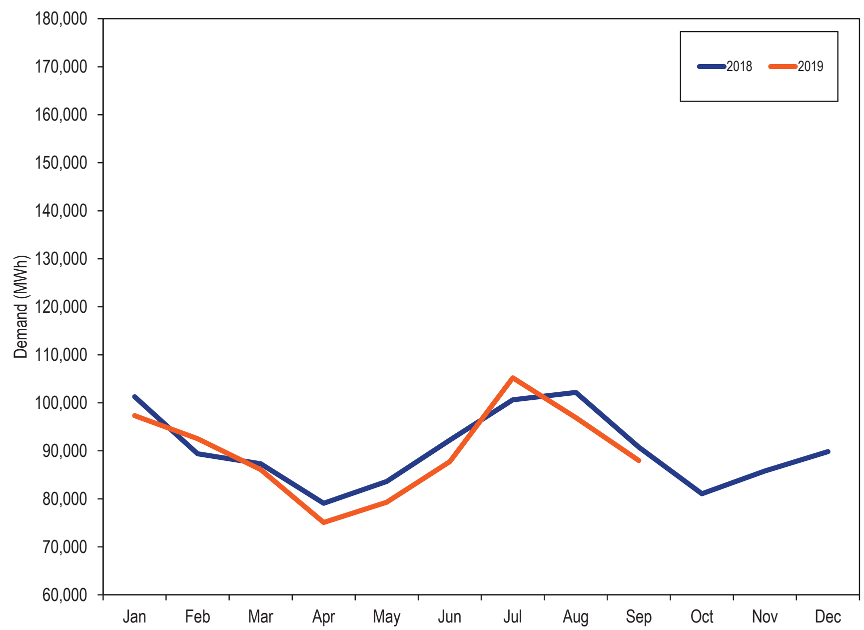
	PJM Real-Time Demand (MWh)				Year-to-Year Change			
	Load		Load Plus Exports		Load		Load Plus Exports	
Jan-Sep	Load	Standard Deviation	Demand	Standard Deviation	Load	Standard Deviation	Demand	Standard Deviation
2001	31,060	6,156	32,900	5,861	NA	NA	NA	NA
2002	35,715	8,688	37,367	8,878	15.0%	41.1%	13.6%	51.5%
2003	37,996	7,187	39,965	7,120	6.4%	(17.3%)	7.0%	(19.8%)
2004	45,294	10,512	49,176	11,556	19.2%	46.3%	23.0%	62.3%
2005	78,235	17,541	85,295	17,794	72.7%	66.9%	73.4%	54.0%
2006	80,717	15,568	87,326	16,147	3.2%	(11.2%)	2.4%	(9.3%)
2007	83,114	15,386	89,390	16,008	3.0%	(1.2%)	2.4%	(0.9%)
2008	80,611	14,389	87,788	14,893	(3.0%)	(6.5%)	(1.8%)	(7.0%)
2009	76,954	13,879	82,118	14,360	(4.5%)	(3.5%)	(6.5%)	(3.6%)
2010	81,068	16,209	86,994	16,687	5.3%	16.8%	5.9%	16.2%
2011	83,762	17,604	89,628	17,799	3.3%	8.6%	3.0%	6.7%
2012	88,687	17,431	93,763	17,329	5.9%	(1.0%)	4.6%	(2.6%)
2013	89,123	16,384	93,647	16,254	0.5%	(6.0%)	(0.1%)	(6.2%)
2014	90,567	16,662	96,015	16,518	1.6%	1.7%	2.5%	1.6%
2015	91,857	17,211	96,102	17,300	1.4%	3.3%	0.1%	4.7%
2016	90,599	18,183	95,340	18,571	(1.4%)	5.6%	(0.8%)	7.3%
2017	87,243	16,008	91,954	15,794	(3.7%)	(12.0%)	(3.6%)	(15.0%)
2018	91,905	17,064	95,795	17,245	5.3%	6.6%	4.2%	9.2%
2019	89,834	16,794	94,918	16,924	(2.3%)	(1.6%)	(0.9%)	(1.9%)

21 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.

PJM Real-Time, Monthly Average Load

Figure 3-12 compares the real-time, monthly average hourly loads for 2018 and the first nine months of 2019.

Figure 3-12 Real-time monthly average hourly load: January 2018 through September 2019



PJM real-time load is significantly affected by temperature. Table 3-8 compares the PJM monthly heating and cooling degree days in the first nine months of 2018 and 2019.[22] Heating degree days decreased 6.4 percent, and cooling degree days decreased 5.9 percent compared to the first nine months of 2018.

22 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

Table 3-8 Heating and cooling degree days: January 2018 through September 2019

	2018		2019		Percent Change	
	Heating Degree Days	Cooling Degree Days	Heating Degree Days	Cooling Degree Days	Heating Degree Days	Cooling Degree Days
Jan	941	0	909	0	(3.4%)	0.0%
Feb	575	0	688	0	19.7%	0.0%
Mar	658	0	607	0	(7.8%)	0.0%
Apr	359	1	145	0	(59.6%)	(77.0%)
May	0	139	23	90	0.0%	(35.8%)
Jun	0	245	0	210	0.0%	(14.3%)
Jul	0	363	0	423	0.0%	16.6%
Aug	0	363	0	312	0.0%	(14.1%)
Sep	0	213	0	211	0.0%	(0.6%)
Oct	207	65				
Nov	566	0				
Dec	675	0				
Jan-Sep	2,532	1,324	2,372	1,246	(6.4%)	(5.9%)

Day-Ahead Demand

PJM average day-ahead demand in the first nine months of 2019, including DECs and up to congestion transactions, increased by 2.3 percent from the first nine months of 2018, from 111,589 MWh to 114,133 MWh.

PJM average day-ahead demand in the first nine months of 2019, including DECs, up to congestion transactions, and exports, increased by 2.3 percent from of the first nine months of 2018, from 114,373 MWh to 117,048 MWh.

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.

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.

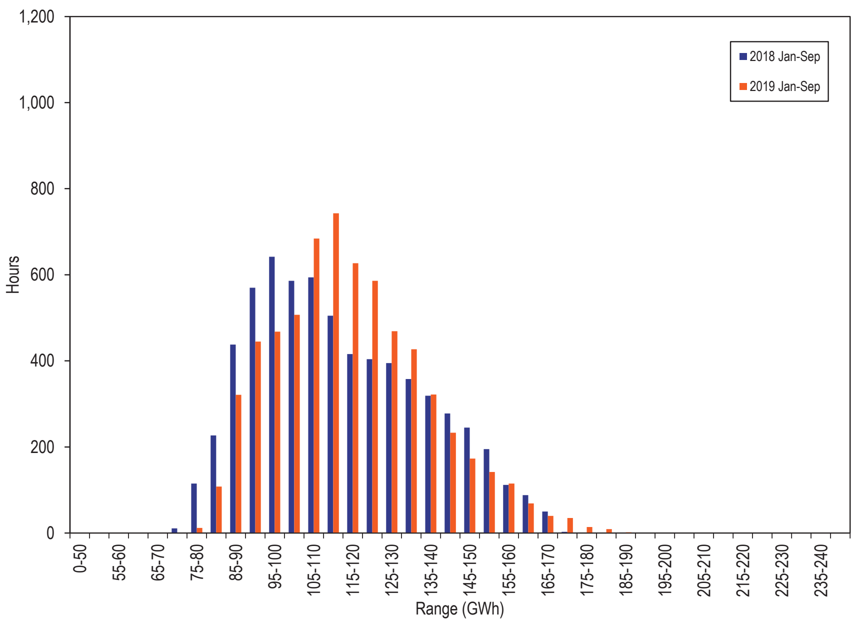
- **Up to Congestion Transaction (UTC).** A conditional transaction that permits a market participant to specify a maximum price spread between the transaction source and sink. An up to congestion transaction is evaluated as a matched pair of an injection and a withdrawal.
- **Export.** An external energy 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 3-13 shows the hourly distribution of PJM day-ahead demand, including decrement bids, up to congestion transactions, and exports for the first nine months of 2018 and 2019.

Figure 3-13 Distribution of day-ahead demand plus exports: January through September, 2018 and 2019[23]



PJM Day-Ahead, Average Demand

Table 3-9 presents day-ahead hourly demand summary statistics for the first nine months of each year from 2001 to 2019.

Table 3-9 Average hourly day-ahead demand and day-ahead demand plus exports: January through September, 2001 through 2019

	PJM Day-Ahead Demand (MWh)				Year-to-Year Change			
	Demand		Demand Plus Exports		Demand		Demand Plus Exports	
Jan-Sep	Demand	Standard Deviation	Demand	Standard Deviation	Demand	Standard Deviation	Demand	Standard Deviation
2001	33,944	7,016	34,444	6,817	NA	NA	NA	NA
2002	41,634	11,073	41,726	11,120	22.7%	57.8%	21.1%	63.1%
2003	45,371	8,377	45,477	8,354	9.0%	(24.4%)	9.0%	(24.9%)
2004	55,830	13,319	56,558	13,753	23.1%	59.0%	24.4%	64.6%
2005	93,525	19,126	96,302	19,455	67.5%	43.6%	70.3%	41.5%
2006	99,403	18,165	102,520	18,687	6.3%	(5.0%)	6.5%	(3.9%)
2007	107,295	17,580	110,711	17,949	7.9%	(3.2%)	8.0%	(4.0%)
2008	103,586	16,618	107,169	16,810	(3.5%)	(5.5%)	(3.2%)	(6.3%)
2009	96,020	16,995	99,084	17,117	(7.3%)	2.3%	(7.5%)	1.8%
2010	105,018	22,972	109,113	23,286	9.4%	35.2%	10.1%	36.0%
2011	113,724	22,444	117,533	22,651	8.3%	(2.3%)	7.7%	(2.7%)
2012	132,494	18,115	135,840	18,235	16.5%	(19.3%)	15.6%	(19.5%)
2013	145,139	18,667	148,444	18,696	9.5%	3.1%	9.3%	2.5%
2014	156,542	23,584	160,425	23,533	7.9%	26.3%	8.1%	25.9%
2015	113,553	19,788	117,090	19,951	(27.5%)	(16.1%)	(27.0%)	(15.2%)
2016	129,070	22,508	132,607	22,817	13.7%	13.7%	13.3%	14.4%
2017	128,450	20,002	131,569	20,158	(0.5%)	(11.1%)	(0.8%)	(11.7%)
2018	111,589	21,194	114,373	21,392	(13.1%)	6.0%	(13.1%)	6.1%
2019	114,133	19,233	117,048	19,465	2.3%	(9.3%)	2.3%	(9.0%)

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

PJM Day-Ahead, Monthly Average Demand

Figure 3-14 compares the day-ahead, monthly average hourly demand, including decrement bids and up to congestion transactions in 2018 and the first nine months of 2019.

Figure 3-14 Day-ahead monthly average hourly demand: January 2018 through September 2019

Real-Time and Day-Ahead Demand

Table 3-10 presents summary statistics for the first nine months of 2018 and 2019 day-ahead and real-time demand. All data are cleared MWh. The last two columns of Table 3-10 are the day-ahead demand minus the real-time demand. The first such column is the total physical day-ahead load (fixed demand plus price-sensitive demand) less the physical real-time load and the second such column is the total day-ahead demand less the total real-time demand.

Table 3-10 Cleared day-ahead and real-time demand (MWh): January through September, 2018 and 2019

		Day-Ahead						Real-Time		Day-Ahead Less Real-Time	
Jan-Sep	Year	Fixed Demand	Price Sensitive	DEC Bids	Up-to Congestion	Exports	Total Demand	Load	Total Demand	Total Demand	Total Load
Average	2018	88,840	2,258	2,851	17,639	2,784	114,373	91,905	95,795	18,578	(807)
	2019	88,424	1,309	3,970	20,430	2,915	117,048	89,834	94,918	22,130	(102)
Median	2018	86,670	2,296	2,539	15,754	2,687	110,917	89,193	92,919	17,998	(228)
	2019	86,655	1,320	3,595	20,316	2,799	114,900	87,550	92,608	22,292	424
Standard Deviation	2018	16,252	570	1,413	8,143	933	21,392	17,064	17,245	4,148	(242)
	2019	16,136	234	1,705	4,442	782	19,465	16,794	16,924	2,541	(423)
Peak Average	2018	98,048	2,490	3,176	18,713	2,837	125,263	100,932	104,723	20,541	(394)
	2019	97,584	1,437	4,418	21,849	3,016	128,305	98,591	103,696	24,609	431
Peak Median	2018	95,515	2,687	2,927	16,630	2,716	124,075	97,793	101,406	22,669	409
	2019	95,861	1,461	4,123	21,695	2,943	125,655	96,633	101,682	23,973	689
Peak Standard Deviation	2018	13,911	552	1,386	8,633	925	19,250	15,023	15,534	3,717	(560)
	2019	13,858	224	1,715	4,249	826	16,575	14,902	15,226	1,350	(819)
Off-Peak Average	2018	80,789	2,056	2,567	16,700	2,738	104,850	84,013	87,989	16,861	(1,168)
	2019	80,415	1,196	3,578	19,190	2,827	107,206	82,178	87,242	19,963	(567)
Off-Peak Median	2018	78,412	2,210	2,211	14,967	2,672	100,275	81,210	85,003	15,272	(588)
	2019	78,444	1,203	3,214	19,038	2,707	104,883	79,913	84,865	20,018	(266)
Off-Peak Standard Deviation	2018	13,673	505	1,376	7,566	937	18,423	14,661	14,691	3,732	(483)
	2019	13,515	179	1,596	4,231	731	16,197	14,453	14,419	1,778	(759)

Figure 3-15 shows the average hourly cleared volumes of day-ahead demand and real-time demand for the first nine months of 2019. 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 3-15 Day-ahead and real-time demand (Average hourly volumes): January through September, 2019

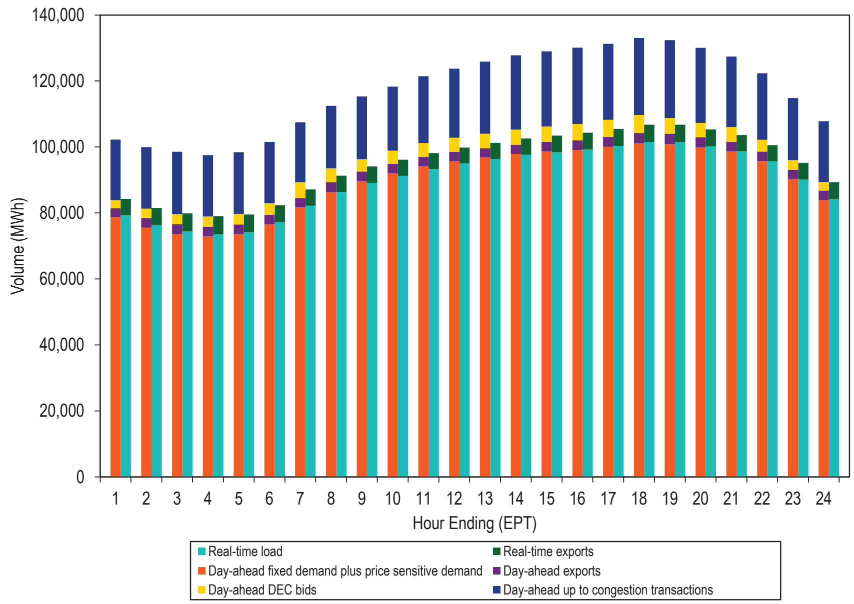
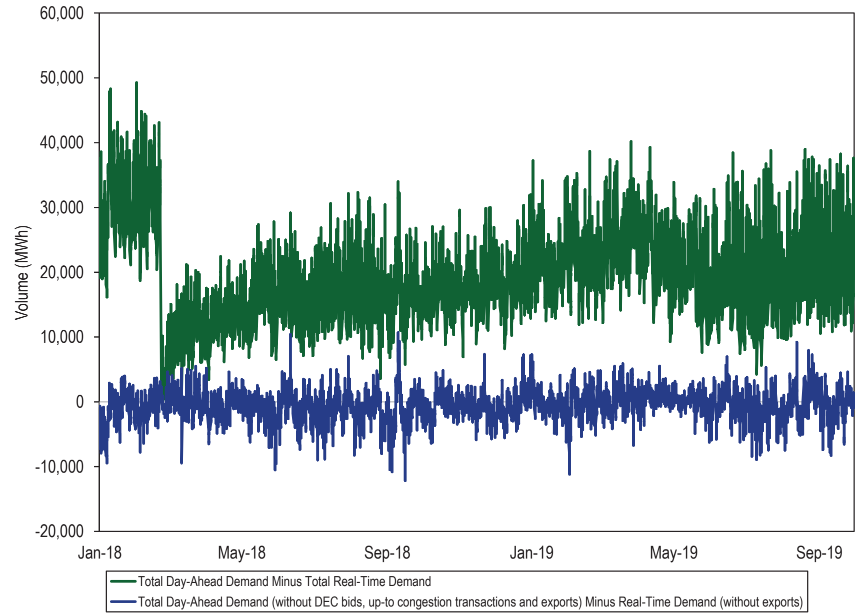


Figure 3-16 shows the difference between the day-ahead and real-time average daily demand for 2018 and the first nine months of 2019.

Figure 3-16 Difference between day-ahead and real-time demand (Average daily volumes): January 2018 through September 2019



Market Behavior

Generator Offers

Generator offers are categorized as dispatchable (Table 3-11) or self scheduled (Table 3-12).[24] 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 3-11 and Table 3-12 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. Generators may have multiple available offers. In order to select one offer, if there are active emergency conditions a PLS offer is used, if there is no active emergency the lowest price-based offer is used, if there is no price-based offer a cost-based offer is used, and if there are multiple cost-based offers the cheapest commitment cost-based offer is used.

Table 3-11 shows the proportion of day-ahead MW offered by dispatchable units, by unit type and by offer price range, in the first nine months of 2019. For example, 39.9 percent of all CC offer MW were the economic minimum offered MW and 33.3 percent of CC offer MW 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, including the economic minimum and emergency MW. For example, 77.3 percent of all CC unit offers were dispatchable, including the 39.9 percent of economic minimum MW and 3.6 percent of emergency MW offered by CC units. The dispatchable range of a unit is between the economic minimum and emergency range. For example, 33.8 percent of all CC unit offers have an economic dispatch range. 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, 23.2 percent of all dispatchable offers were in the $0 to $200 per MWh price range. The total column in the all dispatchable offers row is the proportion of all MW offers that were offered as available for economic dispatch, including emergency MW. Among all the generator offers in the first nine months of 2019, 26.3 percent of all dispatchable offers have an economic dispatch range.

24 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 3-11 Distribution of day-ahead MW for dispatchable unit offer prices: January through September, 2019

		Dispatchable (Range)							
Unit Type	Economic Minimum	($200) - $0	$0 - $200	$200 - $400	$400 - $600	$600 - $800	$800 - $1,000	Emergency	Total
CC	39.9%	0.0%	33.3%	0.4%	0.1%	0.0%	0.0%	3.6%	77.3%
CT	64.6%	0.0%	24.0%	2.4%	0.5%	0.0%	0.0%	7.3%	98.8%
Diesel	39.3%	0.0%	16.4%	4.8%	0.0%	0.0%	0.0%	16.8%	77.3%
Nuclear	5.9%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	5.9%
Pumped Storage	0.0%	0.0%	12.4%	0.0%	0.0%	0.0%	0.0%	39.9%	52.3%
Run of River	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%
Solar	0.1%	0.0%	15.0%	0.0%	0.0%	0.0%	0.0%	0.0%	15.1%
Steam - Coal	21.8%	0.0%	26.6%	0.0%	0.0%	0.0%	0.0%	1.2%	49.6%
Steam - Other	29.2%	0.0%	49.2%	1.7%	0.4%	0.0%	0.0%	3.1%	83.6%
Wind	1.0%	0.0%	8.9%	0.0%	0.0%	0.0%	0.0%	1.0%	10.8%
All Dispatchable Offers	30.4%	0.0%	23.2%	0.7%	0.1%	0.0%	0.0%	4.2%	60.9%

Table 3-12 shows the proportion of day-ahead MW offers by unit type that were self scheduled to generate fixed output by unit type and price range for self scheduled and dispatchable units, for the first nine months of 2019. For example, 10.5 percent of CC offer MW were the economic minimum and 10.4 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, 22.7 percent of all CC 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 1.5 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 14.9 percent of all offers and self scheduled and dispatchable units accounted for 23.2 percent of all offers. The total column in the all self scheduled offers row is the proportion of all MW offers that were either self scheduled to generate at fixed output or self scheduled to generate at economic minimum and dispatchable up to economic maximum, including emergency MW. Among all the generator offers in the first nine months of 2019, 14.3 percent were offered as self scheduled and 24.2 percent were offered as self scheduled and dispatchable.

Table 3-12 Distribution of day-ahead MW for self scheduled and dispatchable unit offer prices: January through September, 2019

	Self Scheduled		Self Scheduled and Dispatchable (Range)								
Unit Type	Must Run	Emergency	Economic Minimum	($200) - $0	$0 - $200	$200 - $400	$400 - $600	$600 - $800	$800 - $1,000	Emergency	Total
CC	0.2%	0.1%	10.5%	0.0%	10.4%	0.0%	0.0%	0.0%	0.0%	1.5%	22.7%
CT	0.2%	0.0%	0.6%	0.0%	0.3%	0.0%	0.0%	0.0%	0.0%	0.1%	1.2%
Diesel	16.5%	0.0%	2.0%	0.0%	1.4%	0.0%	0.0%	0.0%	0.0%	0.0%	20.0%
Fuel Cell	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%
Nuclear	65.4%	0.0%	23.0%	0.0%	2.2%	0.0%	0.0%	0.0%	0.0%	0.0%	90.6%
Pumped Storage	4.2%	5.4%	0.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	9.9%
Run of River	86.8%	11.9%	0.0%	0.0%	1.0%	0.0%	0.0%	0.0%	0.0%	0.0%	99.7%
Solar	10.1%	2.6%	0.0%	0.0%	1.5%	0.0%	0.0%	0.0%	0.0%	0.0%	14.3%
Steam - Coal	2.1%	0.7%	23.0%	0.0%	22.5%	0.0%	0.1%	0.0%	0.1%	1.7%	50.3%
Steam - Other	3.6%	0.7%	5.8%	0.0%	3.6%	0.2%	0.0%	0.0%	0.0%	0.6%	14.5%
Wind	6.7%	6.7%	2.6%	0.0%	0.8%	0.0%	0.0%	0.0%	0.0%	2.6%	19.4%
All Self-Scheduled Offers	14.3%	0.6%	13.2%	0.0%	9.0%	0.0%	0.0%	0.0%	0.0%	0.9%	39.1%

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 day-ahead rebid period. All participants are able to make hourly offers. Participants must opt in on a monthly basis to make intraday offer updates. Table 3-13 shows the daily average number of units that opted in to intraday offer updates and, as a reference, the daily average number of units that make positive offers. In September 2019, a daily average of 327 natural gas fired units had opted in for intraday offer updates out of a daily average of 449 natural gas fired units. This is a decrease of 1.6 percent from the daily average number of natural gas fired units that opted in to intraday offer updates in December 2018.

Table 3-13 Average number of units opted in for intraday offers by month: 2018 and 2019

	2018						2019					
	Number of units opt in			Number of units with positive offers			Number of units opt in			Number of units with positive offers		
	Natural Gas	Other Fuels	Total	Natural Gas	Other Fuels	Total	Natural Gas	Other Fuels	Total	Natural Gas	Other Fuels	Total
Jan	289.0	32.0	321.0	444.0	394.7	838.7	334.0	37.0	371.0	447.9	358.6	806.5
Feb	300.0	32.0	332.0	444.0	395.7	839.7	334.0	37.0	371.0	447.3	355.7	803.0
Mar	302.0	32.0	334.0	444.5	394.6	839.0	334.0	37.0	371.0	447.1	354.3	801.4
Apr	310.6	32.0	342.6	445.9	394.0	839.9	334.0	37.0	371.0	447.5	353.3	800.7
May	323.5	32.0	355.5	444.9	393.2	838.0	334.5	37.0	371.5	449.9	354.1	804.0
Jun	326.0	32.0	358.0	443.3	369.8	813.1	335.0	37.0	372.0	449.4	352.9	802.3
Jul	326.0	34.0	360.0	443.0	367.4	810.5	335.5	37.0	372.5	449.0	350.2	799.2
Aug	326.0	36.0	362.0	445.0	363.7	808.7	327.0	37.2	364.2	449.0	348.8	797.8
Sep	326.0	36.0	362.0	445.2	360.1	805.3	327.0	44.0	371.0	449.0	347.4	796.4
Oct	326.0	36.0	362.0	446.5	360.1	806.6						
Nov	330.0	37.0	367.0	447.8	360.5	808.3						
Dec	332.4	37.0	369.4	448.4	360.2	808.5						

Table 3-14 shows the average number of units that made hourly differentiated offers in the day-ahead market or rebid period. In September 2019, an average of 321.6 units made hourly differentiated offers. This is an increase of 19.4 percent from the average number of units that made hourly differentiated offers in December 2018.

Table 3-14 Average number of units with hourly differentiated offers by month: 2018 and 2019

	2018			2019		
	Natural Gas	Other Fuels	Total	Natural Gas	Other Fuels	Total
Jan	207.0	12.4	219.4	252.3	15.8	268.0
Feb	214.4	10.5	224.9	262.6	16.9	279.5
Mar	215.0	11.6	226.6	265.6	17.0	282.5
Apr	231.3	11.4	242.8	280.6	22.8	303.4
May	242.6	11.8	254.4	298.5	24.5	322.9
Jun	246.6	9.0	255.6	296.0	23.7	319.7
Jul	247.0	11.3	258.3	300.4	23.7	324.0
Aug	259.6	16.6	276.2	314.4	23.4	337.7
Sep	238.2	14.9	253.1	300.1	21.5	321.6
Oct	252.6	17.9	270.5			
Nov	261.9	25.6	287.6			
Dec	244.7	24.6	269.4			

Table 3-15 shows the average number of units that made rebid offer updates and intraday offer updates. In September 2019, an average of 135.6 units made intraday offer updates. This is an increase of 12.1 percent from the average number of units that made intraday offer updates in December 2018.

Table 3-15 Average number of units making rebid or intraday offer updates by month: 2018 and 2019

	2018			2019		
	Average number of units that made real-time offer updates			Average number of units that made real-time offer updates		
	Natural Gas	Other Fuels	Total	Natural Gas	Other Fuels	Total
Jan	114.1	3.8	117.8	134.5	11.7	146.3
Feb	117.3	4.9	122.2	132.5	5.2	137.7
Mar	113.5	6.2	119.7	143.9	5.3	149.2
Apr	116.8	5.2	122.0	132.3	5.6	137.9
May	122.2	4.8	127.0	137.6	6.1	143.7
Jun	124.7	4.4	129.1	139.8	5.9	145.7
Jul	128.1	4.4	132.5	129.5	5.4	134.8
Aug	130.2	3.4	133.6	136.0	7.4	143.4
Sep	124.3	4.3	128.6	127.4	8.2	135.6
Oct	132.0	3.9	135.9			
Nov	127.2	4.5	131.6			
Dec	116.4	4.7	121.0			

Parameter Limited Schedules

Cost-Based Offers

All capacity resources in PJM are required to submit at least one cost-based offer. For the 2018/2019 and 2019/2020 delivery years, PJM procured two types of capacity resources, capacity performance resources and base capacity resources. Since June 1, 2018, there are no longer any RPM resources committed as the legacy annual capacity product that existed prior to the 2018/2019 Delivery Year. 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. For all resources, a parameter limited schedule is to be used by PJM for committing generation resources that fail the Three Pivotal Supplier (TPS) test.

The MMU recommends that in order to ensure effective market power mitigation, PJM always enforce parameter limited values when the TPS test is failed or during high load conditions such as cold and hot weather alerts or emergency conditions. Instead of ensuring that parameter limits apply, PJM chooses the lower of the price-based schedule and the price-based parameter limited schedule during hot and cold weather alerts. Instead of ensuring that parameter limits apply, PJM chooses the lower of the price-based schedule and the cost-based parameter limited schedule when a resource fails the TPS test.

Currently, there are no rules in the PJM tariff or manuals that limit the markup 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 and during high load conditions such as cold and hot weather alerts or more severe emergencies, 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 Limits

For generation capacity resources committed prior to the implementation of the capacity performance rules, the parameters that were subject to limits on their parameter limited schedules were Minimum Run Time, Minimum Down Time, Maximum Daily Starts, Maximum Weekly Starts, and Turn Down Ratio. The limits for these parameters were based on the parameter limited schedule matrix in the PJM operating agreement.[25] Startup times and notification times were not subject to limits. Market sellers could request exceptions to the limits in the matrix on a temporary basis, for up to 30 days, for physical issues that occur at the units at any time during the delivery year. Market sellers could also request longer term exceptions, called period exceptions, supported by technical documentation and historical operating data, submitted in advance

25 See PJM Operating Agreement Schedule 1 § 6.6 (c).

of a delivery year, which were reviewed by PJM and the MMU and approved by PJM. In the PJM energy market, market sellers were required to submit operating parameters in their parameter limited schedules that were at least as flexible as the limits specified in the parameter limited schedule matrix, or an approved exception.

Beginning in the 2016/2017 Delivery Year, resources that had capacity performance (CP) commitments were 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. Startup and notification times are limited for capacity performance resources beginning June 1, 2016, and base capacity resources beginning June 1, 2018, in accordance with predetermined unit specific parameter limits. The unit specific parameter limits for capacity performance and base capacity resources are based on default minimum operating parameter limits posted by PJM by technology type, and any adjustments based on a unit specific review process. These default parameters were based on analysis by the MMU.

Beginning June 1, 2018, all RPM procured capacity resources were either capacity performance or base capacity resources. Entities that elected the fixed resource requirement (FRR) option were allowed to procure the legacy annual capacity product for the 2018/2019 Delivery Year. Beginning June 1, 2019, all capacity resources, including resources in FRR capacity plans, will be either capacity performance or base capacity resources. The PJM tariff specifies that all generation capacity resources, regardless of the current commitment status, are subject to parameter limits on their cost-based offers. However, the tariff currently does not make it clear what parameter limit values are applicable for resources without a capacity commitment. The MMU recommends that PJM update the tariff to clarify that all generation resources are subject to unit specific parameter limits on their cost-based offers using the same standard and process as capacity performance and base capacity resources.

Unit Specific Adjustment Process

Market participants can request an adjustment to the default values of parameter limits for capacity performance and base capacity resources, by submitting supporting documentation, which is reviewed by PJM and the MMU. The default minimum operating parameter limits or approved adjusted values are used by capacity performance resources and base capacity 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 a best practices equipment configuration.

The PJM process for the review of unit specific parameter limit adjustments is generally described in Manual 11: Energy and Ancillary Services Market Operations. The standards used by PJM to review the requests are currently not described in the tariff or PJM manuals. The MMU recommends that PJM clearly define the business rules that apply to the unit specific parameter adjustment process, including PJM's implementation of the tariff rules in the PJM manuals to ensure market sellers know the requirements for their resources.

Only certain technology types are subject to limits on operating parameters in their parameter limited schedules.[26] Solar units, wind units, run of river hydro units, and nuclear units are currently not subject to parameter limits. The MMU analyzed, for the units that are subject to parameter limits, the proportion of units that use the default limits published by PJM and the proportion of units that have been provided unit specific adjustments for some of the parameters. Table 3-16 shows, for the delivery year beginning June 1, 2019, the number of units that submitted and were approved unit specific parameter limit adjustments, and the number of units that used the default

26 For the default parameter limits by technology type, see PJM. "Unit-Specific Minimum Operating Parameters for Capacity Performance and Base Capacity Resources," which can be accessed at <https://www.pjm.com/~/media/committees-groups/committees/elc/postings/20150612-june-2015-capacity-performance-parameter-limitations-informational-posting.ashx>.

parameter limits published by PJM. Table 3-16 shows that 77.5 percent of subcritical coal steam units and 89.1 percent of supercritical coal steam units requested an adjustment to one or more parameter limits from the default limits published by PJM, while only 34.2 percent of combined cycle units, and 35.4 percent of frame combustion turbine units, and 18.9 percent of aero derivative combustion turbine units requested an adjustment to one or more parameter limits from the default limits published by PJM.

Table 3-16 Adjusted unit specific parameter limit statistics: Delivery Year 2019/2020

Technology Classification	Units Using Default Parameter Limits	Units with One or More Adjusted Parameter Limits	Percentage of Units with One or More Adjusted Parameter Limits
Aero CT	137	32	18.9%
Frame CT	190	104	35.4%
Combined Cycle	73	38	34.2%
Reciprocating Internal Combustion Engines	70	3	4.1%
Solid Fuel NUG	43	5	10.4%
Oil and Gas Steam	13	18	58.1%
Subcritical coal steam	20	69	77.5%
Supercritical coal steam	5	41	89.1%
Pumped Storage	10	0	0.0%

Real-Time Values

The MMU previously recommended that PJM market rules recognize the difference between operational parameters that indicate to PJM operators what a unit is capable of during the operating day and the parameters that result in uplift payments. The parameters provided to PJM operators each day should reflect what units are physically capable of so that operators can operate the system. 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. PJM implemented the real-time value variable in Markets Gateway to address this.

PJM market rules allow generators to communicate a resource's current operational capabilities to PJM when a resource cannot operate according to the unit specific parameters. These values are called real-time values (RTVs). The real-time values submittal process is not specified in the PJM Operating Agreement. The process is defined in PJM Manual 11. Unlike parameter exceptions, the use of real-time values makes a unit ineligible for make whole payments, unless the market seller can justify such operation based on an actual constraint.[27]

In practice, real-time values are generally used to communicate lower Turn Down Ratios which result from reduced Economic Max MW due to a derate (partial outage) on a unit, or from a requirement to operate at a defined output for equipment tests, environmental tests, or inspections. The RTV functionality allows units to communicate accurate short term operational parameters to PJM without requiring PJM customers to pay additional uplift charges, if the unit operates out of the money for routine tests and inspections. However, using real-time values to extend the time to start parameters (startup times and notification times) is inconsistent with the goal of real-time values. The protection offered by making units ineligible for uplift is only effective if the unit is committed and operated out of the money because of the RTVs. In the case of the notification time parameter or start time parameter, a longer real-time value decreases the likelihood of the unit being committed at all and may prohibit unit commitment in real time, making the RTV a mechanism for withholding.

The use of real-time values to extend startup times and notification times allows generators to circumvent the parameter limited schedule rules, to avoid commitment by PJM. Using RTVs to remove a unit from the real-time look-ahead dispatch window, and avoid commitment is withholding. These concerns are exacerbated if these units can otherwise provide relief to transmission constraints, and can provide flexibility to meet peak demand conditions. Currently, a resource that is staffed or has remote start capability and offers according to its physical capability, and a resource that makes the economic choice not to staff or invest in remote start and offers to decrease

27 See PJM Operating Agreement, Schedule 1, Section 3.2.3 (e).

the likelihood of commitment, are treated as identical in the capacity market. If a market seller makes an economic decision to not staff the unit or to not have remote start capability, and uses real-time values to communicate the longer time to start to PJM, there is currently no consequence to the market seller.

The MMU recommends that PJM institute rules to assess a penalty for resources that choose to submit real-time values that are less flexible than their unit specific parameter limits or approved parameter limit exceptions based on tariff defined justifications.

Generator Flexibility Incentives under Capacity Performance

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.[28] The Commission directed that capacity performance resources with parameters based on nonphysical constraints should receive uplift payments.[29] 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.[30]

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

28 151 FERC ¶ 61,208 at P 437 (2015) (June 9th Order).
29 Id at P 439.
30 Id at P 440.

The fact that a contract may be 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, who may be affiliates or have market power. 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. 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 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.

Parameter Impacts of Gas Pipeline Conditions

During extreme cold weather conditions, a number of gas fired generators request temporary exceptions to parameter limits for their parameter limited schedules due to restrictions imposed by natural gas pipelines. The parameters affected include notification time, 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 leads to requests for 24 hour minimum run times and turn down ratios close to 1.0, to avoid deviations from the hourly nominated quantity.

Key parameters like startup and notification time were not included in the PLS matrix in 2017 and prior periods, even though other parameters were subject to parameter limits. 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.

The MMU observed instances when generators submitted temporary parameter exceptions based on claimed pipeline constraints even though these constraints are based on the nature of the transportation service that the generator procured from the pipeline. In some instances, generators requested temporary exceptions based on ratable take requirements stated in pipeline tariffs, even though the requirement is not enforced by the pipelines on a routine basis. If a unit were to be dispatched uneconomically using the inflexible parameters, the unit would receive make whole payments based on these temporary exceptions. The MMU recommends that PJM not approve temporary exceptions that are based on pipeline tariff terms that are not routinely enforced or on inferior transportation service procured by the generator.

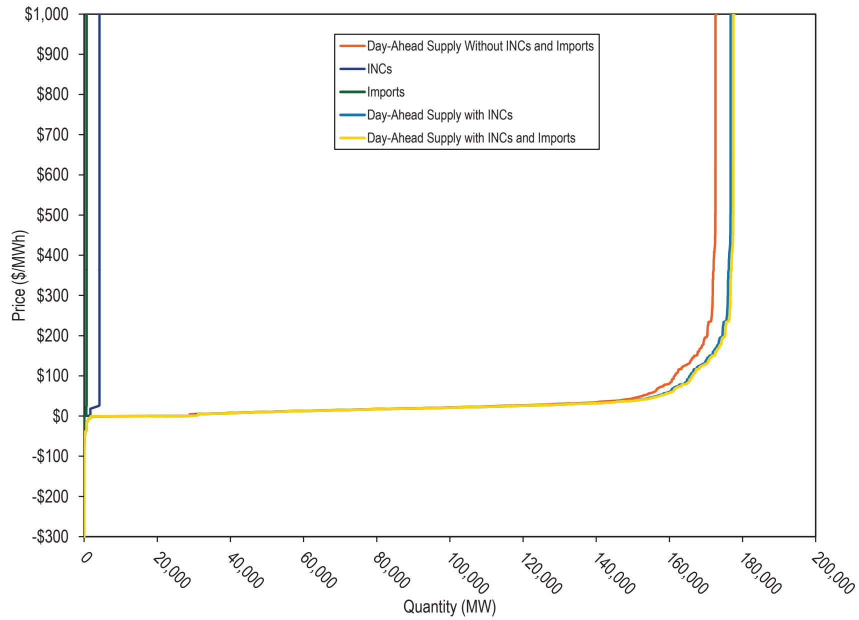
Virtual Offers and Bids

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. On February 20, 2018, FERC issued an order limiting the eligible bidding points for up to congestion transactions to hubs, residual metered load and interfaces.[31] Up to congestion transactions may be submitted between any two buses on a list of 49 buses, eligible for up to congestion transaction bidding.[32] 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 3-17 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 2019.

Figure 3-17 Day-ahead aggregate supply curves: 2019 example day



31 162 FERC ¶ 61,139 (2018).

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

Figure 3-18 shows example PJM day-ahead aggregate supply curves for the typical dispatch price range.

Figure 3-18 Typical dispatch price range for day-ahead aggregate supply curves: 2019 example day

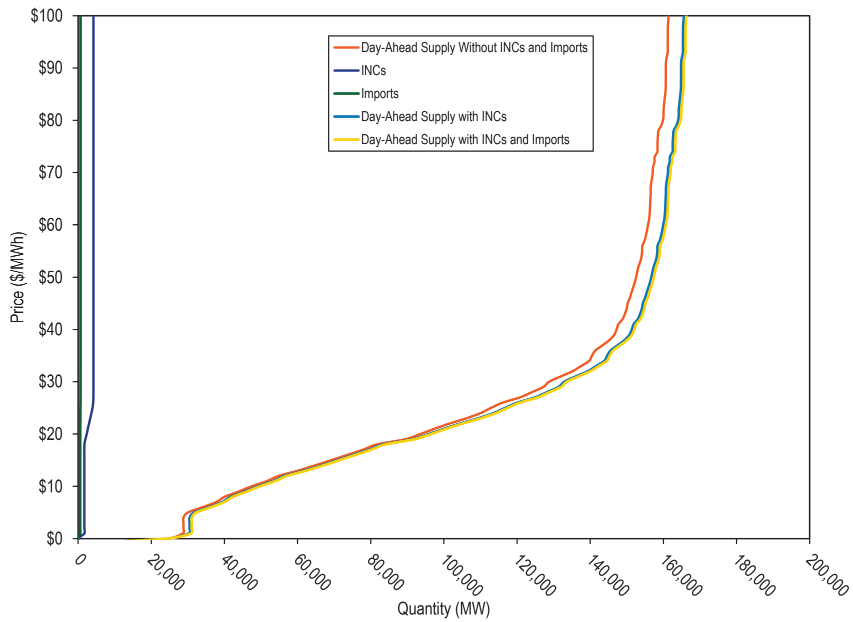


Table 3-17 shows the hourly average number of cleared and submitted increment offers and decrement bids by month in January 2018 through September 2019. The hourly average submitted and cleared increment MW increased by 11.5 percent and 11.6 percent, from 5,725 MW and 2,568 MW in the first nine months of 2018 to 6,382 MW and 2,866 MW in the first nine months of 2019. The hourly average submitted and cleared decrement MW increased by 6.4 percent and 39.7 percent, from 6,854 MW and 2,841 MW in the first nine months of 2018 to 7,293 MW and 3,970 MW in the first nine months of 2019.

Table 3-17 Average hourly number of cleared and submitted INCs and DECs by month: January 2018 through September 2019

		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
2018	Jan	2,903	6,834	293	1,387	2,728	8,782	196	1,188
2018	Feb	2,519	5,415	280	1,160	2,418	5,857	136	634
2018	Mar	2,791	5,986	521	1,267	2,580	7,019	330	978
2018	Apr	3,060	5,848	222	792	2,555	6,919	197	801
2018	May	2,892	5,563	168	650	3,158	6,684	154	662
2018	Jun	2,444	5,601	142	662	3,041	6,460	147	609
2018	Jul	1,829	4,984	130	642	2,721	6,028	145	622
2018	Aug	2,114	5,214	179	744	2,821	6,439	144	618
2018	Sep	2,653	6,252	192	803	3,619	7,631	171	674
2018	Oct	3,230	6,328	281	1,021	3,106	6,714	162	788
2018	Nov	3,258	5,980	287	958	3,020	6,416	154	817
2018	Dec	2,428	5,293	242	951	3,080	6,008	169	736
2018	Annual	2,676	5,776	245	919	2,906	6,753	176	762
2019	Jan	2,934	6,777	282	1,122	3,856	7,149	215	834
2019	Feb	2,895	5,776	260	1,029	3,441	6,115	197	781
2019	Mar	2,973	5,961	268	1,057	3,319	6,830	181	859
2019	Apr	3,048	6,008	286	1,060	3,104	6,226	154	733
2019	May	3,107	6,468	273	1,082	4,236	6,903	178	726
2019	Jun	2,892	6,363	226	977	4,408	7,245	226	863
2019	Jul	2,655	6,712	202	1,051	4,544	9,223	251	1,086
2019	Aug	2,577	6,573	220	1,100	3,744	7,056	217	860
2019	Sep	2,715	6,737	221	972	5,046	8,790	255	900
2019	Jan-Sep	2,866	6,382	249	1,051	3,970	7,293	208	850

Table 3-18 shows the average hourly number of up to congestion transactions and the average hourly MW in January 2018 through September 2019. In the first nine months of 2019, the average hourly submitted and cleared up to congestion MW increased by 5.8 percent and 15.9 percent, compared to the first nine months of 2018.

Table 3-18 Average hourly cleared and submitted up to congestion bids by month: January 2018 through September 2019

		Up to Congestion			
Year		Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume
2018	Jan	31,066	124,101	2,174	6,511
2018	Feb	25,543	94,687	1,857	4,703
2018	Mar	8,990	28,008	733	1,969
2018	Apr	11,930	43,989	877	2,001
2018	May	15,592	50,133	895	2,120
2018	Jun	15,227	46,207	827	1,794
2018	Jul	17,008	49,075	1,102	2,486
2018	Aug	17,658	53,077	997	2,317
2018	Sep	16,180	53,171	856	1,949
2018	Oct	16,284	49,862	939	2,115
2018	Nov	18,027	58,069	1,035	2,173
2018	Dec	18,446	55,795	1,152	2,254
2018	Annual	17,624	58,650	1,117	2,691
2019	Jan	20,624	65,533	1,219	2,489
2019	Feb	21,341	66,240	1,005	2,013
2019	Mar	23,205	75,760	1,045	2,144
2019	Apr	21,323	63,388	872	1,669
2019	May	19,407	59,684	862	1,713
2019	Jun	18,598	51,678	1,021	1,953
2019	Jul	19,197	56,161	1,128	2,265
2019	Aug	20,247	58,841	1,254	2,550
2019	Sep	20,005	74,494	1,136	2,523
2019	Jan-Sep	20,433	63,503	1,061	2,149

Table 3-19 shows the average hourly number of import and export transactions and the average hourly MW in January 2018 through September 2019. In the first nine months of 2019, the average hourly submitted and cleared import transaction MW increased by 30.9 and 25.7 percent, and the average hourly submitted and cleared export transaction MW increased by 13.3 and 13.6 percent, compared to the first nine months of 2018.

Table 3-19 Hourly average day-ahead number of cleared and submitted import and export transactions by month: January 2018 through September 2019

		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
2018	Jan	541	640	8	10	2,531	2,566	13	13
2018	Feb	556	809	7	11	2,778	2,853	14	14
2018	Mar	578	612	7	8	1,895	1,892	10	11
2018	Apr	486	514	6	7	2,150	2,168	11	11
2018	May	382	404	5	6	2,495	2,506	15	15
2018	Jun	246	254	4	4	3,197	3,222	19	19
2018	Jul	260	286	4	5	3,014	3,027	15	15
2018	Aug	358	388	4	5	3,647	3,671	17	17
2018	Sep	230	244	4	4	3,384	3,390	17	17
2018	Oct	362	371	4	5	3,387	3,432	18	18
2018	Nov	501	533	7	7	2,037	1,992	13	13
2018	Dec	453	518	7	8	3,030	3,035	18	18
2018	Annual	412	462	6	7	2,797	2,814	15	15
2019	Jan	545	653	7	9	3,569	3,593	22	22
2019	Feb	564	671	6	8	3,169	3,182	17	18
2019	Mar	387	449	5	7	2,675	2,686	15	15
2019	Apr	255	288	4	5	2,483	2,496	15	15
2019	May	279	298	3	4	2,426	2,458	15	15
2019	Jun	291	308	3	4	2,790	2,806	17	17
2019	Jul	283	311	4	5	3,075	3,106	15	15
2019	Aug	277	303	3	4	2,907	2,923	16	16
2019	Sep	162	177	3	3	3,163	3,193	17	17
2019	Jan-Sep	505	598	6	8	3,154	3,171	18	18

Table 3-20 shows the frequency with which generation offers, import or export transactions, up to congestion transactions, decrement bids, increment offers and price-sensitive demand were marginal in January 2018 through September 2019.

Table 3-20 Type of day-ahead marginal resources: January 2018 through September 2019

	2018						2019					
	Generation	Dispatchable Transaction	Up to Congestion Transaction	Decrement Bid	Increment Offer	Price Sensitive Demand	Generation	Dispatchable Transaction	Up to Congestion Transaction	Decrement Bid	Increment Offer	Price Sensitive Demand
Jan	5.3%	0.1%	82.5%	7.4%	4.6%	0.0%	13.4%	0.3%	59.1%	17.4%	9.9%	0.0%
Feb	5.9%	0.1%	80.8%	9.1%	4.0%	0.0%	11.7%	0.1%	60.0%	15.4%	12.8%	0.0%
Mar	17.2%	0.2%	47.0%	20.4%	15.2%	0.0%	9.3%	0.1%	60.5%	17.0%	13.1%	0.0%
Apr	13.5%	0.1%	45.7%	24.1%	16.6%	0.0%	8.3%	0.1%	64.9%	14.8%	11.9%	0.0%
May	15.2%	0.1%	49.6%	24.0%	11.1%	0.0%	9.9%	0.1%	53.1%	21.0%	15.9%	0.0%
Jun	15.3%	0.1%	54.5%	20.8%	9.3%	0.0%	10.5%	0.0%	49.0%	23.7%	16.8%	0.0%
Jul	12.4%	0.1%	57.8%	19.0%	10.6%	0.1%	9.1%	0.0%	51.5%	26.0%	13.4%	0.0%
Aug	11.1%	0.2%	54.5%	22.5%	11.7%	0.0%	13.0%	0.1%	63.1%	14.1%	9.6%	0.0%
Sep	15.1%	0.2%	50.7%	20.5%	13.5%	0.0%	14.0%	0.1%	60.5%	13.4%	12.0%	0.0%
Oct	12.7%	0.2%	54.3%	19.7%	13.0%	0.0%						
Nov	10.2%	0.1%	56.1%	20.3%	13.2%	0.0%						
Dec	12.1%	0.1%	58.3%	20.4%	9.1%	0.0%						
Annual	10.9%	0.1%	62.3%	16.9%	9.8%	0.0%	10.9%	0.1%	57.7%	18.4%	12.9%	0.0%

Figure 3-19 shows the monthly volume of bid and cleared INC, DEC and up to congestion bids by month from January 2005 through September 2019.

Figure 3-19 Monthly bid and cleared INCs, DECs and UTCs (MW): January 2005 through September 2019

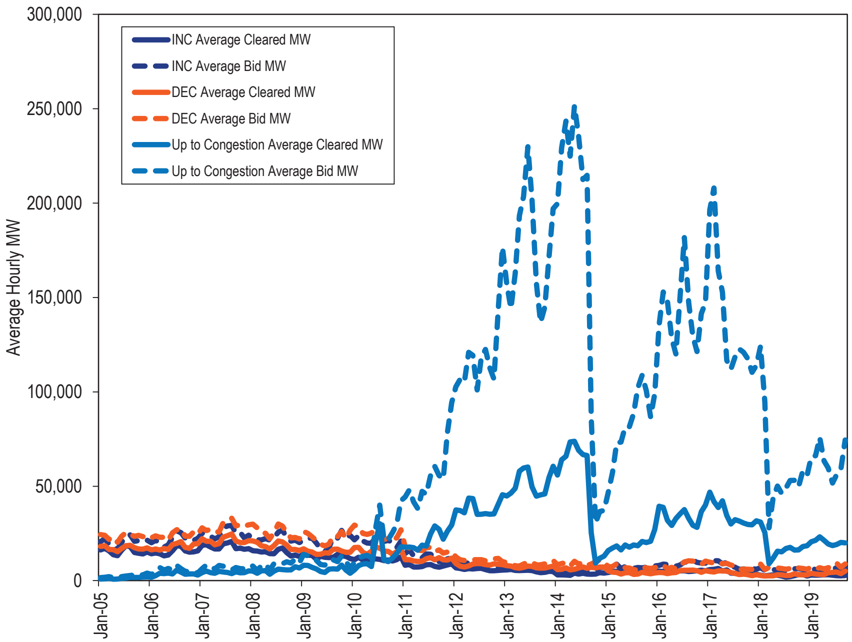
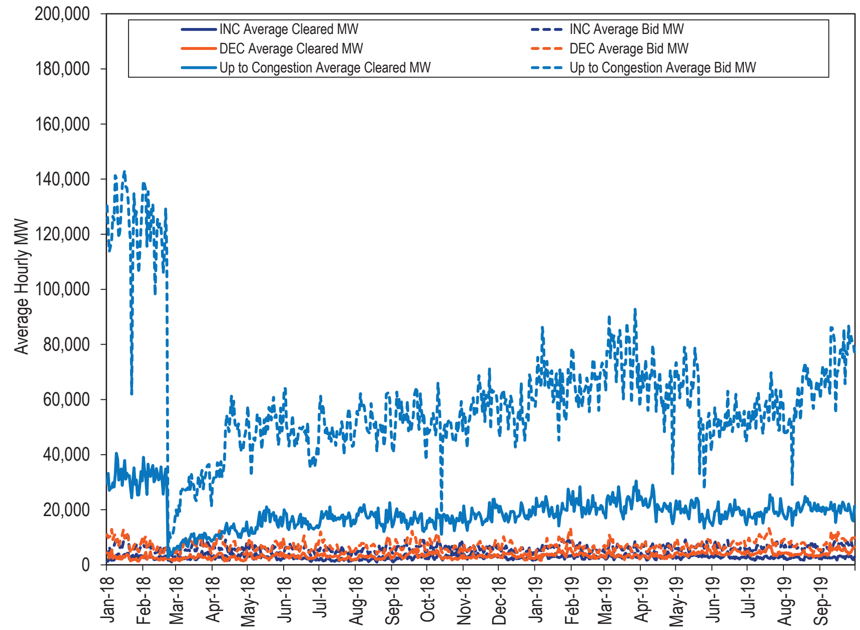


Figure 3-20 shows the daily volume of bid and cleared INC, DEC and up to congestion bids from January 1, 2018 through September 30, 2019.

Figure 3-20 Daily bid and cleared INCs, DECs, and UTCs (MW): January 2018 through September 2019



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 3-21 shows, in the first nine months of 2018 and 2019, the total increment offers and decrement bids and cleared MW by type of parent organization.

Table 3-21 INC and DEC bids and cleared MWh by type of parent organization (MWh): January through September, 2018 and 2019

	2018 (Jan-Sep)				2019 (Jan-Sep)			
Category	Total Virtual Bid MWh	Percent	Total Virtual Cleared MWh	Percent	Total Virtual Bid MWh	Percent	Total Virtual Cleared MWh	Percent
Financial	73,391,780	88.7%	29,636,599	83.3%	76,220,253	85.1%	37,111,117	82.9%
Physical	9,311,371	11.3%	5,926,016	16.7%	13,365,499	14.9%	7,670,318	17.1%
Total	82,703,152	100.0%	35,562,615	100.0%	89,585,752	100.0%	44,781,434	100.0%

Table 3-22 shows, in the first nine months of 2018 and 2019, the total up to congestion bids and cleared MWh by type of parent organization.

Table 3-22 Up to congestion transactions by type of parent organization (MWh): January through September, 2018 and 2019

	2018 (Jan-Sep)				2019 (Jan-Sep)			
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	387,384,301	98.5%	111,150,309	96.2%	408,325,274	98.2%	128,203,350	95.8%
Physical	5,911,253	1.5%	4,401,790	3.8%	7,684,296	1.8%	5,654,374	4.2%
Total	393,295,554	100.0%	115,552,099	100.0%	416,009,570	100.0%	133,857,724	100.0%

Table 3-23 shows, in the first nine months of 2018 and 2019, the total import and export transactions by whether the parent organization was financial or physical.

Table 3-23 Import and export transactions by type of parent organization (MW): January through September, 2018 and 2019

		2018 (Jan-Sep)		2019 (Jan-Sep)	
	Category	Total Import and Export MW	Percent	Total Import and Export MW	Percent
Day-Ahead	Financial	4,882,989	26.5%	5,153,149	27.3%
	Physical	13,561,188	73.5%	13,755,585	72.7%
	Total	18,444,177	100.0%	18,908,733	100.0%
Real-Time	Financial	8,193,181	21.1%	8,634,158	23.7%
	Physical	30,569,553	78.9%	27,730,465	76.3%
	Total	38,762,734	100.0%	36,364,623	100.0%

Table 3-24 shows increment offers and decrement bids by top 10 locations in the first nine months of 2018 and 2019.

Table 3-24 Virtual offers and bids by top 10 locations (MW): January through September, 2018 and 2019

2018 (Jan-Sep)					2019 (Jan-Sep)				
Aggregate/Bus Name	Aggregate/Bus Type	INC MW	DEC MW	Total MW	Aggregate/Bus Name	Aggregate/Bus Type	INC MW	DEC MW	Total MW
WESTERN HUB	HUB	2,239,066	1,063,197	3,302,263	MISO	INTERFACE	92,458	5,480,231	5,572,690
MISO	INTERFACE	163,594	1,552,703	1,716,297	WESTERN HUB	HUB	974,342	1,456,731	2,431,073
SOUTHIMP	INTERFACE	1,637,486	0	1,637,486	AEP-DAYTON HUB	HUB	431,099	771,311	1,202,410
LINDENVFT	INTERFACE	25,426	842,895	868,321	LINDENVFT	INTERFACE	27,083	1,164,030	1,191,114
DOM_RESID_AGG	RESIDUAL_METERED_EDC	109,126	681,083	790,209	DOM_RESID_AGG	RESIDUAL_METERED_EDC	196,888	932,152	1,129,040
NYIS	INTERFACE	579,955	152,743	732,698	DOMINION HUB	HUB	460,460	581,642	1,042,102
BGE_RESID_AGG	RESIDUAL_METERED_EDC	109,757	603,047	712,804	SOUTHIMP	INTERFACE	958,877	0	958,877
N ILLINOIS HUB	HUB	238,444	438,345	676,790	N ILLINOIS HUB	HUB	428,538	521,707	950,245
DOMINION HUB	HUB	100,779	541,778	642,556	BGE_RESID_AGG	RESIDUAL_METERED_EDC	184,216	692,349	876,565
AEP-DAYTON HUB	HUB	232,250	372,813	605,063	NYIS	INTERFACE	571,531	200,621	772,153
Top ten total		5,435,883	6,248,603	11,684,486			4,325,493	11,800,775	16,126,267
PJM total		16,884,534	18,678,081	35,562,615			18,774,506	26,006,928	44,781,434
Top ten total as percent of PJM total		32.2%	33.5%	32.9%			23.0%	45.4%	36.0%

Table 3-25 shows up to congestion transactions by import bids for the top 10 locations and associated profits at each path in the first nine months of 2018 and 2019.[33]

Table 3-25 Cleared up to congestion import bids by top 10 source and sink pairs (MW): January through September, 2018 and 2019

2018 (Jan-Sep)							
Imports							
Source	Source Type	Sink	Sink Type	MW	Source Profit	Sink Profit	UTC Profit
NORTHWEST	INTERFACE	N ILLINOIS HUB	HUB	2,500,524	$836,289	$37,681	$873,970
NORTHWEST	INTERFACE	CHICAGO GEN HUB	HUB	2,033,306	$710,649	$5,210	$715,859
NORTHWEST	INTERFACE	COMED_RESID_AGG	AGGREGATE	1,169,773	$1,074,659	($875,604)	$199,056
OVEC	INTERFACE	DEOK_RESID_AGG	AGGREGATE	1,005,813	$395,063	($195,040)	$200,023
NORTHWEST	INTERFACE	CHICAGO HUB	HUB	808,011	$84,558	$82,739	$167,298
MISO	INTERFACE	CHICAGO GEN HUB	HUB	723,415	$449,862	$476,688	$926,550
OVEC	INTERFACE	AEP GEN HUB	HUB	656,638	$559,109	($597,118)	($38,009)
MISO	INTERFACE	CHICAGO HUB	HUB	627,608	$367,775	$84,105	$451,879
OVEC	INTERFACE	ATSI GEN HUB	HUB	505,828	$239,895	($199,770)	$40,125
MISO	INTERFACE	AEPIM_RESID_AGG	AGGREGATE	497,570	$290,960	($39,112)	$251,848
Top ten total				10,528,487	$5,008,819	($1,220,220)	$3,788,599
PJM total				25,017,329	$8,696,255	($1,399,087)	$7,297,167
Top ten total as percent of PJM total				42.1%	57.6%	87.2%	51.9%
2019 (Jan-Sep)							
Imports							
Source	Source Type	Sink	Sink Type	MW	Source Profit	Sink Profit	UTC Profit
NORTHWEST	INTERFACE	N ILLINOIS HUB	HUB	3,672,891	$2,624,342	($1,008,392)	$1,615,950
NORTHWEST	INTERFACE	CHICAGO GEN HUB	HUB	2,267,861	$1,168,166	($602,967)	$565,200
NORTHWEST	INTERFACE	COMED_RESID_AGG	AGGREGATE	2,118,015	$1,937,641	($1,056,650)	$880,991
NYIS	INTERFACE	RECO_RESID_AGG	AGGREGATE	1,430,149	($484,469)	$675,323	$190,854
MISO	INTERFACE	AEPIM_RESID_AGG	AGGREGATE	1,214,494	$169,568	$530,215	$699,783
NEPTUNE	INTERFACE	JCPL_RESID_AGG	AGGREGATE	1,017,897	$247,481	($164,126)	$83,355
NORTHWEST	INTERFACE	CHICAGO HUB	HUB	903,699	$483,274	($96,332)	$386,942
SOUTHIMP	INTERFACE	AEP GEN HUB	HUB	758,037	$1,224,095	($730,682)	$493,413
SOUTHIMP	INTERFACE	AEPAPCO_RESID_AGG	AGGREGATE	671,711	$471,888	($115,309)	$356,579
NORTHWEST	INTERFACE	AEPIM_RESID_AGG	AGGREGATE	537,544	$471,504	($22,757)	$448,746
Top ten total				14,592,297	$8,313,490	($2,591,677)	$5,721,814
PJM total				28,290,352	$16,511,901	($6,245,518)	$10,266,384
Top ten total as percent of PJM total				51.6%	50.3%	41.5%	55.7%

33 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 3-26 shows up to congestion transactions by export bids for the top 10 locations and associated profits at each path in the first nine months of 2018 and 2019.

Table 3-26 Cleared up to congestion export bids by top 10 source and sink pairs (MW): January through September, 2018 and 2019

2018 (Jan-Sep)							
Exports							
Source	Source Type	Sink	Sink Type	MW	Source Profit	Sink Profit	UTC Profit
CHICAGO GEN HUB	HUB	NIPSCO	INTERFACE	680,418	$810,686	$224,042	$1,034,728
COMED_RESID_AGG	AGGREGATE	NIPSCO	INTERFACE	578,424	$481,961	$916,736	$1,398,697
N ILLINOIS HUB	HUB	NIPSCO	INTERFACE	548,284	$764,912	$300,696	$1,065,608
JCPL_RESID_AGG	AGGREGATE	HUDSONTP	INTERFACE	258,375	($113,399)	($96,689)	($210,087)
CHICAGO HUB	HUB	NIPSCO	INTERFACE	211,817	$380,861	($180,976)	$199,886
OHIO HUB	HUB	NIPSCO	INTERFACE	188,956	($81,760)	$145,948	$64,188
OVEC	ZONE	SOUTHEXP	INTERFACE	143,241	$156,894	($91,374)	$65,520
AEPIM_RESID_AGG	AGGREGATE	NIPSCO	INTERFACE	136,319	($115,086)	$101,487	($13,599)
SULLIVAN-AEP	EHVAGG	OVEC	INTERFACE	116,654	$445,574	($132,307)	$313,267
112 WILTON	EHVAGG	NIPSCO	INTERFACE	108,254	($107,221)	$146,103	$38,882
Top ten total				2,970,741	$2,623,422	$1,333,668	$3,957,090
PJM total				9,622,817	($3,121,469)	$7,175,533	$4,054,064
Top ten total as percent of PJM total				30.9%	(84.0%)	18.6%	97.6%
2019 (Jan-Sep)							
Exports							
Source	Source Type	Sink	Sink Type	MW	Source Profit	Sink Profit	UTC Profit
COMED_RESID_AGG	AGGREGATE	NIPSCO	INTERFACE	1,846,088	$1,383,522	$869,684	$2,253,206
N ILLINOIS HUB	HUB	NIPSCO	INTERFACE	1,618,617	$1,088,917	($348,429)	$740,488
CHICAGO GEN HUB	HUB	NIPSCO	INTERFACE	1,405,388	$278,839	$679,091	$957,930
CHICAGO HUB	HUB	NIPSCO	INTERFACE	1,063,992	$978,025	$366,039	$1,344,064
CHICAGO HUB	HUB	MISO	INTERFACE	739,298	$211,933	($148,459)	$63,474
AEP GEN HUB	HUB	SOUTHEXP	INTERFACE	711,021	($951,226)	$1,885,040	$933,814
CHICAGO GEN HUB	HUB	MISO	INTERFACE	518,556	$41,936	$37,577	$79,513
N ILLINOIS HUB	HUB	MISO	INTERFACE	490,740	$82,582	($144,049)	($61,467)
N ILLINOIS HUB	HUB	SOUTHEXP	INTERFACE	486,524	($29,001)	$200,765	$171,764
CHICAGO GEN HUB	HUB	NORTHWEST	INTERFACE	396,963	($433,776)	$555,526	$121,750
Top ten total				9,277,187	$2,651,751	$3,952,784	$6,604,535
PJM total				15,943,796	($247,518)	$10,144,990	$9,897,473
Top ten total as percent of PJM total				58.2%	(1071.3%)	39.0%	66.7%

Table 3-27 shows up to congestion transactions by wheel bids and associated profits at each path for the top 10 locations in the first nine months of 2018 and 2019.

Table 3-27 Cleared up to congestion wheel bids by top 10 source and sink pairs (MW): January through September, 2018 and 2019

2018 (Jan-Sep)							
Wheels							
Source	Source Type	Sink	Sink Type	MW	Source Profit	Sink Profit	UTC Profit
MISO	INTERFACE	NIPSCO	INTERFACE	1,066,046	$1,798,781	($134,396)	$1,664,385
MISO	INTERFACE	NORTHWEST	INTERFACE	782,843	$262,002	$138,497	$400,498
NORTHWEST	INTERFACE	MISO	INTERFACE	407,681	$501,015	($133,475)	$367,540
NORTHWEST	INTERFACE	NIPSCO	INTERFACE	253,579	$42,045	$431,202	$473,248
SOUTHIMP	INTERFACE	OVEC	INTERFACE	218,305	($1,235,838)	$1,167,990	($67,848)
SOUTHIMP	INTERFACE	NIPSCO	INTERFACE	176,893	($581,953)	$841,593	$259,640
OVEC	INTERFACE	SOUTHEXP	INTERFACE	158,012	$289,778	($220,284)	$69,494
MISO	INTERFACE	OVEC	INTERFACE	148,690	$66,484	($83,633)	($17,149)
SOUTHWEST	INTERFACE	SOUTHEXP	INTERFACE	143,660	$558,551	$31,300	$589,850
MISO	INTERFACE	SOUTHEXP	INTERFACE	131,717	$254,943	($120,606)	$134,338
Top ten total				3,487,425	$1,955,808	$1,918,187	$3,873,996
PJM total				4,774,729	$1,614,703	$1,876,453	$3,491,156
Top ten total as percent of PJM total				73.0%	121.1%	102.2%	111.0%
2019 (Jan-Sep)							
Wheels							
Source	Source Type	Sink	Sink Type	MW	Source Profit	Sink Profit	UTC Profit
NORTHWEST	INTERFACE	NIPSCO	INTERFACE	1,781,084	$1,130,395	$53,205	$1,183,599
MISO	INTERFACE	NIPSCO	INTERFACE	1,758,144	$1,645,884	($194,491)	$1,451,394
MISO	INTERFACE	SOUTHEXP	INTERFACE	889,111	($959,623)	$3,152,146	$2,192,524
NORTHWEST	INTERFACE	MISO	INTERFACE	869,753	$837,161	($470,939)	$366,222
MISO	INTERFACE	NORTHWEST	INTERFACE	581,756	$274,179	$64,171	$338,350
SOUTHIMP	INTERFACE	MISO	INTERFACE	354,465	$454,176	($261,645)	$192,531
SOUTHIMP	INTERFACE	NIPSCO	INTERFACE	297,721	$230,377	$556,152	$786,529
NORTHWEST	INTERFACE	SOUTHEXP	INTERFACE	262,102	$456,506	($146,641)	$309,865
LINDENVFT	INTERFACE	HUDSONTP	INTERFACE	194,779	$94,362	($42,611)	$51,751
IMO	INTERFACE	SOUTHEXP	INTERFACE	184,970	$10,997	$517,445	$528,443
Top ten total				7,173,885	$4,174,415	$3,226,792	$7,401,208
PJM total				8,420,422	$4,306,298	$2,939,003	$7,245,301
Top ten total as percent of PJM total				85.2%	96.9%	109.8%	102.2%

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 16.5 percent of the PJM total internal up to congestion transactions MW in the first nine months of 2019.

Table 3-28 shows up to congestion transactions by internal bids for the top 10 locations and associated profits at each path in the first nine months of 2018 and 2019. The total internal UTC profits decreased by $10.8 million, from $16.4 million in the first nine months of 2018 to $5.5 million in the first nine months of 2019. The total internal cleared MW increased by 5.1 million MW, or 6.7 percent, from 76.1 million MW in the first nine months of 2018 to 81.2 million MW in the first nine months of 2019.

Table 3-28 Cleared up to congestion internal bids by top 10 source and sink pairs (MW): January through September, 2018 and 2019

2018 (Jan-Sep)							
Internal							
Source	Source Type	Sink	Sink Type	MW	Source Profit	Sink Profit	UTC Profit
WESTERN HUB	HUB	N ILLINOIS HUB	HUB	1,218,355	$751,591	($1,054,714)	($303,123)
SMECO_RESID_AGG	AGGREGATE	BGE_RESID_AGG	AGGREGATE	828,418	$207,187	($23,401)	$183,785
AEP GEN HUB	HUB	FEOHIO_RESID_AGG	AGGREGATE	718,784	$334,502	$442,483	$776,985
CHICAGO HUB	HUB	COMED_RESID_AGG	AGGREGATE	658,496	$1,355,347	($1,284,070)	$71,277
WESTERN HUB	HUB	AEP-DAYTON HUB	HUB	625,073	($87,925)	$358,785	$270,860
ATSI GEN HUB	HUB	FEOHIO_RESID_AGG	AGGREGATE	623,342	($217,567)	$556,418	$338,852
AECO_RESID_AGG	AGGREGATE	VINELAND_RESID_AGG	AGGREGATE	604,955	($251,565)	($166,358)	($417,923)
AEP GEN HUB	HUB	AEPOHIO_RESID_AGG	AGGREGATE	584,448	$101,911	$9,916	$111,827
DOM_RESID_AGG	AGGREGATE	DOMINION HUB	HUB	573,175	$1,690,631	($1,460,111)	$230,521
PPL_RESID_AGG	AGGREGATE	METED_RESID_AGG	AGGREGATE	456,014	$847,488	($1,210,388)	($362,900)
Top ten total				6,891,061	$4,731,599	($3,831,440)	$900,160
PJM total				76,137,224	($13,137,136)	$29,517,862	$16,380,726
Top ten total as percent of PJM total				9.1%	(36.0%)	(13.0%)	5.5%
2019 (Jan-Sep)							
Internal							
Source	Source Type	Sink	Sink Type	MW	Source Profit	Sink Profit	UTC Profit
OVEC_RESID_AGG	AGGREGATE	DEOK_RESID_AGG	AGGREGATE	1,987,576	$56,715	($350,761)	($294,047)
SMECO_RESID_AGG	AGGREGATE	BGE_RESID_AGG	AGGREGATE	1,710,830	$1,190,773	($624,876)	$565,897
AEP GEN HUB	HUB	AEPOHIO_RESID_AGG	AGGREGATE	1,688,489	$18,599	$313,596	$332,194
OVEC_RESID_AGG	AGGREGATE	DAY_RESID_AGG	AGGREGATE	1,534,526	$127,249	($43,063)	$84,185
AEP GEN HUB	HUB	AEP-DAYTON HUB	HUB	1,353,911	$578,741	($433,479)	$145,263
AEP GEN HUB	HUB	FEOHIO_RESID_AGG	AGGREGATE	1,251,621	$674,656	($693,980)	($19,324)
N ILLINOIS HUB	HUB	CHICAGO HUB	HUB	1,013,611	($245,478)	$367,797	$122,319
WESTERN HUB	HUB	AEP-DAYTON HUB	HUB	1,005,492	$764,059	($481,265)	$282,793
CHICAGO GEN HUB	HUB	AEPIM_RESID_AGG	AGGREGATE	992,387	($9,936)	$464,675	$454,739
AECO_RESID_AGG	AGGREGATE	VINELAND_RESID_AGG	AGGREGATE	900,369	($583,798)	$104,069	($479,728)
Top ten total				13,438,811	$2,571,580	($1,377,287)	$1,194,292
PJM total				81,203,154	$19,532,927	($13,994,454)	$5,538,473
Top ten total as percent of PJM total				16.5%	13.2%	9.8%	21.6%

Table 3-29 shows the number of source-sink pairs that were offered and cleared monthly for January 1, 2018 through September 30, 2019.

Table 3-29 Number of offered and cleared source and sink pairs: January 2018 through September 2019

		Daily Number of Source-Sink Pairs			
Year	Month	Average Offered	Max Offered	Average Cleared	Max Cleared
2018	Jan	7,983	8,492	5,658	6,481
2018	Feb	5,909	8,299	4,559	6,398
2018	Mar	1,399	1,736	1,088	1,461
2018	Apr	1,479	1,608	1,240	1,388
2018	May	1,345	1,426	1,148	1,221
2018	Jun	1,411	1,563	1,236	1,350
2018	Jul	1,727	2,159	1,457	1,796
2018	Aug	1,816	2,124	1,463	1,703
2018	Sep	1,424	1,559	1,208	1,326
2018	Oct	1,838	2,118	1,610	1,954
2018	Nov	1,539	1,922	1,371	1,689
2018	Dec	1,606	1,787	1,426	1,608
2018	Annual	2,456	2,899	1,955	2,365
2019	Jan	1,693	1,893	1,527	1,712
2019	Feb	1,701	1,881	1,496	1,733
2019	Mar	1,673	1,806	1,506	1,653
2019	Apr	1,555	1,806	1,395	1,653
2019	May	1,584	1,856	1,424	1,718
2019	Jun	1,770	1,970	1,601	1,797
2019	Jul	1,767	1,950	1,635	1,819
2019	Aug	1,880	2,034	1,690	1,879
2019	Sep	1,891	2,007	1,702	1,842
2019	Jan-Sep	1,689	1,860	1,510	1,699

Table 3-30 Cleared up to congestion transactions by type (MW): January through September, 2018 and 2019

	2018 (Jan-Sep)				
	Cleared Up to Congestion Bids				
	Import	Export	Wheel	Internal	Total
Top ten total (MW)	10,528,487	2,970,741	3,487,425	6,891,061	23,877,713
PJM total (MW)	25,017,329	9,622,817	4,774,729	76,137,224	115,552,099
Top ten total as percent of PJM total	42.1%	30.9%	73.0%	9.1%	20.7%
PJM total as percent of all up to congestion transactions	21.7%	8.3%	4.1%	65.9%	100.0%
	2019 (Jan-Sep)				
	Cleared Up to Congestion Bids				
	Import	Export	Wheel	Internal	Total
Top ten total (MW)	14,592,297	9,277,187	7,173,885	13,438,811	44,482,179
PJM total (MW)	28,290,352	15,943,796	8,420,422	81,203,154	133,857,724
Top ten total as percent of PJM total	51.6%	58.2%	85.2%	16.5%	33.2%
PJM total as percent of all up to congestion transactions	21.1%	11.9%	6.3%	60.7%	100.0%

Table 3-30 and Figure 3-21 show total cleared up to congestion transactions by type in the first nine months of 2018 and 2019. Total up to congestion transactions in the first nine months of 2019 increased by 15.8 percent from 115.6 million MW in the first nine months of 2018 to 133.9 million MW in the first nine months of 2019. Internal up to congestion transactions in the first nine months of 2019 were 60.7 percent of all up to congestion transactions compared to 65.9 percent in the first nine months of 2018.

Figure 3-21 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.[34] But in 2018, the percent of marginal up to congestion transactions again decreased significantly as the result of a FERC order issued on February 20, 2018 and implemented on February 22, 2018.[35] The order limited UTC trading to hubs, residual metered load, and interfaces. The reduction in UTC bid locations effective February 22, 2018, resulted in a significant reduction in total activity. UTC activity has increased, following that reduction.

34 Id.
35 162 FERC ¶ 61,139 (2018).

Figure 3-21 Monthly cleared up to congestion transactions by type (MW): January 2005 through September 2019

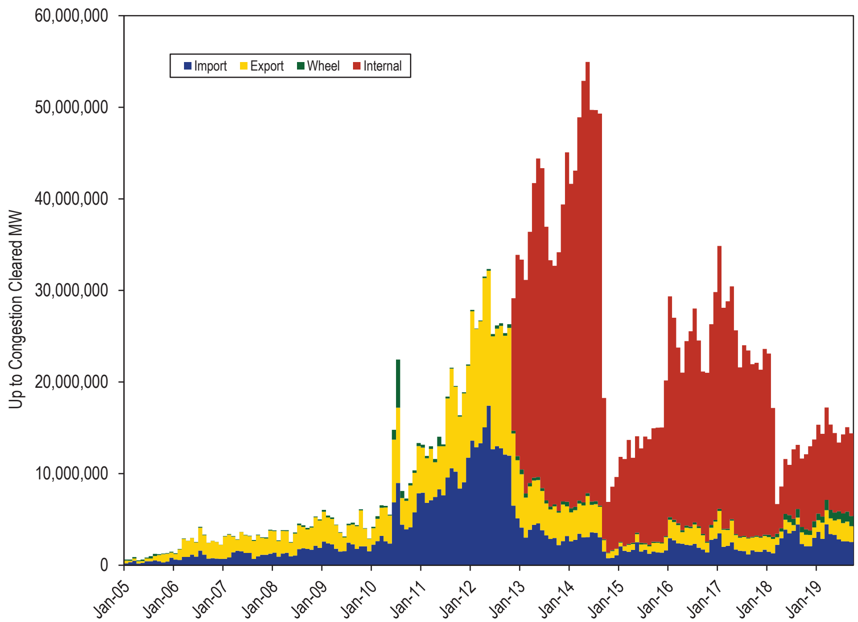
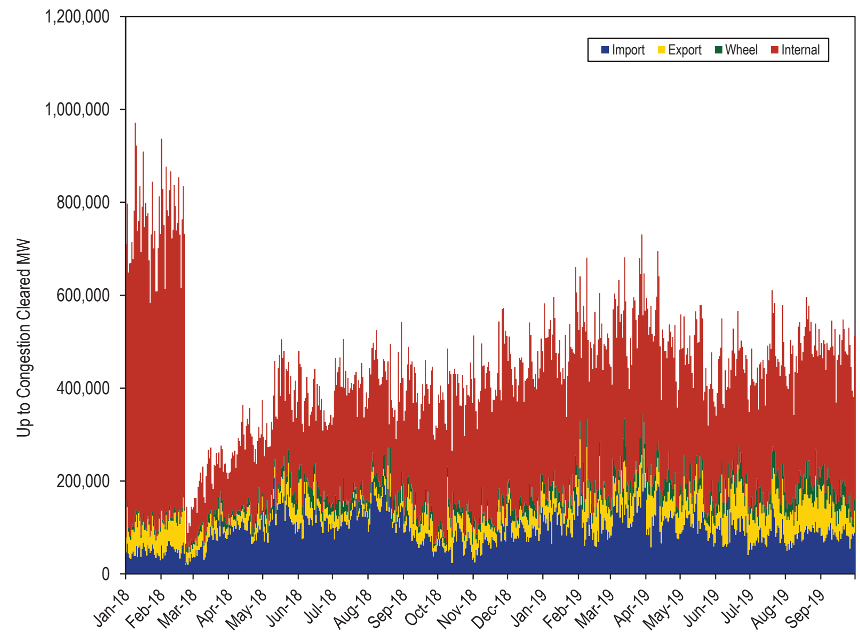


Figure 3-22 shows the daily cleared up to congestion MW by transaction type from January 1, 2018 through September 30, 2019.

Figure 3-22 Daily cleared up to congestion transaction by type (MW): January 2018 through September 2019



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. In a competitive market, prices equal the short run marginal cost of the marginal unit of output and reflect the most efficient and least cost allocation of resources to meet demand.

LMP

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 or influence prices through manual interventions such as load biasing, changing constraint limits and penalty factors, and committing reserves beyond the requirement.

Real-time and day-ahead energy market load-weighted prices were 30.0 percent and 28.4 percent lower in the first nine months of 2019 than in the first nine months of 2018.

PJM real-time energy market prices decreased in the first nine months of 2019 compared to the first nine months of 2018. The average LMP was 28.0 percent lower in the first nine months of 2019 than in the first nine months of 2018, $26.30 per MWh versus $36.52 per MWh. The load-weighted average real-time LMP was 30.0 percent lower in the first nine months of 2019 than in the first nine months of 2018, $27.60 per MWh versus $39.43 per MWh.

The real-time load-weighted average LMP for the first nine months of 2019 was 12.8 percent lower than the real-time fuel-cost adjusted, load-weighted, average LMP for the first nine months of 2019. If fuel and emission costs in the first nine months of 2019 had been the same as in the first nine months of 2018, holding everything else constant, the load-weighted LMP would have been higher, $31.65 per MWh instead of the observed $27.60 per MWh.

PJM day-ahead energy market prices decreased in the first nine months of 2019 compared to the first nine months of 2018. The day-ahead average LMP was 26.7 percent lower in the first nine months of 2019 than in the first nine months of 2018, $26.41 per MWh versus $36.04 per MWh. The day-ahead load-weighted average LMP was 28.4 percent lower in the first nine months of 2019 than in the first nine months of 2018, $27.70 per MWh versus $38.71 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 curve.[36] 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.[37]

LMP may, at times, be set by transmission penalty factors, which exceed $1,000 per MWh. 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

36 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.

37 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).

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

Real-Time Average LMP

Real-time average LMP is the hourly average LMP for the PJM Real-Time Energy Market.[38]

PJM Real-Time, Average LMP

Table 3-31 shows the PJM real-time, average LMP for the first nine months of 1998 through 2019.[39]

Table 3-31 Real-time, average LMP (Dollars per MWh): January through September, 1998 through 2019

	Real-Time LMP			Year-to-Year Change		
Jan-Sep	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$23.18	$16.86	$36.00	NA	NA	NA
1999	$31.65	$18.77	$83.28	36.6%	11.3%	131.3%
2000	$25.88	$18.22	$23.70	(18.2%)	(2.9%)	(71.5%)
2001	$36.00	$25.48	$51.30	39.1%	39.9%	116.4%
2002	$28.13	$20.70	$23.92	(21.9%)	(18.8%)	(53.4%)
2003	$40.42	$33.68	$26.00	43.7%	62.7%	8.7%
2004	$43.85	$39.99	$21.82	8.5%	18.7%	(16.1%)
2005	$54.69	$44.53	$33.67	24.7%	11.4%	54.3%
2006	$51.79	$43.50	$34.93	(5.3%)	(2.3%)	3.7%
2007	$57.34	$49.40	$35.52	10.7%	13.6%	1.7%
2008	$71.94	$61.33	$41.64	25.4%	24.2%	17.2%
2009	$37.42	$33.00	$17.92	(48.0%)	(46.2%)	(57.0%)
2010	$46.13	$37.89	$26.99	23.3%	14.8%	50.6%
2011	$45.79	$37.05	$32.25	(0.7%)	(2.2%)	19.5%
2012	$32.45	$28.78	$21.94	(29.1%)	(22.3%)	(32.0%)
2013	$37.30	$32.44	$22.84	15.0%	12.7%	4.1%
2014	$52.72	$36.06	$74.17	41.3%	11.2%	224.8%
2015	$35.96	$27.88	$30.75	(31.8%)	(22.7%)	(58.5%)
2016	$27.43	$23.61	$15.73	(23.7%)	(15.3%)	(48.8%)
2017	$28.79	$25.28	$16.81	5.0%	7.1%	6.9%
2018	$36.52	$27.26	$33.22	26.8%	7.8%	97.6%
2019	$26.30	$23.39	$17.69	(28.0%)	(14.2%)	(46.8%)

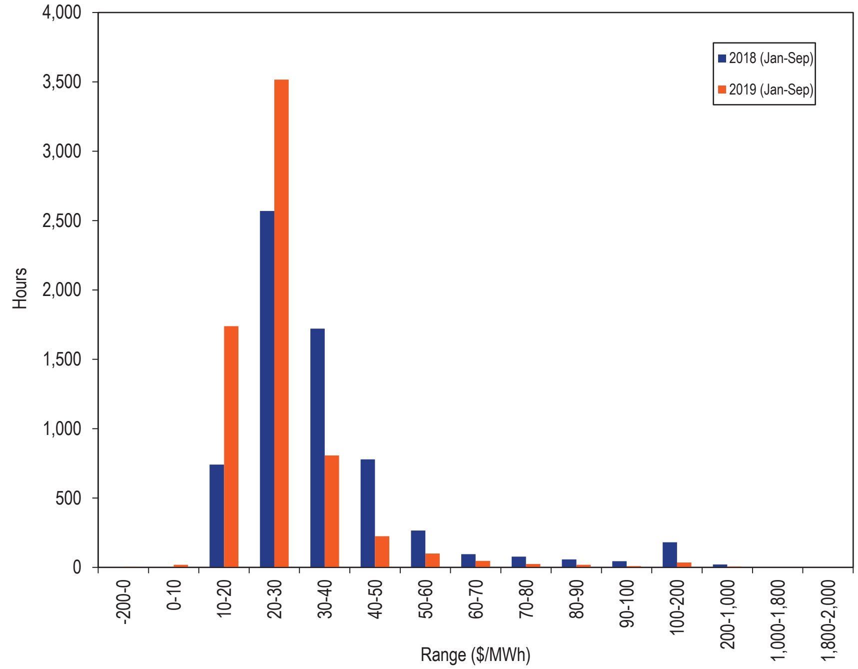
38 See the 2010 State of the Market Report for PJM: Technical Reference for PJM Markets, at "Calculating Locational Marginal Price," p 16-18 for detailed definition of Real-Time LMP. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

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

PJM Real-Time Average LMP Duration

Figure 3-23 shows the hourly distribution of PJM real-time average LMP for the first nine months of 2018 and 2019.

Figure 3-23 Average LMP for the Real-Time Energy Market: January through September, 2018 and 2019



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 3-32 shows the PJM real-time, load-weighted, average LMP in the first nine months of 1998 through 2019.

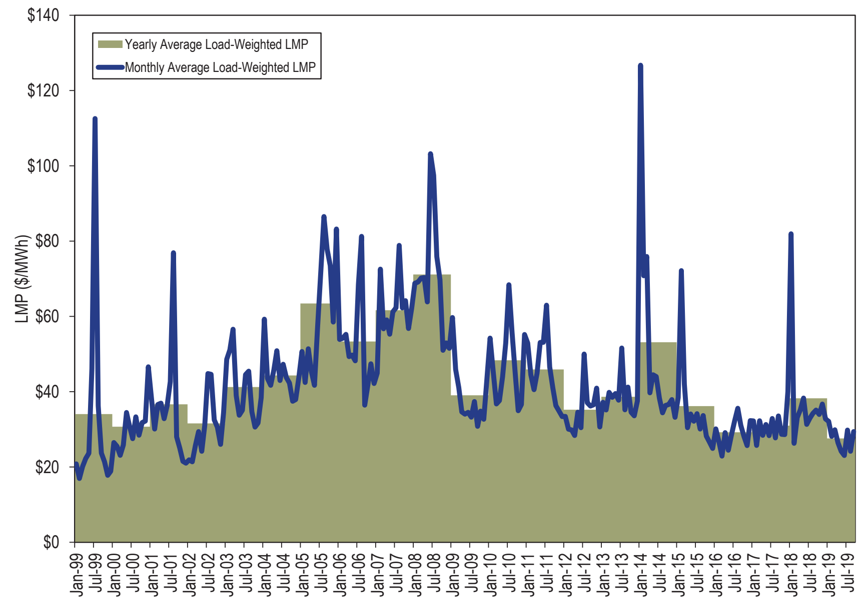
Table 3-32 Real-time, load-weighted, average LMP (Dollars per MWh): January through September, 1998 through 2019

	Real-Time, Load-Weighted, Average LMP			Year-to-Year Change		
(Jan-Sep)	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$26.06	$18.20	$44.65	NA	NA	NA
1999	$38.65	$20.02	$104.17	48.3%	10.0%	133.3%
2000	$28.49	$19.30	$26.89	(26.3%)	(3.6%)	(74.2%)
2001	$40.96	$28.18	$64.57	43.8%	46.0%	140.1%
2002	$31.95	$23.09	$29.14	(22.0%)	(18.1%)	(54.9%)
2003	$43.57	$38.17	$26.53	36.3%	65.3%	(9.0%)
2004	$46.44	$43.03	$21.89	6.6%	12.7%	(17.5%)
2005	$60.44	$50.10	$36.52	30.2%	16.4%	66.9%
2006	$56.39	$46.82	$40.70	(6.7%)	(6.5%)	11.4%
2007	$61.83	$55.12	$37.98	9.7%	17.7%	(6.7%)
2008	$77.27	$66.73	$43.80	25.0%	21.1%	15.3%
2009	$39.57	$34.57	$19.04	(48.8%)	(48.2%)	(56.5%)
2010	$49.91	$40.33	$29.65	26.2%	16.7%	55.7%
2011	$49.48	$38.72	$37.02	(0.9%)	(4.0%)	24.8%
2012	$35.02	$29.84	$25.44	(29.2%)	(22.9%)	(31.3%)
2013	$39.75	$33.61	$26.47	13.5%	12.6%	4.0%
2014	$58.60	$37.93	$86.22	47.4%	12.8%	225.8%
2015	$38.94	$29.09	$33.95	(33.5%)	(23.3%)	(60.6%)
2016	$29.32	$24.60	$17.13	(24.7%)	(15.4%)	(49.6%)
2017	$30.36	$26.26	$18.81	3.5%	6.7%	9.8%
2018	$39.43	$28.78	$36.82	29.9%	9.6%	95.7%
2019	$27.60	$24.23	$18.69	(30.0%)	(15.8%)	(49.2%)

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

Figure 3-24 shows the PJM real-time monthly and annual load-weighted LMP for January 1999 through September 2019.

Figure 3-24 Real-time, monthly and annual, load-weighted, average LMP: January 1999 through September 2019



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

Figure 3-25 shows the PJM real-time monthly load-weighted average LMP and inflation adjusted monthly load-weighted average LMP for 1998, through September 2019.[40] Table 3-33 shows the PJM real-time load-weighted average LMP and inflation adjusted, load-weighted average LMP for the first nine months of every year from 1998 through 2019. The PJM real-time inflation adjusted load-weighted average LMP for January through September, 2019

40 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 October 1, 2019)

was the lowest nine month value since PJM real-time markets started on April 1, 1999. The real-time inflation adjusted monthly load-weighted average LMP for June 2019 ($14.54 per MWh) was the lowest monthly value since April 1, 1999.

Figure 3-25 Real-time, monthly, load-weighted, average LMP unadjusted and adjusted for inflation: January 1998 through September 2019

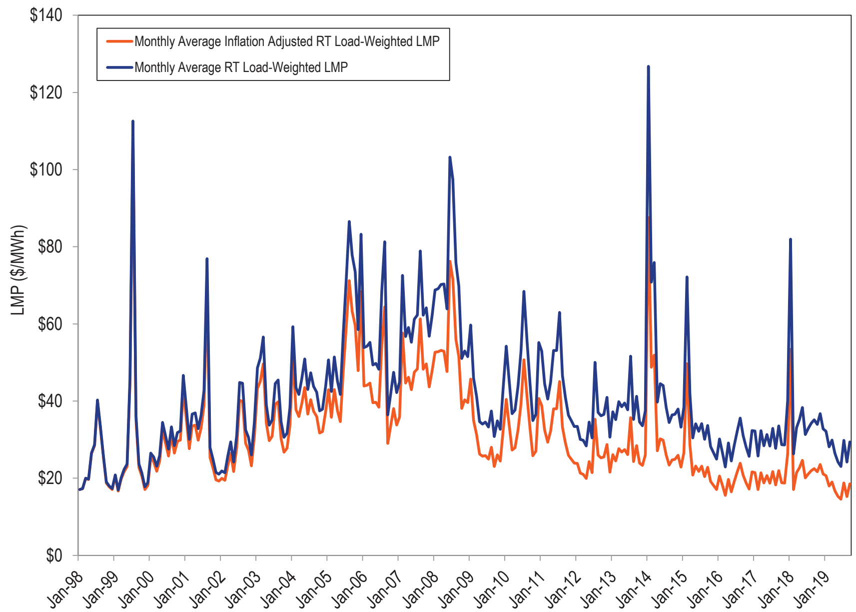


Table 3-33 Real-time, yearly, load-weighted, average LMP unadjusted and adjusted for inflation: January through September, 1998 through 2019

	Load-Weighted, Average LMP	Inflation Adjusted Load-Weighted, Average LMP
1998	$26.06	$25.86
1999	$38.65	$37.55
2000	$28.49	$26.82
2001	$40.96	$37.39
2002	$31.95	$28.72
2003	$43.57	$38.33
2004	$46.44	$39.85
2005	$60.44	$50.09
2006	$56.39	$45.16
2007	$61.83	$48.36
2008	$77.27	$57.70
2009	$39.57	$29.93
2010	$49.91	$37.04
2011	$49.48	$35.59
2012	$35.02	$24.68
2013	$39.75	$27.58
2014	$58.60	$40.11
2015	$38.94	$26.60
2016	$29.32	$19.77
2017	$30.36	$20.05
2018	$39.43	$25.45
2019	$27.60	$17.49

Real-Time Dispatch and Pricing

The PJM Real-Time Energy Market consists of a series of applications that produce the generator dispatch for energy and reserves, and five minute locational marginal prices (LMPs). These applications include the ancillary services optimizer (ASO), real-time security constrained economic dispatch (RT SCED), and the locational pricing calculator (LPC).[41] The final real-time LMPs and ancillary service clearing prices are determined for every five minute interval by LPC.

The processes to commit and dispatch reserves determine whether PJM implements scarcity pricing. Scarcity pricing transparency requires greater transparency around the processes used to commit and dispatch reserves and to calculate prices.

41 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Rev. 107 (Sep. 26, 2019)

Real-Time SCED and LPC

LPC uses data from an approved RT SCED solution that was used to dispatch the resources in the system. On average, PJM operators approve more than one RT SCED case per five minute interval to send dispatch signals to resources. PJM operators select only a subset of these approved RT SCED cases to be used in LPC to calculate real-time LMPs. Generally, LPC uses the latest available approved RT SCED case to calculate prices. However, LPC assigns the prices to a target interval that is different from the target interval of the RT SCED case it used.

PJM operators approve a larger number of RT SCED cases to send dispatch signals to generators than the number of RT SCED cases used to calculate prices in LPC. As a result, a number of dispatch directives are not reflected in real-time energy market prices.

Figure 3-26 shows, on a daily basis for the first nine months of 2019, the total number of solved RT SCED cases, the number of operator approved RT SCED cases, and the number of RT SCED cases that were used in LPC to calculate five minute LMPs. Table 3-34 shows, on a monthly basis for the first nine months of 2019, the number of solved RT SCED cases, the number and percent of solved cases that were approved and the number and percent of solved cases used in LPC. RT SCED is executed every three minutes. Each execution of RT SCED produces three solutions, using three different levels of load bias. Since prices are calculated every five minutes while three SCED solutions are produced every three minutes, there is a larger number of solved SCED cases than are five minute intervals in any given period. Table 3-34 shows that only 61.5 percent of approved RT SCED cases that are used to send dispatch signals to generators are used in calculating real-time energy market prices. This weakens the incentives to follow dispatch by generators, especially when RT SCED cases that reflect shortage pricing are not used in calculating real-time prices in LPC.

Figure 3-26 Daily RT SCED cases solved, approved and used in pricing: January through September, 2019

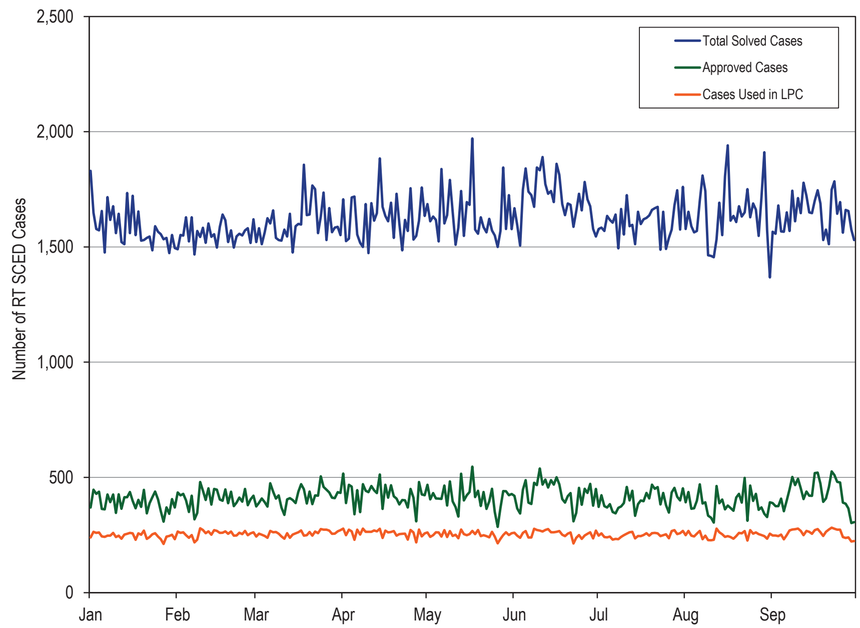


Table 3-34 RT SCED cases solved, approved and used in pricing: January through September, 2019

Month (2019)	Number of Solved RT SCED Cases	Number of Approved RT SCED Cases	Number of Approved RT SCED Cases Used in LPC	Approved RT SCED Cases as Percent of Solved Cases	RT SCED Cases Used in LPC as Percent of Solved Cases	RT SCED Cases Used in LPC as Percent of Approved Cases
Jan	49,158	12,177	7,656	24.8%	15.6%	62.9%
Feb	43,628	11,484	7,186	26.3%	16.5%	62.6%
Mar	49,753	12,942	7,966	26.0%	16.0%	61.6%
Apr	48,765	12,759	7,768	26.2%	15.9%	60.9%
May	50,772	12,890	7,808	25.4%	15.4%	60.6%
Jun	51,299	12,988	7,651	25.3%	14.9%	58.9%
Jul	50,011	12,484	7,752	25.0%	15.5%	62.1%
Aug	50,769	12,012	7,731	23.7%	15.2%	64.4%
Sep	49,276	12,870	7,737	26.1%	15.7%	60.1%
Total	443,431	112,606	69,255	25.4%	15.6%	61.5%

PJM's process of selecting approved RT SCED cases to use in LPC to calculate LMPs has an inconsistency that leads to downstream impacts for energy and reserve settlements. The MMU has identified systematic differences in the target intervals for the RT SCED cases approved to send dispatch signals to generators, and the cases used to calculate energy and ancillary service prices in LPC. RT SCED solves the dispatch problem for a target interval that is generally 10 to 14 minutes in the future. An RT SCED case is approved and sends dispatch signals to generators. The approved RT SCED case is then used to calculate LMPs in LPC. However, the target interval in LPC is consistently before the target interval from the RT SCED case used for the dispatch signal. For example the LPC case that calculates prices for the interval beginning 10:00 EPT uses an approved RT SCED case that sent MW dispatch signals for the target interval 10:10 EPT. This discrepancy leads to a mismatch between the MW dispatch and real-time LMPs.

Table 3-35 compares the RT SCED and LPC target intervals for the first nine months of 2019. Table 3-35 shows that in the first nine months of 2019, 67.7 percent of the five minute intervals have prices assigned for a target interval that is 10 minutes prior to the dispatch target interval and 27.5 percent of five minute intervals have prices assigned for a target interval that is five minutes prior to the dispatch target interval.

Table 3-35 Difference in RT SCED and LPC target intervals: January through September, 2019

Difference between RT SCED and LPC Target Intervals (mins)	Percent of Five Minute Intervals
(10)	0.1%
(5)	0.5%
0	4.0%
5	27.5%
10	67.7%

For correct price signals and compensation, LMP and ancillary service pricing should align with the dispatch solution that creates those prices for each and every real-time market interval.[42] The MMU recommends that PJM approve one RT SCED case for each five minute interval to send dispatch signals, and that PJM calculate prices for that five minute interval using the same approved SCED case.

Recalculation of Five Minute Real-Time Prices

PJM's five minute interval LMPs are obtained from solved LPC optimization cases. PJM recalculates five minute interval real-time LMPs as it believes necessary to correct errors. To do so, PJM reruns LPC optimization cases with modified inputs. The PJM OATT allows for posting of recalculated real-time prices no later than 5:00 p.m. of the tenth calendar day following the

42 *See* Order No. 825: Settlement Intervals and Shortage Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators, 155 FERC ¶ 61,276 (June 16, 2016).

operating day. The OATT also requires PJM to notify market participants of the underlying error no later than 5:00 pm of the second business day following the operating day.[43] Table 3-36 shows the number of five minute intervals in each month and number of five minute intervals in each month for which PJM recalculated real-time prices. In the first nine months of 2019, among 78,612 five minute intervals, PJM recalculated LMPs for 334 five minute intervals or 0.42 percent of the total five minute intervals in the first nine months.

Table 3-36 Number of five minute interval real-time prices recalculated, January through September, 2019

Month	Number of Five Minute Intervals	Number of Five Minute Intervals for which LMPs were recalculated
January	8,928	10
February	8,064	14
March	8,916	51
April	8,640	19
May	8,928	19
June	8,640	28
July	8,928	69
August	8,928	79
September	8,640	45
Total	78,612	334

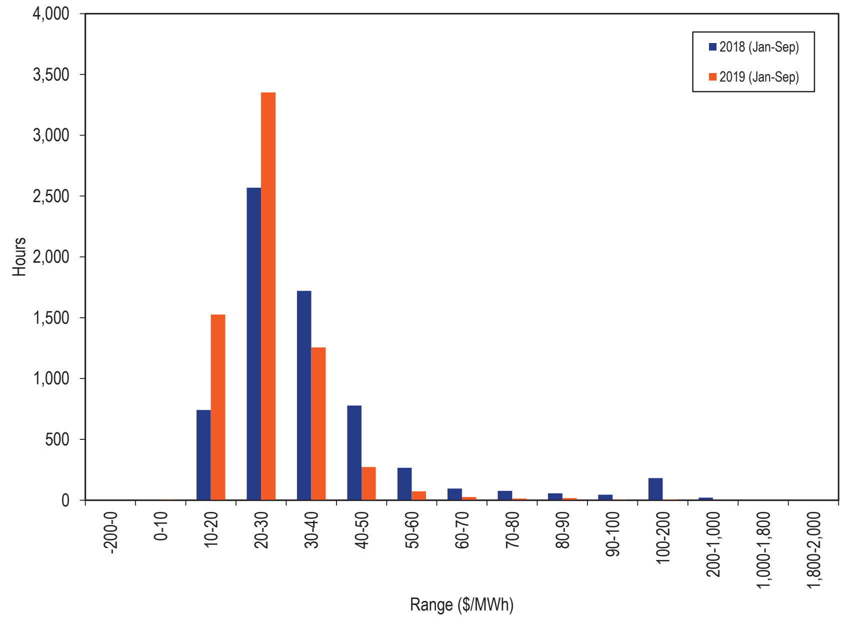
Day-Ahead Average LMP

Day-ahead average LMP is the hourly average LMP for the PJM Day-Ahead Energy Market.[44]

PJM Day-Ahead Average LMP Duration

Figure 3-27 shows the hourly distribution of PJM day-ahead average LMP in the first nine months of 2018 and 2019.

Figure 3-27 Average LMP for the Day-Ahead Energy Market: January through September, 2018 and 2019



43 OATT Attachment K § 1.10.8(e).

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

PJM Day-Ahead, Average LMP

Table 3-37 shows the PJM day-ahead, average LMP in the first nine months of 2000 through 2019.

Table 3-37 Day-ahead, average LMP (Dollars per MWh): January through September, 2000 through 2019

	Day-Ahead LMP			Year-to-Year Change		
(Jan-Sep)	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2000	$28.19	$21.10	$19.10	NA	NA	NA
2001	$36.07	$30.02	$34.25	28.0%	42.3%	79.4%
2002	$28.29	$22.54	$19.09	(21.6%)	(24.9%)	(44.3%)
2003	$41.20	$38.24	$22.02	45.6%	69.7%	15.4%
2004	$42.64	$42.07	$17.47	3.5%	10.0%	(20.7%)
2005	$54.48	$46.67	$28.83	27.8%	10.9%	65.1%
2006	$50.45	$46.32	$24.93	(7.4%)	(0.8%)	(13.5%)
2007	$54.24	$51.40	$24.95	7.5%	11.0%	0.1%
2008	$71.43	$66.38	$33.11	31.7%	29.2%	32.7%
2009	$37.35	$35.29	$14.32	(47.7%)	(46.8%)	(56.8%)
2010	$45.81	$41.03	$19.59	22.7%	16.3%	36.8%
2011	$45.14	$40.20	$22.68	(1.5%)	(2.0%)	15.7%
2012	$32.16	$30.10	$14.54	(28.8%)	(25.1%)	(35.9%)
2013	$37.50	$34.70	$16.96	16.6%	15.3%	16.6%
2014	$53.76	$39.92	$58.98	43.4%	15.0%	247.8%
2015	$36.67	$30.56	$25.21	(31.8%)	(23.4%)	(57.3%)
2016	$27.90	$25.23	$11.37	(23.9%)	(17.4%)	(54.9%)
2017	$28.90	$26.60	$10.73	3.6%	5.4%	(5.6%)
2018	$36.04	$29.75	$25.12	24.7%	11.8%	134.2%
2019	$26.41	$24.76	$9.58	(26.7%)	(16.8%)	(61.9%)

Day-Ahead, Load-Weighted, Average LMP

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

PJM Day-Ahead, Load-Weighted, Average LMP

Table 3-38 shows the PJM day-ahead, load-weighted, average LMP in the first nine months of 2000 through 2019.

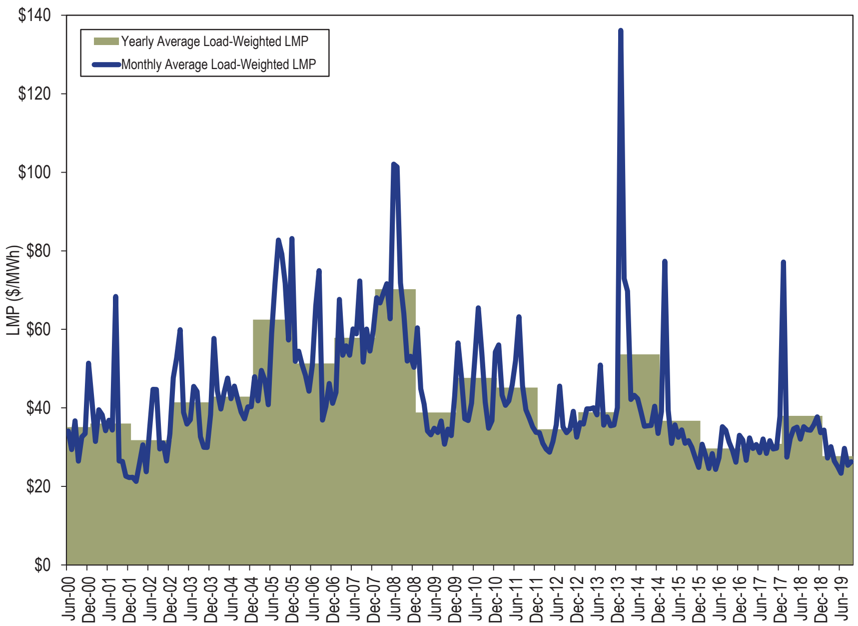
Table 3-38 Day-ahead, load-weighted, average LMP (Dollars per MWh): January through September, 2000 through 2019

	Day-Ahead, Load-Weighted, Average LMP			Year-to-Year Change		
(Jan-Sep)	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2000	NA	NA	NA	NA	NA	NA
2001	$39.88	$32.68	$42.01	NA	NA	NA
2002	$32.29	$25.22	$22.81	(19.0%)	(22.8%)	(45.7%)
2003	$44.11	$41.51	$22.34	36.6%	64.6%	(2.1%)
2004	$44.59	$44.47	$17.40	1.1%	7.1%	(22.1%)
2005	$59.51	$51.33	$31.13	33.5%	15.4%	78.9%
2006	$54.19	$48.87	$28.35	(8.9%)	(4.8%)	(8.9%)
2007	$57.79	$55.62	$26.07	6.6%	13.8%	(8.0%)
2008	$75.96	$70.35	$35.19	31.5%	26.5%	35.0%
2009	$39.35	$36.92	$14.98	(48.2%)	(47.5%)	(57.4%)
2010	$49.12	$43.33	$21.35	24.8%	17.4%	42.6%
2011	$48.34	$42.35	$26.54	(1.6%)	(2.3%)	24.3%
2012	$34.29	$31.17	$17.12	(29.1%)	(26.4%)	(35.5%)
2013	$39.49	$35.96	$19.90	15.1%	15.4%	16.3%
2014	$59.09	$42.08	$67.27	49.6%	17.0%	238.0%
2015	$39.51	$32.15	$28.05	(33.1%)	(23.6%)	(58.3%)
2016	$29.69	$26.60	$12.38	(24.8%)	(17.3%)	(55.8%)
2017	$30.26	$27.95	$11.59	1.9%	5.1%	(6.4%)
2018	$38.71	$31.62	$27.75	27.9%	13.1%	139.5%
2019	$27.70	$25.85	$10.40	(28.4%)	(18.3%)	(62.5%)

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

Figure 3-28 shows the PJM day-ahead, monthly and annual, load-weighted LMP from June 1, 2000 through September 30, 2019.[45]

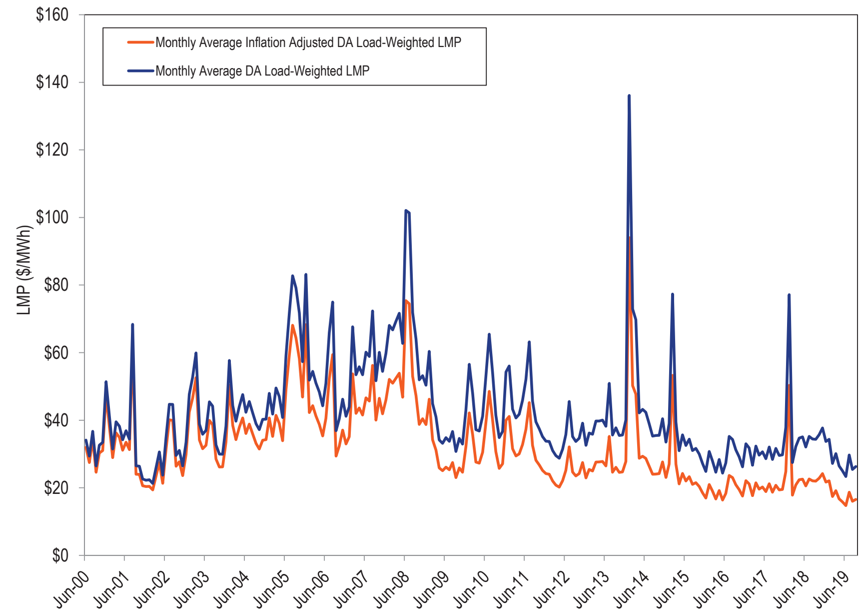
Figure 3-28 Day-ahead, monthly and annual, load-weighted, average LMP: June 2000 through September 2019



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

Figure 3-29 shows the PJM day-ahead monthly load-weighted average LMP and inflation adjusted monthly day-ahead load-weighted average LMP for June 2000 through September 2019.[46] Table 3-39 shows the PJM day-ahead load-weighted average LMP and inflation adjusted load-weighted average LMP for the first nine months of every year from 2000 through 2019. The PJM day-ahead inflation adjusted load-weighted average LMP for January through September, 2019 was the lowest nine month value since PJM day-ahead markets started in 2000. The day-ahead inflation adjusted monthly load-weighted average LMP for June 2019 ($14.73 per MWh) was the lowest monthly value since 2000.

Figure 3-29 Day-ahead, monthly, load-weighted, average LMP unadjusted and inflation adjusted: June 2000 through September 2019



45 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.

46 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 October 1, 2019).

Table 3-39 Day-ahead, yearly, load-weighted, average LMP unadjusted and inflation adjusted: January through September, 2000 through 2019

	Load-Weighted, Average LMP	Inflation Adjusted Load-Weighted, Average LMP
2000	$31.81	$29.74
2001	$39.88	$36.41
2002	$32.29	$29.02
2003	$44.11	$38.81
2004	$44.59	$38.26
2005	$59.51	$49.32
2006	$54.19	$43.40
2007	$57.79	$45.19
2008	$75.96	$56.73
2009	$39.35	$29.77
2010	$49.12	$36.46
2011	$48.34	$34.79
2012	$34.29	$24.17
2013	$39.49	$27.40
2014	$59.09	$40.45
2015	$39.51	$26.99
2016	$29.69	$20.03
2017	$30.26	$19.99
2018	$38.71	$24.98
2019	$27.70	$17.55

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 3-40 shows the number of cleared UTC transactions, the number of profitable cleared UTCs, the number of cleared UTCs that were profitable at their source point and the number of cleared UTCs that were profitable at their sink point in the first nine months of 2018 and 2019. In the first nine months of 2019, 48.9 percent of all cleared UTC transactions were net profitable. Of cleared UTC transactions, 67.0 percent were profitable on the source side and 33.5 were profitable on the sink side but only 6.5 percent were profitable on both the source and sink side.

Table 3-40 Cleared UTC profitability by source and sink point: January through September, 2018 and 2019[47]

(Jan-Sep)	Cleared UTCs	Profitable UTCs	UTC Profitable at Source Bus	UTC Profitable at Sink Bus	UTC Profitable at Source and Sink	Profitable UTC	Profitable Source	Profitable Sink	Profitable at Source and Sink
2018	7,480,780	3,730,433	4,763,121	2,768,109	422,976	49.9%	63.7%	37.0%	5.7%
2019	6,953,487	3,399,845	4,656,194	2,329,766	450,234	48.9%	67.0%	33.5%	6.5%

Table 3-41 shows the number of cleared INC and DEC transactions, the number of profitable cleared transactions in the first nine months of 2018 and 2019. Of cleared INC and DEC transactions in the first nine months of 2019, 67.9 percent of INCs were profitable and 35.4 percent of DECs were profitable.

Table 3-41 Cleared INC and DEC profitability: January through September, 2018 and 2019

(Jan-Sep)	Cleared INC	Profitable INC	Profitable INC Percent	Cleared DEC	Profitable DEC	Profitable DEC Percent
2018	1,549,323	1,015,130	65.5%	1,182,673	452,282	38.2%
2019	1,628,241	1,105,533	67.9%	1,364,023	482,371	35.4%

47 Calculations exclude PJM administrative charges.

Figure 3-30 shows total UTC daily gross profits, the sum of all positive profit UTC transactions, gross losses, the sum of all negative profit UTC transactions, and net profits and losses in the first nine months of 2019.

Figure 3-30 UTC daily gross profits and losses and net profits: January through September, 2019[48]

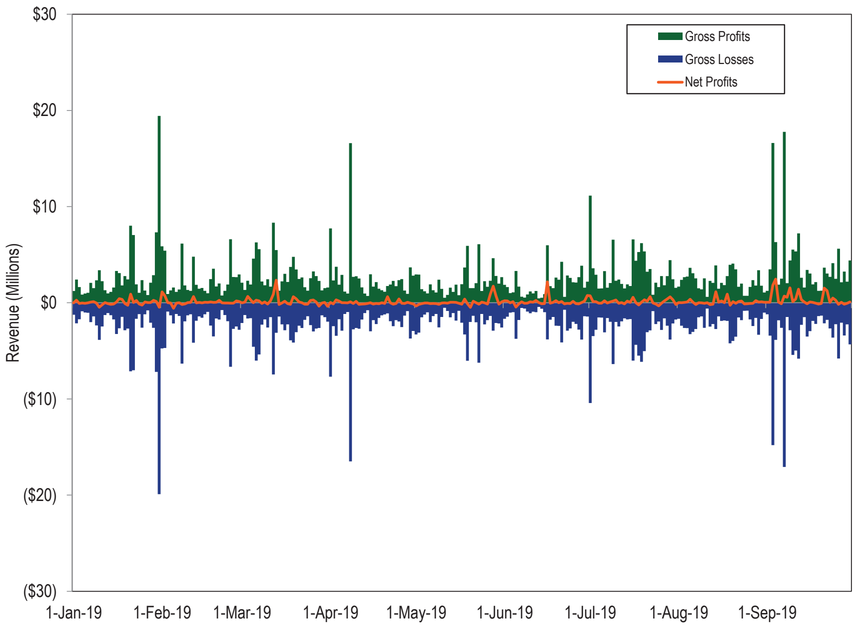
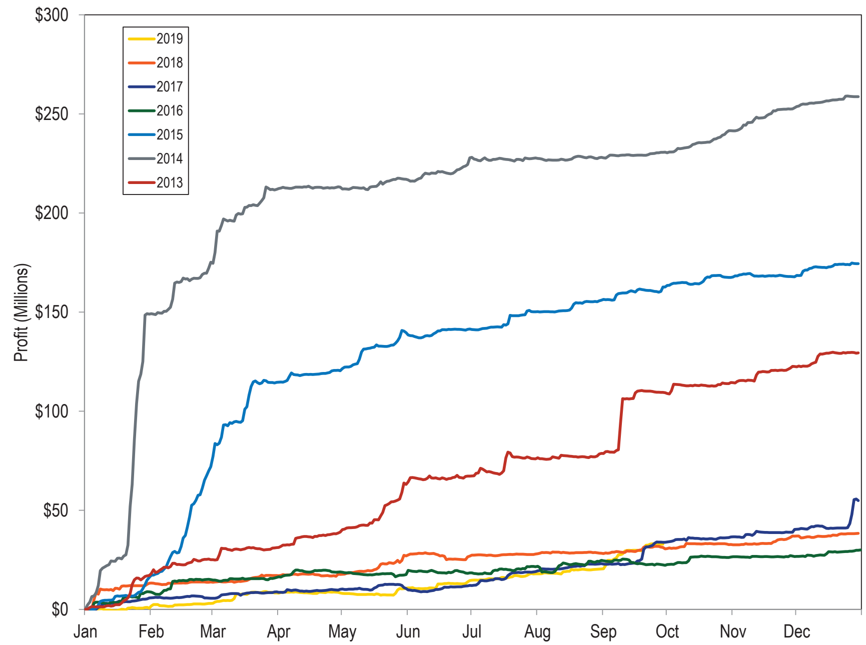


Figure 3-31 shows the cumulative UTC daily profits for January 1, 2013 through September 30, 2019. UTC profits during this period were primarily a result of significant unanticipated price differences between day-ahead and real-time LMPs.

Figure 3-31 Cumulative daily UTC profits: January 2013 through September 2019



48 Calculations exclude PJM administrative charges.

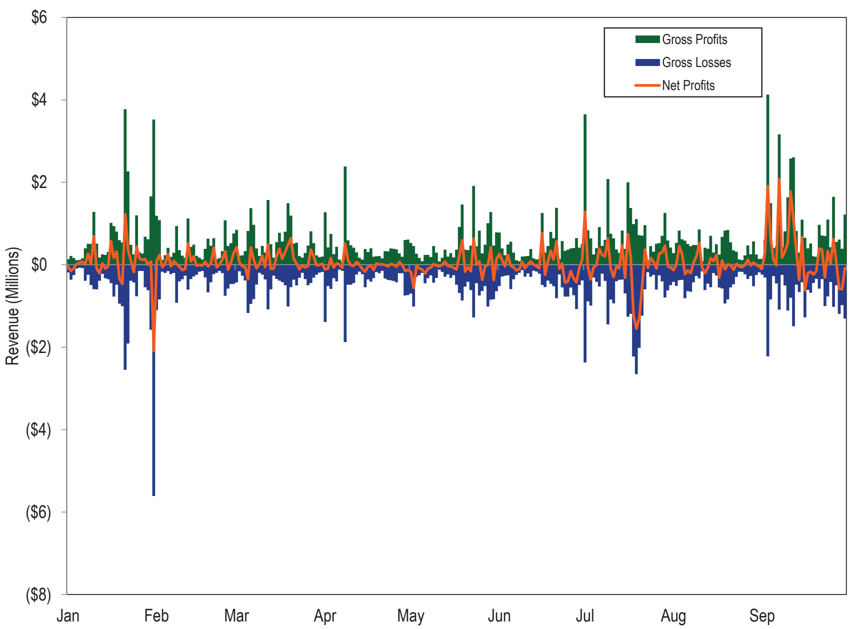
Table 3-42 shows UTC profits by month for January 1, 2013 through September 30, 2019. May 2016, September 2016, February 2017 and June 2018 were the only months in the past six years where the total monthly profits were negative.

Table 3-42 UTC profits by month: January 2013 through September 2019

	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
2018	$13,184,346	$506,509	$3,410,577	$688,796	$9,499,735	($768,614)	$1,163,380	$692,736	$2,845,649	$1,452,515	$4,339,363	$1,358,446	$38,373,436
2019	$574,901	$2,407,307	$5,287,985	$332,036	$1,833,879	$3,382,009	$4,066,461	$2,442,971	$12,599,278				$32,926,829

Figure 3-32 shows total INC and DEC daily gross profits, the sum of all positive profit transactions, gross losses, the sum of all negative profit transactions, and net profits and losses in the first nine months of 2019.

Figure 3-32 INC and DEC daily gross profits and losses and net profits: January through September, 2019[49]



49 Calculations exclude PJM administrative charges.

Figure 3-33 shows total INC daily gross profits and losses and net profits and losses in the first nine months of 2019.

Figure 3-33 INC daily gross profits and losses and net profits: January through September, 2019[50]

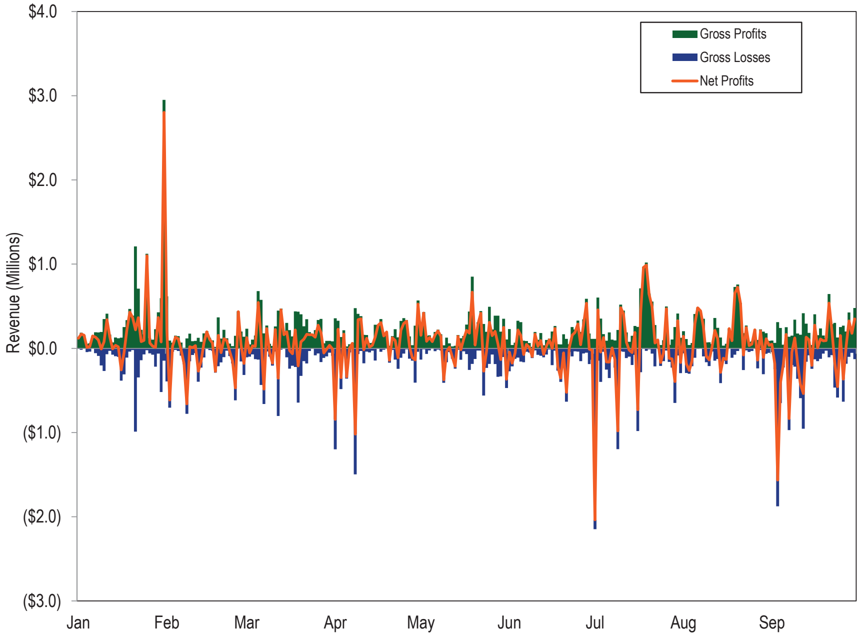
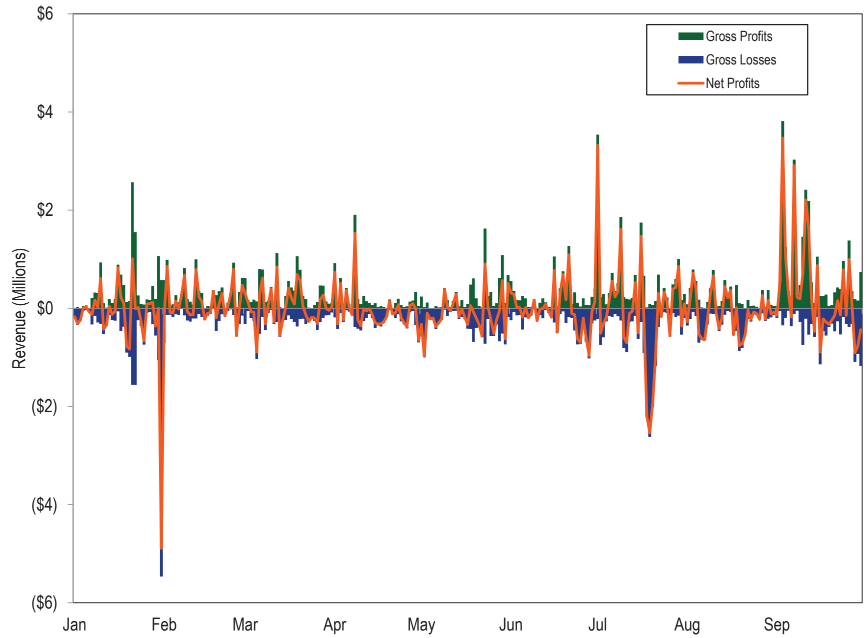


Figure 3-34 shows total DEC daily gross profits and losses and net profits and losses in the first nine months of 2019.

Figure 3-34 DEC daily gross profits and losses and net profits: January through September, 2019[51]



50 Calculations exclude PJM administrative charges.

51 Calculations exclude PJM administrative charges.

Figure 3-35 shows the cumulative INC and DEC daily profits for January 1, through September 30, 2019.

Figure 3-35 Cumulative daily INC and DEC profits: January through September, 2019

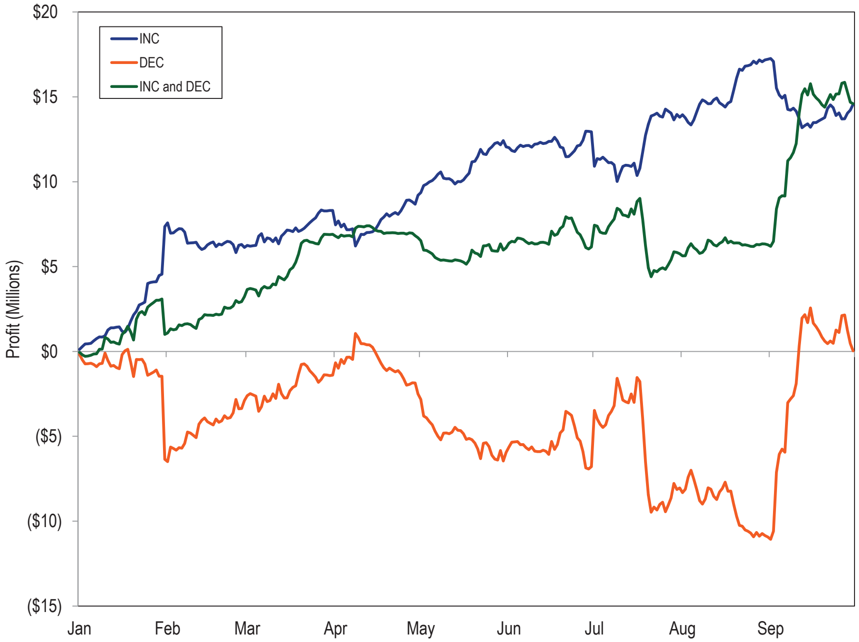


Table 3-43 shows INC and DEC profits by month for January 1, through September 30, 2019.

Table 3-43 INC and DEC profits by month: January through September, 2019

	January	February	March	April	May	June	July	August	September	Total
INCs	$7,354,057	($1,229,270)	$2,180,622	$898,417	$2,853,902	$885,231	$856,466	$3,417,744	($2,653,011)	$14,564,157
DECs	($6,349,787)	$3,455,508	$1,497,078	($1,109,340)	($3,439,754)	($841,301)	($1,256,859)	($2,882,716)	$10,958,759	$31,587
INCs and DECs	$1,004,269	$2,226,238	$3,677,699	($210,923)	($585,853)	$43,930	($400,393)	$535,027	$8,305,748	$14,595,744

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 3-37).

Table 3-44 shows that the difference between the average real-time price and the average day-ahead price was $0.48 per MWh in the first nine months of 2018, and -$0.11 per MWh in the first nine months of 2019. The difference between average peak real-time price and the average peak day-ahead price was -$0.20 per MWh in the first nine months of 2018 and -$0.32 per MWh in the first nine months of 2019.

Table 3-44 Day-ahead and real-time average LMP (Dollars per MWh): January through September, 2018 and 2019[52]

	2018 (Jan-Sep)				2019 (Jan-Sep)			
	Day-Ahead	Real-Time	Difference	Percent of Real Time	Day-Ahead	Real-Time	Difference	Percent of Real Time
Average	$36.04	$36.52	$0.48	1.3%	$26.41	$26.30	($0.11)	(0.4%)
Median	$29.75	$27.26	($2.48)	(9.1%)	$24.76	$23.39	($1.37)	(5.8%)
Standard deviation	$25.12	$33.22	$8.10	24.4%	$9.58	$17.69	$8.11	45.9%
Peak average	$41.90	$41.70	($0.20)	(0.5%)	$30.72	$30.39	($0.32)	(1.1%)
Peak median	$35.92	$32.30	($3.62)	(11.2%)	$28.38	$26.03	($2.34)	(9.0%)
Peak standard deviation	$25.56	$31.13	$5.57	17.9%	$9.98	$20.67	$10.69	51.7%
Off peak average	$30.91	$31.98	$1.07	3.3%	$22.63	$22.71	$0.08	0.3%
Off peak median	$24.37	$23.44	($0.93)	(4.0%)	$21.24	$20.53	($0.71)	(3.5%)
Off peak standard deviation	$23.57	$34.31	$10.74	31.3%	$7.37	$13.61	$6.25	45.9%

The price difference between the Real-Time and the Day-Ahead Energy Markets results in part, from conditions in the Real-Time Energy Market that are difficult, or impossible, to anticipate in the Day-Ahead Energy Market.

Table 3-45 shows the difference between the real-time load-weighted and the day-ahead load-weighted energy market prices for the first nine months of 2001 through 2019.

Table 3-45 Day-ahead load-weighted and real-time load-weighted average LMP (Dollars per MWh): January through September, 2001 through 2019

(Jan-Sep)	Day-Ahead	Real-Time	Difference	Percent of Real Time
2001	$36.07	$36.00	($0.07)	(0.2%)
2002	$28.29	$28.13	($0.16)	(0.6%)
2003	$41.20	$40.42	($0.77)	(1.9%)
2004	$42.64	$43.85	$1.22	2.9%
2005	$54.48	$54.69	$0.21	0.4%
2006	$50.45	$51.79	$1.34	2.7%
2007	$54.24	$57.34	$3.10	5.7%
2008	$71.43	$71.94	$0.51	0.7%
2009	$37.35	$37.42	$0.08	0.2%
2010	$45.81	$46.13	$0.32	0.7%
2011	$45.14	$45.79	$0.65	1.4%
2012	$32.16	$32.45	$0.29	0.9%
2013	$37.50	$37.30	($0.20)	(0.5%)
2014	$53.76	$52.72	($1.04)	(1.9%)
2015	$36.67	$35.96	($0.70)	(1.9%)
2016	$27.90	$27.43	($0.47)	(1.7%)
2017	$28.90	$28.79	($0.11)	(0.4%)
2018	$36.04	$36.52	$0.48	1.3%
2019	$26.41	$26.30	($0.11)	(0.4%)

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

Table 3-46 provides frequency distributions of the differences between PJM real-time load-weighted hourly LMP and PJM day-ahead load-weighted hourly LMP for the first nine months of 2018 and 2019.

Table 3-46 Frequency distribution by hours of real-time load-weighted LMP minus day-ahead load-weighted LMP (Dollars per MWh): January through September, 2018 and 2019

	2018 (Jan-Sep)		2019 (Jan-Sep)	
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)	1	0.02%	0	0.00%
($150) to ($100)	3	0.06%	0	0.00%
($100) to ($50)	31	0.53%	5	0.08%
($50) to $0	4,130	63.58%	4,400	67.24%
$0 to $50	2,244	97.83%	2,102	99.33%
$50 to $100	102	99.39%	22	99.66%
$100 to $150	24	99.76%	14	99.88%
$150 to $200	5	99.83%	1	99.89%
$200 to $250	8	99.95%	3	99.94%
$250 to $300	1	99.97%	1	99.95%
$300 to $350	1	99.98%	1	99.97%
$350 to $400	0	99.98%	0	99.97%
$400 to $450	1	100.00%	0	99.97%
$450 to $500	0	100.00%	0	99.97%
$500 to $750	0	100.00%	2	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 3-36 shows the hourly differences between day-ahead and real-time hourly LMP in the first nine months of 2019.

Figure 3-36 Real-time hourly LMP minus day-ahead hourly LMP: January through September, 2019

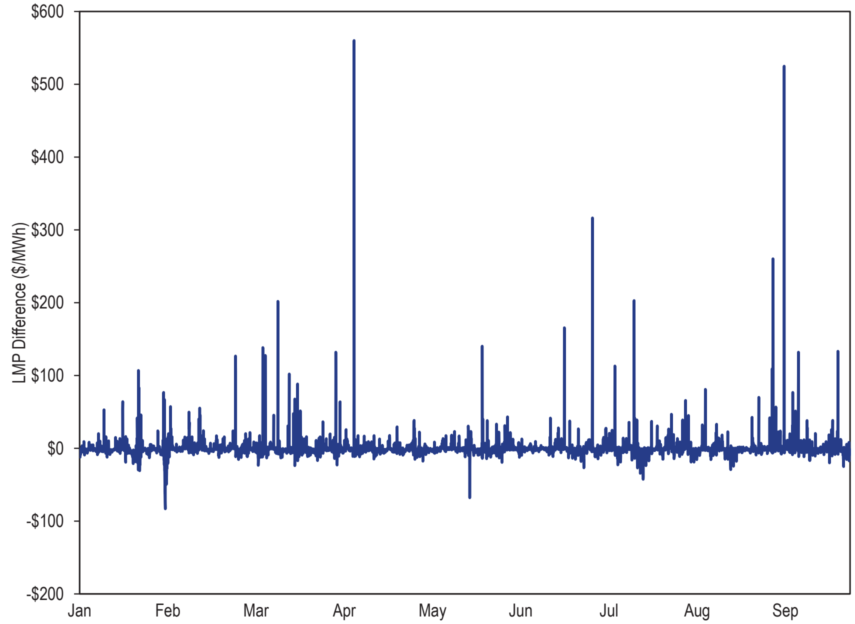


Figure 3-37 shows the monthly average, and monthly absolute value, of the differences between the day-ahead and real-time PJM average LMPs in the first nine months of 2019.

Figure 3-37 Monthly average, and monthly absolute value, of real-time minus day-ahead LMP: January 2013 through September 2019

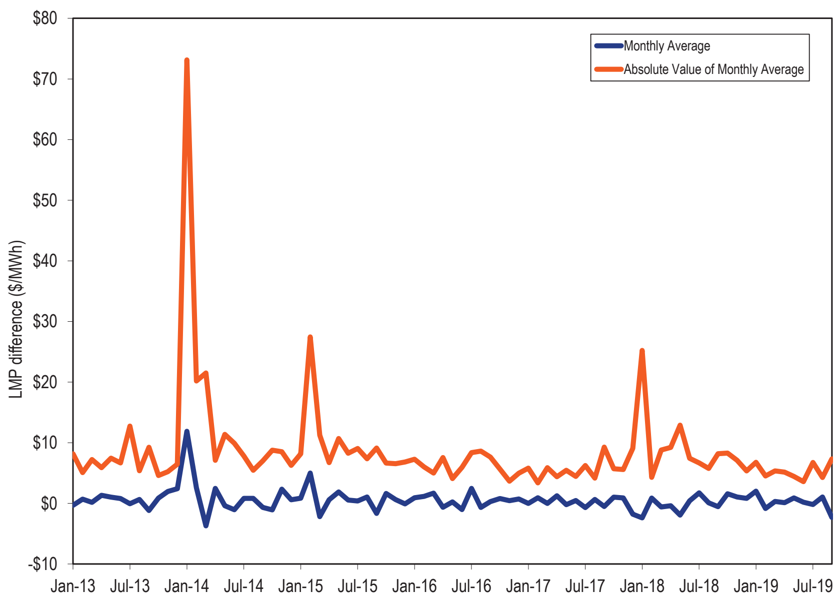
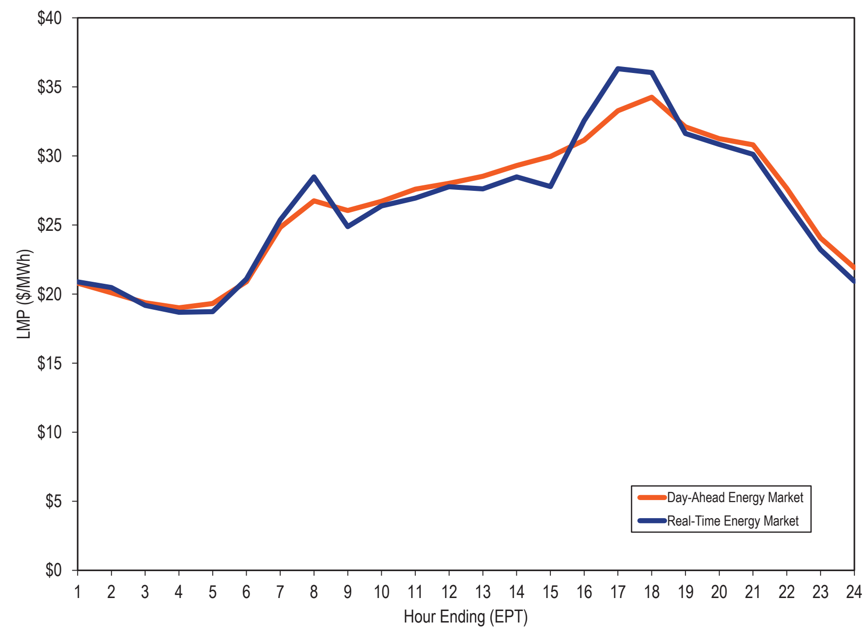


Figure 3-38 shows day-ahead and real-time load-weighted LMP on an average hourly basis for the first nine months of 2019. Hour ending 17 had the largest difference between the DA and RT load-weighted LMP, at $3.04 per MWh, and hour ending 1 had the smallest difference at $0.08 per MWh. The average for the first nine months of 2019 was $0.11 per MWh lower in the RT LMP than DA LMP.

Figure 3-38 System hourly average LMP: January through September, 2019



Zonal LMP and Dispatch

Table 3-47 shows zonal real-time, and real-time, load-weighted, average LMP in the first nine months of 2018 and 2019.

Table 3-47 Zonal real-time and real-time, load-weighted, average LMP (Dollars per MWh): January through September, 2018 and 2019

	Real-Time Average LMP			Real-Time, Load-Weighted, Average LMP		
Zone	2018 (Jan-Sep)	2019 (Jan-Sep)	Percent Change	2018 (Jan-Sep)	2019 (Jan-Sep)	Percent Change
AECO	$34.67	$24.61	(29.0%)	$37.27	$25.95	(30.4%)
AEP	$36.20	$26.94	(25.6%)	$38.79	$28.19	(27.3%)
APS	$38.06	$26.71	(29.8%)	$41.51	$28.02	(32.5%)
ATSI	$38.80	$26.96	(30.5%)	$41.48	$28.12	(32.2%)
BGE	$42.03	$29.11	(30.7%)	$46.51	$31.03	(33.3%)
ComEd	$28.25	$24.04	(14.9%)	$29.97	$25.20	(15.9%)
DAY	$37.25	$27.87	(25.2%)	$39.98	$29.32	(26.7%)
DEOK	$37.55	$26.88	(28.4%)	$40.56	$28.23	(30.4%)
DLCO	$40.41	$27.64	(31.6%)	$45.28	$29.16	(35.6%)
Dominion	$38.32	$26.43	(31.0%)	$44.03	$29.26	(33.5%)
DPL	$38.42	$26.59	(30.8%)	$41.19	$27.79	(32.5%)
EKPC	$33.44	$26.46	(20.9%)	$36.98	$28.07	(24.1%)
JCPL	$34.91	$24.58	(29.6%)	$38.10	$26.10	(31.5%)
Met-Ed	$34.46	$25.43	(26.2%)	$37.97	$26.92	(29.1%)
OVEC	NA	$25.97	NA	NA	$26.33	NA
PECO	$34.42	$24.30	(29.4%)	$37.63	$25.67	(31.8%)
PENELEC	$36.34	$25.54	(29.7%)	$38.83	$26.56	(31.6%)
Pepco	$40.77	$28.15	(31.0%)	$44.76	$29.79	(33.5%)
PPL	$33.63	$23.89	(29.0%)	$37.33	$25.21	(32.5%)
PSEG	$35.18	$24.89	(29.2%)	$37.70	$26.06	(30.9%)
RECO	$35.54	$25.09	(29.4%)	$38.30	$26.37	(31.2%)
PJM	$36.52	$26.30	(28.0%)	$39.43	$27.60	(30.0%)

Table 3-48 shows zonal day-ahead, and day-ahead, load-weighted, average LMP in the first nine months of 2018 and 2019.[53]

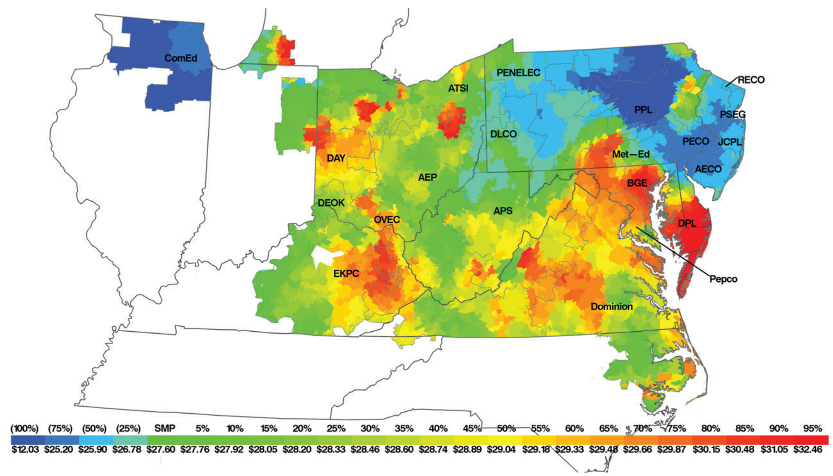
Table 3-48 Zonal day-ahead and day-ahead, load-weighted, average LMP (Dollars per MWh): January through September, 2018 and 2019

	Day-Ahead Average LMP			Day-Ahead, Load-Weighted, Average LMP		
Zone	2018 (Jan-Sep)	2019 (Jan-Sep)	Percent Change	2018 (Jan-Sep)	2019 (Jan-Sep)	Percent Change
AECO	$34.66	$24.55	(29.2%)	$36.95	$25.76	(30.3%)
AEP	$35.53	$26.92	(24.2%)	$37.90	$28.23	(25.5%)
APS	$37.42	$26.92	(28.1%)	$40.21	$28.22	(29.8%)
ATSI	$37.35	$27.24	(27.1%)	$39.53	$28.42	(28.1%)
BGE	$41.57	$29.48	(29.1%)	$45.54	$31.38	(31.1%)
ComEd	$28.06	$24.26	(13.5%)	$29.80	$25.35	(14.9%)
DAY	$36.90	$28.01	(24.1%)	$39.43	$29.43	(25.3%)
DEOK	$38.09	$27.28	(28.4%)	$41.25	$28.77	(30.3%)
DLCO	$40.18	$28.04	(30.2%)	$44.78	$29.70	(33.7%)
Dominion	$37.83	$26.12	(30.9%)	$42.98	$28.73	(33.2%)
DPL	$37.29	$26.86	(28.0%)	$39.70	$28.02	(29.4%)
EKPC	$33.14	$26.43	(20.3%)	$36.25	$28.11	(22.5%)
JCPL	$34.78	$24.47	(29.7%)	$37.44	$25.75	(31.2%)
Met-Ed	$34.67	$25.08	(27.7%)	$37.51	$26.35	(29.7%)
OVEC	NA	$25.98	NA	NA	$29.70	NA
PECO	$34.36	$24.04	(30.0%)	$36.96	$25.19	(31.8%)
PENELEC	$35.44	$25.97	(26.7%)	$37.95	$27.38	(27.9%)
Pepco	$40.44	$28.61	(29.3%)	$44.15	$30.33	(31.3%)
PPL	$33.59	$23.86	(29.0%)	$36.66	$25.05	(31.7%)
PSEG	$35.47	$24.81	(30.1%)	$37.97	$25.94	(31.7%)
RECO	$35.59	$25.34	(28.8%)	$38.05	$26.78	(29.6%)
PJM	$36.04	$26.41	(26.7%)	$38.71	$27.70	(28.4%)

53 The OVEC Zone did not have any day-ahead load in 2018.

Figure 3-39 is a map of the real-time, load-weighted, average LMP in the first nine months of 2019. 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.

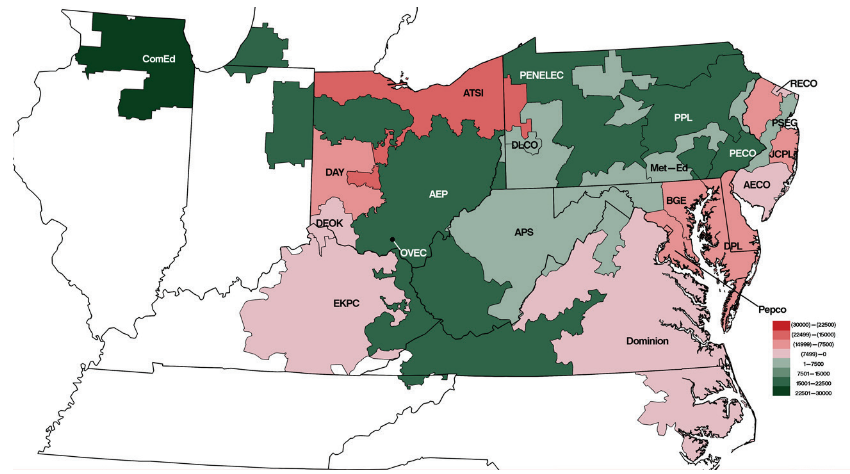
Figure 3-39 Real-time, load-weighted, average LMP: January through September, 2019



Net Generation by Zone

Figure 3-40 shows the difference between the PJM real-time generation and real-time load by zone in in the first nine months of 2019. Figure 3-40 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 3-49 shows the difference between the PJM real-time generation and real-time load by zone in the first nine months of 2018 and 2019.

Figure 3-40 Map of real-time generation, less real-time load, by zone: January through September, 2019[54]



54 Zonal real-time generation data for the map and corresponding table is based on the zonal designation for every bus listed in the most current PJM LMP bus model, which can be found at <http://www.pjm.com/markets-and-operations/energy/lmp-model-info.aspx>.

Table 3-49 Real-time generation less real-time load by zone (GWh): January through September, 2018 and 2019

Zonal Generation and Load (GWh)						
Jan-Sep	2018			2019		
Zone	Generation	Load	Net	Generation	Load	Net
AECO	4,242.8	7,867.9	(3,625.1)	4,628.6	7,706.6	(3,078.0)
AEP	123,589.1	97,834.0	25,755.1	112,736.6	95,294.1	17,442.5
APS	35,587.8	37,502.7	(1,914.8)	38,336.0	37,010.6	1,325.3
ATSI	29,389.7	51,351.5	(21,961.9)	30,033.3	49,525.0	(19,491.6)
BGE	16,196.6	24,178.2	(7,981.6)	13,670.1	23,908.7	(10,238.6)
ComEd	100,500.7	74,776.7	25,724.0	101,601.2	71,864.4	29,736.8
DAY	4,504.3	13,273.5	(8,769.2)	827.8	13,057.7	(12,230.0)
DEOK	13,325.7	21,067.3	(7,741.6)	15,239.3	20,554.2	(5,314.9)
Dominion	73,760.9	76,737.1	(2,976.1)	76,091.4	76,949.2	(857.9)
DPL	5,052.1	14,373.1	(9,321.0)	4,265.1	14,052.0	(9,786.9)
DLCO	12,211.4	10,622.5	1,588.9	12,577.3	10,224.9	2,352.4
EKPC	7,007.3	9,970.2	(2,962.8)	5,218.7	9,579.6	(4,360.9)
JCPL	12,900.4	17,662.1	(4,761.7)	8,811.3	16,953.4	(8,142.2)
Met-Ed	17,255.1	11,911.8	5,343.3	18,219.4	11,731.7	6,487.7
OVEC	0.0	0.0	0.0	8,169.2	97.9	8,071.3
PECO	50,623.4	31,075.1	19,548.3	52,836.8	30,342.4	22,494.4
PENELEC	32,966.8	12,986.4	19,980.4	30,321.2	12,649.6	17,671.6
Pepco	9,471.3	23,140.5	(13,669.2)	9,092.4	22,660.4	(13,567.9)
PPL	41,907.0	30,831.8	11,075.2	48,893.1	30,485.2	18,407.8
PSEG	35,525.9	33,755.6	1,770.3	34,257.8	32,754.0	1,503.8
RECO	0.0	1,152.6	(1,152.6)	0.0	1,104.0	(1,104.0)

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.

Fuel Prices, LMP, and Dispatch

Energy Production by Fuel Source

Table 3-50 shows PJM generation by fuel source in GWh for the first nine months of 2018 and 2019. In the first nine months of 2019, generation from coal units decreased 16.4 percent, generation from natural gas units increased 17.2 percent, and generation from oil decreased 49.4 percent compared to the first nine months of 2018.[55] The increase in gas fired generation offsets the decreases in coal, oil and nuclear generation. Wind and solar output rose by 2,405 GWh compared to the first nine months of 2018, supplying 3.03 percent of PJM energy in the first nine months of 2019.

55 Generation data are the sum of GWh 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 3-50 Generation (By fuel source (GWh)): January through September, 2018 and 2019[56 57 58]

	2018 (Jan - Sep)		2019 (Jan - Sep)		Change in
	GWh	Percent	GWh	Percent	Output
Coal	185,756.1	29.2%	155,308.3	24.5%	(16.4%)
Bituminous	155,985.6	24.5%	132,915.7	21.0%	(14.8%)
Sub Bituminous	23,582.9	3.7%	17,661.9	2.8%	(25.1%)
Other Coal	6,187.5	1.0%	4,730.8	0.7%	(23.5%)
Nuclear	214,603.2	33.8%	210,542.6	33.2%	(1.9%)
Gas	196,583.1	30.9%	229,892.5	36.2%	16.9%
Natural Gas	194,845.4	30.7%	228,282.7	36.0%	17.2%
Landfill Gas	1,724.1	0.3%	1,606.4	0.3%	(6.8%)
Other Gas	13.6	0.0%	3.5	0.0%	(74.6%)
Hydroelectric	14,190.8	2.2%	13,415.7	2.1%	(5.5%)
Pumped Storage	4,497.7	0.7%	3,785.4	0.6%	(15.8%)
Run of River	8,196.3	1.3%	8,528.3	1.3%	4.1%
Other Hydro	1,496.9	0.2%	1,102.0	0.2%	(26.4%)
Wind	15,120.1	2.4%	16,973.8	2.7%	12.3%
Waste	3,356.8	0.5%	3,253.2	0.5%	(3.1%)
Solid Waste	3,155.7	0.5%	3,180.2	0.5%	0.8%
Miscellaneous	201.1	0.0%	73.0	0.0%	(63.7%)
Oil	3,066.6	0.5%	1,551.8	0.2%	(49.4%)
Heavy Oil	435.1	0.1%	101.6	0.0%	(76.6%)
Light Oil	899.9	0.1%	226.3	0.0%	(74.9%)
Diesel	358.8	0.1%	68.0	0.0%	(81.0%)
Gasoline	0.0	0.0%	0.0	0.0%	NA
Kerosene	58.8	0.0%	10.0	0.0%	(83.0%)
Jet Oil	8.0	0.0%	0.0	0.0%	(100.0%)
Other Oil	1,306.0	0.2%	1,145.8	0.2%	(12.3%)
Solar, Net Energy Metering	1,709.5	0.3%	2,260.3	0.4%	32.2%
Battery	10.6	0.0%	15.1	0.0%	42.7%
Biofuel	1,306.6	0.2%	1,017.9	0.2%	(22.1%)
Total	635,703.2	100.0%	634,231.2	100.0%	(0.2%)

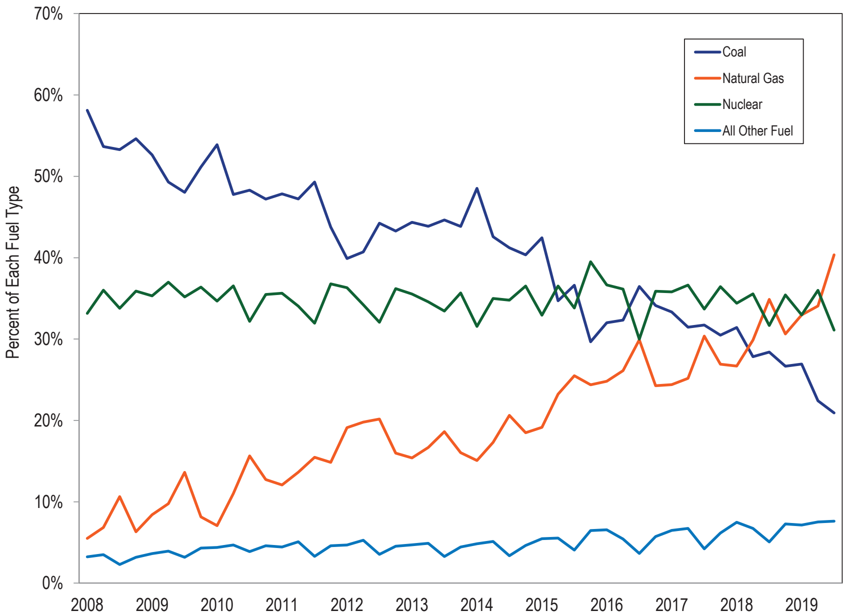
56 All generation is total gross generation output and does not net out the MWh withdrawn at a generation bus to provide auxiliary/parasitic power or station power, power to synchronous condenser motors, or power to run pumped storage pumps.
57 Net Energy Metering is combined with Solar due to data confidentiality reasons.
58 Other Gas includes: Propane, Butane, Hydrogen, Gasified Coal, and Refinery Gas. Other Coal includes: Lignite, Liquefied Coal, Gasified Coal, and Waste Coal.

Table 3-51 Monthly generation (By fuel source (GWh)): January through September, 2019

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
Coal		23,151.4	16,444.7	17,418.6	12,890.6	14,846.9	15,112.1	21,599.4	17,945.8	15,898.9	155,308.3
	Bituminous	19,242.9	13,611.1	14,630.3	10,530.5	12,913.2	13,573.7	18,607.4	15,987.8	13,818.7	132,915.7
	Sub Bituminous	3,093.6	2,185.0	2,106.3	1,889.3	1,457.1	977.2	2,600.6	1,557.0	1,795.9	17,661.9
	Other Coal	814.9	648.6	682.0	470.8	476.6	561.2	391.4	401.0	284.2	4,730.8
Nuclear		25,595.0	22,303.6	21,899.6	21,078.7	23,997.8	23,735.1	24,670.8	24,471.5	22,790.6	210,542.6
Gas		23,457.9	23,274.3	23,627.3	19,184.6	20,646.8	25,825.1	34,360.8	32,346.0	27,169.7	229,892.5
	Natural Gas	23,265.9	23,104.3	23,443.2	19,012.7	20,465.9	25,651.6	34,177.6	32,164.6	26,996.8	228,282.7
	Landfill Gas	192.0	170.0	184.2	171.9	180.9	173.3	180.3	181.0	172.9	1,606.4
	Other Gas	0.0	0.0	0.0	0.0	0.0	0.2	2.9	0.4	0.0	3.5
Hydroelectric		1,805.1	1,453.6	1,699.3	1,593.8	1,742.6	1,523.0	1,518.7	1,185.9	893.5	13,415.7
	Pumped Storage	337.2	322.7	326.3	348.9	454.4	399.2	624.3	561.9	410.5	3,785.4
	Run of River	1,361.4	1,037.2	1,289.2	1,159.2	1,155.5	999.6	702.0	471.7	352.4	8,528.3
	Other Hydro	106.5	93.7	83.7	85.7	132.7	124.2	192.4	152.4	130.7	1,102.0
Wind		2,611.7	2,228.4	2,467.1	2,665.7	1,925.4	1,746.6	1,056.0	930.5	1,342.4	16,973.8
Waste		385.1	317.6	332.2	338.6	372.1	380.1	382.1	389.9	355.6	3,253.2
	Solid Waste	362.0	298.3	307.3	332.8	372.1	380.1	382.1	389.9	355.6	3,180.2
	Miscellaneous	23.0	19.3	24.9	5.7	0.0	0.0	0.0	0.0	0.0	73.0
Oil		214.5	127.2	145.4	99.1	169.0	152.3	265.8	251.1	127.4	1,551.8
	Heavy Oil	5.6	0.8	0.0	0.0	0.0	0.0	26.4	68.8	0.0	101.6
	Light Oil	41.8	15.0	13.5	4.6	8.6	4.6	85.5	27.1	25.6	226.3
	Diesel	15.5	4.6	41.9	1.2	1.2	0.7	1.4	1.2	0.4	68.0
	Gasoline	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Kerosene	9.7	0.1	0.0	0.0	0.0	0.1	0.0	0.1	0.0	10.0
	Jet Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Other Oil	141.9	106.7	90.0	93.4	159.2	146.9	152.4	153.9	101.4	1,145.8
Solar, Net Energy Metering		130.1	145.8	230.4	254.5	293.2	295.6	344.6	300.0	266.1	2,260.3
Battery		2.0	2.0	2.2	1.9	1.7	1.3	1.6	1.3	1.3	15.1
Biofuel		107.3	80.7	108.3	96.1	98.5	101.4	143.9	140.2	141.7	1,017.9
Total		77,460.1	66,377.8	67,930.3	58,203.5	64,093.8	68,872.5	84,343.6	77,962.2	68,987.2	634,231.2

Figure 3-41 shows total generation percentage of natural gas, coal, nuclear and all other fuel types in the Real-Time Energy Market since 2008.

Figure 3-41 Generation by fuel source (Percentage): January 2008 through September 2019



Fuel Diversity

Figure 3-42 shows the fuel diversity index (FDI_e) for PJM energy generation.[59] 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 results when each fuel type has an equal share of total generation. For a generation fleet composed of 10 fuel types, the maximum achievable index is 0.9. The fuel type categories used in the calculation of the FDI_e are the 10 primary fuel sources in Table 3-51 with nonzero generation values. As fuel diversity has increased, seasonality in the FDI_e has decreased and the FDI_e has exhibited less volatility. Since 2012, the monthly FDI_e has been less volatile as a result of the decline in the share of coal from 51.3 percent prior to 2012 to 38.6 percent from 2012 through 2018. 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.[60] The increasing trend that began in 2008 is a result of decreasing coal generation, increasing gas generation and increasing wind generation. Coal generation as a share of total generation was 54.9 percent for 2008 and 24.5 percent for the first nine months of 2019. Gas generation as a share of total generation was 7.4 percent for 2008 and 36.2 percent for the first nine months of 2019. Wind generation as a share of total generation was 0.5 percent for 2008 and 2.7 percent for the first nine months of 2019.

The average FDI_e decreased 0.9 percent in the first nine months of 2019 compared to the first nine months in 2018. The FDI_e was also used to measure the impact on fuel diversity of potential retirements. Twenty-four coal units with installed capacity totaling 12,017 MW were identified as being at risk of retirement.[61] Generation owners that intend to retire a generator are required by the tariff to notify PJM at least 90 days in advance.[62] There are 8,093.7 MW of generation that have requested retirement after September 30, 2019.[63] The at risk units and other generators with deactivation notices generated 49.1 GWh in the first nine months of 2019. The dashed line in Figure 3-42 shows a counterfactual result for FDI_e assuming the 49.1 GWh of generation from at risk units and other generators with deactivation notices were replaced by gas generation. The average FDI_e for the first nine months of 2019 under the counterfactual assumption would have been 3.3 percent lower than the actual FDI_e.

59 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.

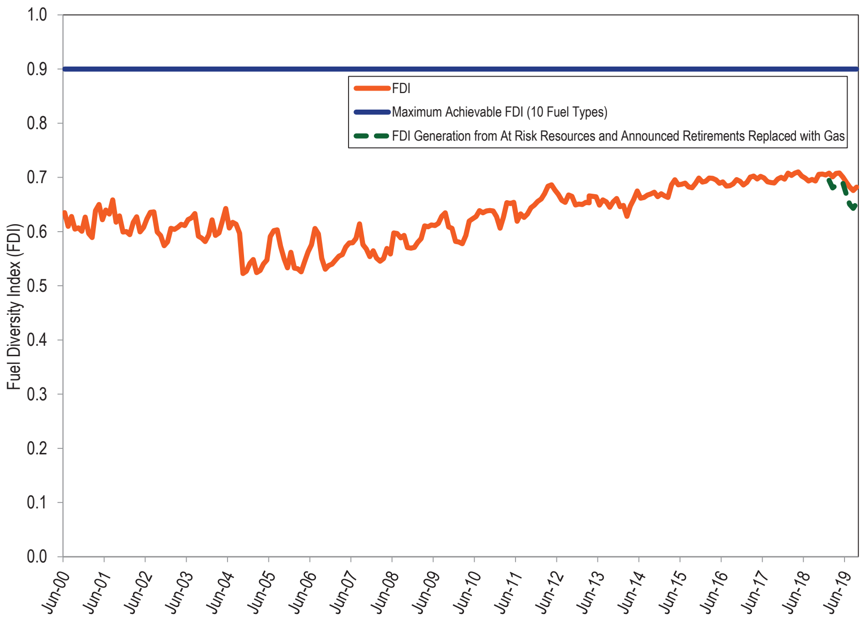
60 See the 2018 State of the Market Report for PJM, Volume 2, Appendix A, "PJM Geography" for an explanation of the expansion of the PJM footprint. The integration of the ComEd Control Area occurred in May 2004 and the integration of the AEP and Dayton control zones occurred in October 2004.

61 See the 2018 State of the Market Report for PJM, Volume 2, Section 7: Net Revenue, Units at Risk. The list of at risk units has been updated to reflect the subsidies included in Ohio HB 6 which was passed by the Ohio legislature on July 23, 2019 <https://www.legislature.ohio.gov/legislation/legislation-summary?id=GA133-HB-6>.

62 See PJM. OATT: § V "Generation Deactivation."

63 Includes the generators in Table 12-9 plus four pseudo tied generators.

Figure 3-42 Fuel diversity index for monthly generation: June 2000 through September 2019



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 3-52 shows the type of fuel used and technology by marginal resources in the Real-Time Energy Market. There can be more than one marginal resource in any given interval as a result of transmission constraints. In the first nine months of 2019, coal units were 27.2 percent and natural gas units were 69.7 percent of marginal resources. In the first nine months of 2019, natural gas combined cycle units were 62.2 percent of marginal resources. In the first nine months of 2018, coal units were 29.7 percent and natural gas units were 62.1 percent of the total marginal resources. In the first nine months of 2018, natural gas combined cycle units were 52.6 percent of the total marginal resources. In the first nine months of 2019, 92.9 percent of the wind marginal units had negative offer prices, 6.5 percent had zero offer prices and 0.6 percent had positive offer prices. In the first nine months of 2018, 72.5 percent of the wind marginal units had negative offer prices, 25.0 percent had zero offer prices and 2.5 percent had positive offer prices.

The proportion of marginal nuclear units decreased from 1.06 percent in the first nine months of 2018 to 0.81 percent in the first nine months of 2019. Most nuclear units are offered as fixed generation in the PJM market. A small number of nuclear units were offered with a dispatchable range since 2015. The dispatchable nuclear units do not always respond to dispatch instructions.

Table 3-52 Type of fuel used and technology (By real-time marginal units): January through September, 2015 through 2019[64]

		(Jan - Sep)				
Fuel	Technology	2015	2016	2017	2018	2019
Gas	CC	28.75%	29.25%	44.63%	52.58%	62.16%
Coal	Steam	54.45%	46.21%	32.28%	29.71%	27.17%
Gas	CT	3.98%	7.05%	4.70%	7.19%	5.87%
Wind	Wind	2.74%	2.67%	7.28%	2.78%	1.66%
Gas	Steam	3.77%	5.01%	3.53%	1.91%	1.34%
Uranium	Steam	0.03%	0.92%	1.23%	1.06%	0.81%
Oil	CT	3.35%	7.51%	5.18%	2.88%	0.46%
Gas	RICE	0.06%	0.10%	0.39%	0.42%	0.31%
Other	Steam	0.42%	0.12%	0.19%	0.19%	0.08%
Oil	RICE	1.54%	0.96%	0.26%	0.52%	0.06%
Oil	Steam	0.17%	0.05%	0.05%	0.39%	0.04%
Other	Solar	0.01%	0.03%	0.18%	0.09%	0.02%
Landfill Gas	Steam	0.01%	0.03%	0.05%	0.00%	0.01%
Landfill Gas	CT	0.00%	0.01%	0.01%	0.02%	0.01%
Oil	CC	0.62%	0.03%	0.01%	0.17%	0.01%
Landfill Gas	RICE	0.01%	0.05%	0.01%	0.04%	0.01%
Municipal Waste	Steam	0.06%	0.01%	0.01%	0.04%	0.00%
Gas	Fuel Cell	0.04%	0.00%	0.00%	0.00%	0.00%

64 The unit type RICE refers to Reciprocating Internal Combustion Engines.

Figure 3-43 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 3-43 Type of fuel used (By real-time marginal units): January through September, 2004 through 2019

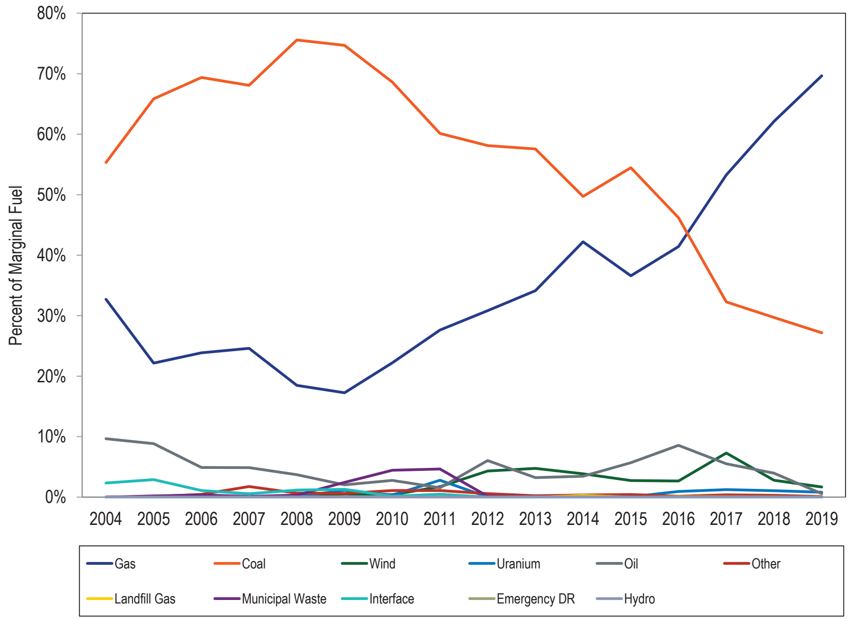


Table 3-53 shows the type of fuel used and technology where relevant, of marginal resources in the Day-Ahead Energy Market. In the first nine months of 2019, up to congestion transactions were 57.7 percent of marginal resources. Up to congestion transactions were 63.9 percent of marginal resources in the first nine months of 2018.

Table 3-53 Day-ahead marginal resources by type/fuel used and technology: January through September, 2011 through 2019

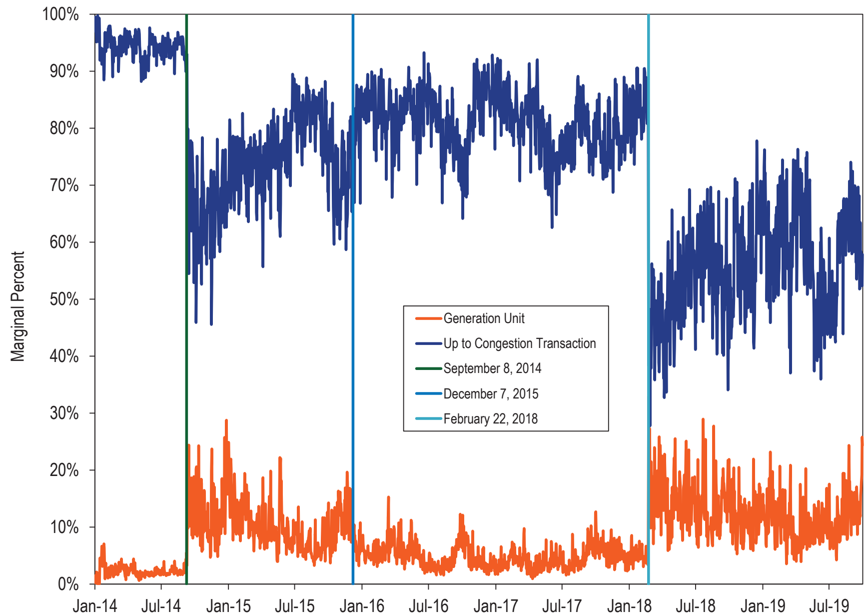
		(Jan - Sep)								
Type/Fuel	Technology	2011	2012	2013	2014	2015	2016	2017	2018	2019
Up to Congestion Transaction	NA	68.53%	86.21%	95.96%	93.09%	74.65%	81.19%	79.84%	63.90%	57.70%
DEC	NA	14.22%	5.12%	1.24%	2.17%	8.38%	8.82%	10.03%	16.06%	18.41%
INC	NA	8.33%	4.34%	1.00%	1.58%	4.83%	4.22%	5.49%	9.24%	12.86%
Gas	Steam	2.12%	1.40%	0.54%	1.25%	3.96%	2.52%	2.30%	5.32%	6.23%
Coal	Steam	6.06%	2.66%	1.13%	1.71%	7.15%	2.42%	1.74%	4.57%	4.23%
Gas	CT	0.14%	0.09%	0.01%	0.05%	0.32%	0.11%	0.10%	0.29%	0.18%
Dispatchable Transaction	NA	0.23%	0.07%	0.06%	0.08%	0.30%	0.05%	0.03%	0.13%	0.10%
Wind	Wind	0.07%	0.04%	0.04%	0.03%	0.14%	0.04%	0.17%	0.16%	0.10%
Uranium	Steam	0.00%	0.00%	0.00%	0.00%	0.00%	0.09%	0.06%	0.12%	0.06%
Oil	CT	0.00%	0.00%	0.00%	0.00%	0.16%	0.52%	0.19%	0.04%	0.04%
Gas	RICE	0.00%	0.01%	0.00%	0.00%	0.00%	0.01%	0.02%	0.05%	0.04%
Other	Solar	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.03%	0.02%
Other	Steam	0.00%	0.00%	0.00%	0.00%	0.02%	0.01%	0.00%	0.01%	0.01%
Municipal Waste	RICE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.01%
Oil	Steam	0.01%	0.01%	0.00%	0.02%	0.02%	0.00%	0.00%	0.07%	0.01%
Price Sensitive Demand	NA	0.27%	0.05%	0.01%	0.01%	0.03%	0.00%	0.00%	0.02%	0.00%
Oil	RICE	0.00%	0.00%	0.00%	0.00%	0.04%	0.00%	0.01%	0.00%	0.00%
Municipal Waste	Steam	0.01%	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Water	Hydro	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.01%	0.00%	0.00%
Municipal Waste	CT	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Total		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Figure 3-44 shows, for the Day-Ahead Energy Market from January 2014 through September 2019, the daily proportion of marginal resources that were up to congestion transaction and/or generation units. The percent of marginal up to congestion transactions (UTC) 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.[65] That trend reversed as a result of the expiration of the 15 month uplift refund period for UTC transactions. But in February of 2018, the percent of marginal up to congestion transactions again decreased significantly as the result of a FERC order issued on February 20, 2018, and implemented on February 22, 2018.[66] The order limited UTC trading to hubs, residual metered load, and interfaces. The share of marginal UTCs decreased from 63.9 percent in the first nine months of 2018 to 57.7 percent in the first nine months of 2019.

The average number of up to congestion bids submitted in the Day-Ahead Energy Market decreased by 24.9 percent, from 68,693 bids per day in the first nine months of 2018 to 51,594 bids per day in the first nine months of 2019. The average cleared volume of up to congestion bids submitted in the Day-Ahead Energy Market increased by 15.9 percent, from 423,268 MWh per day in the first nine months of 2018, to 490,421 MWh per day in the first nine months of 2019.

65 See 18 CFR § 385.213 (2014).
66 162 FERC ¶ 61,139 (2018).

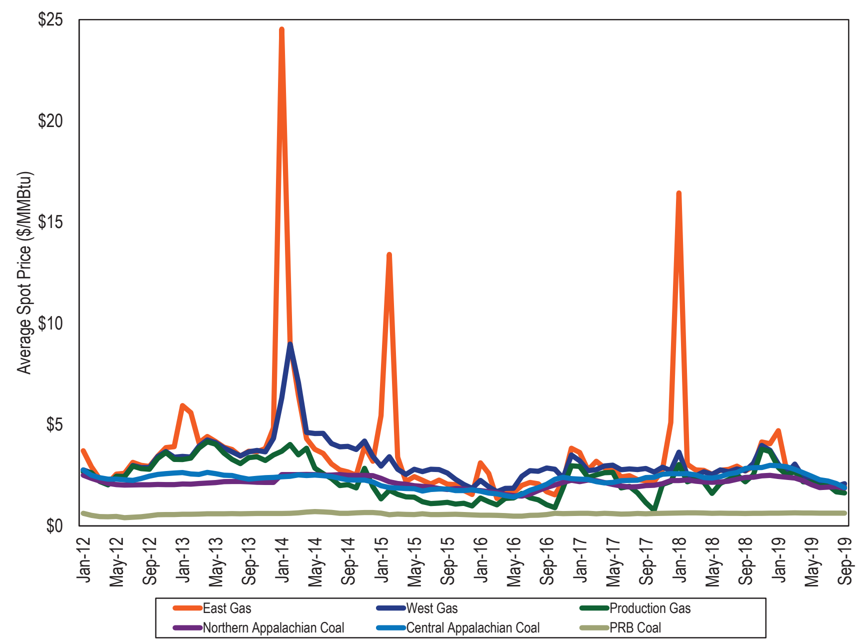
Figure 3-44 Day-ahead marginal up to congestion transaction and generation units: January 2014 through September 2019



Fuel Price Trends and LMP

In a competitive market, changes in LMP should follow 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 short run 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. Gas prices fell in the first nine months of 2019 compared to the first nine months of 2018. Changes in emission allowance costs are another contributor to changes in the marginal cost of marginal units. Natural gas prices decreased in the first nine months of 2019 compared to the first nine months of 2018. The price of natural gas in the Marcellus Shale production area is lower than in other areas of PJM. A number of new combined cycle plants have located in the production area since 2016. In the first nine months of 2019, the price of production gas was 3.3 percent lower than in the first nine months of 2018. The price of eastern natural gas was 39.6 percent lower and the price of western natural gas was 12.7 percent lower. (Figure 3-45) The price of Northern Appalachian coal was 5.2 percent lower; the price of Central Appalachian coal was 2.9 percent lower; and the price of Powder River Basin coal was 0.6 percent higher.[67]

Figure 3-45 Spot average fuel price comparison: January 2012 through September 2019 ($/MMBtu)



67 Eastern natural gas consists of the average of Texas M3, Transco Zone 6 non-NY, Transco Zone 6 NY and Transco Zone 5 daily indices. Western natural gas prices are the average of Columbia Appalachia and Chicago Citygate daily indices. Production gas prices are the average of Dominion South Point, Tennessee Zone 4, and Transco Leidy Line receipts daily indices. Coal prices are the average of daily fuel prices for Central Appalachian coal, Northern Appalachian coal, and Powder River Basin coal. All fuel prices are from Platts.

Table 3-54 compares the first nine months of 2019 PJM real-time fuel-cost adjusted, load-weighted, average LMP to the first nine months of 2019 load-weighted, average LMP.[68] The real-time, load-weighted average LMP for the first nine months of 2019 decreased by $11.83 or -30.0 percent from real-time load-weighted, average LMP for the first nine months of 2018. The real-time load-weighted, average LMP for the first nine months of 2019 was 12.8 percent lower than the real-time fuel-cost adjusted, load-weighted average LMP for the first nine months of 2019. The real-time, fuel-cost adjusted, load-weighted average LMP for the first nine months of 2019 was 19.7 percent lower than the real-time load-weighted, average LMP for the first nine months of 2018. If fuel and emissions costs in the first nine months of 2019 had been the same as in the first nine month of 2018, holding everything else constant, the real-time, load-weighted, average LMP in the first nine months of 2019 would have been higher, $31.65 per MWh, than the observed $27.60 per MWh. Only 34 percent of the decrease in real-time, load-weighted, average LMP, $4.05 per MWh out of $11.83 per MWh, is directly attributable to fuel costs. Contributors to the other $7.78 per MWh are decreased load, increased supply, adjusted dispatch, and lower markups.

Table 3-54 Real-time, fuel-cost adjusted, load-weighted average LMP (Dollars per MWh): January through September, 2018 and 2019

	2019 Fuel-Cost Adjusted, Load-Weighted LMP	2019 Load-Weighted LMP	Change	Percent Change
Average	$31.65	$27.60	($4.05)	(12.8%)
	2018 Load-Weighted LMP	2019 Fuel-Cost Adjusted, Load-Weighted LMP	Change	Percent Change
Average	$39.43	$31.65	($7.78)	(19.7%)
	2018 Load-Weighted LMP	2019 Load-Weighted LMP	Change	Change
Average	$39.43	$27.60	($11.83)	(30.0%)

Table 3-55 shows the impact of each fuel type on the difference between the fuel-cost adjusted, load-weighted average LMP and the load-weighted LMP in the first nine months of 2019. Table 3-55 shows that lower natural gas prices explain all of the fuel-cost related decrease in the real-time annual, load-weighted average LMP in the first nine months of 2019 from the first nine months of 2018.

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

Table 3-55 Change in real-time, fuel-cost adjusted, load-weighted average LMP ($/MWh) by fuel type: January through September, 2018 to 2019

Fuel Type	Share of Change in Fuel Cost Adjusted, Load Weighted LMP	Percent
Other	$0.00	0.0%
Uranium	$0.00	0.0%
Municipal Waste	$0.00	0.0%
Wind	$0.00	0.0%
Oil	($0.01)	0.1%
Coal	($0.10)	2.5%
Gas	($3.95)	97.4%
NA	$0.00	0.0%
Total	($4.05)	100.0%

Table 3-56 shows the first nine months of 2019 PJM real-time fuel-cost adjusted, load-weighted, average LMP using the first nine months of 2018, 2017, 2016, and 2015 fuel and emission costs. If fuel and emissions costs in the first nine months of 2019 had been the same as in first nine months of 2015, holding everything else constant, the real-time load-weighted LMP in the first nine months of 2019 would have been higher, $28.35 per MWh, than the observed $27.60 per MWh. If only fuel and emission costs of natural gas units in the first nine months of 2019 had been the same as in the first nine months of 2015, holding everything else constant, the real-time load-weighted LMP in the first nine months of 2019 would have been higher, $28.70 per MWh, than the observed $27.60 per MWh.

Table 3-56 Historical Real-time, fuel-cost adjusted, load-weighted average LMP by Fuel Type (Dollars per MWh): January through September, 2015 through 2019

	2019 Fuel-Cost Adjusted, Load Weighted LMP			
	All Units	Gas Units	Coal Units	Oil Units
2019 Fuel and Emission Costs	$27.60	$27.60	$27.60	$27.60
2018 Fuel and Emission Costs	$31.65	$31.55	$27.70	$27.61
2017 Fuel and Emission Costs	$28.21	$28.36	$27.46	$27.59
2016 Fuel and Emission Costs	$25.01	$25.62	$27.00	$27.59
2015 Fuel and Emission Costs	$28.35	$28.70	$27.26	$27.59

Components of LMP

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 (VOM) 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.[69] 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 the SCED solution does not meet the reserve requirements, PJM should invoke shortage pricing. During 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.

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

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 3-59 shows the frequency and average shadow price of transmission constraints in PJM. In the first nine months of 2019, there were 96,836 transmission constraint intervals in the real-time market with a nonzero shadow price. For nearly 5 percent of these transmission constraint intervals, the line limit was violated, meaning that the flow exceeded the facility limit.[70] In the first nine months of 2019, the average shadow price of transmission constraints when the line limit was violated was nearly fourteen 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 had been using 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 factors have not directly set the shadow price through 2018. In 2018, for all the violated transmission constraints for which the penalty factor was greater than or equal to $2,000 per MWh, 59 percent of the constraints' shadow prices were within 10 percent of the penalty factor. The MMU recommended 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. PJM adopted the MMU's recommendation to remove the constraint relaxation logic and

70 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.

allow transmission penalty factors to set prices in the day-ahead and real-time markets for all internal transmission constraints. PJM also revised the tariff to list the conditions under which transmission penalty factors would be changed from their default value of $2,000 per MWh. The new rules went into effect on February 1, 2019. PJM has not yet adopted the same MMU recommendation for reciprocally coordinated market to market constraints with neighboring RTOs. PJM continues the practice of discretionary reduction in line ratings.

Table 3-60 shows the frequency of changes to the magnitude of transmission penalty factor of binding and violated transmission constraints in the PJM real-time market. In the first nine months of 2019, there were 3,203 or 69 percent of internal violated transmission constraint intervals in the real-time market with transmission penalty factor equal to the default $2,000 per MWh. In the first nine months of the 2019, there were 1,380 or 30 percent of internal violated transmission constraint intervals in the real-time market with transmission penalty factor below the default, $2,000 per MWh.

The components of LMP are shown in Table 3-57, including markup using unadjusted cost-based offers.[71] Table 3-57 shows that in the first nine months of 2019, 26.8 percent of the load-weighted LMP was the result of coal costs, 42.7 percent was the result of gas costs and 0.87 percent was the result of the cost of emission allowances. Using adjusted cost-based offers, markup was 14.7 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. For several intervals, PJM fails to provide all the data needed to accurately calculate generator sensitivity factors. As a result, the LMP for those intervals cannot be decomposed into component costs. The cumulative effect of excluding those five-minute intervals is the component NA. In the first nine months of 2019, nearly 14 percent of all five-minute intervals had insufficient data. The percent column is the difference in the proportion of LMP represented by each component between the first nine months of 2019 and 2018.

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

Table 3-57 Components of real-time (Unadjusted), load-weighted, average LMP: January through September, 2018 and 2019

	2018 (Jan - Sep)		2019 (Jan - Sep)		Change
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Percent
Gas	$15.51	39.3%	$11.79	42.7%	3.4%
Coal	$7.84	19.9%	$7.40	26.8%	6.9%
Ten Percent Adder	$2.76	7.0%	$2.12	7.7%	0.7%
Markup	$5.17	13.1%	$1.95	7.1%	(6.0%)
VOM	$1.48	3.8%	$1.69	6.1%	2.4%
Increase Generation Adder	$0.92	2.3%	$1.42	5.1%	2.8%
NA	$2.11	5.3%	$0.32	1.1%	(4.2%)
Scarcity Adder	$0.03	0.1%	$0.26	1.0%	0.9%
CO_2 Cost	$0.12	0.3%	$0.22	0.8%	0.5%
Ancillary Service Redispatch Cost	$0.41	1.0%	$0.21	0.7%	(0.3%)
LPA Rounding Difference	$0.65	1.6%	$0.14	0.5%	(1.1%)
Opportunity Cost Adder	$0.08	0.2%	$0.09	0.3%	0.1%
Oil	$2.23	5.7%	$0.06	0.2%	(5.5%)
NO_x Cost	$0.11	0.3%	$0.02	0.1%	(0.2%)
Constraint Violation Adder	($0.00)	(0.0%)	$0.01	0.0%	0.0%
Other	$0.07	0.2%	$0.00	0.0%	(0.2%)
Market-to-Market Adder	$0.01	0.0%	$0.00	0.0%	(0.0%)
SO_2 Cost	$0.01	0.0%	$0.00	0.0%	(0.0%)
Landfill Gas	$0.00	0.0%	$0.00	0.0%	0.0%
Uranium	($0.00)	(0.0%)	$0.00	0.0%	0.0%
Municipal Waste	$0.13	0.3%	$0.00	0.0%	(0.3%)
Wind	($0.01)	(0.0%)	$0.00	0.0%	0.0%
LPA-SCED Differential	($0.02)	(0.1%)	($0.01)	(0.0%)	0.0%
Renewable Energy Credits	($0.04)	(0.1%)	($0.02)	(0.1%)	0.0%
Decrease Generation Adder	($0.13)	(0.3%)	($0.06)	(0.2%)	0.1%
Total	$39.43	100.0%	$27.60	100.0%	0.0%

In order to accurately assess the markup behavior of market participants, real-time and day-ahead LMPs are decomposed using two different approaches. In the first approach (Table 3-57 and Table 3-61), markup is simply the difference between the price offer and the cost-based offer (unadjusted markup). In the second approach (Table 3-58 and Table 3-62), the 10 percent markup is removed from the cost-based offers of coal gas and oil units (adjusted markup).

The components of LMP are shown in Table 3-58, including markup using adjusted cost-based offers.

Table 3-58 Components of real-time (Adjusted), load-weighted, average LMP: January through September, 2018 and 2019

	2018 (Jan - Sep)		2019 (Jan - Sep)		Change
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Percent
Gas	$15.51	39.3%	$11.79	42.7%	3.4%
Coal	$7.84	19.9%	$7.40	26.8%	6.9%
Markup	$7.90	20.0%	$4.07	14.7%	(5.3%)
VOM	$1.48	3.8%	$1.69	6.1%	2.4%
Increase Generation Adder	$0.92	2.3%	$1.42	5.1%	2.8%
NA	$2.11	5.3%	$0.32	1.1%	(4.2%)
Scarcity Adder	$0.03	0.1%	$0.26	1.0%	0.9%
CO_2 Cost	$0.12	0.3%	$0.22	0.8%	0.5%
Ancillary Service Redispatch Cost	$0.41	1.0%	$0.21	0.7%	(0.3%)
LPA Rounding Difference	$0.65	1.6%	$0.14	0.5%	(1.1%)
Opportunity Cost Adder	$0.08	0.2%	$0.09	0.3%	0.1%
Oil	$2.23	5.7%	$0.06	0.2%	(5.5%)
NO_x Cost	$0.11	0.3%	$0.02	0.1%	(0.2%)
Constraint Violation Adder	($0.00)	(0.0%)	$0.01	0.0%	0.0%
Other	$0.07	0.2%	$0.00	0.0%	(0.2%)
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%	(0.0%)
SO_2 Cost	$0.01	0.0%	$0.00	0.0%	(0.0%)
Landfill Gas	$0.00	0.0%	$0.00	0.0%	0.0%
Uranium	($0.00)	(0.0%)	$0.00	0.0%	0.0%
Municipal Waste	$0.13	0.3%	$0.00	0.0%	(0.3%)
Wind	($0.01)	(0.0%)	$0.00	0.0%	0.0%
LPA-SCED Differential	($0.02)	(0.1%)	($0.01)	(0.0%)	0.0%
Renewable Energy Credits	($0.04)	(0.1%)	($0.02)	(0.1%)	0.0%
Decrease Generation Adder	($0.13)	(0.3%)	($0.06)	(0.2%)	0.1%
Total	$39.43	100.0%	$27.60	100.0%	0.0%

Table 3-59 Frequency and average shadow price of transmission constraints: January through September, 2018 and 2019

	Frequency (Constraint Intervals)		Average Shadow Price	
Description	2018 (Jan - Sep)	2019 (Jan - Sep)	2018 (Jan - Sep)	2019 (Jan - Sep)
PJM Internal Violated Transmission Constraints	10,539	4,653	$1,307.70	$1,488.52
PJM Internal Binding Transmission Constraints	71,036	59,363	$198.67	$100.08
Market to Market Transmission Constraints	37,027	32,820	$424.61	$233.61
All Transmission Constraints	118,602	96,836	$367.76	$212.05

Table 3-60 Frequency of changes to the magnitude of transmission penalty factor (constraint intervals): January through September, 2018 and 2019

	2018 (Jan - Sep)			2019 (Jan - Sep)		
Description	$2,000 per MWh (Default)	Above $2,000 per MWh	Below $2,000 per MWh	$2,000 per MWh (Default)	Above $2,000 per MWh	Below $2,000 per MWh
PJM Internal Violated Transmission Constraints	6,535	1,193	2,811	3,203	70	1,380
PJM Internal Binding Transmission Constraints	59,830	4,369	6,837	56,230	696	2,437
Market to Market Transmission Constraints	12,631	53	24,343	6,557	3	26,260
All Transmission Constraints	78,996	5,615	33,991	65,990	769	30,077

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 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, Maryland and New Jersey.[72] 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 3-61 shows the components of the PJM day-ahead, annual, load-weighted average LMP. In the first nine months of 2019, 22.2 percent of the load-weighted LMP was the result of coal costs, 19.8 percent of the load-weighted LMP was the result of gas costs, 21.2 percent was the result of DEC bid costs, 21.3 percent was the result of INC bid costs and 2.2 percent was the result of the up to congestion transaction costs.

72 New Jersey withdrew from RGGI, effective January 1, 2012 and rejoined RGGI, effective January 29, 2018.

Table 3-61 Components of day-ahead, (unadjusted), load-weighted, average LMP (Dollars per MWh): January through September, 2018 and 2019

	2018 (Jan - Sep)		2019 (Jan - Sep)		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change Percent
Coal	$6.40	16.5%	$6.14	22.2%	5.6%
INC	$7.01	18.1%	$5.90	21.3%	3.2%
DEC	$11.30	29.2%	$5.86	21.2%	(8.0%)
Gas	$6.93	17.9%	$5.48	19.8%	1.9%
Ten Percent Cost Adder	$1.57	4.1%	$1.30	4.7%	0.6%
VOM	$1.04	2.7%	$1.22	4.4%	1.7%
Markup	$1.26	3.3%	$0.67	2.4%	(0.9%)
Up to Congestion Transaction	$1.15	3.0%	$0.62	2.2%	(0.7%)
Dispatchable Transaction	$0.49	1.3%	$0.33	1.2%	(0.1%)
CO_2	$0.07	0.2%	$0.14	0.5%	0.3%
Oil	$1.17	3.0%	$0.02	0.1%	(2.9%)
NO_x	$0.09	0.2%	$0.01	0.1%	(0.2%)
Price Sensitive Demand	$0.06	0.1%	$0.01	0.1%	(0.1%)
Other	($0.00)	(0.0%)	$0.01	0.0%	0.0%
DASR Offer Adder	($0.03)	(0.1%)	$0.00	0.0%	0.1%
DASR LOC Adder	$0.17	0.4%	$0.00	0.0%	(0.4%)
Constrained Off	$0.00	0.0%	$0.00	0.0%	0.0%
SO_2	$0.01	0.0%	$0.00	0.0%	(0.0%)
Municipal Waste	$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%)	($0.02)	(0.1%)	(0.0%)
Total	$38.70	100.0%	$27.70	100.0%	0.0%

Table 3-62 shows the components of the PJM day-ahead, annual, load-weighted average LMP including the adjusted markup calculated by excluding the 10 percent adder from the coal, gas or oil units.

Table 3-62 Components of day-ahead, (adjusted), load-weighted, average LMP (Dollars per MWh): January through September, 2018 and 2019

	2018 (Jan - Sep)		2019 (Jan - Sep)		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change Percent
Coal	$6.40	16.5%	$6.14	22.2%	5.6%
INC	$7.01	18.1%	$5.90	21.3%	3.2%
DEC	$11.30	29.2%	$5.86	21.2%	(8.0%)
Gas	$6.93	17.9%	$5.48	19.8%	1.9%
Markup	$2.81	7.3%	$1.95	7.0%	(0.2%)
VOM	$1.04	2.7%	$1.22	4.4%	1.7%
Up to Congestion Transaction	$1.15	3.0%	$0.62	2.2%	(0.7%)
Dispatchable Transaction	$0.49	1.3%	$0.33	1.2%	(0.1%)
CO_2	$0.07	0.2%	$0.14	0.5%	0.3%
Oil	$1.17	3.0%	$0.02	0.1%	(2.9%)
Ten Percent Cost Adder	$0.03	0.1%	$0.02	0.1%	0.0%
NO_x	$0.09	0.2%	$0.01	0.1%	(0.2%)
Price Sensitive Demand	$0.06	0.1%	$0.01	0.1%	(0.1%)
Other	($0.00)	(0.0%)	$0.01	0.0%	0.0%
DASR Offer Adder	($0.03)	(0.1%)	$0.00	0.0%	0.1%
DASR LOC Adder	$0.17	0.4%	$0.00	0.0%	(0.4%)
Constrained Off	$0.00	0.0%	$0.00	0.0%	0.0%
SO_2	$0.01	0.0%	$0.00	0.0%	(0.0%)
Municipal Waste	$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%)	($0.02)	(0.1%)	(0.0%)
Total	$38.70	100.0%	$27.70	100.0%	0.0%

Scarcity

PJM's energy market experienced five minute shortage pricing for 27 intervals on fourteen days in the first nine months of 2019. Table 3-63 shows a summary of the number of days emergency alerts, warnings and actions were declared in PJM in the first nine months of 2018 and 2019.

Table 3-63 Summary of emergency events declared: January through September, 2018 and 2019

	Number of days events declared	
Event Type	Jan -Sep, 2018	Jan - Sep, 2019
Cold Weather Alert	12	9
Hot Weather Alert	23	15
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	14
Energy export recalls from PJM capacity resources	0	0

Figure 3-46 shows the number of days that weather and capacity emergency alerts were issued in PJM in the first nine months from 2015 through 2019. Figure 3-47 shows the number of days emergency warnings were issued and actions were taken in PJM in the first nine months from 2015 through 2019.

Figure 3-46 Declared emergency alerts: January through September, 2015 through 2019

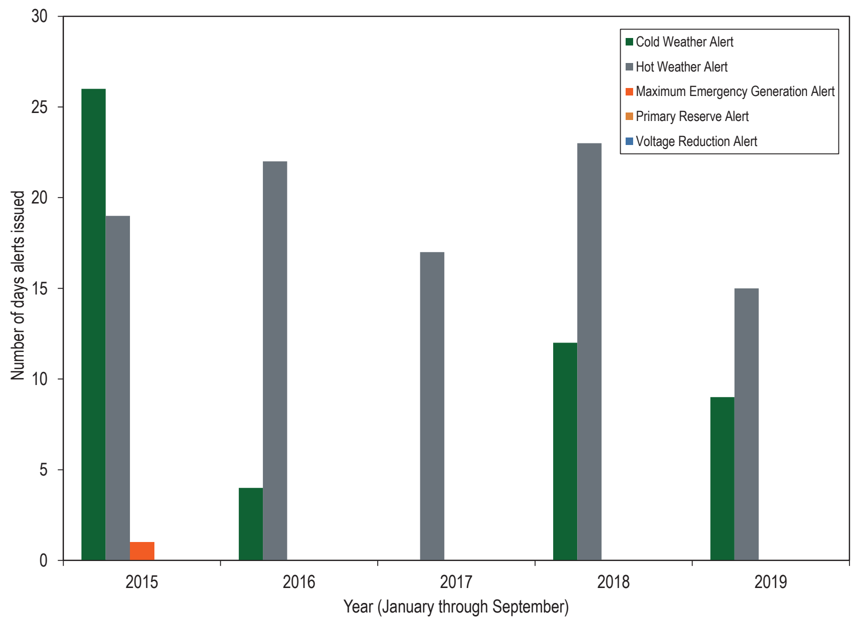
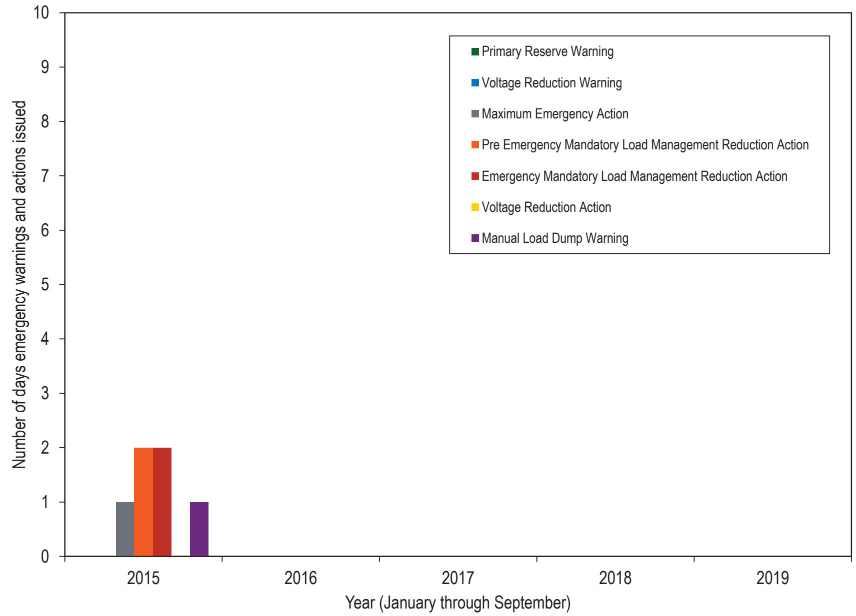


Figure 3-47 Declared emergency warnings and actions: January through September, 2015 through 2019



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.

Table 3-64 provides a description of PJM declared emergency procedures.[73] [74] [75] [76]

Table 3-64 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.

73 See PJM. "Manual 13: Emergency Operations," Rev. 72 (Sep. 26, 2019), Section 3.3 Cold Weather Alert.
74 See PJM. "Manual 13: Emergency Operations," Rev. 72 (Sep 26, 2019), Section 3.4 Hot Weather Alert.
75 See PJM. "Manual 13: Emergency Operations," Rev. 72 (Sep. 26, 2019), Section 2.3.1 Advanced Notice Emergency Procedures: Alerts.
76 See PJM. "Manual 13: Emergency Operations," Rev. 72 (Sep. 26, 2019), 2.3.2 Real-Time Emergency Procedures (Warnings and Actions).

Table 3-65 shows the dates when emergency alerts and warnings were declared and when emergency actions were implemented in the first nine months of 2019.

Table 3-65 Declared emergency alerts, warnings and actions: January through September, 2019

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	Manual Load Dump Action	Load Shed Directive
1/20/2019	Western													
1/21/2019	PJM RTO													
1/22/2019	PJM RTO													
1/25/2019	Western													
1/29/2019	ComEd													
1/30/2019	Western													
1/31/2019	PJM RTO													
2/1/2019	PJM RTO													
3/4/2019	ComEd													
6/27/2019		Mid Atlantic and Southern												
6/28/2019		Mid Atlantic and Southern												
6/29/2019		Mid Atlantic and Southern												
7/17/2019		Mid Atlantic and Dominion												
7/18/2019		PJM RTO												
7/19/2019		PJM RTO												
7/20/2019		PJM RTO												
7/21/2019		PJM RTO except ComEd												
7/29/2019		Mid Atlantic												
7/30/2019		Mid Atlantic												
8/18/2019		Mid Atlantic and Western except ComEd												
8/19/2019		PJM RTO except ComEd												
8/20/2019		Mid Atlantic and Dominion												
8/21/2019		Mid Atlantic												
9/12/2019		PJM RTO												

PAIs and Capacity Performance

In the first nine months of 2019, PJM did not declare any emergency actions that triggered Performance Assessment Intervals (PAIs). In 2018, PJM declared two localized load shed events in the AEP Zone, in the Twin Branch - Edison area and Lonesome Pine – Bluefield area. Both the Twin Branch and Lonesome Pine events triggered Performance Assessment Intervals (PAIs) in very limited locations. Both the events occurred due to the simultaneous planned outages and unplanned outages of transmission facilities including transmission lines, transformers and capacitors. While these events involved shedding load to ensure the contingencies did not have cascading effects on the grid, they are not directly related to capacity shortages to meet load at the zonal, regional or the RTO level. PJM determined that there were no generation or demand resources in either case that could have helped resolve the contingency flow or low voltage issues identified during these events. PJM did not assess nonperformance charges to any resources for these events.

The balancing ratio is theoretically defined as the ratio of actual load and reserve requirements during an emergency event in an area to the total committed capacity in the area. In the case of both these events, if the area is defined as the location where the load was shed, the balancing ratio is undefined because there were no committed resources in the area, other than less than 1.0 MW of demand response. It would not be appropriate or correct to calculate a balancing ratio as a measure of capacity needed during these events by defining a wider area to include committed capacity. It is also not appropriate to use a balancing ratio defined in that way in defining the capacity market offer cap. These events occurred in a very small local area where no capacity resources were held to CP performance requirements. Assessing nonperformance to resources located in the wider area would not be appropriate because their performance would not have helped, and may have even exacerbated the transmission issues identified during these events. These events also do not reflect the type of events that are modeled to define the target installed reserve margin in the capacity market. The MMU recommends that PJM not include the balancing ratios calculated for localized Performance Assessment Intervals (PAIs) in the calculation of the capacity market default offer cap, and only include those events that trigger emergencies at a defined sub-zonal or zonal level.

Scarcity and Scarcity Pricing

In electricity markets, scarcity means that demand, including reserve requirements, is nearing the limits of the currently available capacity of the system. Scarcity pricing is a mechanism for signaling scarcity conditions through energy prices. Under the PJM rules that were in place through September 30, 2012, 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. Shortage pricing is an administrative scarcity pricing mechanism in which PJM sets a high energy price at a predetermined level when the system operates with less real time reserves than required.

In the first nine months of 2019, there were 27 five minute intervals with shortage pricing that occurred on fourteen days in PJM.

With Order No. 825, 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.[77] 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) reflected 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.

Voltage reduction actions and manual load dump actions are also triggers for shortage pricing, reflecting the fact that when operators need to take these emergency actions to maintain reliability, the system is short reserves and

77 *Id* at P 162.

prices should reflect that condition, even if the data does not show a shortage of reserves.[78]

PJM Tariff Revisions to Operating Reserve Demand Curves

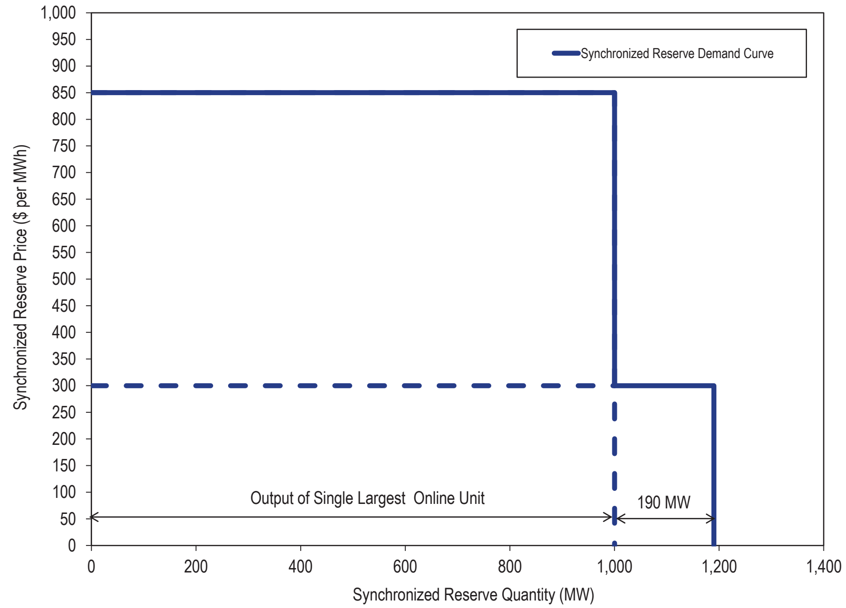
On May 12, 2017, PJM submitted tariff revisions to reflect changes to the Operating Reserve Demand Curves (ORDC) used in the Real-Time Energy Market to price shortage of primary reserves and synchronized reserves.[79] The updates to the ORDC went into effect on July 12, 2017.

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 3-48 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.

78 *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).

79 See PJM Filing, FERC Docket No. ER17-1590-000 (May 12, 2017).

Figure 3-48 Updated synchronized reserve demand curve showing the permanent second step



Scarcity Pricing and Energy Price Formation

The current operating reserve demand curves (ORDC) in PJM define an administrative price for estimated reserves (primary and synchronized reserves) up to the extended reserve requirement quantities. The demand curve shown in Figure 3-48 drops to a zero price for quantities above the extended reserve requirement. The price for reserve quantities less than the reserve requirement is $850 per MWh, and the price for reserve quantities above the reserve requirement to 190 MW above the reserve requirement is $300 per MWh. The price below the reserve requirement should be sufficient to cover the marginal cost of any generator on the system capable of responding.

Unlike an energy only market, PJM does not set scarcity prices to compensate the full fixed and avoidable cost of the resources needed to meet peak demand.

The PJM market compensates resources with a capacity market obligation for availability to the system when they are needed to meet demand. In addition, because consumers do not respond in the short run to real-time energy market prices, scarcity pricing cannot ration scarce energy among consumers according to their marginal willingness to pay. By extension, PJM cannot measure consumers' willingness to pay for reserves to avoid a loss of load. Therefore, the ORDC appropriately does not attempt to administratively represent consumers' willingness to pay for reserves, or customers' value of lost load.

Locational Reserve Requirements

In addition to the construction of the operating reserve demand curves to reflect the value of maintaining reserves and avoiding a loss of load event, the modeling of reserve requirements should reflect locational needs and should price operator actions, for example, to commit more reserves than required.

The current operating reserve demand curves are modeled for reserve requirements for the RTO level (RTO reserve zone) and for the Mid-Atlantic and Dominion region (MAD Subzone). This was a result of historical congestion patterns where limits to transmission capacity to deliver power from outside the MAD Subzone into the MAD Subzone necessitated maintaining reserves in the MAD area to respond to disturbances within the subzone. However, in real-time operations, due to generator outages, transmission outages, and local weather patterns, PJM may need to maintain or operate resources in other local areas to maintain local reliability, in addition to the RTO and MAD reserve levels. Currently, these units are committed out of market for reliability reasons, or are modeled as artificial closed loop interfaces with limited deliverability modeled inside the closed loop from resources located outside. The value of operating these resources, including generators that are manually committed for reliability and demand resources that may be dispatched inside a closed loop, is not correctly reflected in prices. A more efficient way to reflect these requirements would be to have locational reserve requirements that are adjusted based on PJM forecasts and reliability studies.

Operator Actions

Actions taken by PJM operators to maintain reliability, such as committing more reserves than required, may suppress reserve prices. The need to commit more reserves could instead be reflected in the ORDC, allowing the market to efficiently account for the reliability commitment in the energy and reserves markets.

Reserve Shortages in 2019

Reserve Shortage in Real-Time SCED

The MMU analyzed the RT SCED solved cases to determine how many of the solved RT SCED cases indicated a shortage of any of the reserve products (synchronized reserve and primary reserve at RTO reserve zone and MAD reserve subzone), how many of these solved cases were approved by PJM, and how many of these were used in LPC to calculate prices. Reserves are considered short if the quantity (MW) of reserves dispatched by RT SCED for a five minute interval was less than the extended reserve requirement. Table 3-66 shows the number and percent of RT SCED cases solved that indicated a shortage of any of the four reserve products (RTO synchronized reserve, RTO primary reserve, MAD synchronized reserve, and MAD primary reserve), the number and percent of the solved RT SCED cases with shortage that were approved by PJM, and the number and percent of the RT SCED cases with shortage that were used in LPC to calculate real-time prices. Table 3-66 shows that, in the first nine months of 2019, PJM operators approved 35 RT SCED cases that indicated a shortage of reserves, from a total of 4,166 RT SCED solutions that indicated shortage. Among the 35 approved cases, only 25 cases were used in LPC to calculate LMPs and reserve clearing prices. In comparison, in the first nine months of 2018, PJM operators approved only five cases that indicated a shortage of reserves, from a total of 5,484 RT SCED solutions that indicated shortage. While the fraction of SCED solutions with shortage decreased from 1.2 percent in the first nine months of 2018 to 0.9 percent in the first nine months of 2019, the fraction of solved SCED cases with shortage that were approved by PJM operators increased from 0.1 percent in the first nine months of 2018 to 0.8 percent in the first nine months of 2019. It is unclear what criteria PJM operators use to approve the RT SCED cases to send dispatch signals to resources.

Table 3-66 RT SCED cases with reserve shortage: January through September, 2019

Month (2019)	Number of Solved RT SCED Cases	Number of Solved RT SCED Cases With Reserve Shortage	Number of Approved RT SCED Cases With Reserve Shortage	Number of Approved RT SCED Cases With Reserve Shortage Used in LPC	Cases With Reserve Shortage as Percent of Solved RT SCED Cases	Approved RT SCED Cases With Reserve Shortage as Percent of Solved RT SCED Cases With Shortage	RT SCED Cases With Shortage Used in LPC as Percent of Solved RT SCED Cases With Shortage
Jan	49,158	151	3	3	0.3%	2.0%	2.0%
Feb	43,628	317	0	0	0.7%	0.0%	0.0%
Mar	49,753	713	16	10	1.4%	2.2%	1.4%
Apr	48,765	796	9	6	1.6%	1.1%	0.8%
May	50,772	364	0	0	0.7%	0.0%	0.0%
Jun	51,299	377	0	0	0.7%	0.0%	0.0%
Jul	50,011	544	3	3	1.1%	0.6%	0.6%
Aug	50,769	379	0	0	0.7%	0.0%	0.0%
Sep	49,276	525	4	3	1.1%	0.8%	0.6%
Total	443,431	4,166	35	25	0.9%	0.8%	0.6%

While there were 4,166 solved RT SCED cases that indicated shortage, the number of five minute intervals where RT SCED indicated shortage was only 2,307. This is because PJM solves multiple RT SCED cases for each five minute target interval.[80]

The MMU analyzed the intervals where one or more solved RT SCED cases indicated a shortage of one or more reserve products. Table 3-67 shows, for each month in the first nine months of 2019, the total number of five minute intervals, the number of intervals where at least one solved SCED case showed a shortage of reserves, the number of intervals where more than one solved SCED case showed a shortage of reserves, and the number of five minute intervals where the LPC solution showed a shortage of reserves. Table 3-67 shows that 2,307 intervals, or 2.9 percent of all five minute intervals in the first nine months of 2019 had at least one solved SCED case showing a shortage of reserves, and 1,045 intervals, or 1.3 percent of all five minute intervals in the first nine months of 2019 had more than one solved SCED case showing a shortage of reserves.

Table 3-67 Five minute intervals with shortage: January through September, 2019

Month (2019)	Number of Five Minute Intervals	Number of Intervals With At Least One Solved SCED Case Short of Reserves	Percent Intervals With At Least One Solved SCED Case Short of Reserves	Number of Intervals With Multiple Solved SCED Cases Short of Reserves	Percent Intervals With Multiple Solved SCED Cases Short of Reserves	Number of Intervals With Five Minute Shortage Prices in LPC	Percent Intervals With Five Minute Shortage Prices in LPC
Jan	8,928	87	1.0%	34	0.4%	3	0.0%
Feb	8,064	185	2.3%	79	1.0%	0	0.0%
Mar	8,916	350	3.9%	175	2.0%	10	0.1%
Apr	8,640	424	4.9%	217	2.5%	7	0.1%
May	8,928	203	2.3%	94	1.1%	0	0.0%
Jun	8,640	233	2.7%	93	1.1%	0	0.0%
Jul	8,928	314	3.5%	135	1.5%	3	0.0%
Aug	8,928	219	2.5%	85	1.0%	0	0.0%
Sep	8,640	292	3.4%	133	1.5%	4	0.0%
Total	78,612	2,307	2.9%	1,045	1.3%	27	0.0%

80 A case is executed when it begins to solve. Most but not all cases are solved. SCED cases take about one to two minutes to solve.

While a single solved SCED case indicating a shortage for a target interval among multiple SCED cases that solved for that interval could be the result of operator bias or erroneous inputs, it is less likely that an interval with multiple RT SCED cases indicating shortage was the result of an error. There were 27 five minute intervals with shortage pricing that occurred on fourteen days in the first nine months of 2019, while there were 1,045 five minute intervals where multiple solved SCED cases showed a shortage of reserves. The data indicates reluctance on the part of PJM operators to approve SCED cases with a shortage.

The PJM Real-Time Energy Market produces an efficient outcome only when prices are allowed to reflect the fundamental supply and demand conditions in the market in real time. While it is appropriate for operators to ensure that cases use data that reflect the actual state of the system, it is essential that operator discretion not extend beyond what is necessary and that operator discretion not prevent shortage pricing when there are shortage conditions. This is a critical issue now that PJM settles all real-time energy transactions on a five minute basis using the prices calculated by LPC. The MMU recommends that PJM clearly define the criteria for operator approval of RT SCED cases used to send dispatch signals to resources, and for pricing, to minimize operator discretion and implement a rule based approach.

Shortage Pricing Intervals in LPC

There were 27 intervals with five minute shortage pricing that occurred on 14 days in the first nine months of 2019, compared to zero intervals in the first nine months of 2018, in PJM. In 26 of the 27 intervals, shortage pricing was triggered only due to synchronized reserves being short of the extended synchronized reserve requirement.[81] In one of the 27 intervals, shortage pricing was triggered due to both synchronized reserves and primary reserves being short of their extended reserve requirements. Table 3-68 shows the extended synchronized reserve requirement, the total synchronized reserves, the synchronized reserve shortage, and the synchronized reserve clearing prices for the RTO reserve zone during the 27 intervals with shortage pricing due to synchronized reserve shortage. Table 3-69 shows the extended synchronized reserve requirement, the total synchronized reserves, the synchronized reserve shortage, and the synchronized reserve clearing prices for the MAD reserve subzone during the 27 intervals with shortage pricing due to synchronized reserve shortage. Table 3-70 shows the extended primary reserve requirement, the total primary reserves, the primary reserve shortage, and the primary reserve clearing prices for the RTO reserve zone during the one interval with shortage pricing due to primary reserve shortage. Table 3-71 shows the extended primary reserve requirement, the total primary reserves, the primary reserve shortage, and the primary reserve clearing prices for the MAD reserve subzone during the one interval with shortage pricing due to primary reserve shortage.

PJM enforces an RTO wide reserve requirement and a supplemental reserve requirement for the MAD region. The MAD reserve subzone is nested within the RTO reserve zone. Resources located in the MAD reserve subzone can simultaneously satisfy the synchronized reserve requirement of the RTO reserve zone and the synchronized reserve requirement of the MAD reserve subzone. Resources located outside the MAD reserve subzone can satisfy the synchronized reserve requirement of the RTO reserve zone, and subject to transfer limits defined by transmission constraints, satisfy the reserve requirement of the MAD Subzone. The synchronized reserve clearing price of the RTO reserve zone is set by the shadow price of the binding reserve requirement constraint of the RTO reserve zone.[82] The synchronized reserve clearing price of the MAD reserve subzone, nested within the RTO reserve zone, is set by the sum of the shadow prices of the binding reserve requirement constraint of the RTO reserve zone and the shadow price of the binding reserve requirement constraint of the MAD reserve subzone.

In all 27 intervals in the first nine months of 2019 with shortage pricing, both the RTO Zone and the MAD Subzone cleared with synchronized reserves less than their extended requirement. The clearing price for synchronized reserves in the RTO Zone is the sum of the shadow prices of the synchronized reserve constraint for the RTO Zone and the primary reserve constraint for the RTO Zone. The clearing price for synchronized reserves in the MAD Subzone is

81 The extended synchronized reserve requirement is defined as the reliability synchronized reserve requirement plus 190 MW.

82 If the reserve requirement cannot be met by the resources located within the reserve zone, the shadow price of the reserve requirement is set the applicable operating reserve demand curve.

the sum of the shadow prices of the synchronized reserve constraints for the RTO Zone and MAD Subzone and the shadow prices of the primary reserve constraints in the RTO and MAD Subzone. For the two intervals on March 18 at 0635 EPT and March 19 at 0535 EPT, the clearing prices for RTO and MAD synchronized reserves reflect the non-zero shadow price of the RTO primary reserve constraint in addition to the synchronized reserve constraint shadow prices. On January 31, March 12, and April 1, 2019, the RTO synchronized reserve price exceeded $300 per MWh because the synchronized reserve shortage MW equals 190 MW, the second step of the synchronized reserve demand curve. On April 8, 2019, the RTO synchronized reserve price exceeded $300 per MWh because the synchronized reserve shortage MW is greater than 190 MW, the second step of the synchronized reserve demand curve.

Table 3-68 RTO Synchronized Reserve Shortage Intervals: January through September, 2019

Interval (EPT)	RTO Extended Synchronized Reserve Requirement (MW)	Total RTO Synchronized Reserves (MW)	RTO Synchronized Reserve Shortage (MW)	RTO Synchronized Reserve Clearing Price ($/MWh)
09-Jan-19 16:35	1,678.0	1,548.9	129.1	$300.0
30-Jan-19 18:00	1,681.0	1,538.6	142.4	$300.0
31-Jan-19 01:30	1,856.0	1,666.0	190.0	$620.5
06-Mar-19 22:10	1,645.5	1,562.2	83.3	$300.0
06-Mar-19 22:15	1,645.4	1,515.3	130.1	$300.0
12-Mar-19 07:20	1,615.7	1,610.2	5.5	$300.0
12-Mar-19 07:25	1,615.5	1,425.5	190.0	$457.9
12-Mar-19 07:30	1,615.3	1,425.3	190.0	$412.5
16-Mar-19 07:05	1,834.0	1,676.5	157.5	$300.0
16-Mar-19 07:10	1,841.0	1,814.2	26.8	$300.0
17-Mar-19 19:55	1,818.0	1,641.7	176.3	$300.0
18-Mar-19 06:35	1,860.0	1,810.2	49.8	$309.0
19-Mar-19 05:35	1,854.0	1,789.4	64.6	$421.3
01-Apr-19 19:50	1,841.0	1,651.0	190.0	$692.8
01-Apr-19 19:55	1,846.0	1,706.8	139.2	$300.0
01-Apr-19 20:00	1,847.0	1,657.0	190.0	$663.0
08-Apr-19 06:55	1,535.9	1,423.4	112.5	$300.0
08-Apr-19 07:00	1,538.1	1,178.6	359.5	$850.0
08-Apr-19 07:05	1,538.1	1,178.6	359.5	$850.0
08-Apr-19 07:10	1,538.9	1,430.8	108.1	$300.0
01-Jul-19 16:55	1,817.1	1,813.8	3.3	$300.0
01-Jul-19 17:00	1,817.5	1,500.8	316.7	$1,472.3
01-Jul-19 17:05	1,817.7	1,700.6	117.1	$307.3
03-Sep-19 16:55	1,795.3	1,593.9	201.4	$1,150.0
03-Sep-19 17:00	1,795.3	1,593.9	201.4	$1,150.0
07-Sep-19 15:20	1,990.0	1,800.0	190.0	$847.5
07-Sep-19 15:25	1,990.0	1,800.0	190.0	$847.5

Table 3-69 MAD Synchronized Reserve Shortage Intervals: January through September, 2019

Interval (EPT)	MAD Extended Synchronized Reserve Requirement (MW)	Total MAD Synchronized Reserves (MW)	MAD Synchronized Reserve Shortage (MW)	MAD Synchronized Reserve Clearing Price ($/MWh)
09-Jan-19 16:35	1,678.0	1,548.9	129.1	$600.0
30-Jan-19 18:00	1,681.0	1,538.6	142.4	$600.0
31-Jan-19 01:30	1,856.0	1,666.0	190.0	$920.5
06-Mar-19 22:10	1,645.5	1,562.2	83.3	$600.0
06-Mar-19 22:15	1,645.4	1,515.3	130.1	$600.0
12-Mar-19 07:20	1,615.7	1,610.2	5.5	$600.0
12-Mar-19 07:25	1,615.5	1,425.5	190.0	$757.9
12-Mar-19 07:30	1,615.3	1,425.3	190.0	$712.5
16-Mar-19 07:05	1,834.0	1,676.5	157.5	$600.0
16-Mar-19 07:10	1,841.0	1,814.2	26.8	$600.0
17-Mar-19 19:55	1,818.0	1,641.7	176.3	$600.0
18-Mar-19 06:35	1,860.0	1,810.2	49.8	$609.0
19-Mar-19 05:35	1,854.0	1,789.4	64.6	$721.3
01-Apr-19 19:50	1,841.0	1,651.0	190.0	$992.8
01-Apr-19 19:55	1,846.0	1,706.8	139.2	$600.0
01-Apr-19 20:00	1,847.0	1,657.0	190.0	$963.0
08-Apr-19 06:55	1,535.9	1,423.4	112.5	$600.0
08-Apr-19 07:00	1,538.1	1,178.6	359.5	$1,700.0
08-Apr-19 07:05	1,538.1	1,178.6	359.5	$1,700.0
08-Apr-19 07:10	1,538.9	1,430.8	108.1	$600.0
01-Jul-19 16:55	1,817.1	1,813.8	3.3	$600.0
01-Jul-19 17:00	1,817.5	1,500.8	316.7	$1,700.0
01-Jul-19 17:05	1,817.7	1,700.6	117.1	$607.3
03-Sep-19 16:55	1,795.3	1,593.9	201.4	$1,700.0
03-Sep-19 17:00	1,795.3	1,593.9	201.4	$1,700.0
07-Sep-19 15:20	1,990.0	1,800.0	190.0	$1,147.5
07-Sep-19 15:25	1,990.0	1,800.0	190.0	$1,147.5

Table 3-70 RTO Primary Reserve Shortage Intervals: January through September, 2019

Interval (EPT)	RTO Extended Primary Reserve Requirement (MW)	Total RTO Primary Reserves (MW)	RTO Primary Reserve Shortage (MW)	RTO Primary Reserve Clearing Price ($/MWh)
01-Jul-19 17:00	2,631.3	2,468.0	163.2	$300.0

Table 3-71 MAD Primary Reserve Shortage Intervals: January through September, 2019

Interval (EPT)	MAD Extended Primary Reserve Requirement (MW)	Total MAD Primary Reserves (MW)	MAD Primary Reserve Shortage (MW)	MAD Primary Reserve Clearing Price ($/MWh)
01-Jul-19 17:00	2,631.3	2,468.0	163.2	$600.0

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, such as tier 1 bias or operator load bias. 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.[83] PJM cannot accurately measure or price reserves due to the inaccuracy of its generator models. PJM's commitment and dispatch models rely on generator data to properly commit and dispatch generators. Generator data includes offers and parameters. When the models do not properly account for the different generator characteristics, both PJM dispatchers and generators have to make simplifications and assumptions using the tools available. Most of these

83 See Comments of the Independent Market Monitor for PJM, Docket No. RM15-24-000 (December 1, 2015) at 9.

actions taken by generators and by PJM dispatchers are not transparent. PJM manuals do not provide clarity regarding what actions generators can take when the PJM models and tools do not reflect their operational characteristics and PJM manuals do not provide sufficient clarity regarding the actions PJM dispatchers can take when generators do not follow dispatch.

In the energy and reserve markets, the actions that both generators and PJM dispatchers take have a direct impact on the amount of supply available for energy and reserves and the prices for energy and reserves. These flaws in PJM's models do not allow PJM to accurately calculate the amount of reserves available. PJM does not accurately model discontinuities in generator ramp rates, such as duct burners on combined cycle plants. PJM's generator models do not account for the complexities that may result in generators underperforming their submitted ramp rates. Instead of addressing these complexities through generator modeling improvements, PJM relies on a nontransparent method of adjusting generator parameters, called Degree of Generator Performance (DGP).[84] PJM also fails to accurately model unit starts. The market software does not account for the energy output a resource produces prior to reaching its economic minimum output level, during its soak time.

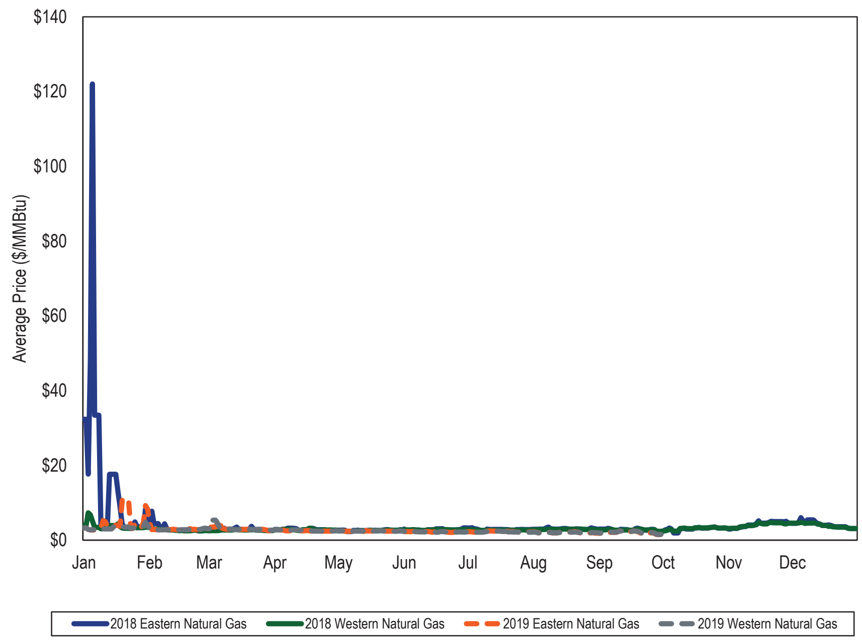
PJM adjusts ramp rates using the DGP metric, deselects specific units from providing reserves, and overrides the dispatch signal to certain units to set it equal to actual resource output. These manual interventions are crude approximations of the capability of generators and result in an inaccurate measurement of reserves.

PJM Cold Weather Operations 2019

Natural Gas Supply and Prices

As of September 30, 2019, gas fired generation was 42.1 percent (78,477.3 MW) of the total installed PJM capacity (186,502.9 MW).[85] Figure 3-49 shows the average daily price of delivered natural gas for eastern and western parts of PJM service territory in 2018 and the first nine months of 2019.[86]

Figure 3-49 Average daily delivered price for natural gas: 2018 and 2019 ($/MMBtu)



During the first nine months of 2019, 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. These notices 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

84 *See* PJM Manual 12 (Revision 39, Effective February 21, 2019) Attachment A, P78. PJM Manual 11 (Energy and Ancillary Services Market Operations) does not mention the use of DGP in the market clearing engine.

85 *2019 Quarterly State of the Market Report for PJM: January through September*, Section 5: Capacity Market, at Installed Capacity.

86 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.

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 demonstrates the potential benefits to creating a separate gas 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.

Competitive Assessment

Market Structure

Market Concentration

Analysis of supply curve segments of the PJM energy market in the first nine months of 2019 indicates low concentration in the base load segment, and high concentration in the intermediate segment and the peaking segment.[87] High concentration levels, particularly in the peaking segment, increase the probability that a generation owner will be pivotal in the aggregate market. 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.

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

When transmission constraints exist, local markets are created with ownership that is typically significantly more concentrated than the overall energy market. PJM offer capping rules that limit the exercise of local market power were generally effective in preventing the exercise of market power in the first nine months of 2019, 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 with scheduled imports (Table 3-72).

In theory, the HHI provides insight into the relationship between market structure, behavior, and performance. In the case where participants compete by producing output at constant, but potentially different, marginal costs, the HHI is directly proportional to the expected average price cost markup in the market:[88]

$$\frac{HHI}{\varepsilon} = \frac{P - MC}{P}$$

where ε is the absolute value of the price elasticity of demand, *P* is the market price, and *MC* is the average marginal cost of production. This is called the Lerner Index. The left side of the equation quantifies market structure, and the right side of the equation measures market performance. The assumed participant behavior is profit maximization. If HHI is very low, implying a more competitive market, prices converge to marginal cost, the competitive market outcome. But even a low HHI may result in substantial markup with a low price elasticity of demand. If HHI is very high, meaning competition is lacking, prices approach the monopoly level. Price elasticity of demand (ε) determines the degree to which suppliers with market power can impose higher prices on customers. The Lerner Index is a measure of market power that

88 *See* Tirole, Jean. *The Theory of Industrial Organization*, MIT (1988), Chapter 5: Short-Run Price Competition.

connects market structure (HHI and demand elasticity) to market performance (markup).

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 indicate 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.[89]

The PJM energy market HHIs and the FERC concentration cutoffs may understate the degree of market power because, in the absence of aggregate market power mitigation, even the unconcentrated HHI level would imply substantial markups due to the low short run price elasticity of demand. For example, research estimates find short run electricity demand elasticity ranging from -0.2 to -0.4.[90] Using the Lerner Index, the elasticities imply, for example, an average markup ranging from 25 to 50 percent at the unconcentrated to moderately concentrated threshold HHI of 1000:[91]

$$\frac{HHI}{\varepsilon} = \frac{0.1}{0.2} = \frac{P - MC}{P} = 50\%$$

With knowledge of HHI, elasticity, and marginal cost, one can solve for the price level theoretically indicated by the Lerner Index, based on profit maximizing behavior including the exercise of market power. With marginal costs of $25.65 per MWh and an average HHI of 773 in the first nine months of 2019, average PJM prices would theoretically range from $32 to $42 per MWh using the elasticity range of -0.2 to -0.4.[92] The theoretical prices exceed marginal costs because the exercise of market power is profit maximizing in the absence of market power mitigation. Actual prices, averaging $27.60 per MWh, and markups, at 7.1 percent, are lower than the theoretical range, supporting the MMU's competitive assessment of the market. However, markup is not zero. In some hours, markup and prices reach levels that reflect the exercise of market power.

PJM HHI Results

Calculations for hourly HHI indicate that by FERC standards, the PJM energy market during the first nine months of 2019 was unconcentrated (Table 3-72).

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

90 See Patrick, Robert H. and Frank A. Wolak (1997), "Estimating the Customer-Level Demand for Electricity Under Real-Time Market Prices, <https://web.stanford.edu/group/fwolak/cgi-bin/sites/default/files/files/Estimating%20the%20Customer-Level%20Demand%20for%20Electricity%20Under%20Real-Time%20Market%20Prices_Aug%201997_Patrick,%20Wolak.pdf>, last accessed August 3, 2018 and Fan, Shu and Rob Hyndman (2010), "The price elasticity of electricity demand in South Australia," <https://robjhyndman.com/papers/Elasticity2010.pdf>.

91 The HHI used in the equation is based on market shares. For the FERC HHI thresholds and standard HHI reporting, market shares are multiplied by 100 prior to squaring the market shares.

92 The average HHI is found in Table 3-72. Marginal costs are the sum of all components of LMP except markup, as shown in Table 3-57.

Table 3-72 Hourly energy market HHI: January through September, 2018 and 2019[93]

	Hourly Market HHI (Jan - Sep, 2018)	Hourly Market HHI (Jan - Sep, 2019)
Average	821	773
Minimum	609	572
Maximum	1165	1098
Highest market share (One hour)	28%	26%
Average of the highest hourly market share	19%	19%
# Hours	6,551	6,551
# Hours HHI > 1800	0	0
% Hours HHI > 1800	0%	0%

Table 3-73 includes HHI values by supply curve segment, including base, intermediate and peaking plants for the first nine months of 2018 and 2019. The PJM energy market was unconcentrated overall with low concentration in the baseload segment and high concentration in the intermediate segment and the peaking segment.

Table 3-73 Hourly energy market HHI (By supply segment): January through September, 2018 and 2019

	Jan - Sep, 2018			Jan - Sep, 2019		
	Minimum	Average	Maximum	Minimum	Average	Maximum
Base	725	892	1283	659	808	1120
Intermediate	733	1483	5030	694	1803	9237
Peak	679	6071	10000	701	6241	10000

93 This analysis includes all hours in the first nine months of 2018 and 2019, regardless of congestion.

Figure 3-50 shows the total installed capacity (ICAP) MW of units in the baseload, intermediate and peaking segments by fuel source in the first nine months of 2019.

Figure 3-50 Fuel source distribution in unit segments: January through September, 2019[94]

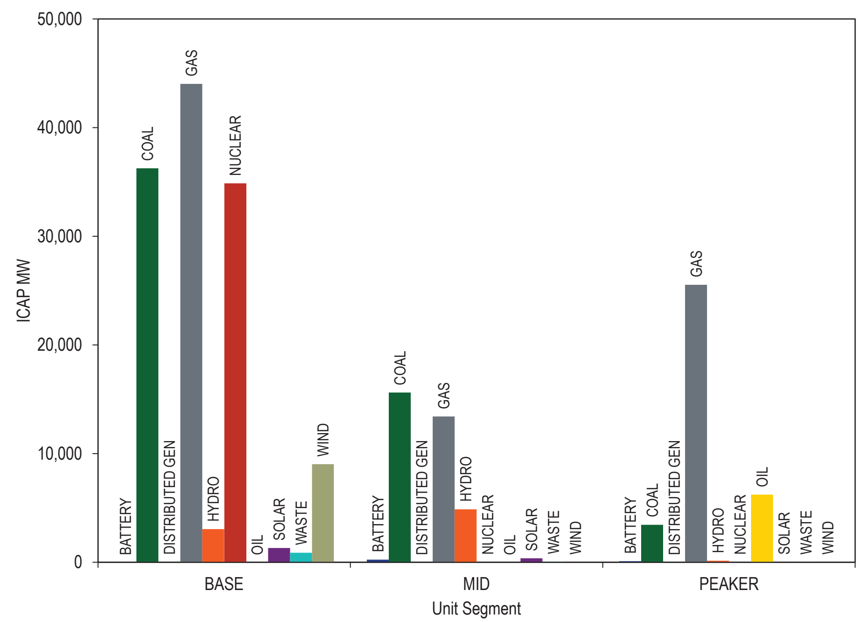


Figure 3-51 shows the ICAP of coal fired and gas fired units in PJM that are classified as baseload, intermediate and peaking segments for the first nine months from 2015 through 2019. Figure 3-51 shows that the total ICAP of coal fired units in PJM that are classified as baseload has been steadily decreasing and the total ICAP of gas fired units in PJM that are classified as baseload is steadily increasing using operating history for the period from

94 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) 1st Read - Final Report and Proposed Manual Revisions," (June 28, 2012) <http://www.pjm.com/~/media/committees-groups/task-forces/nemstf/postings/20120628-first-read-item-04-nemstf-report-and-proposed-manual-revisions.ashx>.

2015 through 2019. In the first nine months of 2019, ICAP of gas fired units classified as baseload exceeded ICAP of coal fired units classified as baseload for the first time.

Figure 3-51 Unit segment classification by fuel: January through September, 2015 through 2019

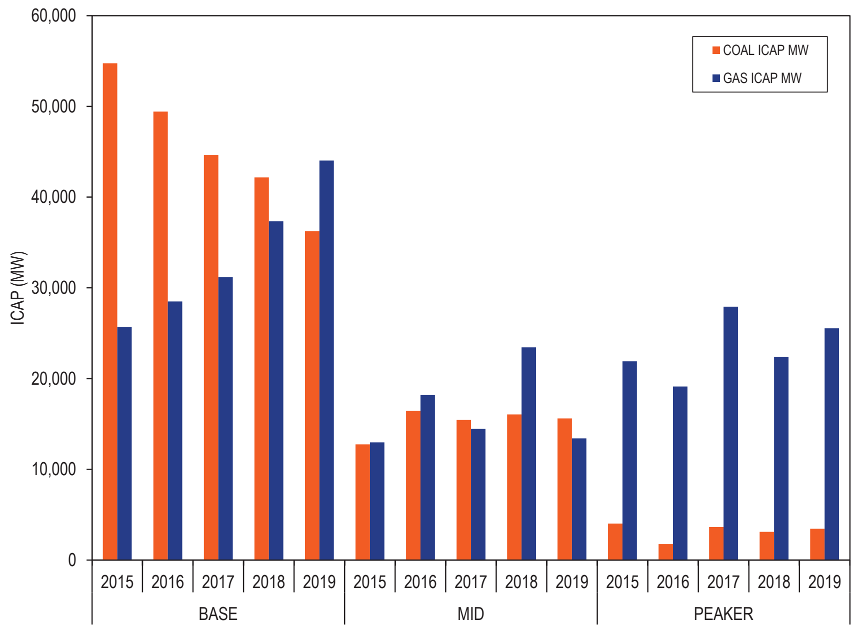
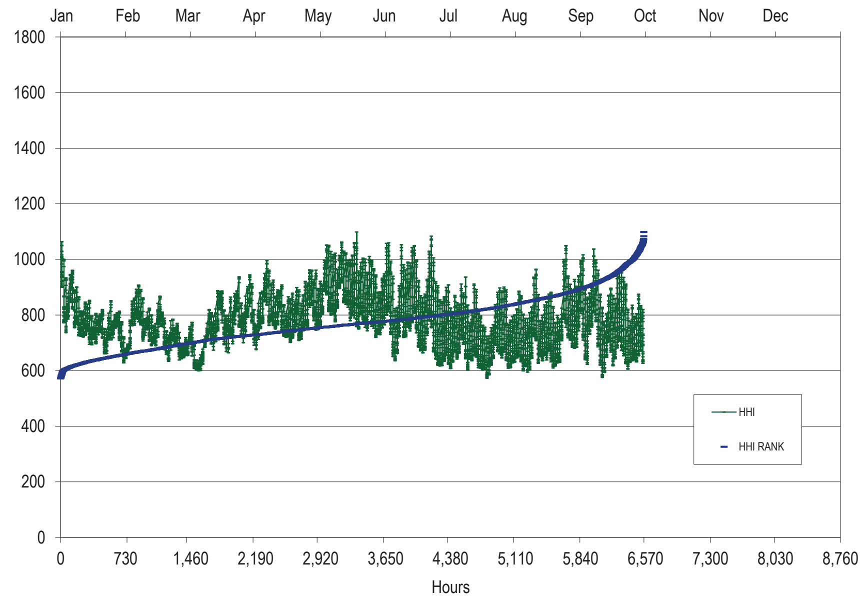


Figure 3-52 presents the hourly HHI values in chronological order and an HHI duration curve for the first nine months of 2019.

Figure 3-52 Hourly energy market HHI: January through September, 2019



Merger Reviews

FERC reviews contemplated dispositions, consolidations, acquisitions, and changes in control of jurisdictional generating units and transmission facilities under section 203 of the Federal Power Act to determine whether such transactions are "consistent with the public interest."[95]

FERC applies tests set forth in the 1996 Merger Policy Statement.[96] FERC currently is reviewing those guidelines.[97]

95 18 U.S.C. § 824b.
96 See Order No. 592, FERC Stats. & Regs. ¶ 31,044 (1996) (1996 Merger Policy Statement), reconsideration denied, Order No. 592-A, 79 FERC ¶ 61,321 (1997). See also FPA Section 203 Supplemental Policy Statement, FERC Stats. & Regs. ¶ 31,253 (2007), order on clarification and reconsideration, 122 FERC ¶ 61,157 (2008).
97 See 156 FERC ¶ 61,214 (2016); FERC Docket No. RM16-21-000.

The 1996 Merger Policy Statement provides for review of jurisdictional transactions based on "(1) the effect on competition; (2) the effect on rates; and (3) the effect on regulation." FERC adopted the 1992 Department of Justice Guidelines and the Federal Trade Commission Horizontal Merger Guideline (1992 Guidelines) to evaluate the effect on competition. Following the 1992 Guidelines, FERC applies a five step framework, which includes: (1) defining the market; (2) analyze market concentration; (3) analyze mitigative effects of new entry; (4) assess efficiency gains; and (5) assess viability of parties without merger. FERC also applies a Competitive Analysis Screen.

The MMU reviews proposed mergers based on a three pivotal supplier test applied to the actual operation of the PJM market. The MMU routinely files comments including such analyses.[98] The MMU has proposed that FERC adopt this approach when evaluating mergers in PJM.[99] FERC has considered the MMU's analysis in reviewing mergers.[100]

The MMU has also facilitated settlements for mitigation of market power, in cases where market power concerns have been identified.[101] Such mitigation generally is designed to mitigate behavior over the long term, in addition to or instead of imposing short term asset divestiture requirements.

Legislation limiting the scope of section 203 reviews has passed Congress (H.R. 1109). The legislation limits the transactions reviewed to those facilities valued more than $10,000,000. In order to avoid breaking up transactions to evade review, the legislation also requires FERC to establish a notice requirement rule for transactions involving facilities valued at more than $1,000,000. The legislation requires that such rule "minimize the paperwork burden resulting from the collection of information." In February 2019, the Commission issued Order No. 855 amending Section 203 of the Federal Power Act to implement the $10,000,000 minimum value for transactions requiring the Commission's review.[102]

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, one supplier was singly pivotal on the summer peak day, two suppliers were jointly pivotal on 28 days, and three suppliers were jointly pivotal on 164 days in the first nine months of 2019. The frequency of pivotal suppliers increased during the summer months of 2018 and 2019, on high demand days in September 2018 and 2019, from January 1 to 10, 2018, and on January 22, 2019. On January 22, 2019, total energy market uplift and energy offer markups exceeded average levels for the quarter.

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.

98 See, e.g., Comments of the Independent Market Monitor for PJM, FERC Docket No. EC14-141-000 (Nov. 10, 2014); Comments of the Independent Market Monitor for PJM, FERC Docket No. EC14-96-000 (July 21, 2014) Comments of the Independent Market Monitor for PJM, FERC Docket No. EC11-83-000 (July 21, 2011); Comments of the Independent Market Monitor for PJM, FERC Docket No. EC14-14 (Dec. 9, 2013) Comments of the Independent Market Monitor for PJM, FERC Docket No. EC14-112-000 (Sept. 15, 2014)

99 See Comments of the Independent Market Monitor for PJM, Docket No. RM16-21 (Dec. 12, 2016).

100 See Dynegy Inc., et al., 150 FERC ¶ 61, 231 (2015); Exelon Corporation, Constellation Energy Group, Inc., 138 FERC ¶ 61,167 (2012); NRG Energy Holdings, Inc., Edison Mission Energy, 146 FERC ¶ 61,196 (2014); see also Analysis of Horizontal Market Power under the Federal Power Act, 138 FERC ¶ 61,109 (2012).

101 See 138 FERC ¶ 61,167 at P 19.

102 See 166 FERC ¶ 61,120 (2019), Docket No. RM19-4.

The existing market power mitigation measures do not address aggregate market power.[103] 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.

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.[104] 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 3-53 shows the number of days in 2018 and in the first nine months of 2019 with one pivotal supplier, two jointly pivotal suppliers, and three jointly pivotal suppliers for the Day-Ahead Energy Market. No supplier was singly pivotal for any day in 2018, and one supplier was singly pivotal on the summer peak day in 2019. Two suppliers were jointly pivotal on 42 days in 2018 and on 28 days in the first nine months of 2019. Three suppliers were jointly pivotal on 212 days in 2018 and 164 days in the first nine months of 2019, despite average HHIs at persistently unconcentrated levels. In 2018 and 2019, the highest levels of aggregate market power occur in the third quarter, PJM's peak load season. In the first nine months of 2019, the highest levels of aggregate market power occurred on July 2 and July 16 through 21, 2019.

Figure 3-53 Days with pivotal suppliers and numbers of pivotal suppliers in the Day-Ahead Energy Market by quarter

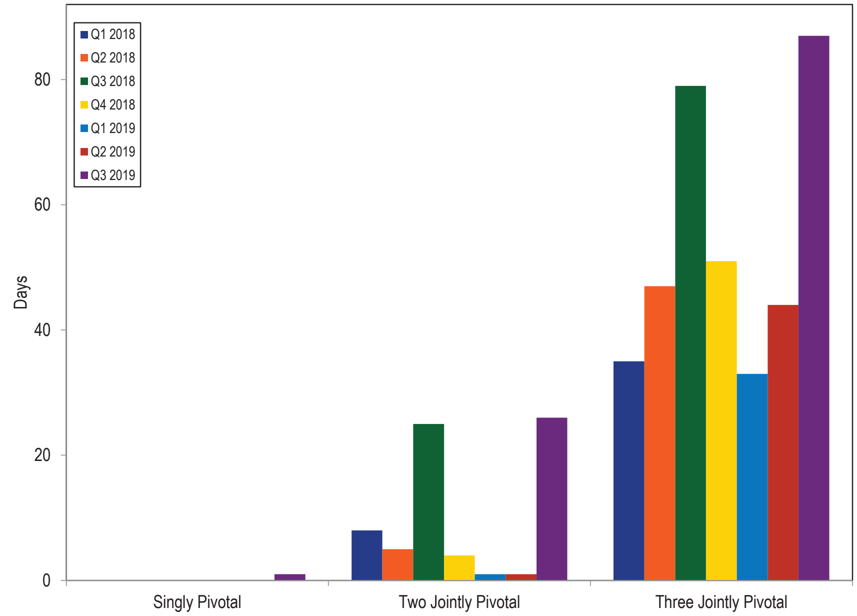


Table 3-74 provides the frequency with which each of the top 10 pivotal suppliers was singly or jointly pivotal for the Day-Ahead Energy Market in 2019. The first pivotal supplier was pivotal on July 19, 2019. The first and second pivotal suppliers were pivotal on 9.9 percent of days in the first nine months of 2019. All of the top 10 suppliers were one of three pivotal suppliers on at least 61 days in the first nine months of 2019.

103 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).

104 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.

Table 3-74 Day-ahead market pivotal supplier frequency: January through September, 2019

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	1	0.4%	27	9.9%	167	61.2%
2	0	0.0%	27	9.9%	164	60.1%
3	0	0.0%	20	7.3%	167	61.2%
4	0	0.0%	8	2.9%	132	48.4%
5	0	0.0%	8	2.9%	131	48.0%
6	0	0.0%	3	1.1%	67	24.5%
7	0	0.0%	1	0.4%	85	31.1%
8	0	0.0%	1	0.4%	73	26.7%
9	0	0.0%	1	0.4%	68	24.9%
10	0	0.0%	1	0.4%	61	22.3%

Market Behavior

Local Market Power

In the PJM energy market, market power mitigation rules currently apply only for local market power. Local market power exists when transmission constraints or reliability issues create local markets that are structurally noncompetitive. If the owners of the units required to solve the constraint or reliability issue are pivotal or jointly pivotal, they have the ability to set the price. Absent market power mitigation, unit owners that submit noncompetitive offers, or offers with inflexible operating parameters, could exercise market power. This could result in LMPs being set at higher than competitive levels, or could result in noncompetitive uplift payments.

The three pivotal supplier (TPS) test is the test for local market power in the energy market.[105] If the TPS test is failed, market power mitigation is applied by offer capping the resources of the owners who have been identified as having local market power. Offer capping is designed to set offers at competitive levels. Competitive offers are defined to be cost-based energy offers. In the PJM energy market, units are required to submit cost-based energy offers, defined by fuel cost policies, and have the option to submit market-based or price-based offers. Units are committed and dispatched on price-based offers, if offered, as the default offer. When a unit that submits both cost-based and price-based offers is mitigated to its cost-based offer by PJM, it is considered offer capped. A unit that submits only cost-based offers, or that requests PJM to dispatch it on its cost-based offer, is not considered offer capped.

Local market power mitigation is implemented in both the Day-Ahead and Real-Time Energy Markets. However, the implementation of the TPS test and offer capping differ in the Day-Ahead and Real-Time Energy Markets.

Day-Ahead Local Market Power Mitigation

In the Day-Ahead Energy Market, the TPS test is performed in a tool that is separate from the Day-Ahead market clearing software, called PROBE. PROBE is third party software, and the details of how it dispatches the system, estimates binding constraints, and calculates TPS and offer capping results are proprietary information not available to PJM or the MMU. PROBE uses the results from PJM's Resource Scheduling and Commitment (RSC) tool as an input to generate its day-ahead market solution and TPS test results. PROBE includes both physical and virtual bids and offers, including generation, physical load, virtual supply (INCs), virtual demand (DECs) and up to congestion (UTC) transactions to clear the market. Transmission constraints in the Day-Ahead Energy Market can be caused by the flow of energy that results from all these transactions. PROBE uses only physical resources and virtual supply (increment offers) as sources of relief to binding transmission constraints. If a unit owner fails the TPS test for a constraint, PROBE picks the unit schedule resulting in the lowest bid production cost for the system over the 24 hour commitment period. This calculation is internal to the PROBE software, so the MMU does not have access to the information necessary to evaluate its assumptions or accuracy.

A unit that is offer capped in PROBE does not necessarily result in the unit being offer capped in the final day-ahead market results. The process used to determine the final set of units subject to offer capping in the day-ahead market is not transparent and is not documented in the PJM manuals.

Real-Time Local Market Power Mitigation

In the Real-Time Energy Market, the TPS test is embedded in the IT SCED tool, which is a look ahead commitment and dispatch tool. In the Real-Time Energy Market, the TPS test uses physical resources, physical load forecasts, and reserve requirements to commit resources available in a look ahead window. The IT SCED tool is executed every five minutes and solves for four future intervals: a minimum of 135 minutes; 90 minutes; 45 minutes; and 30 minutes ahead. The TPS test results in offer capping recommendations applicable to online and offline resources.

PJM dispatchers use the recommendations from the IT SCED tool to commit resources to provide relief to a constraint on the cheaper of the price or cost schedule at the time of commitment, using the dispatch cost formula. Since each IT SCED case solution produces TPS test results for four look ahead intervals for each individual constraint that requires relief, it is unclear how dispatchers use all the available TPS results to select a unit to commit and the schedule to commit the unit on.

Another limitation of running the TPS test in IT SCED is that market conditions may differ between the IT SCED solution and the RT SCED solution that is used to dispatch and price the system. Constraints may create local market power differently in the RT SCED model than in the IT SCED model. Market power in the RT SCED may go unmitigated.

TPS Test Statistics for Local Market Power

The TPS test in the energy market defines whether one, two or three suppliers are jointly pivotal in a defined local market. The TPS test is applied every time the system solution indicates that out of merit resources are needed to relieve a transmission constraint. The TPS test result for a constraint for a specific interval indicates whether a supplier failed or passed the test for that constraint for that interval. A failed test indicates that the resource owner has structural market power.

A metric to describe the number of local markets created by transmission constraints and the applicability of the TPS is the number of hours that each transmission constraint was binding in the real-time energy market over a period, by zone.

In the first nine months of 2019, the AECO, AEP, ATSI, BGE, ComEd, Dominion, Met-Ed, PECO, PENELEC, PPL and PSEG control zones experienced congestion resulting from one or more constraints binding for 75 or more hours or resulting from an interface constraint (Table 3-75). The APS, DAY, DEOK, DLCO, DPL, EKPC, JCPL, OVEC, Pepco, and RECO control zones did not have constraints binding for 75 or more hours in the first nine months of 2019. Table 3-75 shows that AEP, BGE, ComEd, Dominion, and PSEG were the control zones that experienced congestion resulting from one or more constraints binding for 75 or more hours or resulting from an interface constraint that was binding for one or more hours in every year from the first nine months of 2009 through 2019.

Table 3-75 Congestion hours resulting from one or more constraints binding for 75 or more hours or from an interface constraint: January through September, 2009 through 2019

	(Jan - Sep)										
	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
AECO	149	163	234	0	0	0	192	413	0	94	97
AEP	1,005	1,265	2,452	178	2,018	1,821	1,891	633	469	1,592	595
APS	421	1,121	87	89	0	170	451	157	136	184	0
ATSI	140	0	0	208	68	481	424	1	427	2,355	259
BGE	127	274	368	1,582	1,192	4,416	6,006	8,506	1,748	2,644	622
ComEd	784	2,108	1,118	1,808	3,169	1,928	1,708	4,754	1,401	761	78
DEOK	0	0	0	185	0	0	0	0	0	75	0
DLCO	156	393	0	209	0	223	617	0	0	0	0
Dominion	456	889	1,266	559	674	77	1,341	647	80	136	90
DPL	0	111	0	382	783	542	1,138	2,691	326	398	0
EKPC	0	0	0	0	0	0	0	0	0	368	0
JCPL	0	0	0	0	0	0	79	0	94	0	0
Met-Ed	0	168	0	0	0	0	222	0	0	1,259	548
PECO	247	0	276	0	390	1,826	718	826	975	218	83
PENELEC	80	96	77	0	0	2,147	1,287	451	1,992	1,338	1,006
Pepco	149	0	76	143	200	41	0	0	0	0	0
PPL	176	117	40	146	609	148	224	398	1,370	0	718
PSEG	379	515	1,132	259	1,993	2,268	2,509	170	159	324	174

The local market structure in the Real-Time Energy Market associated with each of the frequently binding constraints was analyzed using the three pivotal supplier results in the first nine months of 2019.[106] While the real-time constraint hours include constraints that were binding in the five minute real-time pricing solution (LPC), IT SCED may contain different binding constraints because IT SCED looks ahead to intervals that are in the near future to solve for constraints that could be binding, using the load forecast for these intervals. The TPS statistics shown in this section present the data from the IT SCED TPS solution. The results of the TPS test are shown for tests that could have resulted in offer capping and tests that resulted in offer capping.

Table 3-76 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 3-77 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 ten constraints that were binding for the most hours in the PJM Real-Time Energy Market. Table 3-76 and Table 3-77 include analysis of all the tests for every interval where IT SCED determined that constraint relief was needed for each of the constraints shown. The same interval can be evaluated by multiple IT SCED cases at different look ahead times.

Table 3-76 Three pivotal supplier test details for interface constraints: January through September, 2019

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
AP South	Peak	611	708	12	1	11
	Off Peak	464	575	13	2	11
Eastern	Peak	897	960	16	1	15
	Off Peak	648	756	14	0	13
PA Central	Peak	49	160	4	0	4
	Off Peak	71	192	4	0	4
Cleveland	Peak	NA	NA	NA	NA	NA
	Off Peak	392	369	27	0	27

Table 3-77 Three pivotal supplier test details for top 10 congested constraints: January through September, 2019

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Conastone - Peach Bottom	Peak	284	503	20	10	10
	Off Peak	258	466	18	9	9
Graceton - Safe Harbor	Peak	88	118	11	3	8
	Off Peak	64	91	10	3	8
Lenox - North Meshoppen	Peak	22	55	2	0	2
	Off Peak	7	48	1	0	1
East Towanda - Hillside	Peak	28	141	2	0	2
	Off Peak	25	166	1	0	1
Asylum - East Towanda	Peak	16	257	1	0	1
	Off Peak	8	237	1	0	1
Siegfried	Peak	44	51	3	0	3
	Off Peak	43	58	3	0	3
Face Rock	Peak	23	14	1	0	1
	Off Peak	13	5	1	0	1
Tanners Creek - Miami Fort	Peak	142	172	5	0	5
	Off Peak	148	185	5	0	5
Boonetown - South Reading	Peak	37	124	2	0	2
	Off Peak	33	70	3	0	3
Haviland	Peak	20	32	1	0	1
	Off Peak	23	19	1	0	1

106 See the MMU Technical Reference for PJM Markets, p. 38 "Three Pivotal Supplier Test" for a more detailed explanation of the three pivotal supplier test. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

The three pivotal supplier test is applied every time the IT SCED 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 offer 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 3-78 and Table 3-79 provide, for the identified 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 other than providing relief to a binding constraint.

Table 3-78 Summary of three pivotal supplier tests applied for interface constraints: January through September, 2019

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
AP South	Peak	337	333	99%	7	2%	2%
	Off Peak	148	148	100%	2	1%	1%
Eastern	Peak	242	242	100%	24	10%	10%
	Off Peak	120	120	100%	2	2%	2%
PA Central	Peak	1,379	1,053	76%	0	0%	0%
	Off Peak	93	43	46%	0	0%	0%
Cleveland	Peak	0	0	NA	0	NA	NA
	Off Peak	4	4	100%	0	0%	0%

Table 3-79 Summary of three pivotal supplier tests applied for top 10 congested constraints: January through September, 2019

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
Conastone - Peach Bottom	Peak	47,736	47,724	100%	2,193	5%	5%
	Off Peak	35,640	35,631	100%	983	3%	3%
Graceton - Safe Harbor	Peak	3,190	3,112	98%	7	0%	0%
	Off Peak	9,470	9,431	100%	43	0%	0%
Lenox - North Meshoppen	Peak	5,145	2,450	48%	4	0%	0%
	Off Peak	4,238	948	22%	0	0%	0%
East Towanda - Hillside	Peak	3,586	2,012	56%	0	0%	0%
	Off Peak	2,668	810	30%	0	0%	0%
Asylum - East Towanda	Peak	1,902	204	11%	0	0%	0%
	Off Peak	1,296	101	8%	0	0%	0%
Siegfried	Peak	7,544	3,277	43%	1	0%	0%
	Off Peak	6,692	2,878	43%	1	0%	0%
Face Rock	Peak	299	114	38%	0	0%	0%
	Off Peak	70	57	81%	0	0%	0%
Tanners Creek - Miami Fort	Peak	5,177	4,870	94%	232	4%	5%
	Off Peak	2,351	2,173	92%	57	2%	3%
Boonetown - South Reading	Peak	2,107	1,045	50%	4	0%	0%
	Off Peak	716	395	55%	0	0%	0%
Haviland	Peak	1,656	338	20%	2	0%	1%
	Off Peak	2,042	31	2%	0	0%	0%

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.

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

In both the Day-Ahead and Real-Time Energy Markets, generators with market power have the ability to evade 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-based 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.[107] Prior to the implementation of hourly offers, dispatch cost was calculated as:

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

Beginning November 1, 2017, with hourly differentiated offers, the cheaper of cost and price based offers are determined using total dispatch cost, where:

$$\text{Total Dispatch Cost} = \text{Startup Cost} + \sum_{\text{Min Run}} \text{Hourly Dispatch Cost}$$

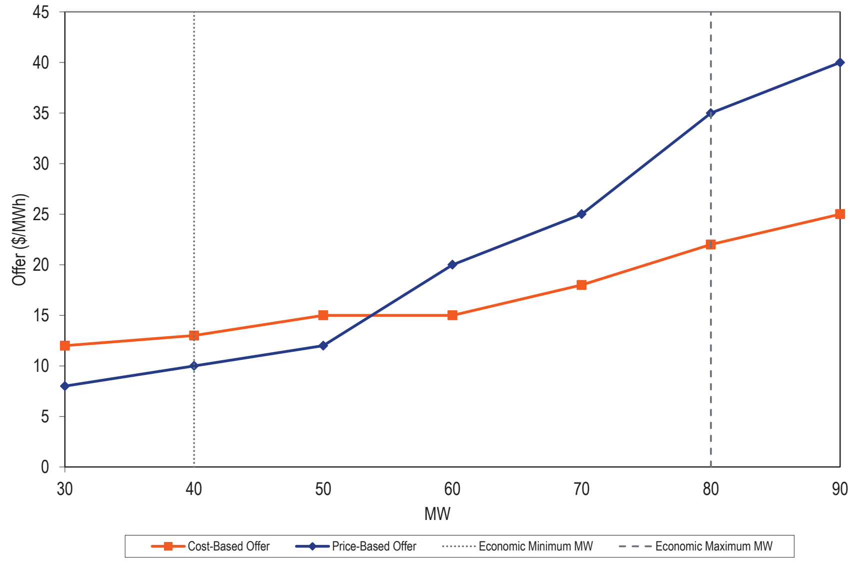
where the hourly dispatch cost is calculated for each hour using the offers applicable for that hour as:

$$\text{Hourly Dispatch Cost} = (\text{Incremental Energy Offer@EcoMin} \times \text{EcoMin MW}) + \text{NoLoad Cost}$$

With the ability to submit offer curves with varying markups at different output levels in the price-based offer, unit owners with market power can evade mitigation by using a low markup at low output levels and a high markup at higher output levels. Figure 3-54 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.

107 See PJM Operating Agreement Schedule 1 § 6.4.1(g).

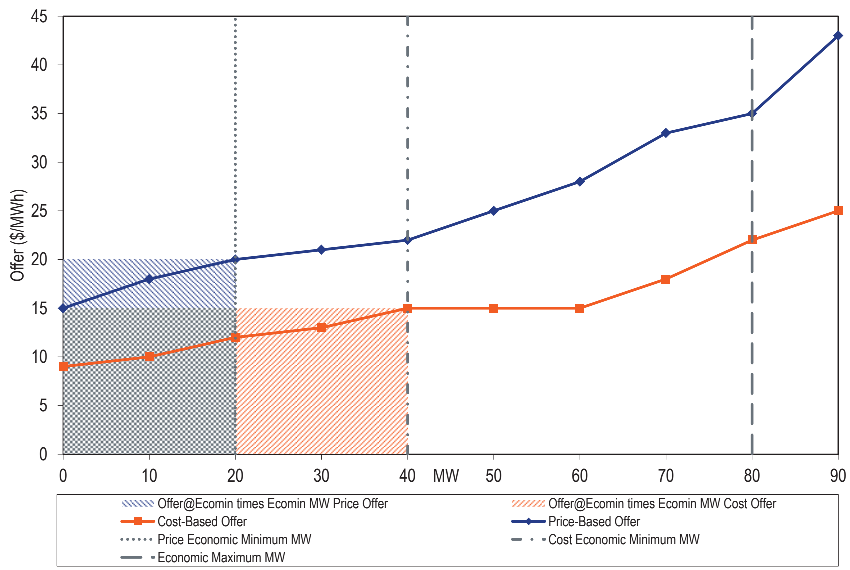
Figure 3-54 Offers with varying markups at different MW output levels



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 evade 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.

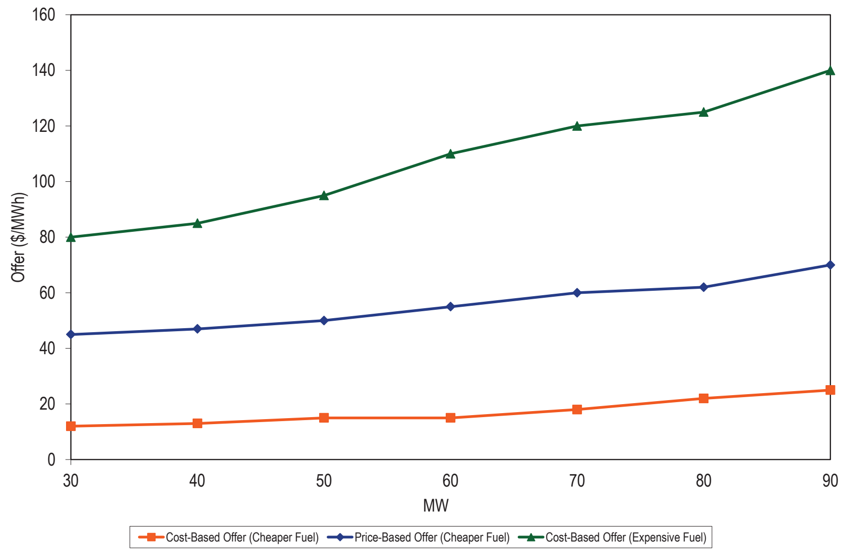
A unit may offer a lower economic minimum MW level on the price-based offer than the cost-based offer. Such a unit may appear to be cheaper to commit on the price-based offer even with a positive markup. A unit with a positive markup can have lower dispatch cost with the price-based offer with a lower economic minimum level compared to cost-based offer. Figure 3-55 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 3-55 Offers with a positive markup but different economic minimum MW



In case of dual fuel units, if the price-based offer uses a cheaper fuel and the cost-based offer uses a more expensive fuel, the price-based offer will appear to be lower cost even when it includes a markup. Figure 3-56 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 3-56 Dual fuel unit offers



These issues can be solved by simple rule changes.[108] The MMU recommends that markup of price-based offers over cost-based offers be constant across the offer curve, that there be at least one cost-based offer using the same fuel as the available price-based offer, and that operating parameters on parameter limited schedules (PLS) be at least as flexible as price-based non-PLS offers.

Levels of offer capping have historically been low in PJM, as shown in Table 3-81. But offer capping remains a critical element of PJM market rules because it is designed to prevent the exercise of local market power. While overall offer capping levels have been low, there are a significant number of units with persistent structural local market power that would have a significant impact on prices in the absence of local market power mitigation. 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

108 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.

beyond their original commitment (day-ahead or real-time) can be offer capped if the owner fails the TPS test, and the latest available cost-based offer is determined to be lower than the price-based offer.[109] Units running in real time as part of their original commitment on the price-based offer on economics, and that can provide incremental relief to a constraint, cannot be switched to their cost-based offer.

The offer capping percentages shown in Table 3-80 include units that are committed to provide constraint relief whose owners failed the TPS test in the energy market excluding units that were committed for reliability reasons, providing black start and providing reactive support. Offer capped unit run hours and offer capped generation (in MWh) are shown as a percentage of the total run hours and the total generation (MWh) from all the units in the PJM energy market.[110] Beginning November 1, 2017, with the introduction of hourly offers, certain online units, whose owners fail the TPS test in the real-time energy market for providing constraint relief, can be offer capped and dispatched on their cost-based offer subsequent to a real-time hourly offer update. This is reflected in the higher offer capping percentages in the real-time energy market in 2018 and 2019 compared to 2017.

Table 3-80 Offer capping statistics – energy only: January through September, 2015 to 2019

	Real-Time		Day-Ahead	
(Jan-Sep)	Unit Hours Capped	MWh Capped	Unit Hours Capped	MWh Capped
2015	0.4%	0.3%	0.2%	0.2%
2016	0.4%	0.3%	0.0%	0.1%
2017	0.3%	0.1%	0.0%	0.1%
2018	1.0%	0.5%	0.1%	0.1%
2019	1.6%	1.1%	1.1%	0.7%

Table 3-81 shows the offer capping percentages including units committed to provide constraint relief and units committed for reliability reasons, including units committed to provide black start service and reactive support. 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 3-80.

Table 3-81 Offer capping statistics for energy and reliability: January through September, 2015 to 2019

	Real-Time		Day-Ahead	
(Jan-Sep)	Unit Hours Capped	MWh Capped	Unit Hours Capped	MWh Capped
2015	0.8%	0.9%	0.7%	0.8%
2016	0.4%	0.3%	0.1%	0.1%
2017	0.4%	0.4%	0.1%	0.3%
2018	1.2%	0.8%	0.2%	0.3%
2019	1.6%	1.1%	1.1%	0.7%

Table 3-82 shows the offer capping percentages for units committed for reliability reasons, including units committed to provide black start service and reactive support. The data in Table 3-82 is the difference between the offer cap percentages shown in Table 3-81 and Table 3-80.

Table 3-82 Offer capping statistics for reliability: January through September, 2015 to 2019

	Real-Time		Day-Ahead	
(Jan-Sep)	Unit Hours Capped	MWh Capped	Unit Hours Capped	MWh Capped
2015	0.4%	0.6%	0.5%	0.6%
2016	0.0%	0.0%	0.1%	0.0%
2017	0.1%	0.3%	0.1%	0.2%
2018	0.1%	0.3%	0.1%	0.2%
2019	0.0%	0.0%	0.0%	0.0%

109 See OATT Attachment K Appendix § 6.4.1.

110 Prior to the 2018 Quarterly State of the Market report for PJM: January through June, these tables presented the offer cap percentages based on total bid unit hours and total load MWh. Beginning with the quarterly report for January through June, 2018, the statistics have been updated with percentages based on run hours and total generation MWh from units modeled in the energy market.

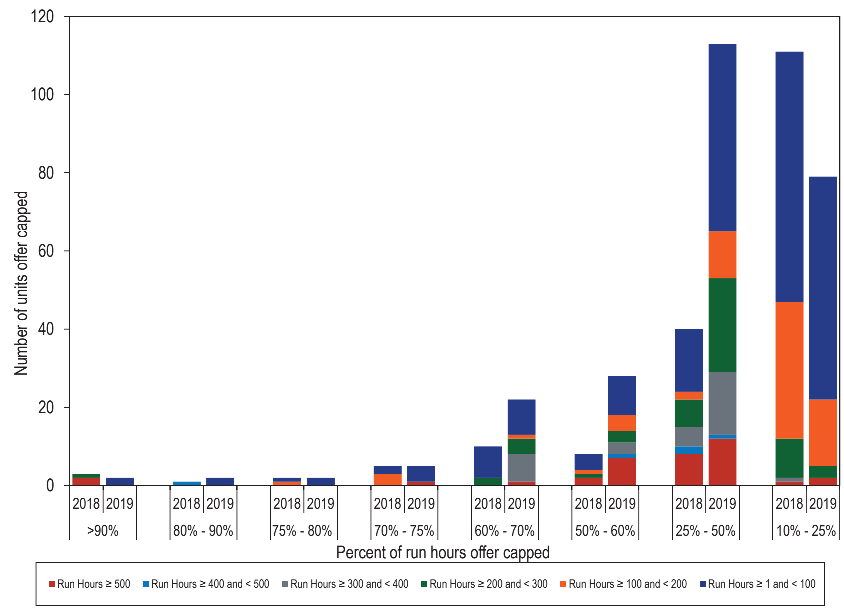
Table 3-83 presents data on the frequency with which units were offer capped in the first nine months of 2018 and 2019 as a result of failing the TPS test to provide energy for constraint relief in the Real-Time Energy Market and for reliability reasons. Table 3-83 shows that two units were offer capped for 90 percent or more of their run hours in the first nine months of 2019 compared to three units in the first nine months of 2018.

Table 3-83 Real-time offer capped unit statistics: January through September, 2018 and 2019

		Offer-Capped Hours					
Run Hours Offer-Capped, Percent Greater Than Or Equal To:	Jan - Sep	Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	2018	2	0	0	1	0	0
	2019	0	0	0	0	0	2
80% and < 90%	2018	0	1	0	0	0	0
	2019	0	0	0	0	0	2
75% and < 80%	2018	0	0	0	0	1	1
	2019	0	0	0	0	0	2
70% and < 75%	2018	0	0	0	0	3	2
	2019	1	0	0	0	0	4
60% and < 70%	2018	0	0	0	2	0	8
	2019	1	0	7	4	1	9
50% and < 60%	2018	2	0	0	1	1	4
	2019	7	1	3	3	4	10
25% and < 50%	2018	8	2	5	7	2	16
	2019	12	1	16	24	12	48
10% and < 25%	2018	1	0	1	10	35	64
	2019	2	0	0	3	17	57

Figure 3-57 shows the frequency with which units were offer capped in the first nine months of 2018 and 2019 for failing the TPS test to provide energy for constraint relief in the Real-Time Energy Market and for reliability reasons.

Figure 3-57 Real-time offer capped unit statistics: January through September, 2018 and 2019



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.[111] 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

111 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.

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 3-84 shows the average markup index of marginal units in the Real-Time Energy Market, by offer price category using unadjusted cost-based offers. Table 3-85 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.[112] 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 introduction of hourly offers and intraday offer updates in November 2017 allows gas and oil generators to directly incorporate the impact of ambient temperature changes in fuel consumption in offers.

Even the adjusted markup overestimates the negative markup because units facing increased competitive pressure have excluded both the 10 percent and components of operating and maintenance costs that are not short run marginal costs. 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.[113]

In the first nine months of 2019, 97.6 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 positive ($0.18 per MWh) when using unadjusted cost-based offers. The average dollar markups of units with offer prices between $25 and $50 was positive ($1.77 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 the first nine month of 2019, less than 0.1 percent had offer prices above $400 per MWh. Among the units that were marginal in the first nine months of 2018, 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 the first nine months of 2019 was more than $400, while the highest markup in the first nine months of 2018 was more than $500.

Table 3-84 Average, real-time marginal unit markup index (By offer price category unadjusted): January through September, 2018 and 2019

	2018 (Jan - Sep)			2019 (Jan - Sep)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $25	0.03	($0.46)	55.2%	0.03	$0.18	77.5%
$25 to $50	0.07	$2.24	34.6%	0.07	$1.77	20.2%
$50 to $75	0.35	$19.93	3.2%	0.37	$22.17	1.0%
$75 to $100	0.33	$27.13	1.1%	0.57	$48.74	0.4%
$100 to $125	0.31	$33.99	0.6%	0.34	$36.36	0.3%
$125 to $150	0.11	$15.28	1.2%	0.48	$66.73	0.1%
$150 to $400	0.07	$14.41	4.0%	0.07	$14.78	0.5%
>= $400	0.49	$241.08	0.1%	0.11	$51.44	0.0%

112 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.

113 See PJM. "Manual 15: Cost Development Guidelines," Rev. 32 (May 13, 2019).

Table 3-85 Average, real-time marginal unit markup index (By offer price category adjusted): January through September 2018 and 2019

	2018 (Jan - Sep)			2019 (Jan - Sep)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $25	0.11	$1.22	55.2%	0.11	$1.82	77.5%
$25 to $50	0.15	$4.91	34.6%	0.15	$4.33	20.2%
$50 to $75	0.41	$23.27	3.2%	0.43	$25.41	1.0%
$75 to $100	0.39	$32.34	1.1%	0.61	$52.05	0.4%
$100 to $125	0.38	$40.98	0.6%	0.40	$42.86	0.3%
$125 to $150	0.20	$26.18	1.2%	0.53	$73.12	0.1%
$150 to $400	0.16	$32.28	4.0%	0.16	$30.19	0.5%
>= $400	0.53	$261.61	0.1%	0.20	$87.44	0.0%

Table 3-86 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.[114] Table 3-87 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 the first nine months of 2019, using unadjusted cost-based offers for coal units, 53.42 percent of marginal coal units had negative markups. In the first nine months of 2019, using adjusted cost-based offers for coal units, 35.27 percent of marginal coal units had negative markups.

Table 3-86 Percent of marginal units with markup below, above and equal to zero (By fuel type unadjusted): January through September, 2018 and 2019

	2018 (Jan - Sep)			2019 (Jan - Sep)		
Type/Fuel	Negative	Zero	Positive	Negative	Zero	Positive
Coal	49.91%	21.32%	28.76%	53.42%	21.86%	24.72%
Gas	43.61%	10.77%	45.62%	36.65%	8.70%	54.65%
Oil	9.29%	82.26%	8.45%	8.52%	90.56%	0.91%

Table 3-87 Percent of marginal units with markup below, above and equal to zero (By fuel type adjusted): January through September, 2018 and 2019

	2018 (Jan - Sep)			2019 (Jan - Sep)		
Type/Fuel	Negative	Zero	Positive	Negative	Zero	Positive
Coal	17.92%	0.04%	82.04%	35.27%	0.31%	64.43%
Gas	9.38%	0.06%	90.56%	12.83%	0.02%	87.15%
Oil	0.58%	0.00%	99.42%	6.85%	0.00%	93.15%

Figure 3-58 shows the frequency distribution of hourly markups for all gas units offered in the first nine months of 2018 and 2019 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.[115] Of the gas units offered in the PJM market in the first nine months of 2019, nearly 25.0 percent of gas unit-hours had a maximum markup that was negative. More than 10.9 percent of gas fired unit-hours had a maximum markup above $100 per MWh.

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

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

Figure 3-58 Frequency distribution of highest markup of gas units offered using unadjusted cost offers: January through September, 2018 and 2019

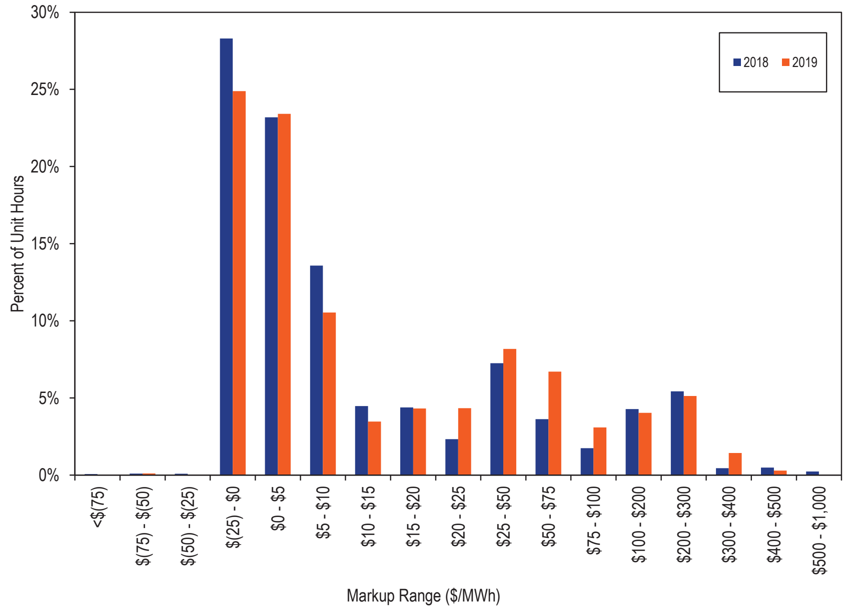


Figure 3-59 shows the frequency distribution of hourly markups for all coal units offered in the first nine months of 2018 and 2019 using unadjusted cost-based offers. Of the coal units offered in the PJM market in the first nine months of 2019, nearly 40.1 percent of coal unit-hours had a maximum markup that was negative or equal to zero.

Figure 3-59 Frequency distribution of highest markup of coal units offered using unadjusted cost offers: January through September, 2018 and 2019

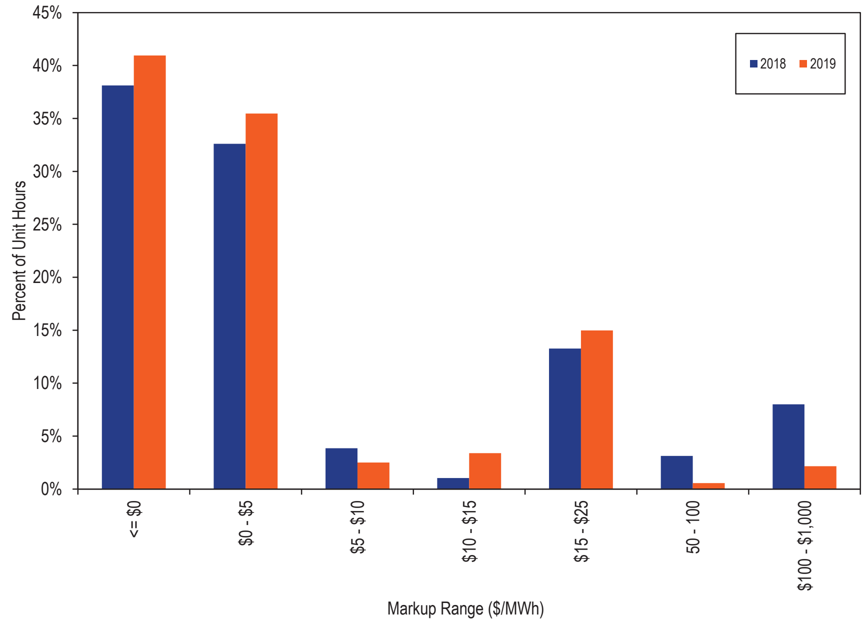
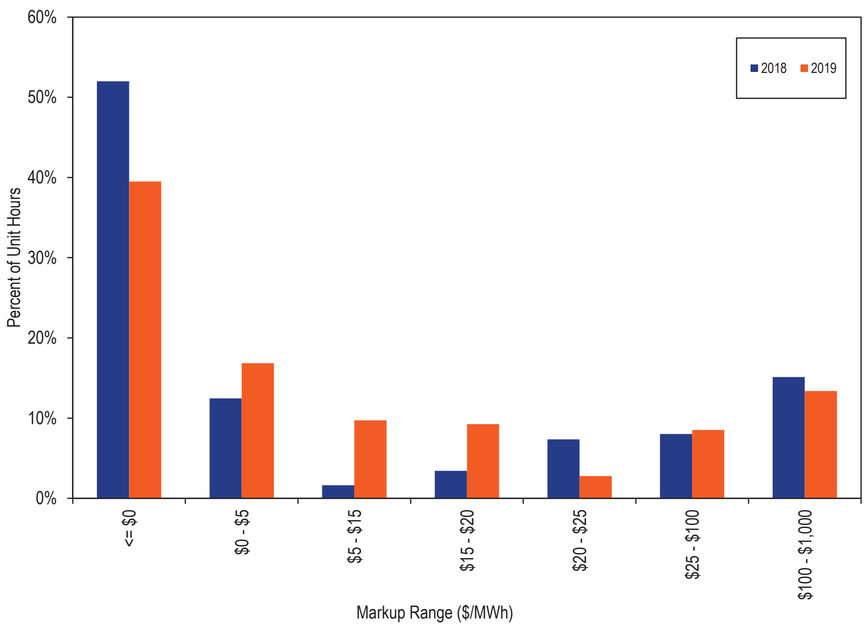


Figure 3-60 shows the frequency distribution of hourly markups for all offered oil units in the first nine months of 2018 and 2019 using unadjusted cost-based offers. Of the oil units offered in the PJM market in the first nine months of 2019, nearly 39.6 percent of oil unit-hours had a maximum markup that was negative or equal to zero. More than 13 percent of oil fired unit-hours had a maximum markup above $100 per MWh.

Figure 3-60 Frequency distribution of highest markup of oil units offered using unadjusted cost offers: January through September, 2018 and 2019

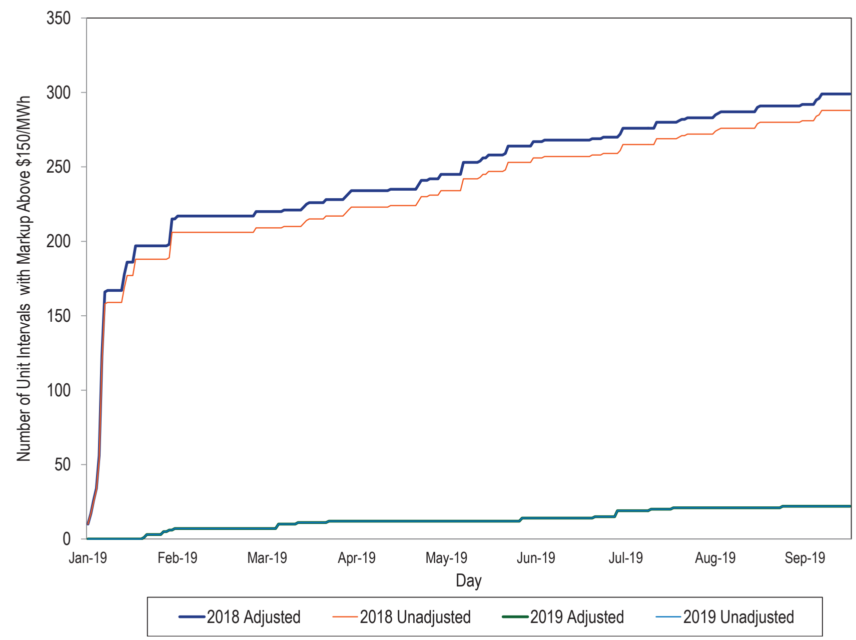


The markup frequency distributions show that a significant proportion of units make price-based offers less than the cost-based offers permitted under the PJM market rules. This behavior means that competitive price-based offers reveal actual unit marginal costs and that PJM market rules permit the inclusion 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 3-61 shows the number of marginal unit intervals in the first nine months of 2019 and 2018 with markup above $150 per MWh. The number of intervals with markups above $150 per MWh increased during the first eight days of January 2018, when the PJM region experienced low temperatures.

Figure 3-61 Cumulative number of unit intervals with markups above $150 per MWh: January through September, 2018 and 2019



Day-Ahead Markup Index

Table 3-88 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 the first nine months of 2019, 98.4 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 ($0.48 per MWh) when using unadjusted cost-based offers. The average dollar markups of units with offer prices between $25 and $50 was positive ($1.38 per MWh) when using unadjusted cost-based offers.

Some marginal units did have substantial markups. Among the units that were marginal in the day-ahead market in January through September, 2018 and 2019, none had offer prices above $400 per MWh. Using the unadjusted cost-based offers, the highest markup for any marginal unit in the day-ahead market in the first nine months of 2019 was about $90 per MWh while the highest markup in the first nine months of 2018 was about $200 per MWh.

Table 3-88 Average day-ahead marginal unit markup index (By offer price category, unadjusted): January through September, 2018 and 2019

	2018 (Jan - Sep)			2019 (Jan - Sep)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $25	0.04	$0.19	54.9%	0.11	$0.48	72.2%
$25 to $50	0.10	$3.33	40.4%	0.05	$1.38	26.2%
$50 to $75	0.27	$14.82	2.1%	0.17	$9.28	0.9%
$75 to $100	0.28	$21.98	0.7%	0.35	$32.13	0.1%
$100 to $125	0.02	$1.85	0.4%	0.52	$53.65	0.1%
$125 to $150	0.07	$8.99	0.6%	0.32	$45.31	0.1%
>= $150	0.08	$14.98	1.0%	0.06	$10.11	0.4%

Table 3-89 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 the first nine months of 2019, 0.1 percent of marginal generating units had offers between $75 and $100 per MWh, and the average dollar markup and the average markup index were both positive. The average markup index increased from 0.13 in the first nine months of 2018, to 0.19 in the first nine months of 2019 in the offer price category less than $25.

Table 3-89 Average day-ahead marginal unit markup index (By offer price category, adjusted): January through September, 2018 and 2019

	2018 (Jan - Sep)			2019 (Jan - Sep)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $25	0.13	$1.90	54.9%	0.19	$2.16	72.2%
$25 to $50	0.18	$5.90	40.4%	0.13	$3.91	26.2%
$50 to $75	0.33	$18.55	2.1%	0.24	$13.53	0.9%
$75 to $100	0.34	$27.57	0.7%	0.41	$37.34	0.1%
$100 to $125	0.11	$11.80	0.4%	0.56	$57.92	0.1%
$125 to $150	0.15	$20.16	0.6%	0.38	$53.81	0.1%
>= $150	0.16	$32.32	1.0%	0.14	$26.18	0.4%

Energy Market Cost-Based Offers

The application of market power mitigation rules in the Day-Ahead Energy Market and the Real-Time Energy Market helps ensure competitive market outcomes even in the presence of structural market power.

Cost-based offers in PJM affect all aspects of the PJM energy market. Cost-based offers affect prices when units are committed and dispatched on their cost-based offers. In the first nine months of 2019, 9.3 percent of the marginal units set prices based on cost-based offers, 1.0 percentage points less than in the first nine months of 2018.

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 in the PJM market rules is not 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

Short run marginal costs are the only costs relevant to competitive offers in the energy market. Specifically, the competitive energy offer level is the short run marginal cost of production. The current PJM market rules distinguish costs includable in cost-based energy offers from costs includable in cost-based capacity market offers based on whether costs are directly related to energy production. The rules do not provide a clear standard. Energy production is the sole purpose of a power plant. Therefore, all costs, including the sunk costs, are directly related to energy production. This current ambiguous criterion is incorrect and, in addition, allows for multiple interpretations, which could lead to tariff violations. The incorrect rules will lead to higher energy market prices and higher uplift.

There are three types of costs identified under PJM rules as of April 15, 2019: variable costs, avoidable costs, and fixed costs. The criterion for whether a generator may include a cost in an energy market cost-based offer is that the cost is "directly related to electric production."[116]

Variable costs are comprised of short run marginal costs and avoidable costs that are directly related to electric production. Short run marginal costs are the 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, emission allowance costs, operating costs, and energy market opportunity costs.[117]

Avoidable costs are annual costs that would be avoided if energy were not produced over an annual period. The PJM rules divide avoidable costs into those that are directly related to electric production and those not directly related to electric production. The distinction is ambiguous at best. PJM includes overhaul and maintenance costs and overtime staffing costs in costs related to electric production. PJM includes taxes, preventative maintenance to auxiliary equipment, and pipeline reservation charges in costs not related to electric production.

116 See PJM Interconnection L.L.C., 167 FERC ¶ 61,030 (April 15, 2019).
117 See PJM Operating Agreement Schedule 2 (a)

Fixed costs are costs associated with an investment in a facility including the return on and of capital.

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

Fuel Cost Policies

Fuel cost policies (FCP) 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

Table 3-90 shows the status of all Fuel Cost Policies as of September 30, 2019. As of September 30, 2019, 1,135 units (88 percent) had an FCP passed by the MMU, zero units had an FCP under the MMU review (submitted) and 162 units (12 percent) had an FCP failed by the MMU. The number of units with fuel cost policies failed by the MMU included units with 27,536 MW. All units had an FCP approved by PJM. As of September 30, 2019, one unit had FCPs under PJM's review. The number of units with fuel cost policies passed by the MMU increased one percentage point from 87 percent in 2018 Annual Fuel Cost Policy Review to 88 percent as of September 30, 2019.

Table 3-90 FCP Status: September 30, 2019

	MMU Status			
PJM Status	Pass	Submitted	Fail	Total
Submitted	0	0	0	0
Under Review	1	0	0	1
Customer Input Required	0	0	0	0
Approved	1,134	0	162	1,296
Revoked	0	0	0	0
Expired	0	0	0	0
Total	1,135	0	162	1,297

The MMU performed a detailed review of every FCP. PJM approved the FCPs that the MMU passed. PJM 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:[118] Verifiable means that the FCP must provide that a market seller 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 means that the FCP must document a standardized method or methods for calculating fuel costs including objective triggers for each method.[119] PJM and FERC did not agree that Fuel Cost Policies should be algorithmic:[120] Algorithmic means that the FCP must use a set of defined, logical steps, analogous to a recipe, to calculate the fuel costs. 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').[121]

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:[122] accuracy (reflect applicable costs accurately); procurement practices (provide information sufficient for the verification of the market seller's fuel procurement practices where relevant); fuel contracts (reflect the market seller's applicable commodity and/or transportation contracts where it holds such contracts).

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, objective, 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. The point of FCPs is to eliminate such practices as the basis for fuel costs, as most companies have done. 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 an FCP. If it is not verifiable, an 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 generally not an accurate indication of the expected fuel cost. The price of uncleared offers on the exchange generally exceeds the price of cleared transactions, often by a wide margin. 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.

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.

118 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.
119 Protest of the Independent Market Monitor for PJM, Docket No. ER16-372-002 (September 16, 2016) ("September 16th Filing") at P 8.
120 October 7th Filing at P12; 158 FERC ¶ 61,133 at P 57 (2017) ("February 3rd Order").
121 September 16th Filing at P 8.
122 See PJM Operating Agreement Schedule 2 § 2.3 (a).

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.

The MMU recommends that PJM change the Fuel Cost Policy requirement to apply only to units that will be offered with nonzero cost-based offers. PJM should set to zero the cost-based offers of units without an approved Fuel Cost Policy.

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.[123] Penalties became effective May 15, 2017.

In the first nine months of 2019, 48 penalty cases were identified, 44 resulted in assessed cost-based offer penalties, zero resulted in disagreement between the MMU and PJM, and four remain pending PJM's determination. These cases were from 48 units owned by 15 different companies. Table 3-92 shows the penalties by the year in which participants were notified.

123 158 FERC ¶ 61,133 (2017) ("February 3rd Order").

Table 3-91 Cost-based offer penalty cases by year notified: 2017 through 2019

Year notified	Cases	Assessed penalties	MMU and PJM Disagreement	Pending cases	Number of units impacted	Number of companies impacted
2017	57	56	1	0	55	16
2018	187	159	26	2	137	35
2019	48	44	0	4	48	15
Total	292	259	27	6	231	50

Since 2017, 292 penalty cases have been identified, 259 resulted in assessed cost-based offer penalties, 27 resulted in disagreement between the MMU and PJM, and six remain pending PJM's determination. The 259 cases were from 231 units owned by 50 different companies. The total penalties were $2.2 million, charged to units that totaled 59,189 available MW. The average penalty was $1.72 per available MW.[124] Table 3-92 shows the total cost-based offer penalties since 2017 by year.

Table 3-92 Cost-based offer penalties by year: May 2017 through September 2019

Year	Number of units	Number of companies	Penalties	Average Available Capacity Charged (MW)	Average Penalty ($/MW)
2017	92	20	$556,826	16,930	$1.56
2018	125	33	$1,257,292	26,054	$2.28
2019	48	13	$394,524	16,204	$1.05
Total	265	50	$2,208,642	59,189	$1.72

The incorrect cost-based offers resulted from incorrect application of Fuel Cost Policies, lack of approved Fuel Cost Policies, Fuel Cost Policy violations, 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.

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

124 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.

description of the components of cost-based offers based on short run marginal costs and the correct calculation of cost-based offers.

Variable Operating and Maintenance Costs

PJM Manual 15 and the PJM Operating Agreement Schedule 2 include rules related to VOM costs. On October 29, 2018, PJM filed tariff revisions changing the rules related to VOM costs.[125] The changes proposed by PJM attempted to clarify the rules. The proposed rules defined all costs directly related to electricity production as includable in cost-based offers. This also included the long term maintenance costs of combined cycles and combustion turbines, which had been explicitly excluded in PJM Manual 15.

On April 15, 2019, FERC accepted PJM's filing order, subject to revisions requested by FERC.[126] On October 28, 2019, FERC issued a final order accepting PJM's compliance filing.[127] Regardless of the changes, the rules remain unclear and are now inconsistent with economic theory. The purpose of cost-based energy offers is to prevent the exercise of market power in the PJM energy market. PJM administers market power mitigation in the energy market by replacing a generator's market-based offer with its cost-based offer when the generator owner fails the structural test for local market power, the Three Pivotal Supplier ("TPS") test, or is required for reliability. The effectiveness of market power mitigation in delivering competitive market outcomes is based entirely on cost-based offers as the measure of the competitive offer level. When market power is not mitigated, energy prices exceed the competitive level, uplift payments exceed the efficient level, and economic withholding allows generators to collect capacity payments without running, while raising prices for other generators and for load. The competitive offer level is the short run marginal cost of the generator for the relevant market hour.

Maintenance costs are not short run marginal costs. Generators perform maintenance during outages. Generators do not perform maintenance in the short run, while operating the generating unit. Generators do not perform maintenance in real time to increase the output of a unit. Some maintenance costs are correlated with the historic operation of a generator. Correlation between operating hours or starts and maintenance expenditures over a long run, multiyear time frame does not indicate the necessity of any specific maintenance expenditure to produce power in the short run.

A generating unit does not consume a defined amount of maintenance parts and labor in order to start. A generating unit does not consume a defined amount of maintenance parts and labor in order to produce an additional MWh. Maintenance events do not occur in the short run. The company cannot optimize its maintenance costs in the short run.

In the nine six months of 2019, VOM costs reviewed and approved by PJM for 2019 remained in place based on the previous rules. In June 2019, PJM began reviewing revised operating costs and maintenance costs based on the April 15th Order. Operating and maintenance costs approved by PJM in 2019 based on the April 15th Order become effective within seven days of approval.

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. 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.[128]

125 See PJM Interconnection Maintenance Adder Revisions to the Amended and Restated Operating Agreement, L.L.C., Docket No. EL19-8-000.
126 167 FERC ¶ 61,030.
127 168 FERC ¶ 61,134.
128 The peak adder is equal to $300 times three divided by 5 MW.

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

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. To account for this, PJM Manual 15 requires reducing the station service MWh used during the start sequence by the output in MWh produced by each combustion turbine after synchronization and before the HRSG steam pressure matches the steam turbine steam pressure. The formula and the language in this definition are not appropriate and are unclear.

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 steam turbine breaker close 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)

The new rules for determining the qualification of a unit as an FMU or AU became effective November 1, 2014. 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 units eligible for an FMU or AU adder for the period between December 2014 and August 2019.[129] One unit qualified for an FMU adder for the month of September 2019.

Effective in planning year 2020/2021, default Avoidable Cost Rates will no longer be defined. If a generating unit's Projected PJM Market Revenues plus the unit's PJM capacity market revenues on a rolling 12-month basis (in $/MW-year) are greater than zero, and if the generating unit does not have an approved unit specific Avoidable Cost Rate, the generating unit will not qualify as an FMU as the Avoidable Cost Rate will be assumed to be zero for FMU qualification purposes.

The MMU recommends the elimination of FMU and AU adders. FMU and AU adders no longer serve the purpose for which they were created and interfere with the efficient operation of PJM markets.

Market Performance

Ownership of Marginal Resources

Table 3-93 shows the contribution to real-time, load-weighted LMP by individual marginal resource owners.[130] The contribution of each marginal resource to price at each load bus is calculated for each five-minute interval of the first nine months of 2019, and summed by the parent company that offers the marginal resource into the Real-Time Energy Market. In the first nine months of 2019, the offers of one company resulted in 13.7 percent of the real-time, load-weighted PJM system LMP and the offers of the top four companies resulted in 39.7 percent of the real-time, load-weighted, average PJM system LMP. During the first nine months of 2018, the offers of one company resulted in 13.3 percent of the real-time, load-weighted PJM system LMP and offers of the top four companies resulted in 39.1 percent of the real-time, load-weighted, average PJM system LMP. In the first nine months of 2019, the offers of one company resulted in 15.2 percent of the peak hour real-time, load-weighted PJM system LMP. In the first nine months of 2018, the offers of one company resulted in 12.1 percent of the peak hour, real-time, load-weighted PJM system LMP. The decline in the concentration of marginal resource ownership largely paralleled the decline in the share of marginal coal resources in the real time energy market. In the PJM energy market, the ownership of coal resources is highly concentrated unlike the ownership of new entrant natural gas resources.

129 For a definition of FMUs and AUs, and for historical FMU/AU results, see the 2018 State of the Market Report for PJM, Volume 2, Section 3, Energy Market, at Frequently Mitigated Units (FMU) and Associated Units (AU).
130 See the MMU Technical Reference for PJM Markets, at "Calculation and Use of Generator Sensitivity/Unit Participation Factors."

Table 3-93 Marginal unit contribution to real-time, load-weighted LMP (By parent company): January through September, 2018 and 2019

2018 (Jan - Sep)						2019 (Jan - Sep)					
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	13.3%	13.3%	1	12.1%	12.1%	1	13.7%	13.7%	1	15.2%	15.2%
2	10.0%	23.3%	2	10.0%	22.1%	2	10.7%	24.4%	2	11.2%	26.4%
3	8.6%	31.9%	3	8.0%	30.1%	3	9.1%	33.5%	3	7.9%	34.3%
4	7.2%	39.1%	4	7.5%	37.6%	4	6.2%	39.7%	4	5.4%	39.7%
5	6.6%	45.7%	5	6.0%	43.6%	5	5.2%	44.9%	5	5.0%	44.7%
6	4.7%	50.5%	6	5.5%	49.0%	6	4.6%	49.5%	6	4.2%	48.9%
7	4.7%	55.1%	7	5.4%	54.5%	7	4.5%	54.0%	7	3.9%	52.8%
8	4.5%	59.7%	8	4.9%	59.4%	8	4.2%	58.2%	8	3.9%	56.7%
9	4.1%	63.8%	9	3.7%	63.1%	9	3.7%	61.9%	9	3.8%	60.5%
Other (79 companies)	36.2%	100.0%	Other (76 companies)	36.9%	100.0%	Other (70 companies)	38.1%	100.0%	Other (67 companies)	39.5%	100.0%

Table 3-94 shows the contribution to day-ahead, load-weighted LMP by individual marginal resource owners.[131] The contribution of each marginal resource to price at each load bus is calculated hourly, and summed by the parent company that offers the marginal resource into the Day-Ahead Energy Market. The results show that in the first nine months of 2019, the offers of one company contributed 10.0 percent of the day-ahead, load-weighted, PJM system LMP and that the offers of the top four companies contributed 30.1 percent of the day-ahead, load-weighted, average, PJM system LMP. In the first nine months of 2018, the offers of one company contributed 12.1 percent of the day-ahead, load-weighted PJM system LMP and offers of the top four companies contributed 30.2 percent of the day-ahead, load-weighted, average PJM system LMP.

Table 3-94 Marginal resource contribution to day-ahead, load-weighted LMP (By parent company): January through September, 2018 and 2019

2018 (Jan - Sep)						2019 (Jan - Sep)					
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	12.1%	12.1%	1	14.1%	14.1%	1	10.0%	10.0%	1	12.1%	12.1%
2	7.2%	19.3%	2	7.1%	7.1%	2	7.8%	17.8%	2	6.1%	18.3%
3	6.1%	25.4%	3	5.4%	5.4%	3	6.2%	24.0%	3	5.8%	24.1%
4	4.8%	30.2%	4	5.0%	5.0%	4	6.1%	30.1%	4	5.3%	29.4%
5	4.4%	34.6%	5	5.0%	5.0%	5	4.6%	34.7%	5	5.1%	34.5%
6	4.2%	38.8%	6	4.1%	4.1%	6	3.6%	38.3%	6	3.6%	38.1%
7	3.8%	42.6%	7	3.9%	3.9%	7	3.5%	41.8%	7	3.4%	41.5%
8	3.7%	46.4%	8	3.5%	3.5%	8	3.4%	45.2%	8	3.1%	44.7%
9	3.6%	50.0%	9	3.1%	3.1%	9	3.3%	48.5%	9	3.1%	47.8%
Other (161 companies)	50.0%	100.0%	Other (146 companies)	48.8%	48.8%	Other (142 companies)	51.5%	100.0%	Other (133 companies)	52.2%	100.0%

131 Id.

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 markups are not marginal by altering the economic dispatch order of supply.

The MMU calculates an explicit measure of the impact of marginal unit incremental energy offer markups on LMP using the mathematical relationships among LMPs in the market solution.[132] 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.

132 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 incremental energy offer and the cost-based incremental energy 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. The markup analysis does not include markup in start up or no load offers. See Calculation and Use of Generator Sensitivity/Unit Participation Factors, 2010 State of the Market Report for PJM: Technical Reference for PJM Markets.

Real-Time Markup

Markup Component of Real-Time Price by Fuel, Unit Type

The markup component of price is the difference between the system price, when the system price is determined by the active offers of the marginal units, whether price or cost-based, and the system price, based on the cost-based offers of those marginal units.

Table 3-95 shows the impact (markup component of LMP) of the marginal unit 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 decreased from $7.90 per MWh in the first nine months of 2018 to $4.07 per MWh in the first nine months of 2019. The adjusted markup contribution of coal units in the first nine months of 2019 was $0.93 per MWh. The adjusted markup component of gas fired units in the first nine months of 2019 was $3.17 per MWh, a decrease of $1.76 per MWh from the first nine months of 2018. The markup component of wind units was less than $0.0 per MWh. If a price-based offer is negative, but less negative than a cost-based offer, the markup is positive. In the first nine months of 2018, among the wind units that were marginal, 92.9 percent had negative offer prices.

Table 3-95 Markup component of real-time, load-weighted, average LMP by primary fuel type and unit type: January through September, 2018 and 2019[133]

		2018 (Jan - Sep)		2019 (Jan - Sep)	
Fuel	Technology	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)
Coal	Steam	$1.36	$2.25	$0.06	$0.93
Gas	CC	$2.94	$4.15	$1.86	$2.85
Gas	CT	$0.34	$0.67	$0.20	$0.39
Gas	RICE	$0.00	$0.01	$0.02	$0.03
Gas	Steam	$0.02	$0.10	($0.16)	($0.11)
Landfill Gas	CT	$0.00	$0.00	($0.00)	($0.00)
Landfill Gas	RICE	$0.00	$0.00	$0.00	$0.00
Municipal Waste	CT	$0.00	$0.00	$0.00	$0.00
Municipal Waste	RICE	$0.00	$0.00	$0.00	$0.00
Oil	CC	$0.20	$0.22	($0.00)	$0.00
Oil	CT	$0.07	$0.23	$0.00	$0.00
Oil	RICE	$0.00	$0.00	$0.00	$0.00
Oil	Steam	$0.13	$0.17	($0.03)	($0.03)
Other	Steam	$0.09	$0.09	($0.00)	($0.00)
Uranium	Steam	$0.00	$0.00	$0.00	$0.00
Wind	Wind	$0.01	$0.01	($0.00)	($0.00)
Total		$5.17	$7.90	$1.95	$4.07

Markup Component of Real-Time Price

Table 3-96 shows the markup component, calculated using unadjusted offers, of average prices and of average monthly on peak and off peak prices. Table 3-97 shows the markup component, calculated using adjusted offers, of average prices and of average monthly on peak and off peak prices. In the first nine months of 2019, when using unadjusted cost-based offers, $1.95 per MWh of the PJM real-time load-weighted average LMP was attributable to markup. Using adjusted cost-based offers, $4.07 per MWh of the PJM real-time load-weighted, average LMP was attributable to markup. In the first nine months of 2019, the peak markup component was highest in July, $4.91 per MWh using unadjusted cost-based offers and peak markup component was highest in July, $7.25 per MWh using adjusted cost-based offers. This corresponds to 14.1 percent and 20.9 percent of the real-time peak load-weighted average LMP in July.

133 The unit type RICE refers to Reciprocating Internal Combustion Engines.

Table 3-96 Monthly markup components of real-time load-weighted LMP (Unadjusted): 2018 and 2019

	2018			2019		
	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component
Jan	$9.32	$11.70	$6.90	$2.11	$1.49	$2.70
Feb	$1.47	$0.95	$1.97	$2.34	$1.63	$3.05
Mar	$4.89	$2.58	$7.15	$2.27	$1.82	$2.74
Apr	$5.77	$3.47	$8.03	$1.59	$0.81	$2.27
May	$5.21	$1.57	$8.45	$1.41	$0.56	$2.19
Jun	$2.93	$1.83	$3.95	$1.56	$1.24	$1.89
Jul	$4.84	$1.50	$8.01	$3.58	$2.12	$4.91
Aug	$4.81	$1.94	$7.12	$0.87	$0.99	$0.77
Sep	$6.55	$3.71	$9.63	$1.46	$0.78	$2.14
Oct	$3.93	$2.28	$5.32			
Nov	$2.70	$1.21	$4.16			
Dec	$1.45	$0.91	$2.07			
Total	$4.56	$2.93	$6.13	$1.95	$1.31	$2.56

Table 3-97 Monthly markup components of real-time load-weighted LMP (Adjusted): 2018 and 2019

	2018			2019		
	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component
Jan	$15.04	$17.70	$12.34	$4.66	$3.81	$5.48
Feb	$3.64	$2.96	$4.32	$4.52	$3.72	$5.33
Mar	$7.24	$4.80	$9.63	$4.53	$3.99	$5.11
Apr	$8.24	$5.74	$10.69	$3.60	$2.67	$4.42
May	$7.38	$3.48	$10.87	$3.38	$2.33	$4.33
Jun	$5.04	$3.75	$6.26	$3.42	$2.89	$3.94
Jul	$7.21	$3.61	$10.62	$5.73	$4.06	$7.25
Aug	$7.24	$4.16	$9.71	$2.83	$2.60	$3.03
Sep	$8.92	$5.85	$12.25	$3.50	$2.58	$4.42
Oct	$6.36	$4.48	$7.94			
Nov	$5.57	$3.88	$7.24			
Dec	$4.14	$3.47	$4.92			
Total	$7.29	$5.51	$8.99	$4.07	$3.23	$4.86

Hourly Markup Component of Real-Time Prices

Figure 3-62 shows the markup contribution to the hourly load-weighted LMP using unadjusted cost offers in the first nine months of 2019 and 2018. Figure 3-63 shows the markup contribution to the hourly load-weighted LMP using adjusted cost-based offers in the first nine months of 2019 and 2018. The hourly markup component of real-time prices was higher during the first eight days of January 2018, when the PJM region experienced particularly low temperatures.

Figure 3-62 Markup contribution to real-time hourly load-weighted LMP (Unadjusted): 2018 and 2019

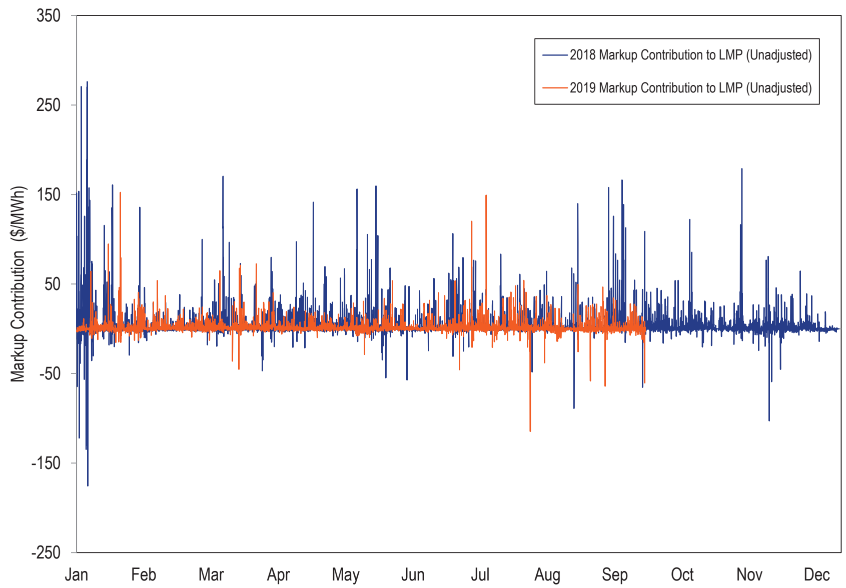
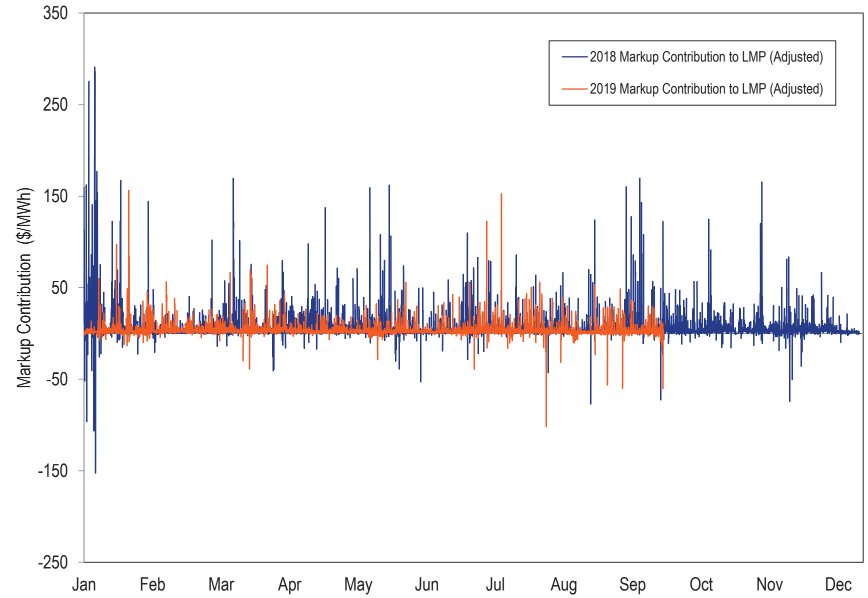


Figure 3-63 Markup contribution to real-time hourly load-weighted LMP (Adjusted): 2018 and 2019



Markup Component of Real-Time Zonal Prices

The unit markup component of average real-time price using unadjusted offers is shown for each zone in the first nine months of 2018 and 2019 in Table 3-98 and for adjusted offers in Table 3-99[134]. The smallest zonal all hours average markup component using unadjusted offers in the first nine months of 2019, was in the ComEd Control Zone, 1.54 per MWh, while the highest was in the DPL Control Zone, $2.48 per MWh. The smallest zonal on peak average markup component using unadjusted offers in the first nine months of 2019, was in the ComEd Control Zone, 2.13 per MWh, while the highest was in the DAY Control Zone, $2.98 per MWh.

134 A marginal unit's offer price affects LMPs in the entire PJM market. The markup component of average zonal real-time price is based on offers of units located within the zone and units located outside the transmission zone.

Table 3-98 Average real-time zonal markup component (Unadjusted): January through September, 2018 and 2019

	2018 (Jan - Sep)			2019 (Jan - Sep)		
	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component
AECO	$4.64	$3.46	$5.76	$2.32	$1.87	$2.77
AEP	$4.91	$3.32	$6.45	$1.89	$1.18	$2.58
APS	$5.62	$3.70	$7.48	$1.87	$1.23	$2.50
ATSI	$6.18	$3.62	$8.60	$1.99	$1.27	$2.68
BGE	$6.92	$4.19	$9.54	$2.05	$1.19	$2.89
ComEd	$3.64	$1.68	$5.47	$1.54	$0.90	$2.13
DAY	$5.21	$3.22	$7.04	$2.14	$1.22	$2.98
DEOK	$5.33	$3.52	$7.07	$1.99	$1.15	$2.78
DLCO	$6.41	$3.87	$8.85	$2.00	$1.27	$2.71
DPL	$5.15	$3.75	$6.49	$2.48	$2.12	$2.84
Dominion	$6.33	$4.86	$7.75	$1.86	$1.23	$2.47
EKPC	$4.82	$3.73	$5.93	$1.87	$1.15	$2.58
JCPL	$4.54	$3.45	$5.51	$2.21	$1.71	$2.68
Met-Ed	$4.79	$3.29	$6.18	$1.94	$1.45	$2.38
OVEC	NA	NA	NA	$1.64	$0.97	$2.39
PECO	$4.50	$3.04	$5.85	$2.39	$2.07	$2.68
PENELEC	$5.14	$3.21	$6.94	$1.82	$1.25	$2.36
PPL	$4.30	$2.81	$5.69	$1.99	$1.51	$2.44
PSEG	$4.29	$3.20	$5.31	$2.24	$1.70	$2.76
Pepco	$6.16	$4.10	$8.09	$1.94	$1.20	$2.64
RECO	$4.76	$3.28	$6.02	$2.02	$1.55	$2.44

Table 3-99 Average real-time zonal markup component (Adjusted): January through September, 2018 and 2019

	2018 (Jan - Sep)			2019 (Jan - Sep)		
	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component
AECO	$7.24	$5.94	$8.49	$4.27	$3.66	$4.87
AEP	$7.57	$5.83	$9.26	$4.04	$3.13	$4.92
APS	$8.51	$6.46	$10.51	$4.04	$3.20	$4.86
ATSI	$8.91	$6.11	$11.56	$4.16	$3.22	$5.04
BGE	$10.12	$7.23	$12.88	$4.40	$3.32	$5.44
ComEd	$5.95	$3.85	$7.92	$3.55	$2.69	$4.36
DAY	$7.86	$5.68	$9.87	$4.36	$3.23	$5.41
DEOK	$7.87	$5.91	$9.75	$4.13	$3.09	$5.12
DLCO	$9.14	$6.33	$11.82	$4.13	$3.19	$5.04
DPL	$8.17	$6.55	$9.72	$4.51	$3.99	$5.01
Dominion	$9.45	$7.99	$10.88	$4.09	$3.26	$4.91
EKPC	$7.38	$6.12	$8.66	$4.03	$3.13	$4.91
JCPL	$7.23	$6.03	$8.31	$4.20	$3.53	$4.82
Met-Ed	$7.39	$5.75	$8.90	$3.98	$3.29	$4.61
OVEC	NA	NA	NA	$3.70	$2.85	$4.65
PECO	$7.17	$5.58	$8.64	$4.33	$3.84	$4.78
PENELEC	$7.81	$5.67	$9.81	$3.89	$3.13	$4.59
PPL	$6.92	$5.36	$8.37	$3.96	$3.30	$4.57
PSEG	$6.92	$5.70	$8.05	$4.21	$3.51	$4.87
Pepco	$9.32	$7.16	$11.35	$4.23	$3.27	$5.14
RECO	$7.34	$5.71	$8.72	$3.96	$3.35	$4.50

Markup by Real-Time Price Levels

Table 3-100 shows the markup contribution to the LMP, based on the unadjusted cost-based offers and adjusted cost-based offers of the marginal units, when the PJM system wide load-weighted average LMP was in the identified price range.

Table 3-100 Real-time markup contribution (By PJM load-weighted LMP category, unadjusted): January through September, 2018 and 2019

	2018 (Jan - Sep)		2019 (Jan - Sep)	
LMP Category	Markup Component	Frequency	Markup Component	Frequency
< $25	($0.35)	40.1%	($0.03)	61.0%
$25 to $50	$3.55	47.4%	$2.77	35.3%
$50 to $75	$18.66	6.5%	$16.07	2.5%
$75 to $100	$22.28	2.1%	$23.33	0.6%
$100 to $125	$29.21	1.5%	$21.82	0.2%
$125 to $150	$21.02	0.7%	$26.17	0.1%
>= $150	$43.56	1.7%	$28.96	0.3%

Table 3-101 Real-time markup contribution (By PJM load-weighted LMP category, adjusted): January through September, 2018 and 2019

	2018 (Jan - Sep)		2019 (Jan - Sep)	
LMP Category	Markup Component	Frequency	Markup Component	Frequency
< $25	$1.60	40.2%	$1.82	61.0%
$25 to $50	$6.12	47.4%	$5.20	35.3%
$50 to $75	$21.86	6.5%	$18.95	2.5%
$75 to $100	$27.19	2.1%	$27.01	0.6%
$100 to $125	$35.77	1.5%	$25.82	0.2%
$125 to $150	$29.62	0.7%	$29.54	0.1%
>= $150	$55.96	1.7%	$31.35	0.3%

Markup by Company

Table 3-102 shows the markup contribution based on the unadjusted cost-based offers and adjusted cost-based offers to real-time, load-weighted average LMP by individual marginal resource owners. The markup contribution of each marginal resource to price at each load bus is calculated for each five-minute interval, and summed by the parent company that offers the marginal resource into the Real-Time Energy Market. In the first nine months of 2019, when using unadjusted cost-based offers, the markup of one company accounted for 2.3 percent of the load-weighted average LMP, the markup of the top five companies accounted for 6.0 percent of the load-weighted average LMP and the markup of all companies accounted for 7.1 percent of the load-weighted average LMP. In the first nine months of 2018, when using unadjusted cost-based offers, the markup of one company accounted for 3.0 percent of the load-weighted average LMP, the markup of the top five companies accounted for 9.1 percent of the load-weighted average LMP and the markup of all companies accounted for 13.1 percent of the load-weighted average LMP. The top five companies' markup contribution to the load-weighted average LMP and the dollar values of their markup decreased in the first nine months of 2019. The markup contribution to the load-weighted average LMP and share of the markup contribution to the load-weighted average LMP also decreased in the first nine months of 2019.

Table 3-102 Markup component of real-time, load-weighted, average LMP by Company: January through September, 2018 and 2019

	2018 (Jan - Sep)				2019 (Jan - Sep)			
	Markup Component of LMP (Unadjusted)		Markup Component of LMP (Adjusted)		Markup Component of LMP (Unadjusted)		Markup Component of LMP (Adjusted)	
	$/MWh	Percent of Load Weighted LMP	$/MWh	Percent of Load Weighted LMP	$/MWh	Percent of Load Weighted LMP	$/MWh	Percent of Load Weighted LMP
Top 1 Company	$1.18	3.0%	$1.53	3.9%	$0.63	2.3%	$0.75	2.7%
Top 2 Companies	$1.94	4.9%	$2.50	6.3%	$0.95	3.5%	$1.39	5.0%
Top 3 Companies	$2.68	6.8%	$3.33	8.4%	$1.22	4.4%	$1.91	6.9%
Top 4 Companies	$3.21	8.1%	$4.02	10.2%	$1.49	5.4%	$2.29	8.3%
Top 5 Companies	$3.58	9.1%	$4.48	11.4%	$1.67	6.0%	$2.54	9.2%
All Companies	$5.17	13.1%	$7.90	20.0%	$1.95	7.1%	$4.07	14.7%

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 3-103. INC, DEC and up to congestion transactions (UTC) have zero markups. INCs were 12.9 percent of marginal resources and DECs were 18.4 percent of marginal resources in the first nine months of 2019. 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 15 months resettlement period for the proceeding related to uplift charges for UTC transactions. The share of marginal up to congestion transactions decreased from 63.9 percent in the first nine months of 2018 to 57.7 percent in the first nine months of 2019 as the result of a FERC order issued on February 20, 2018, and implemented on February 22, 2018.[135] The order limited UTC trading to hubs, residual metered load, and interfaces.

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 3-103 shows the markup component of LMP for marginal generating resources. Generating resources were only 10.9 percent of marginal resources in the first nine months of 2019. Using adjusted cost-based offers, the markup component of LMP for marginal generating resources decreased for coal fired steam units from $1.36 to $0.39 and decreased for gas fired CT units from $0.13 to $0.02. The markup component of LMP for coal fired steam units decreased from $0.65 in the first nine months of 2018 to -$0.32 in the first nine months of 2019 using unadjusted cost-based offers

135 162 FERC ¶ 61,139 (2018).

Table 3-103 Markup component of day-ahead, load-weighted, average LMP by primary fuel type and technology type: January through September, 2018 and 2019

		2018 (Jan - Sep)			2019 (Jan - Sep)		
Fuel	Technology	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)	Frequency	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)	Frequency
Coal	Steam	$0.65	$1.36	43.7%	($0.32)	$0.39	41.6%
Gas	CT	$0.05	$0.13	3.4%	$0.01	$0.02	2.0%
Gas	RICE	$0.00	$0.00	0.7%	($0.00)	($0.00)	0.5%
Gas	Steam	$0.56	$1.20	46.9%	$0.87	$1.42	53.2%
Municipal Waste	RICE	$0.00	$0.00	0.0%	$0.00	$0.00	0.1%
Oil	CT	$0.00	$0.00	0.5%	$0.00	$0.00	0.5%
Oil	RICE	$0.00	$0.00	0.0%	$0.00	$0.00	0.0%
Oil	Steam	($0.01)	$0.10	0.8%	($0.01)	($0.01)	0.1%
Other	Solar	$0.00	$0.00	0.3%	$0.00	$0.00	0.2%
Other	Steam	($0.00)	($0.00)	0.1%	($0.00)	($0.00)	0.1%
Uranium	Steam	$0.00	$0.00	1.5%	$0.00	$0.00	0.7%
Water	Hydro	$0.00	$0.00	0.0%	$0.00	$0.00	0.0%
Wind	Wind	$0.01	$0.01	2.0%	$0.13	$0.13	1.1%
Total		$1.26	$2.81	100.0%	$0.67	$1.95	100.0%

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 3-104 shows the markup component of average prices and of average monthly on-peak and off-peak prices using unadjusted cost-based offers. In the first nine months of 2019, when using unadjusted cost-based offers, $0.67 per MWh of the PJM day-ahead load-weighted average LMP was attributable to markup. In the first nine months of 2019, the peak markup component was highest in July, $4.14 per MWh using unadjusted cost-based offers.

Table 3-104 Monthly markup components of day-ahead (Unadjusted), load-weighted LMP: January 2018 through September 2019

	2018			2019		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
Jan	$3.15	$4.21	$2.08	$0.78	$1.68	($0.16)
Feb	$0.87	$1.65	$0.05	$0.60	$0.80	$0.41
Mar	$0.46	$0.61	$0.31	$0.65	$0.99	$0.32
Apr	$1.09	$1.55	$0.62	$0.15	$0.30	($0.03)
May	$0.83	$1.22	$0.40	$0.11	$0.13	$0.09
Jun	$0.29	$0.67	($0.13)	$0.45	$0.38	$0.53
Jul	$1.39	$2.50	$0.20	$2.50	$4.14	$0.66
Aug	$1.03	$1.76	$0.11	$0.39	$0.44	$0.34
Sep	$1.96	$3.14	$0.85	($0.09)	($0.28)	$0.09
Oct	$1.21	$1.56	$0.80			
Nov	$1.26	$1.98	$0.53			
Dec	$0.81	$1.37	$0.33			
Annual	$1.22	$1.88	$0.53	$0.67	$1.05	$0.26

Table 3-105 shows the markup component of average prices and of average monthly on peak and off peak prices using adjusted cost-based offers. In the first nine months of 2019, when using adjusted cost-based offers, $1.95 per MWh of the PJM day-ahead load-weighted average LMP was attributable to markup. In the first nine months of 2019, the peak markup component was highest in July, $5.17 per MWh using adjusted cost-based offers.

Table 3-105 Monthly markup components of day-ahead (Adjusted), load-weighted LMP: January 2018 through September 2019

	2018			2019		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
Jan	$6.31	$7.41	$5.21	$2.45	$3.33	$1.55
Feb	$2.46	$3.32	$1.57	$2.09	$2.32	$1.87
Mar	$1.78	$1.89	$1.67	$2.01	$2.27	$1.77
Apr	$2.17	$2.51	$1.82	$1.24	$1.25	$1.23
May	$2.00	$2.25	$1.72	$1.29	$1.17	$1.43
Jun	$1.75	$2.01	$1.47	$1.64	$1.62	$1.67
Jul	$2.73	$3.70	$1.70	$3.67	$5.17	$2.00
Aug	$2.36	$2.88	$1.71	$1.55	$1.48	$1.64
Sep	$3.16	$4.17	$2.22	$1.06	$0.81	$1.32
Oct	$2.44	$2.66	$2.17			
Nov	$2.75	$3.21	$2.28			
Dec	$2.69	$3.24	$2.20			
Annual	$2.76	$3.31	$2.19	$1.95	$2.26	$1.62

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 3-106. The markup component of annual average day-ahead price using adjusted cost-based offers is shown for each zone in Table 3-107. The smallest zonal all hours average markup component using adjusted cost-based offers for the first nine months of 2019 was in the ComEd Zone, $1.21 per MWh, while the highest was in the AECO Control Zone, $2.99 per MWh. The smallest zonal on peak average markup using adjusted cost-based offers was in the ComEd Control Zone, $0.98 per MWh, while the highest was in the AECO Control Zone, $3.90 per MWh.

Table 3-106 Day-ahead, average, zonal markup component (Unadjusted): January through September, 2018 and 2019

	2018 (Jan - Sep)			2019 (Jan - Sep)		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
AECO	$1.73	$2.49	$0.90	$1.81	$2.82	$0.76
AEP	$1.20	$1.90	$0.47	$0.48	$0.73	$0.21
APS	$1.19	$1.83	$0.53	$0.43	$0.67	$0.18
ATSI	$1.19	$1.76	$0.58	$0.94	$1.61	$0.21
BGE	$0.98	$1.61	$0.31	$0.90	$1.86	($0.11)
ComEd	$0.97	$1.66	$0.24	($0.05)	($0.24)	$0.15
DAY	$1.28	$1.93	$0.57	$1.40	$2.54	$0.15
DEOK	$1.57	$2.55	$0.52	$1.10	$2.01	$0.12
DLCO	$1.22	$1.80	$0.59	$0.65	$1.11	$0.17
Dominion	$1.06	$1.73	$0.38	$0.38	$0.72	$0.02
DPL	$1.49	$2.13	$0.82	$1.23	$1.68	$0.74
EKPC	$1.53	$2.54	$0.51	$0.53	$0.83	$0.23
JCPL	$1.64	$2.32	$0.88	$1.40	$2.04	$0.69
Met-Ed	$1.59	$2.28	$0.83	$0.88	$1.27	$0.44
OVEC	NA	NA	NA	($0.06)	$0.41	($0.46)
PECO	$1.70	$2.48	$0.86	$1.37	$1.99	$0.70
PENELEC	$1.26	$1.95	$0.52	$0.42	$0.42	$0.43
Pepco	$0.94	$1.55	$0.29	$0.45	$0.92	($0.06)
PPL	$1.65	$2.42	$0.83	$1.01	$1.41	$0.58
PSEG	$1.59	$2.23	$0.88	$1.26	$1.81	$0.68
RECO	$1.59	$2.15	$0.93	$1.02	$1.45	$0.53

Table 3-107 Day-ahead, average, zonal markup component (Adjusted): January through September, 2018 and 2019

	2018 (Jan - Sep)			2019 (Jan - Sep)		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
AECO	$3.39	$4.07	$2.66	$2.99	$3.90	$2.04
AEP	$2.67	$3.25	$2.06	$1.77	$1.93	$1.60
APS	$2.72	$3.21	$2.21	$1.74	$1.90	$1.56
ATSI	$2.67	$3.12	$2.18	$2.26	$2.86	$1.60
BGE	$2.68	$3.19	$2.13	$2.29	$3.20	$1.33
ComEd	$2.34	$2.98	$1.66	$1.21	$0.98	$1.45
DAY	$2.77	$3.31	$2.18	$2.80	$3.89	$1.60
DEOK	$3.00	$3.92	$2.03	$2.45	$3.30	$1.55
DLCO	$2.61	$3.01	$2.18	$1.91	$2.25	$1.55
Dominion	$2.72	$3.25	$2.17	$1.71	$1.96	$1.44
DPL	$3.12	$3.63	$2.59	$2.42	$2.76	$2.05
EKPC	$3.05	$4.04	$2.06	$1.82	$2.04	$1.60
JCPL	$3.31	$3.91	$2.63	$2.62	$3.16	$2.02
Met-Ed	$3.20	$3.81	$2.54	$2.12	$2.43	$1.77
OVEC	NA	NA	NA	$0.89	$1.18	$0.64
PECO	$3.36	$4.04	$2.64	$2.56	$3.08	$1.99
PENELEC	$2.81	$3.41	$2.14	$1.67	$1.59	$1.76
Pepco	$2.61	$3.10	$2.08	$1.83	$2.27	$1.37
PPL	$3.29	$3.95	$2.59	$2.22	$2.54	$1.88
PSEG	$3.24	$3.78	$2.63	$2.45	$2.88	$1.97
RECO	$3.19	$3.68	$2.62	$2.21	$2.51	$1.87

Markup by Day-Ahead Price Levels

Table 3-108 and Table 3-109 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 3-108 Average, day-ahead markup component (By LMP category, unadjusted): January through September, 2018 and 2019

	2018 (Jan - Sep)		2019 (Jan - Sep)	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $25	($0.13)	32.6%	($0.04)	53.7%
$25 to $50	$0.73	55.9%	$0.35	44.1%
$50 to $75	$0.25	6.1%	$0.28	1.5%
$75 to $100	$0.10	2.2%	$0.03	0.6%
$100 to $125	$0.07	1.2%	$0.02	0.1%
$125 to $150	$0.06	0.8%	$0.02	0.0%
>= $150	$0.17	1.2%	$0.01	0.0%

Table 3-109 Average, day-ahead markup component (By LMP category, adjusted): January through September, 2018 and 2019

	2018 (Jan - Sep)		2019 (Jan - Sep)	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $25	$0.29	32.6%	$0.61	53.7%
$25 to $50	$1.52	55.9%	$0.95	44.1%
$50 to $75	$0.33	6.1%	$0.29	1.5%
$75 to $100	$0.16	2.2%	$0.05	0.6%
$100 to $125	$0.13	1.2%	$0.03	0.1%
$125 to $150	$0.10	0.8%	$0.02	0.0%
>= $150	$0.28	1.2%	$0.01	0.0%

Energy Uplift (Operating Reserves)

Energy uplift is paid to market participants under specified conditions in order to ensure that competitive energy and ancillary service market outcomes do not require efficient resources 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 uplift 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 as directed by PJM operators. These credits are paid by PJM market participants as operating reserve charges, reactive services charges, synchronous condensing charges or black start services charges.

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 cannot be eliminated, but uplift payments should 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 based on 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. The PJM market design incorporates efficient prices with minimal uplift payments. There are improvements to the market design and uplift rules that could further reduce uplift payments while maintaining efficient prices.

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.

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. The current payment structure for DR is an inefficient element of the PJM market design.[4]

Overview

Energy Uplift Credits

- **Types of credits.** In the first nine months of 2019, energy uplift credits were $70.6 million, including $13.9 million in day-ahead generator credits, $40.8 million in balancing generator credits, $12.6 million in lost opportunity cost credits, and $2.7 million in local constraint control credits.
- **Types of units.** Coal units received 90.9 percent of all day-ahead generator credits. Combustion turbines received 85.5 percent of all balancing generator credits and 94.8 percent of lost opportunity cost credits.
- **Economic and Noneconomic Generation.** In the first nine months of 2019, 82.7 percent of the day-ahead generation eligible for operating reserve credits was economic and 67.0 percent of the real-time generation eligible for operating reserve credits was economic.
- **Day-Ahead Unit Commitment for Reliability.** In the first nine months of 2019, 0.3 percent of the total day-ahead generation MWh was scheduled as must run by PJM, of which 47.8 percent received energy uplift payments.
- **Concentration of Energy Uplift Credits.** The top 10 units receiving energy uplift credits received 23.6 percent of all credits. The top 10 organizations received 73.5 percent of all credits. The HHI for day-ahead operating reserves was 8500, the HHI for balancing operating reserves was 3340

4 Demand response payments are addressed in Section 6: Demand Response.

and the HHI for lost opportunity cost was 5789, all of which are classified as highly concentrated.

- **Lost Opportunity Cost Credits.** Lost opportunity cost credits decreased by $36.0 million or 74.1 percent, in the first nine months of 2019 compared to the first nine months of 2018, from $48.3 million to $12.6 million. Generation from combustion turbines and diesels scheduled day-ahead but not requested in real time, receiving lost opportunity cost credits decreased by 428 GWh or 46.8 percent in the first nine months of 2019, compared to the first nine months of 2018, from 915.2 GWh to 487 GWh.

Energy Uplift Charges

- **Energy Uplift Charges.** Total energy uplift charges decreased by $106.3 million, or 60.1 percent, in the first nine months of 2019 compared to the first nine months of 2018, from $176.9 million to $70.6 million.
- **Energy Uplift Charges Categories.** The decrease of $106.3 million in the first nine months of 2019 is comprised of a $17.8 million decrease in day-ahead operating reserve charges, a $76.4 million decrease in balancing operating reserve charges, and an $11.9 million decrease in reactive services charges.
- **Average Effective Operating Reserve Rates in the Eastern Region.** Day-ahead load paid $0.022 per MWh, real-time load paid $0.029 per MWh, a DEC paid $0.340 per MWh and an INC and any load, generation or interchange transaction deviation paid $0.318 per MWh.
- **Average Effective Operating Reserve Rates in the Western Region.** Day-ahead load paid $0.022 per MWh, real-time load paid $0.027 per MWh, a DEC paid $0.324 per MWh and an INC and any load, generation or interchange transaction deviation paid $0.302 per MWh.
- **Reactive Services Rates.** The PENELEC, DPL, and Dominion control zones were the three zones with the highest local voltage support rate, excluding reactive capability payments: PENELEC had a rate of $0.011 per MWh, DPL had a rate of $0.007 per MWh, and Dominion had a rate of $0.002 per MWh.

Geography of Charges and Credits

- In the first nine months of 2019, 90.3 percent of all uplift charges allocated regionally (day-ahead operating reserves and balancing operating reserves) were paid by transactions at control zones, 3.0 percent by transactions at hubs and aggregates, and 6.8 percent by transactions at interchange interfaces.
- Generators in the Eastern Region received 41.9 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.
- Generators in the Western Region received 56.4 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.
- External generators received 2.1 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.

Recommendations

- The MMU recommends that uplift be paid only based on operating parameters that reflect the flexibility of the benchmark new entrant unit (CONE unit) in the PJM Capacity Market. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM not use closed loop interface constraints to artificially override nodal prices 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 CT price setting logic to modify transmission line limits 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 implement CT price setting logic, PJM first initiate a stakeholder process to determine whether such modification is appropriate. PJM should file any proposed changes with FERC to ensure review. Any such changes should be incorporated in the PJM tariff. (Priority: Medium. First Reported 2016. Status: Not adopted.)
- The MMU recommends that PJM initiate an analysis of the reasons why a significant number of 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 eliminating intraday segments from the calculation of uplift payments and returning to calculating the need for uplift based on the entire 24 hour operating day. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends the elimination of day-ahead operating reserves 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.)
- The MMU recommends enhancing the current energy uplift allocation rules to reflect the recommended elimination of day-ahead operating reserves, the timing of commitment decisions and the commitment reasons. (Priority: High. First reported 2012. Status: Not adopted.)
- 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 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. (Priority: Low. First reported 2013. Status: Not adopted. Stakeholder process.)
- The MMU recommends three modifications to the energy lost opportunity cost calculations:
  - The MMU recommends calculating LOC based on 24 hour daily periods 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 only flexible fast start units (startup plus notification times of 10 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.)
- 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: Adopted 2018.[5])
- 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 balancing operating reserve

5 As of November 1, 2018, internal bilateral transactions are no longer used for the calculation of deviations for purposes of allocating balancing operating reserve charges. See the 2018 State of the Market Report for PJM, Volume 2, Section 3: "Energy Market" at "Internal Bilateral Transactions" for an analysis of the impact of this change on virtual bidding activity.

credit 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, in addition to real-time load. (Priority: Low. First reported 2013. Status: Not adopted.)
- 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). The MMU recommends that PJM allow wind units to request 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 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: Partially adopted.)
- 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.[6])
- The MMU recommends that PJM pay uplift based on the offer at the lower of the actual unit output or the dispatch signal MW. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM develop and implement an accurate metric to define when a unit is following dispatch to determine eligibility to receive balancing operating reserve credits and for assessing generator deviations. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM eliminate the exemption for fast start resources (CTs and diesels) from the requirement to follow dispatch. The performance of these resources should be evaluated in a manner consistent with all other resources (Priority: Medium. First reported 2018. Status: Not adopted.)

6 On September 7, 2018, PJM made a compliance filing for FERC Order No. 844 to publish unit specific uplift credits. The compliance filing was accepted by FERC on March 21, 2019. PJM will begin posting unit-specific uplift reports on May 1, 2019.

Conclusion

Competitive market outcomes result from energy offers equal to short run marginal costs that incorporate flexible operating parameters. 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. The standard for paying uplift should be the maximum achievable flexibility, based on OEM standards for the benchmark new entrant unit (CONE unit) in the PJM Capacity Market. Applying a weaker standard 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.

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 the inflexible 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.

Implementing combined cycle modeling, to permit the energy market model optimization to take advantage of the versatility and flexibility of combined cycle technology in commitment and dispatch, would provide significant flexibility without requiring a distortion of the market rules.

The reduction of uplift payments should not be a goal to be achieved at the expense of the fundamental logic of the 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 CT price setting logic. The same is true of fast start pricing and of convex hull pricing. The same is true of PJM's proposal to modify the ORDC in order to increase energy prices and reduce uplift.

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 (limited convex hull pricing) and in extensive form by PJM's full convex hull pricing proposal.

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. FERC Order No. 844 authorized the publication of unit specific uplift payments for credits incurred after July 1, 2019.[7]

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.

Up to congestion transactions continue to pay no energy uplift charges, which means that all others who pay these charges are paying too much.[8]

PJM needs to pay substantially more attention to the details of uplift payments including accurately tracking whether units are following dispatch, identifying the actual need for units to be dispatched out of merit and determining whether local reserve zones or better definitions of constraints would be a more market based approach.

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. 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

7 On March 21, 2019 FERC accepted PJM's Order No. 844 compliance filing. The filing stated that PJM would begin posting unit specific uplift reports on May 1, 2019. On April 8, 2019, PJM filed for an extension on the implementation date of the zonal uplift reports and unit specific uplift reports to July 1, 2019. On June 28, 2019, FERC accepted PJM's request for extension of effective dates.

8 On October 17, 2017, PJM filed with FERC a proposed tariff change to allocate uplift to UTC transactions in the same manner in which uplift is currently allocated to other virtual transactions, as a separate injection and withdrawal deviation. FERC rejected the proposed tariff change. The rejection was without prejudice and PJM has the option to submit a new proposal. See FERC Docket No. ER18-86-000. PJM has not filed a new proposal.

level of per MWh charges, to reduce the uncertainty associated with uplift charges and to reduce the impact of energy uplift charges on decisions about how and when to participate in PJM markets.

Energy Uplift Results

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 LMP is less than the offer price including incremental, no load and startup costs. Energy uplift payments also result from units' operational parameters that require PJM to schedule or commit resources when they are not economic. The resulting costs not covered by energy revenues are collected as energy uplift.

Table 4-1 shows the totals for each credit category for the first nine months of 2018 and 2019.[9] In the first nine months of 2019, energy uplift credits decreased by $106.2 million or 60.1 percent compared to the first nine months of 2018.

Table 4-1 Energy uplift credits by category: January through September, 2018 and 2019

Category	Type	(Jan - Sep) 2018 Credits (Millions)	(Jan - Sep) 2019 Credits (Millions)	Change	Percent Change	(Jan - Sep) 2018 Share	(Jan - Sep) 2019 Share
Day-Ahead	Generators	$31.8	$13.9	($17.8)	(56.1%)	18.0%	19.7%
	Imports	$0.0	$0.0	$0.0	259.1%	0.0%	0.0%
	Load Response	$0.0	$0.0	($0.0)	(74.8%)	0.0%	0.0%
Balancing	Canceled Resources	$0.0	$0.0	$0.0	NA	0.0%	0.0%
	Generators	$75.4	$40.8	($34.6)	(45.9%)	42.7%	57.8%
	Imports	$0.5	$0.0	($0.5)		0.3%	0.0%
	Load Response	$0.0	$0.0	($0.0)		0.0%	0.0%
	Local Constraints Control	$8.0	$2.7	($5.3)	(66.3%)	4.5%	3.8%
	Lost Opportunity Cost	$48.5	$12.6	($36.0)	(74.1%)	27.4%	17.8%
Reactive Services	Day-Ahead	$11.2	$0.2	($11.1)	(98.4%)	6.4%	0.3%
	Local Constraints Control	$0.0	$0.0	$0.0	NA	0.0%	0.0%
	Lost Opportunity Cost	$0.0	$0.0	$0.0	94.4%	0.0%	0.0%
	Reactive Services	$0.7	$0.3	($0.4)	(62.0%)	0.4%	0.4%
	Synchronous Condensing	$0.5	$0.0	($0.5)	(98.7%)	0.3%	0.0%
Synchronous Condensing		$0.0	$0.0	($0.0)		0.0%	0.0%
Black Start Services	Day-Ahead	$0.0	$0.0	$0.0	NA	0.0%	0.0%
	Balancing	$0.2	$0.2	($0.0)	(4.5%)	0.1%	0.2%
	Testing	$0.0	$0.0	($0.0)		0.0%	0.0%
Total		$176.8	$70.6	($106.2)	(60.1%)	100.0%	100.0%

9 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 October 11, 2019.

Characteristics of Credits

Types of Units

Table 4-2 shows the distribution of total energy uplift credits by unit type for the first nine months of 2018 and 2019. Uplift credits decreased for all unit types. The reduction in uplift credits was largely the result of lower gas prices during the 2019 winter compared to 2018, replacement of coal units needed for reliability by combined cycles and transmission upgrades that reduced the need to commit units for reactive. Natural gas prices remained low, reducing the costs of gas units and reducing the need for, and level of, make whole payments. The mild weather reduced the need to commit combustion turbines which are the largest recipients of uplift credits. Combustion turbines had the largest reduction in uplift credits with a reduction of $44.1 million or 47.1 percent.

Table 4-2 Energy uplift credits by unit type: January through September, 2018 and 2019[10 11]

Unit Type	(Jan - Sep) 2018 Credits (Millions)	(Jan - Sep) 2019 Credits (Millions)	Change	Percent Change	(Jan - Sep) 2018 Share	(Jan - Sep) 2019 Share
Combined Cycle	$19.3	$2.7	($16.6)	(85.9%)	10.9%	3.8%
Combustion Turbine	$93.6	$49.6	($44.1)	(47.1%)	53.1%	70.2%
Diesel	$1.3	$0.6	($0.7)	(53.0%)	0.7%	0.9%
Hydro	$0.2	$0.0	($0.2)	(100.0%)	0.1%	0.0%
Nuclear	$0.4	$0.0	($0.4)	(100.0%)	0.2%	0.0%
Solar	$0.0	$0.1	$0.1	6,342.6%	0.0%	0.1%
Steam - Coal	$42.3	$15.5	($26.7)	(63.3%)	24.0%	22.0%
Steam - Other	$17.8	$2.0	($15.8)	(88.7%)	10.1%	2.8%
Wind	$1.5	$0.2	($1.3)	(88.5%)	0.8%	0.2%
Total	$176.3	$70.6	($105.7)	(60.0%)	100.0%	100.0%

Table 4-3 shows the distribution of energy uplift credits by category and by unit type in the first nine months of 2019. The characteristics of the different unit types explain why the shares of credit types are dominated by a particular unit type. For example, the majority of day-ahead credits, 96.7 percent, go to steam units. This is because steam units tend to be longer lead time units that need to be committed before the operating day. If a steam unit is needed for reliability and it is uneconomic it will be committed in the Day-Ahead Energy Market and receive day-ahead credits. Coal fired steam units received 48.3 percent of all reactive service credits as a result of the specific locations of the voltage issues and the location of the units. Combustion turbines, which, unlike other unit types, can be committed and decommitted in the real-time market, received 85.5 percent of balancing credits and 93.5 percent of lost opportunity credits. Combustion turbines committed in the real-time market require balancing credits as result of inflexible operating parameters, volatile real-time LMPs, and intraday segment settlements. Combustion turbines with a day-ahead schedule and not committed in real time will receive lost opportunity credits when they incur a loss as a result of not operating. A unit incurs a loss when the real time LMPs are greater than the day-ahead LMPs at the unit's pricing node and the unit's balancing charges are greater than its day-ahead revenues.

10 Table 4-2 does not include balancing imports credits and load response credits in the total amounts.

11 Solar units should be ineligible for all uplift payments because they do not follow PJM's dispatch instructions. The MMU notified PJM of the discrepancy.

Table 4-3 Energy uplift credits by unit type: January through September, 2019

Unit Type	Day-Ahead Generator	Balancing Generator	Canceled Resources	Local Constraints Control	Lost Opportunity Cost	Reactive Services	Synchronous Condensing	Black Start Services
Combined Cycle	2.9%	4.5%	0.0%	8.3%	3.3%	0.0%	0.0%	26.8%
Combustion Turbine	0.3%	85.5%	0.0%	86.5%	93.5%	50.1%	0.0%	73.2%
Diesel	0.0%	0.7%	0.0%	4.9%	1.3%	1.7%	0.0%	0.1%
Hydro	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Nuclear	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Solar	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Steam - Coal	90.9%	6.2%	0.0%	0.0%	0.5%	48.3%	0.0%	0.0%
Steam - Other	5.8%	2.8%	0.0%	0.0%	0.5%	0.0%	0.0%	0.0%
Wind	0.0%	0.1%	0.0%	0.4%	0.9%	0.0%	0.0%	0.0%
Total (Millions)	$13.9	$40.8	$0.0	$2.7	$12.8	$0.5	$0.0	$0.2

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 have 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.[12] Participants can submit units as self scheduled (must run), meaning that the unit must be committed, but a unit submitted as must run by a participant is not eligible for day-ahead operating reserve credits.[13] Units committed for reliability by PJM are eligible for day-ahead operating reserve credits and may set LMP if raised above economic minimum and follow the dispatch signal. Table 4-4 shows the total day-ahead generation and the subset of that generation committed for reliability by PJM. In the first nine months of 2019, 0.3 percent of the total day-ahead generation was committed for reliability by PJM, 1.2 percentage points lower than in the first nine months of 2018. The decrease is the result of a decrease in the need to commit uneconomic steam coal units for reliability in the BGE and Pepco zones as they have been displaced by new combined cycle units in the Pepco Zone. For day ahead reactive service credits, transmission upgrades in MISO reduced commitments for reliability in ComEd, and account for the decrease of 98.4 percent in the first nine months of 2019 compared to the first nine months of 2018.

12 See PJM Operating Agreement Schedule 1 § 3.2.3(b).

13 See PJM. "PJM Markets Gateway User Guide," Section Managing Unit Data (version July 16, 2018) at 33, <http://www.pjm.com/-/media/etools/markets-gateway/markets-gateway-user-guide.ashx?la=en>.

Table 4-4 Day-ahead generation committed for reliability (GWh): January 2018 through September 2019

	2018			2019		
	Total Day-Ahead Generation	Day-Ahead PJM Must Run Generation	Share	Total Day-Ahead Generation	Day-Ahead PJM Must Run Generation	Share
Jan	78,368	1,209	1.5%	77,616	81	0.1%
Feb	63,095	780	1.2%	66,102	91	0.1%
Mar	67,699	1,712	2.5%	68,331	305	0.4%
Apr	59,019	967	1.6%	57,926	0	0.0%
May	65,017	1,799	2.8%	63,432	131	0.2%
Jun	71,001	1,188	1.7%	67,899	301	0.4%
Jul	79,653	846	1.1%	83,474	327	0.4%
Aug	80,864	476	0.6%	77,632	367	0.5%
Sep	69,596	659	0.9%	69,009	357	0.5%
Oct	64,003	533	0.8%			
Nov	64,183	744	1.2%			
Dec	70,864	215	0.3%			
Total (Jan - Sep)	634,312	9,636	1.5%	631,423	1,960	0.3%
Total	833,362	11,128	1.3%	631,423	1,960	0.3%

Pool scheduled units and units committed for reliability 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. Total day-ahead operating reserve credits in the first nine months of 2019 were $13.9 million. The top 10 units received $12.5 million or 89.7 percent of all day-ahead operating reserve credits. These units were large units with long commitment times and inflexible operating parameters.

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 4-5 shows the total day-ahead generation committed for reliability by PJM by category. In the first nine months of 2019, 47.8 percent of the day-ahead generation committed for reliability by PJM received operating reserve credits, of which 32.0 percent was paid as day-ahead operating reserve credits. The remaining 52.2 percent of the day-ahead generation committed for reliability by PJM was economic and did not need to be made whole.

Table 4-5 Day-ahead generation committed for reliability by category (GWh): January through September, 2019

	Reactive Services (GWh)	Day-Ahead Operating Reserves (GWh)	Economic (GWh)	Total (GWh)
Jan	0	35	46	81
Feb	0	58	33	91
Mar	0	222	83	305
Apr	170	163	634	967
May	273	632	893	1,799
Jun	256	532	400	1,188
Jul	79	224	543	846
Aug	95	82	300	476
Sep	142	103	414	659
Oct				
Nov				
Dec				
Total (Jan - Sep)	1,014	2,051	3,347	6,412
Share	15.8%	32.0%	52.2%	100.0%

Total day-ahead operating reserve credits in the first nine months of 2019 were $13.9 million, of which $11.4 million or 81.6 percent was paid to units committed for reliability by PJM, and not scheduled to provide black start or reactive services. An additional $0.2 million or 1.3 percent was paid to units scheduled to provide black start or reactive services or were pool scheduled in the Day-Ahead Energy Market

Balancing Operating Reserve Credits

Balancing operating reserve (BOR) credits are paid to resources operating at PJM's request that do not recover their operating costs from market revenues. BOR credits are calculated as the difference between a resource's revenues (day-ahead market, balancing market, ancillary markets, and day-ahead operating reserve credits) and its real-time costs (startup, no load, and energy offer). Combustion turbines (CTs) received $34.8 million or 85.5 percent of all balancing operating reserve (BOR) credits in the first nine months of 2019. The majority of these credits, 97.7 percent, are paid to CTs that are committed in real time either without or outside of a day-ahead schedule.[14] Such CTs generally are only economic for a short period compared to their minimum run time; operate on more expensive real-time offers compared to day-ahead offers; and are block loaded and provide more energy than is otherwise needed by the system. Uplift is higher than necessary because settlement rules do not include all revenues and costs for the entire day.

Balancing operating reserve credits for generators decreased by 45.9 percent from the first nine months of 2018 to the first nine months of 2019. The decrease was a result of lower natural gas prices in January 2018. Balancing operating reserve credits for generators during the winter months of January through March decreased by $26.5 million in 2019 compared with 2018. The decrease during winter months accounted for 76.5 percent of the total decrease of $34.6 million during the first nine months of 2019.

The credits paid to CTs committed in real time without a day-ahead commitment occurs despite the fact that combustion turbines are committed in the Day-Ahead Energy Market at levels comparable to the Real-Time Energy Market. Table 4-6 shows the monthly day-ahead and real-time generation by combustion turbines. In the first nine months of 2019, generation by combustion turbines was 25.8 percent greater in the Real-Time Energy Market compared to the Day-Ahead Energy Market. However, this varied month to month, with some months having greater day-ahead generation compared to real-time generation. Table 4-6 shows that only 5.3 percent of generation

14 Operating outside of a day-ahead schedule refers to units that operate for a period either before or after their day-ahead schedule, or are committed in the real-time market and do not have a day-ahead schedule for any part of the day.

from combustion turbines in the day-ahead market was uneconomic and did not need day-ahead generator credits. In the Real-Time Energy Market, 29.5 percent of generation from combustion turbines was uneconomic and required $34.8 million in BOR credits.

Table 4-6 Characteristics of day-ahead and real-time generation by combustion turbines: January through September, 2019

Month	Day-Ahead Generation (GWh)	Percent of Day-Ahead Generation that was Noneconomic	Day-Ahead Generator Credits (Millions)	Real-Time Generation (GWh)	Percent of Real-Time Generation that was Noneconomic	Balancing Generator Credits (Millions)	Generation Difference as a Percent of Real-Time Generation
Jan	261	9.5%	$0.0	227	46.6%	$4.0	(15.1%)
Feb	111	1.7%	$0.0	225	51.1%	$2.1	50.5%
Mar	230	0.9%	$0.0	372	43.2%	$3.1	38.0%
Apr	303	1.6%	$0.0	495	46.1%	$3.2	38.8%
May	514	6.3%	$0.0	595	27.2%	$1.6	13.6%
Jun	600	8.7%	$0.0	872	31.2%	$3.7	31.2%
Jul	2,080	5.1%	$0.0	2,866	26.2%	$8.0	27.4%
Aug	1,445	5.9%	$0.0	2,051	26.0%	$4.2	29.5%
Sep	1,450	4.0%	$0.0	1,723	26.5%	$5.0	15.8%
Total (Jan - Sep)	6,993	5.3%	$0.0	9,425	29.5%	$34.8	25.8%

An analysis of real-time generation by combustion turbines shows that BOR credits are incurred almost exclusively by combustion turbines that operate without or outside a day-ahead schedule. Table 4-7 shows that in the first nine months of 2019, 53.3 percent of real-time generation by CTs was from CTs that operated on a day-ahead schedule. Of the generation from CTs operating on a day-ahead schedule, 23.8 percent was uneconomic in the real-time market and did not received BOR credits. Of the 46.7 percent of real-time generation by CTs that operated outside of a day-ahead schedule, 36.0 percent was uneconomic in the real-time market and received $34.0 million in BOR credits. Thus while enough total generation from CTs is committed economically in the Day-Ahead Energy Market, uplift is incurred because the committed units operate at different times than originally scheduled and when CTs that were not committed day ahead operate in real time. For example, in January 2019, although total CT generation committed in the day-ahead market was greater than CT generation in real time, only 51.3 percent of real-time generation by CTs operated on a day-ahead schedule.

There are multiple reasons why the commitment of CTs is different in the day-ahead and real-time markets, including: differences in the hourly pattern of load; differences in interchange transactions; and behavior by other generators. Modeling differences between the day-ahead and real-time markets also affect CT commitment, including: the modeling of different transmission constraints in the day-ahead and real-time market models; the exclusion of soak time for generators in the day-ahead market model; and the different time scales used in the day-ahead and real-time markets.

Table 4-7 Real-time generation by combustion turbines by day-ahead commitment: January through September, 2019

	Real-Time Generation Operating on a Day-Ahead Schedule				Real-Time Generation Operating Outside of a Day-Ahead Schedule			
Month	Generation (GWh)	Share of Real-Time Generation	Percent of Generation that was Noneconomic	Balancing Generator Credits (Millions)	Generation (GWh)	Share of Real-Time Generation	Percent of Generation that was Noneconomic	Balancing Generator Credits (Millions)
Jan	110	48.7%	26.3%	$0.0	116	51.3%	65.9%	$4.0
Feb	48	21.5%	28.6%	$0.0	177	78.5%	57.3%	$2.1
Mar	134	36.0%	27.5%	$0.0	238	64.0%	52.1%	$3.1
Apr	184	37.2%	28.0%	$0.0	311	62.8%	56.8%	$3.2
May	303	51.0%	20.5%	$0.0	292	49.0%	34.1%	$1.6
Jun	414	47.5%	28.2%	$0.1	458	52.5%	33.8%	$3.6
Jul	1,678	58.6%	23.8%	$0.1	1,188	41.4%	29.6%	$7.9
Aug	1,138	55.5%	26.7%	$0.1	913	44.5%	25.1%	$4.1
Sep	1,013	58.8%	18.1%	$0.5	709	41.2%	38.6%	$4.5
Total (Jan - Sep)	5,023	53.3%	23.8%	$0.8	4,401	46.7%	36.0%	$34.0

Lost Opportunity Cost Credits

Balancing operating reserve lost opportunity cost (LOC) credits are intended to provide an incentive for units to follow PJM's dispatch instructions when PJM's dispatch instructions deviate from a unit's desired or scheduled output. LOC credits are paid under two different scenarios. The first scenario occurs if a unit of any type 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 its desired output. This LOC will be referred to as real-time LOC. The second scenario occurs if a combustion turbine or diesel engine is scheduled 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 any loss in the day-ahead financial position of the unit plus the balancing spot energy market position. This LOC will be referred to as day-ahead LOC.

Table 4-8 shows monthly day-ahead and real-time LOC credits in 2018 and the first nine months of 2019. In the first nine months of 2019, LOC credits decreased by $36.0 million or 74.1 percent compared to the first nine months of 2018. The decrease of $36.0 million is comprised of a $22.5 million decrease in day-ahead LOC and a $13.0 million decrease in real-time LOC. The significant reduction in LOC credits was the result of a milder winter in 2019 compared to 2018. Increased operator awareness of LOC and decreased uplift eligibility also contributed to the overall decrease. Table 4-9 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 the first nine months of 2019, 11.6 percent of day-ahead generation by combustion turbines and diesels was not requested in real time, 4.0 percentage points lower than in the first nine months of 2018.

Table 4-8 Monthly lost opportunity cost credits (Millions): January 2018 through September 2019

	2018			2019		
	Day-Ahead Lost Opportunity Cost	Real-Time Lost Opportunity Cost	Total	Day-Ahead Lost Opportunity Cost	Real-Time Lost Opportunity Cost	Total
Jan	$13.7	$8.0	$21.7	$0.4	$0.3	$0.7
Feb	$0.1	$0.0	$0.2	$0.1	$0.0	$0.2
Mar	$3.2	$0.2	$3.4	$0.4	$0.0	$0.5
Apr	$2.0	$1.9	$3.9	$0.5	$0.0	$0.5
May	$6.0	$2.8	$8.8	$1.6	$0.1	$1.6
Jun	$3.5	$0.0	$3.5	$0.7	$0.0	$0.7
Jul	$2.1	$0.0	$2.1	$1.9	$0.0	$2.0
Aug	$1.7	$0.1	$1.9	$1.7	$0.0	$1.7
Sep	$2.2	$0.7	$2.8	$4.7	$0.2	$4.9
Oct	$1.8	$0.7	$2.4			
Nov	$0.6	$0.2	$0.8			
Dec	$0.7	$0.1	$0.7			
Total (Jan - Sep)	$34.6	$13.7	$48.3	$12.1	$0.7	$12.8
Share (Jan - Sep)	71.6%	28.4%	100.0%	94.3%	5.7%	100.0%
Total	$37.6	$14.7	$52.3	$12.1	$0.7	$12.8

Table 4-9 Day-ahead generation from combustion turbines and diesels (GWh): January 2018 through September 2019

	2018			2019		
	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	1,899	382	223	692	38	13
Feb	301	40	19	370	19	4
Mar	1,018	250	109	524	48	12
Apr	1,379	204	71	619	71	21
May	2,095	378	149	848	171	49
Jun	1,432	328	105	938	130	46
Jul	2,343	279	101	2,555	198	69
Aug	1,972	181	71	1,901	198	110
Sep	1,885	200	68	1,808	321	163
Oct	1,398	149	71			
Nov	608	42	15			
Dec	318	37	11			
Total (Jan - Sep)	14,324	2,242	915	10,255	1,193	487
Share (Jan - Sep)	100.0%	15.6%	6.4%	100.0%	11.6%	4.7%
Total	16,648	2,470	1,012	10,255	1,193	487

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 4-10 provides a description of commitment and dispatch status, uplift eligibility and the ability to set price.[15] 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 unable to recover their operating cost for the day or segment.[16]

15 PJM has modified the basic rules of eligibility to set price using its CT price setting logic.
16 Resources do not recover their operating cost when market revenues for the day are less than the short run marginal cost defined by the startup, no load, and incremental offer curve.

Table 4-10 Dispatch status, commitment status and uplift eligibility[17]

			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 4-11 shows day-ahead and real-time generation by commitment and dispatch status. Table 4-11 shows that in the first nine months of 2019, 38.9 percent of generation was pool scheduled in the Day-Ahead Energy Market and 41.5 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 57.7 percent of real-time generation, are self scheduled.

Table 4-11 Day-ahead and real-time generation by status and eligibility to set LMP (GWh): January through September, 2019

	Self Scheduled			Pool Scheduled						
	Dispatchable	Economic Minimum	Block Loaded	Dispatchable	Economic Minimum	Block Loaded	Total GWh	Total Pool Scheduled	Total Self Scheduled	Total Generation Eligible to Set Price
Day-Ahead Generation	77,677	148,164	159,699	108,237	121,880	15,766	631,423	245,883	385,540	185,914
Share of Day-Ahead	12.3%	23.5%	25.3%	17.1%	19.3%	2.5%	100.0%	38.9%	61.1%	29.4%
Real-Time Generation	63,092	132,725	174,089	105,499	136,481	20,334	632,220	262,314	369,906	168,591
Share of Real-Time	10.0%	21.0%	27.5%	16.7%	21.6%	3.2%	100.0%	41.5%	58.5%	26.7%

Economic and Noneconomic Generation[18]

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 to or produce energy in real time at an incremental offer higher than the LMP at 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.

17 PJM allows block loaded CTs to set LMP by relaxing the economic minimum by 10 to 20 percent.
18 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.

Table 4-12 shows the day-ahead and real-time economic and noneconomic generation from units eligible for operating reserve credits. In the first nine months of 2019, 82.7 percent of the day-ahead generation eligible for operating reserve credits was economic and 67.0 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 4-12 shows the separate amounts of economic and noneconomic generation even if the daily or segment generation was economic.

Table 4-12 Economic and noneconomic generation from units eligible for operating reserve credits (GWh): January through September, 2019

Energy Market	Economic Generation	Noneconomic Generation	Total Eligible Generation	Economic Generation Percent	Noneconomic Generation Percent
Day-Ahead	203,259	42,624	245,883	82.7%	17.3%
Real-Time	148,678	73,068	221,746	67.0%	33.0%

Noneconomic generation only leads to operating reserve credits when a unit is unable to recover its operating costs for the day or segment. Table 4-13 shows the generation receiving day-ahead and balancing operating reserve credits. In the first nine months of 2019, 1.0 percent of the day-ahead generation eligible for operating reserve credits received credits and 1.5 percent of the real-time generation eligible for operating reserve credits received credits.

Table 4-13 Generation receiving operating reserve credits (GWh): January through September, 2019

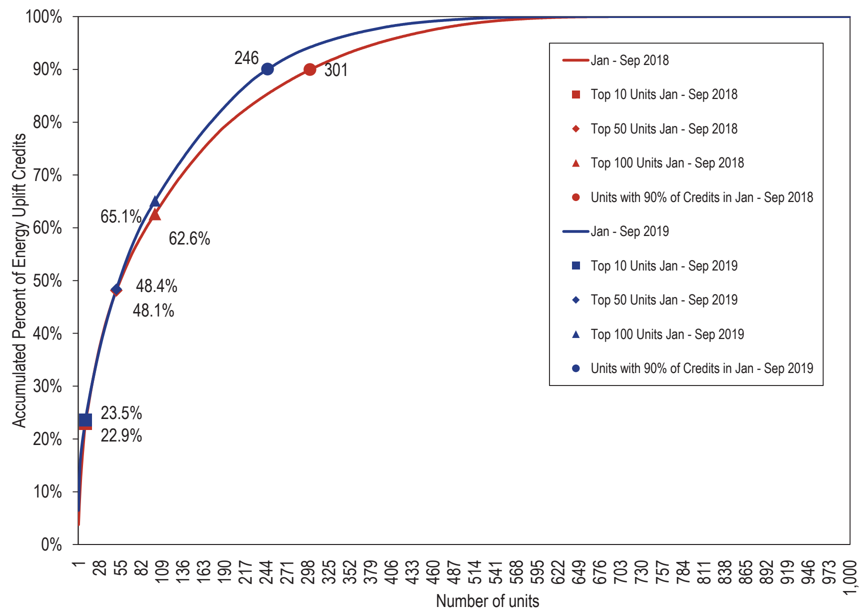
Energy Market	Generation Eligible for Operating Reserve Credits	Generation Receiving Operating Reserve Credits	Generation Receiving Operating Reserve Credits Percent
Day-Ahead	245,883	2,355	1.0%
Real-Time	221,746	3,394	1.5%

Concentration of Energy Uplift Credits

There is 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.[19]

Figure 4-1 shows the concentration of energy uplift credits. The top 10 units received 23.5 percent of total energy uplift credits in the first nine months of 2019, compared to 22.9 percent in the first nine months of 2018. In the first nine months of 2019, 246 units received 90 percent of all energy uplift credits, compared to 301 units in the first nine months of 2018.

Figure 4-1 Cumulative share of energy uplift credits: January through September, 2018 and 2019 by unit



19 As a result of FERC Order No. 844, PJM began publishing total uplift credits by unit by month for credits incurred on and after July 1, 2019 on September 10, 2019.

Table 4-14 shows the credits received by the top 10 units and top 10 organizations in each of the energy uplift categories paid to generators in the first nine months of 2019.

Table 4-14 Top 10 units and organizations energy uplift credits: January through September, 2019

		Top 10 Units		Top 10 Organizations	
Category	Type	Credits (Millions)	Credits Share	Credits (Millions)	Credits Share
Day-Ahead	Generators	$12.5	89.7%	$13.8	98.7%
Balancing	Canceled Resources	$0.0	0.0%	$0.0	0.0%
	Generators	$4.9	12.0%	$30.1	73.7%
	Local Constraints Control	$1.8	67.2%	$2.7	100.0%
	Lost Opportunity Cost	$3.3	26.4%	$9.4	74.4%
Reactive Services		$0.5	96.9%	$0.5	100.0%
Synchronous Condensing		$0.0	0.0%	$0.0	0.0%
Black Start Services		$0.1	48.9%	$0.1	89.1%
Total		$16.7	23.6%	$51.9	73.5%

Table 4-15 shows balancing operating reserve credits received by the top 10 units identified for reliability or for deviations in each region. In the first nine months of 2019, 64.1 percent of all credits paid to these units were allocated to deviations while the remaining 35.9 percent were paid for reliability reasons.

Table 4-15 Balancing operating reserve credits to top 10 units by category and region: January through September, 2019

	Reliability			Deviations			
	RTO	East	West	RTO	East	West	Total
Credits (Millions)	$1.6	$0.1	$0.0	$3.0	$0.1	$0.0	$4.9
Share	32.2%	2.8%	0.9%	60.7%	3.0%	0.4%	100.0%

In the first nine months of 2019, concentration in all energy uplift credit categories was high.[20] [21] The HHI for energy uplift credits was calculated based on each organization's share of daily credits for each category. Table 4-16 shows the average HHI for each category. HHI for day-ahead operating reserve credits to generators was 8500, for balancing operating reserve credits to generators was 3340, for lost opportunity cost credits was 5789 and for reactive services credits was 9802. All of these HHI values are characterized as highly concentrated.

20 See the 2019 Quarterly State of the Market Report for PJM: January through September, Section 3: "Energy Market" at "Market Concentration" for a discussion of concentration ratios and the Herfindahl-Hirschman Index (HHI).

21 Table 4-16 excludes local constraint control categories.

Table 4-16 Daily energy uplift credits HHI: January through September, 2019

Category	Type	Average	Minimum	Maximum	Highest Market Share (One day)	Highest Market Share (All days)
Day-Ahead	Generators	8500	2646	10000	100.0%	61.5%
	Imports	10000	10000	10000	100.0%	100.0%
	Load Response	9903	9708	10000	100.0%	99.1%
Balancing	Canceled Resources	NA	NA	NA	NA	NA
	Generators	3340	772	10000	100.0%	25.3%
	Imports	NA	NA	NA	NA	NA
	Load Response	NA	NA	NA	NA	NA
	Lost Opportunity Cost	5789	1083	10000	100.0%	24.4%
Reactive Services		9802	5518	10000	100.0%	39.2%
Synchronous Condensing		NA	NA	NA	NA	NA
Black Start Services		9374	5727	10000	100.0%	21.4%
Total		3220	725	10000	100.0%	17.6%

Unit Specific Uplift Payments

FERC Order No. 844 allows PJM and the MMU to publish unit specific uplift payments by category by month. Table 4-17 through Table 4-20 show the top 10 recipients of total uplift, day-ahead operating reserve credits and lost opportunity cost credits.

Table 4-17 Top 10 recipients of total uplift: July through September, 2019

Rank	Unit Name	Zone	Total Uplift Credit
1	BC BRANDON SHORES 1 F	BGE	$2,075,673
2	BC BRANDON SHORES 2 F	BGE	$1,998,368
3	DPL INDIAN RIVER 4 F	DPL	$637,876
4	PEP CHALKPOINT 4 F	Pepco	$475,644
5	COM 900 ELWOOD 9 CT	ComEd	$453,035
6	COM 900 ELWOOD 7 CT	ComEd	$425,105
7	COM 900 ELWOOD 8 CT	ComEd	$420,314
8	COM 900 ELWOOD 6 CT	ComEd	$416,278
9	COM 900 ELWOOD 3 CT	ComEd	$413,926
10	COM 900 ELWOOD 5 CT	ComEd	$389,076
Total (Jul-Sep)			$7,705,296
Share of total uplift credits			22.7%

Table 4-18 Top 10 recipients of day-ahead generation credits: July through September, 2019

Rank	Unit Name	Zone	Day-Ahead Operating Reserve Credit
1	BC BRANDON SHORES 1 F	BGE	$2,021,919.2
2	BC BRANDON SHORES 2 F	BGE	$1,965,831
3	DPL INDIAN RIVER 4 F	DPL	$562,508
4	PEP MORGANTOWN 1 F	Pepco	$176,306
5	PEP CHALKPOINT 2 F	Pepco	$160,435
6	DPL VIENNA 8 F	DPL	$117,513
7	PEP CHALKPOINT 1 F	Pepco	$113,532
8	PEP CHALKPOINT 3 F	Pepco	$88,817
9	COM 3 POWERTON 6	ComEd	$69,859
10	PEP CHALKPOINT 4 F	Pepco	$63,487
Total (Jul-Sep)			$5,340,207
Share of total day-ahead operating reserve credits			93.4%

Table 4-19 Top 10 recipients of balancing operating reserve credits: July through September, 2019

Rank	Unit Name	Zone	Balancing Operating Reserve Credit
1	PEP CHALKPOINT 4 F	Pepco	$412,158
2	BC WESTPORT 5 CT	BGE	$293,687
3	AEP FOOT HILLS 2 CT	AEP	$282,523
4	FE LEMOYNE 2 CT	ATSI	$272,152
5	AEP RIVERSIDE ZELDA 3 CT	AEP	$240,516
6	COM 952 ROCKFORD 11 CT	ComEd	$236,435
7	AEP RIVERSIDE ZELDA 1 CT	AEP	$235,660
8	COM 952 ROCKFORD 12 CT	ComEd	$234,139
9	DPL VIENNA 8 F	DPL	$230,753
10	AEP RIVERSIDE ZELDA 2 CT	AEP	$219,711
Total (Jul-Sep)			$2,657,733
Share of balancing operating reserve credits			13.6%

Table 4-20 Top 10 recipients of lost opportunity cost credits: July through September, 2019

Rank	Unit Name	Zone	Lost Opportunity Cost Credit
1	COM 900 ELWOOD 9 CT	ComEd	$386,219
2	COM 900 ELWOOD 3 CT	ComEd	$367,792
3	COM 900 ELWOOD 8 CT	ComEd	$366,269
4	COM 900 ELWOOD 7 CT	ComEd	$356,673
5	COM 900 ELWOOD 6 CT	ComEd	$321,856
6	COM 900 ELWOOD 1 CT	ComEd	$317,010
7	COM 900 ELWOOD 4 CT	ComEd	$312,184
8	COM 900 ELWOOD 2 CT	ComEd	$309,954
9	COM 900 ELWOOD 5 CT	ComEd	$280,878
10	DPL DEMEC - CLAYTON 2 CT	DPL	$251,464
Total (Jul-Sep)			$3,270,298
Share of total lost opportunity cost credits			37.8%

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 4-21 and Table 4-22 show the categories of credits and charges and their relationship. These tables show how the charges are allocated.

Table 4-21 Day-ahead and balancing operating reserve credits and charges

Credits Received For:	Credits Category:		Charges Category:	Charges Paid By:	
		Day-Ahead			
Day-Ahead Import Transactions and Generation Resources	Day-Ahead Operating Reserve Transaction Day-Ahead Operating Reserve Generator	→	Day-Ahead Operating Reserve	Day-Ahead Load Day-Ahead Export Transactions Decrement Bids	in RTO Region
Economic Load Response Resources	Day-Ahead Operating Reserves for Load Response	→	Day-Ahead Operating Reserve for Load Response	Day-Ahead Load Day-Ahead Export Transactions Decrement Bids	in RTO Region
	Unallocated Negative Load Congestion Charges Unallocated Positive Generation Congestion Credits	→	Unallocated Congestion	Day-Ahead Load Day-Ahead Export Transactions Decrement Bids	in RTO Region
		Balancing			
Generation Resources	Balancing Operating Reserve Generator	→	Balancing Operating Reserve for Reliability	Real-Time Load plus Real-Time Export Transactions	in RTO, Eastern or Western Region
			Balancing Operating Reserve for Deviations	Deviations	
			Balancing Local Constraint	Applicable Requesting Party	
Canceled Resources	Balancing Operating Reserve Startup Cancellation				
Lost Opportunity Cost (LOC)	Balancing Operating Reserve LOC	→	Balancing Operating Reserve for Deviations	Deviations	in RTO Region
Real-Time Import Transactions	Balancing Operating Reserve Transaction				
Economic Load Response Resources	Balancing Operating Reserves for Load Response	→	Balancing Operating Reserve for Load Response	Deviations	in RTO Region

Table 4-22 Reactive services, synchronous condensing and black start services credits and charges

Credits Received For:	Credits Category:		Charges Category:	Charges Paid By:
		Reactive		
Resources Providing Reactive Service	Day-Ahead Operating Reserve Reactive Services Generator Reactive Services LOC	→	Reactive Services Charge	Zonal Real-Time Load
	Reactive Services Condensing Reactive Services Synchronous Condensing LOC	→	Reactive Services Local Constraint	Applicable Requesting Party
		Synchronous Condensing		
Resources Providing Synchronous Condensing	Synchronous Condensing Synchronous Condensing LOC	→	Synchronous Condensing	Real-Time Load Real-Time Export Transactions
		Black Start		
Resources Providing Black Start Service	Day-Ahead Operating Reserve Balancing Operating Reserve Black Start Testing	→	Black Start Service Charge	Zone/Non-zone Peak Transmission Use and Point to Point Transmission Reservations

Energy Uplift Results

Energy Uplift Charges

Total energy uplift charges decreased by $106.3 million or 60.1 percent in the first nine months of 2019 compared to the first nine months of 2018.

Table 4-23 shows total energy uplift charges by category in the first nine months of 2018 and 2019.[22] The decrease of $106.3 million is comprised of a decrease of $17.8 million in day-ahead operating reserve charges, a decrease of $76.4 million in balancing operating reserve charges and a decrease of $11.9 million in reactive service charges.

Table 4-23 Total energy uplift charges by category: January through September, 2018 and 2019

Category	(Jan - Sep) 2018 Charges (Millions)	(Jan - Sep) 2019 Charges (Millions)	Change (Millions)	Percent Change
Day-Ahead Operating Reserves	$31.8	$14.0	($17.8)	(56.1%)
Balancing Operating Reserves	$132.5	$56.1	($76.4)	(57.7%)
Reactive Services	$12.4	$0.5	($11.9)	(96.2%)
Synchronous Condensing	$0.0	$0.0	($0.0)	(100.0%)
Black Start Services	$0.2	$0.2	($0.0)	(16.2%)
Total	$176.9	$70.6	($106.3)	(60.1%)
Energy Uplift as a Percent of Total PJM Billing	0.5%	0.2%	0.2%	37.6%

Table 4-24 compares monthly energy uplift charges by category for 2018 and the first nine months of 2019.

Table 4-24 Monthly energy uplift charges: January 2018 through September 2019

	2018 Charges (Millions)						2019 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	$4.8	$55.4	$1.9	$0.0	$0.0	$62.1	$1.0	$6.5	$0.1	$0.0	$0.0	$7.6
Feb	$3.6	$1.9	$2.2	$0.0	$0.0	$7.8	$0.8	$3.9	$0.0	$0.0	$0.0	$4.7
Mar	$4.6	$6.4	$1.9	$0.0	$0.0	$12.9	$2.3	$4.6	$0.0	$0.0	$0.0	$6.9
Apr	$2.1	$9.6	$1.2	$0.0	$0.1	$12.9	$0.1	$4.0	$0.0	$0.0	$0.0	$4.2
May	$6.9	$16.1	$2.2	$0.0	$0.1	$25.2	$1.4	$4.1	$0.1	$0.0	$0.1	$5.7
Jun	$5.7	$11.9	$1.3	$0.0	$0.0	$18.9	$2.6	$4.8	$0.2	$0.0	$0.0	$7.5
Jul	$2.1	$9.5	$0.5	$0.0	$0.0	$12.1	$1.4	$10.8	$0.0	$0.0	$0.0	$12.2
Aug	$0.7	$8.8	$0.2	$0.0	$0.0	$9.8	$2.7	$6.8	$0.0	$0.0	$0.0	$9.5
Sep	$1.3	$12.8	$1.0	$0.0	$0.0	$15.2	$1.66	$10.6	$0.0	$0.0	$0.0	$12.3
Oct	$1.0	$8.6	$0.6	$0.0	$0.1	$10.3						
Nov	$0.6	$7.0	$0.2	$0.0	$0.0	$7.9						
Dec	$0.5	$2.6	$0.0	$0.0	$0.0	$3.2						
Total (Jan - Sep)	$31.8	$132.5	$12.4	$0.0	$0.2	$176.9	$14.0	$56.1	$0.5	$0.0	$0.2	$70.6
Share (Jan - Sep)	18.0%	74.9%	7.0%	0.0%	0.1%	100.0%	19.8%	79.4%	0.7%	0.0%	0.2%	100.0%
Total	$34.0	$150.8	$13.2	$0.0	$0.3	$198.3	$14.0	$56.1	$0.5	$0.0	$0.2	$70.6
Share	17.1%	76.0%	6.6%	0.0%	0.2%	100.0%	19.8%	79.4%	0.7%	0.0%	0.2%	100.0%

22 Table 4-23 includes all categories of charges as defined in Table 4-21 and Table 4-22 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 October 11, 2019. The 2018 uplift charges differ from the 2018 uplift credits by $0.1 million in the PJM data although they should be equal. The MMU is investigating.

Table 4-25 shows the composition of 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.[23] Day-ahead operating reserve charges decreased by $17.8 million or 56.1 percent in the first nine months of 2019 compared to the first nine months of 2018. Day-ahead operating reserve charges decreased in the first nine months of 2019 as a result of a decrease in day-ahead unit commitments for reliability. The decrease in day-ahead operating reserve credits paid to units in Pepco and BGE combined accounted for 56.1 percent of the total decrease in day-ahead operating reserve charges in the first nine months of 2019 compared to the first nine months of 2018.

Table 4-25 Day-ahead operating reserve charges: January through September, 2018 and 2019

Type	(Jan - Sep) 2018 Charges (Millions)	(Jan - Sep) 2019 Charges (Millions)	Change (Millions)	(Jan - Sep) 2018 Share	(Jan - Sep) 2019 Share
Day-Ahead Operating Reserve Charges	$31.8	$14.0	($17.8)	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	$31.8	$14.0	($17.8)	100.0%	100.0%

Table 4-26 shows the composition of the balancing operating reserve charges. Balancing operating reserve charges consist of balancing operating reserve reliability charges (credits to generators), balancing operating reserve deviation charges (credits to generators and import transactions), balancing operating reserve charges for economic load response and balancing local constraint charges. Balancing operating reserve charges decreased by $76.4 million or 57.5 percent in the first nine months of 2019 compared to the first nine months of 2018.

Table 4-26 Balancing operating reserve charges: January through September, 2018 and 2019

Type	(Jan - Sep) 2018 Charges (Millions)	(Jan - Sep) 2019 Charges (Millions)	Change (Millions)	(Jan - Sep) 2018 Share	(Jan - Sep) 2019 Share
Balancing Operating Reserve Reliability Charges	$30.8	$17.1	($13.7)	23.3%	30.6%
Balancing Operating Reserve Deviation Charges	$93.7	$36.2	($57.5)	70.7%	64.6%
Balancing Operating Reserve Charges for Load Response	$0.0	$0.0	($0.0)	0.0%	0.0%
Balancing Local Constraint Charges	$8.0	$2.7	($5.3)	6.0%	4.8%
Total	$132.5	$56.1	($76.4)	100.0%	100.0%

Table 4-27 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 scheduled by PJM but canceled by PJM before coming online. In the first nine months of 2019, energy lost opportunity cost deviation charges decreased by $36.0 million or 74.1 percent, and make whole deviation charges decreased by $21.4 million or 47.5 percent compared to the first nine months of 2018.

23 See PJM Operating Agreement 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 only 10 times since 1999, totaling $26.9 million.

Table 4-27 Balancing operating reserve deviation charges: January through September, 2018 and 2019

Charge Attributable To	(Jan - Sep) 2018 Charges (Millions)	(Jan - Sep) 2019 Charges (Millions)	Change (Millions)	(Jan - Sep) 2018 Share	(Jan - Sep) 2019 Share
Make Whole Payments to Generators and Imports	$45.1	$23.7	($21.4)	48.1%	65.3%
Energy Lost Opportunity Cost	$48.6	$12.6	($36.0)	51.9%	34.7%
Canceled Resources	$0.0	$0.0	$0.0	0.0%	0.0%
Total	$93.7	$36.2	($57.5)	100.0%	100.0%

Table 4-28 shows reactive services, synchronous condensing and black start services charges. Reactive services charges decreased by $11.9 million or 96.2 percent in the first nine months of 2019, compared to the first nine months of 2018. The decrease in reactive service charges resulted from a decrease in the need for reactive service in ComEd.

Table 4-28 Additional energy uplift charges: January through September, 2018 and 2019

Type	(Jan - Sep) 2018 Charges (Millions)	(Jan - Sep) 2019 Charges (Millions)	Change (Millions)	(Jan - Sep) 2018 Share	(Jan - Sep) 2019 Share
Reactive Services Charges	$12.4	$0.5	($11.9)	98.2%	74.5%
Synchronous Condensing Charges	$0.0	$0.0	($0.0)	0.3%	0.0%
Black Start Services Charges	$0.2	$0.2	($0.0)	1.5%	25.5%
Total	$12.6	$0.6	($12.0)	100.0%	100.0%

Table 4-29 and Table 4-30 show the amount and shares of regional balancing charges in the first nine months of 2018 and 2019. Regional balancing operating reserve charges consist of balancing operating reserve reliability and deviation charges. These charges are allocated regionally across PJM. In the first nine months of 2019 the largest share of regional charges was paid by real-time load which paid 30.9 percent of all regional balancing charges. The regional balancing charges allocation table does not include charges attributed for resources controlling local constraints.

In the first nine months of 2019 regional balancing operating reserve charges decreased by $ 71.2 million compared to the first nine months of 2018. Balancing operating reserve reliability charges decreased by $13.7 million or 44.4 percent, and balancing operating reserve deviation charges decreased by $57.5 million, or 61.3 percent.

Table 4-29 Regional balancing charges allocation (Millions): January through September, 2018

Charge	Allocation	RTO		East		West		Total	
Reliability Charges	Real-Time Load	$26.2	21.1%	$2.3	1.8%	$1.4	1.1%	$29.9	24.0%
	Real-Time Exports	$0.8	0.6%	$0.1	0.1%	$0.0	0.0%	$0.9	0.7%
	Total	$27.0	21.7%	$2.4	1.9%	$1.4	1.1%	$30.8	24.7%
Deviation Charges	Demand	$50.8	40.8%	$1.3	1.0%	$2.2	1.8%	$54.3	43.6%
	Supply	$15.3	12.3%	$0.5	0.4%	$0.6	0.5%	$16.4	13.2%
	Generator	$21.5	17.2%	$0.6	0.5%	$1.0	0.8%	$23.1	18.5%
	Total	$87.5	70.3%	$2.4	1.9%	$3.8	3.1%	$93.8	75.3%
Total Regional Balancing Charges		$114.6	92.0%	$4.8	3.8%	$5.2	4.2%	$124.6	100%

Table 4-30 Regional balancing charges allocation (Millions): January through September, 2019

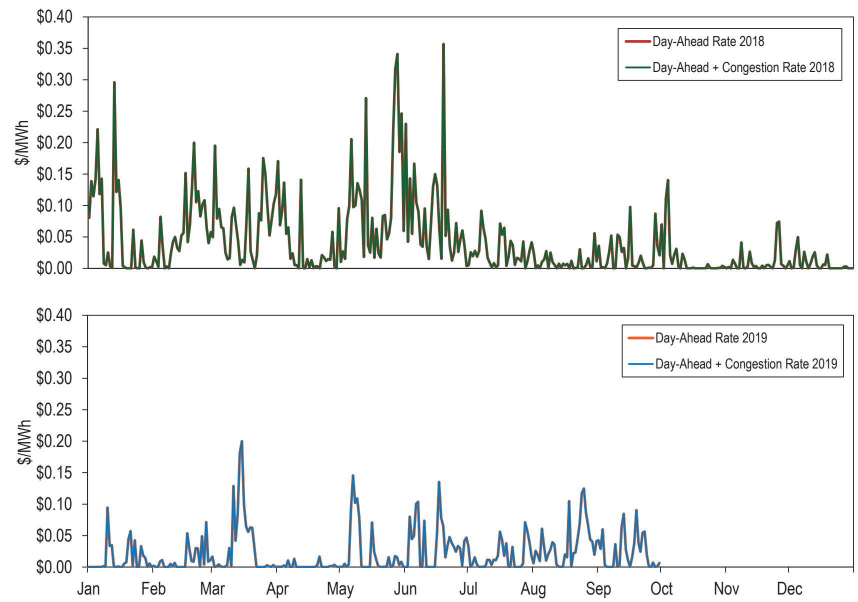
Charge	Allocation	RTO		East		West		Total	
Reliability Charges	Real-Time Load	$14.9	28.0%	$1.1	2.1%	$0.5	0.9%	$16.5	30.9%
	Real-Time Exports	$0.6	1.1%	$0.0	0.1%	$0.0	0.0%	$0.6	1.2%
	Total	$15.5	29.1%	$1.1	2.1%	$0.5	0.9%	$17.1	32.1%
Deviation Charges	Demand	$21.2	39.6%	$0.8	1.6%	$0.3	0.6%	$22.3	41.8%
	Supply	$5.6	10.5%	$0.3	0.5%	$0.1	0.2%	$6.0	11.2%
	Generator	$7.4	13.9%	$0.4	0.7%	$0.1	0.2%	$7.9	14.8%
	Total	$34.2	64.1%	$1.5	2.7%	$0.6	1.0%	$36.2	67.9%
Total Regional Balancing Charges		$49.7	93.2%	$2.6	4.9%	$1.0	2.0%	$53.4	100%

Operating Reserve Rates

Under the operating reserves cost allocation rules, PJM calculates nine separate rates, a day-ahead operating reserve rate, a reliability rate for each region, a deviation rate for each region, a lost opportunity cost rate and a canceled resources rate for the entire RTO region. Table 4-21 shows how these charges are allocated.[24]

Figure 4-2 shows the daily day-ahead operating reserve rate for 2018 and the first nine months of 2019. The average rate in the first nine months of 2019 was $0.022 per MWh, $0.028 per MWh lower than the average in the first nine months of 2018. The highest rate in the first nine months of 2019 occurred on March 15, when the rate reached $0.200 per MWh, $0.157 per MWh lower than the $0.357 per MWh reached in the first nine months of 2018, on June 19. Figure 4-2 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 2018 or the first nine months of 2019.

Figure 4-2 Daily day-ahead operating reserve rate ($/MWh): January 2018 through June 2019



24 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 shows the RTO and the regional reliability rates for 2018 and the first nine months of 2019. The average RTO reliability rate in the first nine months of 2019 was $0.025 per MWh. The highest RTO reliability rate in the first nine months of 2019 occurred on January 22, when the rate reached $0.368 per MWh, $0.363 per MWh lower than the $0.731 per MWh rate reached in the first nine months of 2018, on January 2.

Figure 4-3 Daily balancing operating reserve reliability rates ($/MWh): January 2018 through June 2019

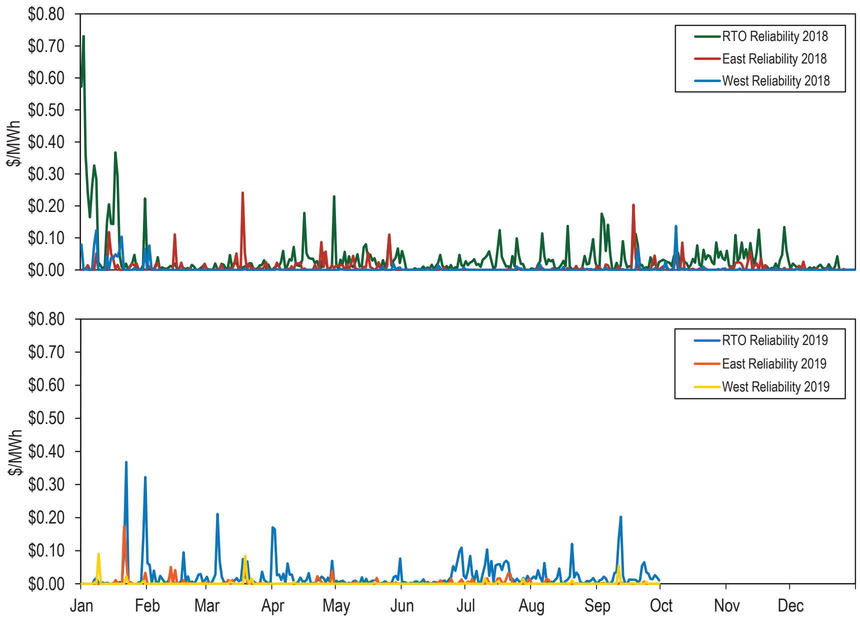


Figure 4-4 shows the RTO and regional deviation rates for 2018 and the first nine months of 2019. The average RTO deviation rate in the first nine months of 2019 was $0.185 per MWh. The highest daily rate in the first nine months of 2019 occurred on July 10, when the RTO deviation rate reached $1.227 per MWh, $3.261 per MWh lower than the $4.488 per MWh rate reached in the first nine months of 2018, on January 1.

Figure 4-4 Daily balancing operating reserve deviation rates ($/MWh): January 2018 through September 2019

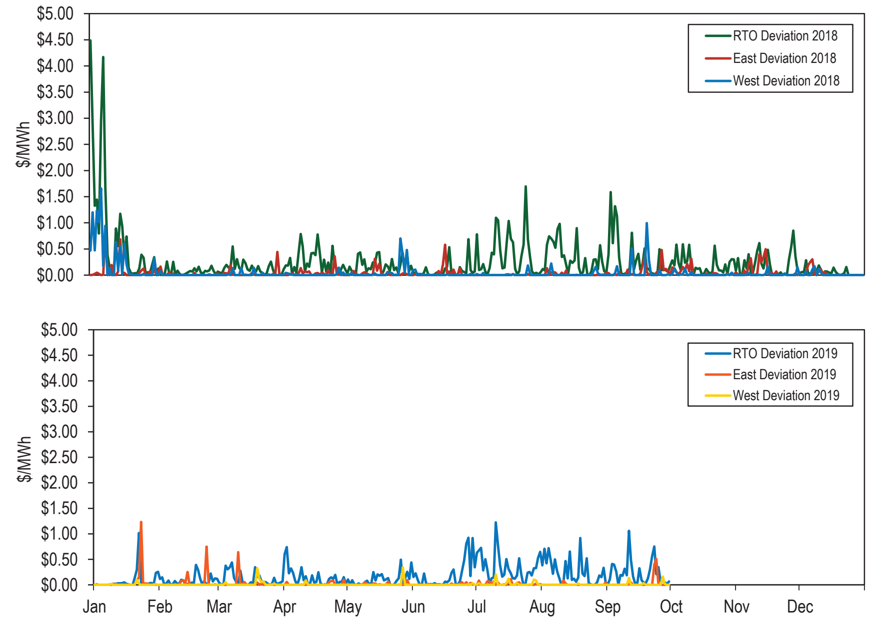


Figure 4-5 shows the daily lost opportunity cost rate and the daily canceled resources rate for 2018 and the first nine months of 2019. The average lost opportunity cost rate in the first nine months of 2019 was $0.107 per MWh. The highest lost opportunity cost rate in the first nine months occurred on May 23, when it reached $2.051 per MWh, $6.965 per MWh lower than the $9.016 per MWh rate reached in the first nine months of 2018, on January 7.[25]

25 For details about this event see **2018 Quarterly State of the Market Report for PJM: January through March**, Section 4: "Energy Uplift"

Figure 4-5 Daily lost opportunity cost and canceled resources rates ($/MWh): January 2018 through September 2019

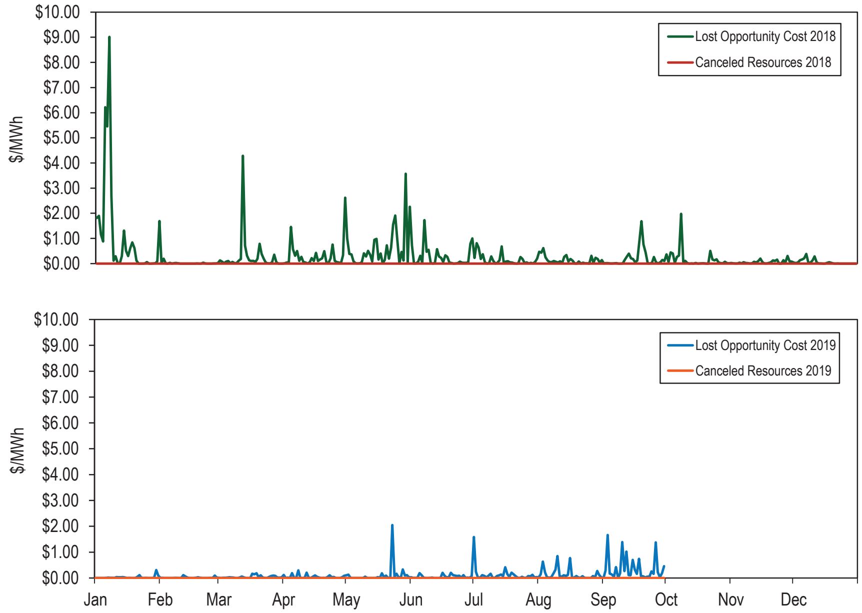


Table 4-31 shows the average rates for each region in each category for the first nine months of 2018 and 2019.

Table 4-31 Operating reserve rates ($/MWh): January through September, 2018 and 2019

Rate	(Jan - Sep) 2018 ($/MWh)	(Jan - Sep) 2019 ($/MWh)	Difference ($/MWh)	Percent Difference
Day-Ahead	0.051	0.022	(0.028)	(56.0%)
Day-Ahead with Unallocated Congestion	0.051	0.022	(0.028)	(56.0%)
RTO Reliability	0.043	0.025	(0.018)	(42.0%)
East Reliability	0.008	0.004	(0.004)	(51.7%)
West Reliability	0.004	0.002	(0.003)	(64.0%)
RTO Deviation	0.335	0.185	(0.150)	(44.8%)
East Deviation	0.039	0.025	(0.014)	(36.4%)
West Deviation	0.070	0.010	(0.061)	(86.3%)
Lost Opportunity Cost	0.419	0.107	(0.311)	(74.4%)
Canceled Resources	0.000	0.000	NA	NA

Table 4-32 shows the operating reserve cost of a one MW transaction in the first nine months of 2019. For example, a decrement bid in the Eastern Region (if not offset by other transactions) paid an average rate of $0.340 per MWh with a maximum rate of $2.252 per MWh, a minimum rate of $0.000 per MWh and a standard deviation of $0.364 per MWh. The rates in Table 4-32 include all operating reserve charges including RTO deviation charges. Table 4-32 illustrates both the average level of operating reserve charges by transaction types and the uncertainty reflected in the maximum, minimum and standard deviation levels. INCs and DECs have higher rates compared to real-time load because they are allocated a deviation charge while day-ahead and real-time load do not necessarily incur a deviation charge.

Table 4-32 Operating reserve rates statistics ($/MWh): January through September, 2019

		Rates Charged ($/MWh)			
Region	Transaction	Maximum	Average	Minimum	Standard Deviation
East	INC	2.219	0.318	0.000	0.364
	DEC	2.252	0.340	0.000	0.364
	DA Load	0.200	0.022	0.000	0.033
	RT Load	0.437	0.029	0.000	0.049
	Deviation	2.219	0.318	0.000	0.364
West	INC	2.230	0.302	0.000	0.357
	DEC	2.264	0.324	0.000	0.357
	DA Load	0.200	0.022	0.000	0.033
	RT Load	0.391	0.027	0.000	0.044
	Deviation	2.230	0.302	0.000	0.357

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 capability revenue requirement charges which are a fixed annual charge based on approved FERC filings.[26] Reactive services charges associated with supporting reactive transfer interfaces above 345 kV are allocated daily to

26 See 2018 State of the Market Report for PJM, Volume 2, Section 10: Ancillary Service Markets.

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 4-33 shows the reactive services rates associated with local voltage support in the first nine months of 2018 and 2019. Table 4-33 shows that in the first nine months of 2019 only two zones incurred reactive charges, in addition to reactive capability charges. Real-time load in the PENELEC Zone paid an average of $0.011 per MWh for reactive services, and real-time load in the DPL Control Zone paid an average of $0.007 per MWh for reactive services. The third highest rate for reactive services was in the Dominion Control Zone, where real-time load paid an average of $0.002 per MWh.

Table 4-33 Local voltage support rates: January through September, 2018 and 2019

Control Zone	(Jan - Sep) 2018 ($/MWh)	(Jan - Sep) 2019 ($/MWh)	Difference ($/MWh)	Percent Difference
AECO	0.000	0.000	(0.000)	(100.0%)
AEP	0.008	0.000	(0.008)	(98.1%)
APS	0.000	0.000	0.000	NA
ATSI	0.000	0.000	0.000	NA
BGE	0.001	0.000	(0.001)	(100.0%)
ComEd	0.144	0.000	(0.144)	(100.0%)
DAY	0.000	0.000	0.000	0.0%
DEOK	0.000	0.000	0.000	0.0%
DLCO	0.000	0.000	0.000	0.0%
Dominion	0.000	0.002	0.002	716.1%
DPL	0.018	0.007	(0.011)	(59.3%)
EKPC	0.018	0.000	(0.018)	(100.0%)
JCPL	0.000	0.000	0.000	0.0%
Met-Ed	0.000	0.000	0.000	0.0%
OVEC	0.000	0.000	0.000	0.0%
PECO	0.028	0.000	(0.028)	(100.0%)
PENELEC	0.000	0.011	0.011	NA
Pepco	0.000	0.000	0.000	0.0%
PPL	0.000	0.000	0.000	0.0%
PSEG	0.000	0.000	0.000	0.0%
RECO	0.000	0.000	0.000	0.0%

Balancing Operating Reserve Determinants

Table 4-34 shows the determinants used to allocate the regional balancing operating reserve charges in the first nine months of 2018 and 2019. Total real-time load and real-time exports were 614,673 GWh, 1.5 percent higher in 2019 compared to 2018. Total deviations summed across the demand, supply, and generator categories were 116,962 GWh, 0.4 percent higher in 2019 compared to 2018.

Table 4-34 Balancing operating reserve determinants (GWh): January through September, 2018 and 2019

		Reliability Charge Determinants (GWh)			Deviation Charge Determinants (GWh)			
		Real-Time Load	Real-Time Exports	Reliability Total	Demand Deviations (MWh)	Supply Deviations (MWh)	Generator Deviations (MWh)	Deviations Total
(Jan - Sep) 2018	RTO	604,102	19,848	623,950	68,645	21,129	26,711	116,485
	East	286,634	11,187	297,822	33,855	12,560	14,390	60,804
	West	317,468	8,660	326,128	34,231	8,447	12,321	55,000
(Jan - Sep) 2019	RTO	588,506	26,167	614,673	70,766	20,748	25,449	116,962
	East	281,297	11,382	292,679	34,450	11,259	12,961	58,670
	West	307,209	14,786	321,994	35,734	9,028	12,488	57,250
Difference	RTO	(15,596)	6,319	(9,277)	2,120	(381)	(1,262)	477
	East	(5,337)	194	(5,143)	595	(1,301)	(1,429)	(2,134)
	West	(10,259)	6,125	(4,134)	1,503	581	167	2,250

Deviations fall into three categories, demand, supply and generator deviations. Table 4-35 shows the different categories by the type of transactions that incurred deviations. In the first nine months of 2019, 31.8 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 68.2 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 4-35 Deviations by transaction type: January through September, 2019

Deviation Category	Transaction	Deviation (GWh)			Share		
		RTO	East	West	RTO	East	West
Demand	DECs Only	17,891	8,881	8,429	15.3%	15.1%	14.7%
	Exports Only	5,347	2,990	2,356	4.6%	5.1%	4.1%
	Load Only	45,601	22,329	23,272	39.0%	38.1%	40.6%
	Combination with DECs	1,922	246	1,677	1.6%	0.4%	2.9%
	Combination without DECs	5	5	0	0.0%	0.0%	0.0%
Supply	Imports Only	3,409	2,560	849	2.9%	4.4%	1.5%
	INCs Only	16,953	8,360	8,132	14.5%	14.2%	14.2%
	Combination with INCs	386	338	48	0.3%	0.6%	0.1%
	Combination without INCs	0	0	0	0.0%	0.0%	0.0%
Generators		25,449	12,961	12,488	21.8%	22.1%	21.8%
Total		116,962	58,670	57,250	100.0%	100.0%	100.0%

Geography of Charges and Credits

Table 4-36 shows the geography of charges and credits in the first nine months of 2019. Table 4-36 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 PPL Control Zone paid 5.6 percent of all operating reserve charges allocated regionally while resources in the PPL Control Zone were paid 1.8 percent of the corresponding credits. The PPL Control Zone received less operating reserve credits than operating reserve charges paid and had 9.7 percent of the deficit. The deficit is the net of the credits and charges paid at a location. Transactions in the BGE Control Zone paid 3.8 percent of all operating reserve charges allocated regionally, and resources in the BGE Control Zone were paid 16.0 percent of the corresponding credits. The BGE Control Zone received more operating reserve credits than operating reserve charges paid and had 31.9 percent of the surplus. The surplus is the net of the credits and charges paid at a location. Table 4-36 also shows that 90.3 percent of all charges were allocated in control zones, 3.0 percent in hubs and aggregates and 6.8 percent in interfaces.

Table 4-36 Geography of regional charges and credits: January through September, 2019

Location		Charges (Millions)	Credits (Millions)	Balance	Shares Total Charges	Total Credits	Deficit	Surplus
Zones	AECO	$1.0	$0.9	($0.1)	1.4%	1.3%	0.3%	0.0%
	AEP	$9.6	$7.7	($1.8)	14.2%	11.5%	7.1%	0.0%
	APS	$3.5	$1.3	($2.2)	5.2%	1.9%	8.6%	0.0%
	ATSI	$4.8	$1.9	($2.9)	7.1%	2.8%	11.2%	0.0%
	BGE	$2.5	$10.7	$8.2	3.8%	16.0%	0.0%	31.9%
	ComEd	$7.9	$14.6	$6.7	11.7%	21.7%	0.0%	26.0%
	DAY	$1.1	$1.9	$0.8	1.7%	2.8%	0.0%	3.0%
	DEOK	$2.0	$1.3	($0.7)	3.0%	2.0%	2.8%	0.0%
	DLCO	$1.0	$0.2	($0.8)	1.4%	0.3%	3.0%	0.0%
	Dominion	$6.9	$10.6	$3.6	10.3%	15.7%	0.0%	14.1%
	DPL	$1.6	$3.6	$2.0	2.5%	5.4%	0.0%	7.8%
	EKPC	$0.8	$1.5	$0.7	1.2%	2.2%	0.0%	2.6%
	External	$0.0	$1.1	$1.1	0.0%	1.7%	0.0%	4.4%
	JCPL	$1.8	$0.1	($1.6)	2.6%	0.2%	6.4%	0.0%
	Met-Ed	$1.4	$0.2	($1.2)	2.1%	0.3%	4.6%	0.0%
	OVEC	$0.2	$0.0	($0.1)	0.2%	0.0%	0.5%	0.0%
	PECO	$3.0	$0.5	($2.5)	4.4%	0.8%	9.7%	0.0%
	PENELEC	$2.2	$1.3	($0.8)	3.2%	1.9%	3.3%	0.0%
	Pepco	$2.4	$5.1	$2.7	3.6%	7.6%	0.0%	10.4%
	PPL	$3.7	$1.2	($2.5)	5.6%	1.8%	9.7%	0.0%
	PSEG	$3.2	$1.5	($1.7)	4.8%	2.2%	6.6%	0.0%
	RECO	$0.2	$0.0	($0.2)	0.2%	0.0%	0.6%	0.0%
	All Zones	$60.7	$67.3	$6.6	90.3%	100.0%	74.5%	100.0%
Hubs and Aggregates	AEP - Dayton	$0.4	$0.0	($0.4)	0.6%	0.0%	1.6%	0.0%
	Dominion	$0.3	$0.0	($0.3)	0.4%	0.0%	1.1%	0.0%
	Eastern	$0.1	$0.0	($0.1)	0.2%	0.0%	0.5%	0.0%
	New Jersey	$0.2	$0.0	($0.2)	0.3%	0.0%	0.7%	0.0%
	Ohio	$0.1	$0.0	($0.1)	0.2%	0.0%	0.5%	0.0%
	Western Interface	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%	0.0%
	Western	$0.9	$0.0	($0.9)	1.3%	0.0%	3.4%	0.0%
	RTEP B0328 Source	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%	0.0%
	All Hubs and Aggregates	$2.0	$0.0	($2.0)	3.0%	0.0%	7.8%	0.0%
Interfaces	CPLE Exp	$0.0	$0.0	($0.0)	0.1%	0.0%	0.2%	0.0%
	CPLE Imp	$0.0	$0.0	($0.0)	0.0%	0.0%	0.1%	0.0%
	Duke Exp	$0.1	$0.0	($0.1)	0.1%	0.0%	0.2%	0.0%
	Duke Imp	$0.1	$0.0	($0.1)	0.1%	0.0%	0.3%	0.0%
	Hudson	$0.2	$0.0	($0.2)	0.2%	0.0%	0.6%	0.0%
	IMO	$0.1	$0.0	($0.1)	0.2%	0.0%	0.4%	0.0%
	Linden	$0.2	$0.0	($0.2)	0.3%	0.0%	0.9%	0.0%
	MISO	$1.9	$0.0	($1.9)	2.8%	0.0%	7.3%	0.0%
	NCMPA Imp	$0.1	$0.0	($0.1)	0.1%	0.0%	0.4%	0.0%
	Neptune	$0.2	$0.0	($0.2)	0.4%	0.0%	0.9%	0.0%
	NIPSCO	$0.1	$0.0	($0.1)	0.1%	0.0%	0.2%	0.0%
	Northwest	$0.1	$0.0	($0.1)	0.2%	0.0%	0.5%	0.0%
	NYIS	$0.5	$0.0	($0.5)	0.8%	0.0%	2.0%	0.0%
	South Exp	$0.5	$0.0	($0.5)	0.7%	0.0%	1.9%	0.0%
	South Imp	$0.5	$0.0	($0.5)	0.7%	0.0%	1.9%	0.0%
	All Interfaces	$4.5	$0.0	($4.5)	6.8%	0.0%	17.6%	0.0%
	Total	$67.3	$67.3	$0.0	100.0%	100.0%	100.0%	100.0%

Energy Uplift Issues

Intraday Segments Uplift Settlement

PJM pays uplift separately for multiple segmented blocks of time during the operating day (intraday).[27] The use of intraday segments to calculate the need for uplift payments results in higher uplift payments than necessary to make units whole, including uplift payments to units that are profitable on a daily basis. The MMU recommends eliminating intraday segments from the calculation of uplift payments and returning to calculating the need for uplift based on the entire 24 hour operating day.

Table 4-37 shows balancing operating reserve credits calculated using intraday segments and balancing operating reserve payments calculated on a daily basis. In 2018, balancing operating reserve credits would have been $19.5 million or 21.9 percent lower if they were calculated on a daily basis. In the first nine months of 2019, balancing operating reserve credits would have been $10.0 million or 24.6 percent lower if they were calculated on a daily basis.

27 See PJM "Manual 28: Operating Reserve Accounting," Rev. 82 (July 25, 2019).

Table 4-37 Intraday segments and daily balancing operating reserve credits: January 2018 through September 2019

	2018 BOR Credits (Millions)			2019 BOR Credits (Millions)		
	Intraday Segments Calculation	Daily Calculation	Difference	Intraday Segments Calculation	Daily Calculation	Difference
Jan	$33.2	$27.8	($5.3)	$5.4	$4.6	($0.8)
Feb	$1.7	$1.3	($0.4)	$2.5	$2.3	($0.3)
Mar	$3.0	$2.4	($0.6)	$3.6	$2.9	($0.7)
Apr	$5.6	$4.2	($1.4)	$3.5	$2.9	($0.6)
May	$5.8	$3.9	($1.9)	$2.3	$1.7	($0.5)
Jun	$2.6	$1.7	($0.9)	$4.1	$3.3	($0.8)
Jul	$7.4	$5.2	($2.1)	$8.8	$6.1	($2.7)
Aug	$6.8	$4.8	($2.0)	$5.1	$3.0	($2.0)
Sep	$9.3	$7.0	($2.3)	$5.7	$4.0	($1.7)
Oct	$5.9	$4.5	($1.3)			
Nov	$6.2	$5.3	($0.9)			
Dec	$1.6	$1.3	($0.3)			
Total (Jan - Sep)	$75.4	$58.4	($17.0)	$40.8	$30.8	($10.0)
Total	$89.1	$69.6	($19.5)	$40.8	$30.8	($10.0)

Prior to April 1, 2018, for purposes of calculating LOC credits, each hour was defined as a unique segment. Following the implementation of five minute settlements on April 1, 2018, LOC credits are calculated with each five minute interval defined as a unique segment. Thus a profit in one five minute segment, resulting from the real-time LMP being lower than the day-ahead LMP, is not used to offset a loss in any other five-minute segment. This change in settlements causes an increase in LOC credits compared to hourly settlement as generators are made whole for any losses incurred in a five minute interval while previously gains and losses were netted across the hour. Table 4-38 shows the impact of changing the settlements of day-ahead LOC credits from an hourly basis to a five minute basis. For the months of April through December 2018, day-ahead LOC credits would have been $5.4 million or 26.3 percent lower had they been settled on an hourly basis compared to being settled on a five minute basis. For the first nine months of 2019, LOC credits would have been $0.8 million or 6.2 percent lower had they been settled on an hourly basis compared to being settled on a five minute basis.

Table 4-38 Five minute settlement and hourly settlement of day-ahead lost opportunity cost credits: April, 2018 through September, 2019

	2018 Day Ahead LOC Credits (Millions)			2019 Day Ahead LOC Credits (Millions)		
	Five Minute Settlement	Hourly Settlement	Difference	Five Minute Settlement	Hourly Settlement	Difference
Jan	NA	NA	NA	$0.4	$0.4	($0.1)
Feb	NA	NA	NA	$0.1	$0.1	($0.0)
Mar	NA	NA	NA	$0.4	$0.4	($0.1)
Apr	$2.0	$1.3	($0.7)	$0.5	$0.5	($0.1)
May	$6.0	$4.7	($1.3)	$1.6	$1.4	($0.1)
Jun	$3.5	$2.3	($1.3)	$0.7	$0.6	($0.1)
Jul	$2.1	$1.5	($0.6)	$1.9	$1.9	($0.1)
Aug	$1.7	$1.4	($0.4)	$1.7	$1.6	($0.1)
Sep	$2.2	$1.7	($0.5)	$4.7	$4.5	($0.2)
Oct	$1.8	$1.4	($0.4)			
Nov	$0.6	$0.5	($0.1)			
Dec	$0.7	$0.4	($0.2)			
Total	$20.6	$15.2	($5.4)	$12.1	$11.3	($0.8)

Table 4-39 shows day-ahead LOC credits calculated using intraday segments and LOC credits calculated on a daily basis. In 2018, LOC credits would have been $ 5.4 million or 14.3 percent lower if they were calculated on a daily basis. In the first nine months of 2019, LOC credits would have been $1.8 million or 14.9 percent lower if they were calculated on a daily basis.

Table 4-39 Five minute settlement and daily settlement of lost opportunity cost credits: January 2018 through September 2019

	2018 Day Ahead LOC Credits (Millions)			2019 Day Ahead LOC Credits (Millions)		
	Intraday Segments Calculation	Daily Calculation	Difference	Intraday Segments Calculation	Daily Calculation	Difference
Jan	$13.7	$11.0	($2.8)	$0.4	$0.3	($0.1)
Feb	$0.1	$0.1	($0.0)	$0.1	$0.1	($0.0)
Mar	$3.1	$2.6	($0.5)	$0.4	$0.3	($0.1)
Apr	$2.0	$1.9	($0.1)	$0.5	$0.4	($0.2)
May	$6.0	$5.5	($0.5)	$1.6	$1.2	($0.3)
Jun	$3.5	$3.0	($0.5)	$0.7	$0.5	($0.2)
Jul	$2.1	$1.8	($0.3)	$1.9	$1.7	($0.2)
Aug	$1.7	$1.6	($0.2)	$1.7	$1.6	($0.1)
Sep	$2.2	$2.0	($0.2)	$4.7	$4.2	($0.5)
Oct	$1.8	$1.6	($0.2)			
Nov	$0.6	$0.5	($0.0)			
Dec	$0.7	$0.6	($0.1)			
Total (Jan - Sep)	$34.6	$29.5	($5.1)	$12.1	$10.3	($1.8)
Total	$37.6	$32.2	($5.4)	$12.1	$10.3	($1.8)

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, including supply, demand, concentration ratios, pivotal suppliers, volumes, prices, outage rates and reliability.[1] The conclusions are a result of the MMU's evaluation of the last Base Residual Auction, for the 2021/2022 Delivery Year.

Table 5-1 The capacity market results were not competitive

Market Element	Evaluation	Market Design
Market Structure: Aggregate Market	Not Competitive	
Market Structure: Local Market	Not Competitive	
Participant Behavior	Not Competitive	
Market Performance	**Not 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] Structural market power is endemic to the capacity market.
- 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 not competitive in the 2021/2022 RPM Base Residual Auction. 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. In the 2021/2022 RPM Base Residual Auction, some participants' offers were above the competitive level. The MMU recognizes that these market participants followed the capacity market rules by offering at less than the stated offer cap of Net CONE times B. But Net CONE times B is not a competitive offer when the expected number of performance assessment intervals is zero or a very small number and the non-performance charge rate is defined as Net CONE/30. Under these circumstances, a competitive offer, under the logic defined in PJM's capacity performance filing, is net ACR. That is the way in which most market participants offered in this and prior capacity performance auctions.
- Market performance was evaluated as not competitive based on the 2021/2022 RPM Base Residual Auction. Although structural market power exists in the Capacity Market, a competitive outcome can result from the application of market power mitigation rules. The outcome of the 2021/2022 RPM Base Residual Auction was not competitive as a result of participant behavior which was not competitive, specifically offers which exceeded the competitive level.
- 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, the inclusion of imports which are not substitutes for internal capacity resources, and the definition of the default offer cap.

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. In the 2021/2022 RPM First Incremental Auction, two participants in the incremental supply in EMAAC passed the TPS test.

Overview

RPM Capacity Market

Market Design

The Reliability Pricing Model (RPM) Capacity Market is a forward-looking, annual, locational market, with a must offer requirement for Existing Generation Capacity Resources and mandatory participation by load, with performance incentives, that includes clear market power mitigation rules and that permits the direct participation of demand-side resources.[4]

Under RPM, capacity obligations are annual. Base Residual Auctions (BRA) are held for delivery years that are three years in the future. Effective with the 2012/2013 Delivery Year, First, Second and Third Incremental Auctions (IA) are held for each delivery year.[5] Prior to the 2012/2013 Delivery Year, the Second Incremental Auction was conducted if PJM determined that an unforced capacity resource shortage exceeded 100 MW of unforced capacity due to a load forecast increase. Effective January 31, 2010, First, Second, and Third Incremental Auctions are conducted 20, 10, and three months prior to the delivery year.[6] Also effective for the 2012/2013 Delivery Year, a Conditional 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 2019/2020 RPM Third Incremental Auction, the 2020/2021 RPM Second Incremental Auction, and the 2021/2022 RPM First Incremental Auction were conducted in the first nine months of 2019. FERC granted PJM's request for waiver of its Open Access Transmission Tariff to delay the 2022/2023 RPM Base Residual Auction from May 2019 to August 2019.[8] FERC subsequently denied PJM's motion seeking clarification of the June 29, 2018, Order (163 FERC ¶ 61,236) and directed PJM not to run the 2022/2023 BRA in August 2019.[9]

On June 9, 2015, FERC accepted changes to the PJM capacity market rules proposed in PJM's Capacity Performance (CP) filing.[10] For a transition period during the 2018/2019 and 2019/2020 delivery years, PJM will procure two product types, Capacity Performance and Base Capacity. PJM also procured Capacity Performance resources in two transition auctions for 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.[11] Effective for the 2018/2019 through the 2019/2020 delivery years, a Base Capacity Demand Resource Constraint and a Base Capacity Resource Constraint are established for each modeled LDA. These maximum quantities are set for reliability purpose to limit the quantity procured of the less available products, including Base Capacity Generation Resources, Base Capacity Demand Resources, and Base Capacity Energy Efficiency Resources. 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.[12] Existing generation capable of qualifying as a capacity resource must be offered into RPM auctions, except for resources owned by entities that elect the fixed resource requirement (FRR) option. Participation by LSEs is mandatory, except for those entities that elect the FRR option. There is an administratively determined demand curve that defines scarcity pricing levels and that, with the supply curve derived from capacity offers, determines market prices in each BRA. RPM rules provide performance incentives for

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 at P 86 (2009).
6 See Letter Order, FERC Docket No. ER10-366-000 (January 22, 2010).
7 See 126 FERC ¶ 61,275 at P 88 (2009).
8 See 164 FERC ¶ 61,153 (2018).
9 See 168 FERC ¶ 61,051 (2019).

10 See 151 FERC ¶ 61,208 (2015).
11 See "PJM Manual 18: PJM Capacity Market," § 1.5 Transition to Capacity Performance, Rev. 42 (July 25, 2019).
12 Transmission constraints are local capacity import capability limitations (low capacity emergency transfer limit (CETL) margin over capacity emergency transfer objective (CETO)) caused by transmission facility limitations, voltage limitations or stability limitations.

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. Market power mitigation is effective only when these definitions are up to date and accurate. Demand resources and energy efficiency resources may be offered directly into RPM auctions and receive the clearing price without mitigation.

Market Structure

- **RPM Installed Capacity.** During the first nine months of 2019, RPM installed capacity increased 6.8 MW or 0.0 percent, from 186,496.1 MW on January 1 to 186,502.9 MW on September 30. Installed capacity includes net capacity imports and exports and can vary on a daily basis.
- **RPM Installed Capacity by Fuel Type.** Of the total installed capacity on September 30, 2019, 42.1 percent was gas; 31.0 percent was coal; 17.3 percent was nuclear; 4.8 percent was hydroelectric; 3.4 percent was oil; 0.6 percent was wind; 0.4 percent was solid waste; and 0.4 percent was solar.
- **Market Concentration.** In the 2020/2021 RPM Second Incremental Auction all participants in the total PJM market as well as the LDA RPM markets failed the three pivotal supplier (TPS) test.[13] In the 2021/2022 RPM First Incremental Auction, two participants in the EMAAC LDA market passed the TPS test. Offer caps were applied to all sell offers for resources which were subject to mitigation when the capacity market seller did not pass the test, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, increased the market clearing price.[14 15 16]
- **Imports and Exports.** Of the 4,470.4 MW of imports in the 2021/2022 RPM Base Residual Auction, 4,051.8 MW cleared. Of the cleared imports, 1,909.9 MW (47.1 percent) were from MISO.
- **Demand-Side and Energy Efficiency Resources.** Capacity in the RPM load management programs was 11,042.8 MW for June 1, 2019, as a result of cleared capacity for demand resources and energy efficiency resources in RPM auctions for the 2019/2020 Delivery Year (13,231.6 MW) less replacement capacity (2,188.8 MW).

Market Conduct

- **2020/2021 RPM Second Incremental Auction.** Of the 464 generation resources that submitted Capacity Performance offers, unit specific offer caps were calculated for six generation resources (1.3 percent).
- **2021/2022 RPM First Incremental Auction.** Of the 301 generation resources that submitted Capacity Performance offers, unit specific offer caps were calculated for zero generation resources (0.0 percent).

Market Performance

- The 2019/2020 RPM Third Incremental Auction, the 2020/2021 RPM Second Incremental Auction, and the 2021/2022 RPM First Incremental Auction were conducted in the first nine months of 2019.[17] The weighted average capacity price for the 2018/2019 Delivery Year is $172.09 per MW-day, including all RPM auctions for the 2018/2019 Delivery Year. The weighted average capacity price for the 2019/2020 Delivery Year

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

14 See OATT Attachment DD § 6.5.

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

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

17 FERC granted PJM's request for waiver of its Open Access Transmission Tariff to delay the 2022/2023 RPM Base Residual Auction from May 2019 to August 2019. See 164 FERC ¶ 61,153 (2018). FERC subsequently denied PJM's motion seeking clarification of the June 29, 2018, Order (163 FERC ¶ 61,236) and directed PJM not to run the 2022/2023 BRA in August 2019. See 168 FERC ¶ 61,051 (2019).

is $109.82 per MW-day, including all RPM auctions for the 2019/2020 Delivery Year.

- For the 2019/2020 Delivery Year, RPM annual charges to load are $7.0 billion.
- In the 2021/2022 RPM Base Residual Auction, market performance was determined to be not competitive as a result of noncompetitive offers that affected market results.

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 the first nine months of 2019 was 6.8 percent, a decrease from 7.3 percent for the first nine months of 2018.[18]
- **Generator Performance Factors.** The PJM aggregate equivalent availability factor for the first nine months of 2019 was 84.7 percent, a slight increase from 84.6 percent for the first nine months of 2018.

Recommendations[19]

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.[20]

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.[21] [22] (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that DR providers be required to have a signed contract with specific customers for specific facilities for specific levels of DR at least six months prior to any capacity auction in which the DR is offered. (Priority: High. First reported 2016. Status: Not adopted.)

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.[23] [24] 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.)

18 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 November 1, 2019. 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.

19 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.

20 151 FERC ¶ 61,208 (2015).

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

22 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2019," <http://www.monitoringanalytics.com/reports/Reports/2019/IMM_Analysis_of_Replacement_Capacity_for_RPM_Commitments_June_1_2007_to_June_1_2019_20190913.pdf> (September 13, 2019).

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

24 See the 2017 State of the Market Report for PJM, Volume 2, Section 7: Net Revenue.

- 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. 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 2017. Status: Not adopted.)
- 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 2017. Status: Not adopted.)
- The MMU recommends that the maximum price on the VRR curve be defined as net CONE. (Priority: Medium. First reported Q1, 2019. Status: Not adopted.)

Offer Caps, Offer Floors, and Must Offer

- The MMU recommends use of the Sustainable Market Rule (SMR) in order to protect competition in the capacity market from nonmarket revenues.[25] (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.[26] (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 2017. Status: Not adopted.)
- The MMU recommends that the offer cap for capacity resources be defined as the net avoidable cost rate (ACR) of each unit so that the clearing prices are a result of such net ACR offers, consistent with the fundamental

25 Brief of the Independent Market Monitor for PJM, Docket No. EL16-49, ER18-1314-000,-001; EL18-178 (October 2, 2018).

26 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).

economic logic for a competitive offer of a CP resource. (Priority: High. First reported 2017. Status: Not adopted.)

- The MMU recommends that PJM develop a process for calculating a forward looking estimate for the expected number of Performance Assessment Intervals (H) to use in calculating the Market Seller Offer Cap (MSOC). The MMU recommends that the Nonperformance Charge Rate be left at its current level. The MMU recommends that PJM develop a forward looking estimate for the Balancing Ratio (B) during Performance Assessment Intervals (PAIs) to use in calculating the MSOC. Both H and B parameters should be included in the annual review of planning parameters for the Base Residual Auction, and should incorporate the actual observed reserve margins, and other assumptions consistent with the annual IRM study. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends that capacity market sellers be required to request the use of minimum MW quantities greater than 0 MW (inflexible sell offer segments) and that the requests should only be permitted for defined physical reasons. (Priority: Medium. First reported 2018. 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.)
- The MMU 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 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 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 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: Not 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. First reported 2017. 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. Market power is and will remain endemic to the structure of the PJM Capacity Market. Nonetheless a competitive outcome can be assured by appropriate market power mitigation rules.

The MMU concludes that the 2021/2022 RPM Base Residual Auction results were not competitive as a result of offers above the competitive level by some market participants. The MMU recognizes that these market participants followed the capacity market rules by offering at less than the stated offer cap of Net CONE times B. But Net CONE times B is not a competitive offer when the expected number of performance assessment intervals is zero or a very small number and the non-performance charge rate is defined as Net CONE/30. Under these circumstances, a competitive offer, under the logic defined in PJM's capacity performance filing, is net ACR. That is the way in which most market participants offered in this and prior capacity performance auctions.

FERC approved PJM tariff defines the offer cap as Net CONE times B, rather than including the full logic supporting the definition of the offer cap under the capacity performance paradigm. If the tariff had defined the offer cap consistent with PJM's filing in the capacity performance matter, the offer cap would have been net ACR rather than Net CONE times B.

The MMU is required to identify market issues and to report them to the Commission and to market participants. The Commission decides on any action related to the MMU's findings.

The MMU found serious market structure issues, measured by the three pivotal supplier test results in the PJM Capacity Market in the last BRA and in the first nine months of 2019. Explicit market power mitigation rules in the RPM construct only partially offset the underlying market structure issues in the PJM Capacity Market under RPM. In the 2021/2022 RPM Base Residual Auction, the default offer cap of net CONE times B exceeded the competitive offer for a number of resources. Some seasonal resources were paid additional make whole based on a failure of the market power rules to apply offer capping.

The MMU has identified serious market design issues with RPM and the MMU has made specific recommendations to address those issues.[27] [28] [29] [30] [31] [32] In 2018 and 2019, 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 continue to 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 had excess reserves of more than 11,000 ICAP MW on June 1, 2019, and will have excess reserves of more than 17,000 ICAP MW on June 1, 2020, based on current positions.[33] A majority of capacity investments in

27 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).
28 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).
29 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).
30 See "Analysis of the 2021/2022 RPM Base Residual Auction - Revised," <http://www.monitoringanalytics.com/reports/Reports/2018/IMM_Analysis_of_the_20212022_RPM_BRA_Revised_20180824.pdf> (August 24, 2018).
31 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).
32 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2019," <http://www.monitoringanalytics.com/reports/Reports/2019/IMM_Analysis_of_Replacement_Capacity_for_RPM_Commitments_June_1_2007_to_June_1_2019_20190913.pdf> (September 13, 2019).
33 The calculated reserve margin for June 1, 2020, does not account for cleared buy bids that have not been used in replacement capacity transactions.

PJM were financed by market sources.[34] Of the 36,859.2 MW of additional capacity that cleared in RPM auctions for the 2007/2008 through 2018/2019 delivery years, 27,306.6 MW (74.1 percent) were based on market funding. Of the 7,171.2 MW of additional capacity that cleared in RPM auctions for the 2019/2020 through 2021/2022 delivery years, 7,014.7 MW (97.8 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, particularly for economic nuclear power plants, continued to evolve. 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 legislation to subsidize both nuclear and coal plants and to eliminate the RPS, the Illinois ZEC legislation to subsidize the Quad Cities nuclear power plant and the requests for additional subsidies, the request in Pennsylvania to subsidize the Three Mile Island and other nuclear power plants, the New Jersey legislation to subsidize the Salem and Hope Creek nuclear power plants, the potential U.S. DOE proposal to subsidize coal and nuclear power plants, and the request by FirstEnergy to the U.S. DOE for subsidies consistent with the DOE Grid Resilience Proposal, 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.

Subsidies are contagious. Competition in the markets could be replaced and is now being 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. Competition to receive subsidies is now a reality and is accelerating in PJM.

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 competitive market participants 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. The MMU calls this approach the Sustainable Market Rule (SMR).[35] The SMR is fully consistent with the renewables targets of many states in the PJM footprint. The SMR is also consistent with incorporating economic nuclear power plants in the capacity market.

A sustainable competitive wholesale power market must recognize three salient structural elements: state nonmarket revenues for renewable energy; a significant level of generation resources subject to cost of service regulation; and the structure and performance of the existing market based generation fleet.

Subsidies to specific resources that are uneconomic as a result of competition are an effort to reverse market outcomes with no commitment to a regulatory model and no attempt to mitigate negative impacts on competition. The unit specific subsidy model is inconsistent with the PJM market design and

34 "PJM Generation and Funding Sources 2007/2008 through 2021/2022 Delivery Years," <http://www.monitoringanalytics.com/reports/Reports/2019/IMM_PJM_Generation_Capacity_and_Funding_Sources_20072008_through_20212022_Delivery_Years_20190912.pdf> (September 12, 2019).

35 The MMU filed several comments as well as a proposal summary in the Capacity Market Investigation focused on the Sustainable Market Rule (SMR) in Docket Nos. ER18-1314-000, -001, EL16-49-000, and EL18-178-000 (October 2, 2018; October 31, 2018; November 6, 2018). MMU filings are located at the Monitoring Analytics website at <http://www.monitoringanalytics.com/Filings/2018.shtml>.

inconsistent with the market paradigm and constitutes a significant threat to both.

The existing FRR approach remains an option for utilities with regulated revenues based on cost of service rates, including both privately and publicly owned (including public power entities and electric cooperatives) utilities. Such regulated utilities have had and continue to have the ability to opt out of the capacity market and provide their own capacity.

Given that states have increasingly aggressive renewable energy targets, a core goal of a competitive market design should be to ensure that the resources required to provide reliability receive appropriate competitive market incentives for entry and for ongoing investment and for exit when uneconomic. A significant level of renewable resources, operating with zero or near zero marginal costs, will result in very low energy prices. Since renewable resources are intermittent, the contribution of renewables to meeting reliability targets must be analyzed carefully to ensure that the capacity value is calculated correctly.

In order to attract and retain adequate resources for the reliable operation of the energy market, revenues from PJM energy, ancillary services and capacity markets must be adequate for those resources. That adequacy requires a capacity market. The capacity market plays the essential role of equilibrating the revenues necessary to incent competitive entry and exit of the resources needed for reliability, with the revenues from the energy market that are directly affected by nonmarket sources.

Price suppression below the competitive level in the capacity market should not be acceptable and is not consistent with a competitive market design. Harmonizing means that the integrity of each paradigm is maintained and respected. Harmonizing permits nonmarket resources to have an unlimited impact on energy markets and energy prices. Harmonizing means designing a capacity market to account for these energy market impacts, clearly limiting the impact of nonmarket revenues on the capacity market and ensuring competitive outcomes in the capacity market and thus in the entire market.

The expected impact of the SMR design on the offers and clearing of renewable resources and nuclear plants would be from zero to insignificant. The competitive offers of renewables, based on the net ACR of current technologies, are likely to clear in the capacity market. The competitive offers of nuclear plants, based on net ACR, are likely to clear in the capacity market.

Cost of service resources have the option of using the existing FRR rules, which would allow regulated utilities to opt out of the capacity market. The expected impact of the SMR design on the offers and clearing of regulated cost of service resources that remained in the capacity market would be from zero to insignificant. The competitive offers of these resources, based on net ACR, are likely to clear in the capacity market.

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/ISO 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: 2018 through September 2019

Date	Name
January 19, 2018	Analysis of Replacement Capacity for RPM Commitments http://www.monitoringanalytics.com/reports/Presentations/2018/IMM_IASTF_Analysis_of_Replacement_Capacity_for_RPM_Commitments_20180119.pdf
January 25, 2018	MOPR-Ex Main Motion http://www.monitoringanalytics.com/reports/Presentations/2018/IMM_MRC_MOPR-Ex_Main_Motion_20180125.pdf
January 25, 2018	MOPR-Ex Alternate Proposal http://www.monitoringanalytics.com/reports/Presentations/2018/IMM_MRC_MOPR-Ex_Alternate_Proposal_20180125.pdf
January 25, 2018	MOPR-Ex Memo http://www.monitoringanalytics.com/reports/Presentations/2018/IMM_MRC_MOPR-Ex_Memo_20180125.pdf
February 23, 2018	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/IMM_Notice_RPM_Must_Offer_Obligations_20180223.pdf
March 9, 2018	Generation Additions and Retirements in the PJM Capacity Market: MW and Funding Sources http://www.monitoringanalytics.com/reports/Reports/2018/IMM_Generation_Additions_and_Retirements_in_the_PJM_Capacity_Market_20180309.pdf
April 11, 2018	IMM Comments re Base Capacity Complaint Docket Nos. EL17-32 and EL17-36 http://www.monitoringanalytics.com/reports/Reports/2018/IMM_Comments_Docket_No_EL17-32_EL17-36_20180411.pdf
May 9, 2018	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2019/2020, 2020/2021 and 2021/2022 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/Messages/IMM_Notice_RPM_Must_Offer_Obligations_20180509.pdf
June 1, 2018	IMM CONE CT Study Results http://www.monitoringanalytics.com/reports/Presentations/2018/IMM_MIC_Quadrennial_Review_Special_Session_CONE_CT_Study_Results_20180601.pdf
June 7, 2018	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2019/2020, 2020/2021 and 2021/2022 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/Messages/IMM_Notice_RPM_Must_Offer_Obligations_20180706.pdf
June 13, 2018	IMM Post Technical Conf. Comments re Base Capacity Complaint Docket No. EL17-31, -36 http://www.monitoringanalytics.com/Filings/2018/IMM_Post_Tech_Conf_Comments_Docket_No_EL17-32_-36_20180713.pdf
June 22, 2018	IMM CONE CT Study Results http://www.monitoringanalytics.com/reports/Presentations/2018/IMM_MIC_Quadrennial_Review_Special_Session_CONE_CT_Study_Results_20180601.pdf
August 24, 2018	Analysis of the 2021/2022 RPM Base Residual Auction - Revised http://www.monitoringanalytics.com/reports/Reports/2018/IMM_Analysis_of_the_20212022_RPM_BRA_Revised_20180824.pdf
August 24, 2018	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2019/2020, 2020/2021 and 2021/2022 Delivery Years (PDF) http://www.monitoringanalytics.com/reports/Market_Messages/Messages/IMM_Notice_RPM_Must_Offer_Obligations_20180824.pdf
September 26, 2018	MOPR/FRR Sensitivity Analyses of the 2021/2022 RPM Base Residual Auction http://www.monitoringanalytics.com/reports/Reports/2018/IMM_MOPR_FRR_Sensitivity_Analyses_Report_20180926.pdf
October 2, 2018	IMM Brief re Capacity Market Investigation Docket Nos. EL16-49-000,ER18-1314-000,-001, EL18-178 http://www.monitoringanalytics.com/Filings/2018/IMM_Brief_Docket_No_EL16-49_EL18-178_ER18-1314_20181002.pdf
October 22, 2018	IMM Comments re NJ ZECs Docket No. EO18080899 http://www.monitoringanalytics.com/Filings/2018/IMM_Comments_Docket_No_EO18080899_20181022.pdf
October 23, 2018	IMM Notice of Withdrawal re Fairless MOPR Docket No. EL17-82 http://www.monitoringanalytics.com/Filings/2018/IMM_Notice_of_Withdrawal_Docket_No_EL17-82_20181023.pdf
October 31, 2018	IMM Summary of Position re Capacity Market Investigation Docket Nos. EL18-178, ER18-1314-000,-001, EL16-49 http://www.monitoringanalytics.com/Filings/2018/IMM_Summary_of_Position_Docket_No__EL18-178_ER18-1314_EL16-49.pdf
November 6, 2018	IMM Brief re Capacity Market Investigation Docket Nos. EL18-178, ER18-1314-000,-001, EL16-49 http://www.monitoringanalytics.com/Filings/2018/IMM_Reply_Brief_Docket_No_EL18-178_ER18-1314-000_001_EL16-49_20181106.pdf
November 19, 2018	IMM Protest re Quadrennial Review Docket No. ER19-105 http://www.monitoringanalytics.com/Filings/2018/IMM_Protest_Docket_No_ER19-105_20181119.pdf
November 19, 2018	IMM Protest re Maintenance Adders Docket No. ER19-210 http://www.monitoringanalytics.com/Filings/2018/IMM_Protest_Docket_No_ER19-210_20181119.pdf
December 21, 2018	IMM Answer and Motion for Leave to Answer re VOM Complaint and Maintenance Adder Docket No. EL19-8, ER19-210 http://www.monitoringanalytics.com/Filings/2018/IMM_Answer_Docket_Nos_EL19-8_ER19-210_20181221.pdf
December 31, 2018	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2019/2020, 2020/2021 and 2021/2022 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/Messages/RPM_Must_Offer_Obligation_20181231.pdf
February 21, 2019	IMM Complaint re CONE x B Offers Docket No. EL19-xxx http://www.monitoringanalytics.com/Filings/2019/IMM_Complaint_Docket_No_EL19-XXX_20190221.pdf
February 22, 2019	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2019/2020, 2020/2021 and 2021/2022 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/Messages/RPM_Must_Offer_Obligation_20190222.pdf
April 2, 2019	IMM Comments re ACR Review Waiver Docket No. ER19-1404 http://www.monitoringanalytics.com/Filings/2019/IMM_Comments_Docket_No_ER19-1404_20190402.pdf
April 10, 2019	IMM Answer and Motion for Leave to Answer re Cube Yadkin Complaint Docket No. EL19-51 http://www.monitoringanalytics.com/Filings/2019/IMM_Answer_Docket_No_EL19-51_20190410.pdf
April 11, 2019	IMM Answer re Brookfield Energy Complaint Docket No. EL19-34 http://www.monitoringanalytics.com/Filings/2019/IMM_Answer_Docket%20No.%20EL19-34_20190411.pdf
April 30, 2019	IMM Answer Re CONE x B Offers Docket No. EL19-47 http://www.monitoringanalytics.com/Filings/2019/IMM_Answer_Docket_No_EL19-47_20190430.pdf
May 24, 2019	IMM Answer to PJM re MSOC Docket No. EL19-47, EL19-63 http://www.monitoringanalytics.com/Filings/2019/IMM_Answer_to_PJM_EL19-47_-63_20190524.pdf
June 28, 2019	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2020/2021, 2021/2022 and 2022/2023 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/Messages/RPM_Must_Offer_Obligation_20190628.pdf
August 23, 2019	IMM Answer re Capacity Resources and Must Offer Exception Process Docket No. ER19-2417 http://www.monitoringanalytics.com/Filings/2019/IMM_Answer_Docket_No_ER19-2417_20190823.pdf
September 6, 2019	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2020/2021, 2021/2022 and 2022/2023 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/Messages/RPM_Must_Offer_Obligations_20190906.pdf
September 12, 2019	PJM Generation Capacity and Funding Sources 2007/2008 through 2021/2022 Delivery Years http://www.monitoringanalytics.com/reports/Reports/2019/IMM_PJM_Generation_Capacity_and_Funding_Sources_20072008_through_20212022_Delivery_Years_20190912.pdf
September 13, 2019	Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2019 http://www.monitoringanalytics.com/reports/Reports/2019/IMM_Analysis_of_Replacement_Capacity_for_RPM_Commitments_June_1_2007_to_June_1_2019_20190913.pdf

Installed Capacity

On January 1, 2019, RPM installed capacity was 186,496.1 MW (Table 5-3).[36] Over the next nine months, new generation, unit deactivations, facility reratings, plus import and export shifts resulted in RPM installed capacity of 186,502.9 MW on September 30, 2019, an increase of 6.8 MW or 0.0 percent from the January 1 level.[37] [38] The 6.8 MW increase was the result of new or reactivated generation (3,601.7 MW), uprates (467.5 MW), and an increase in imports (0.4 MW), offset by deactivations (3,922.5 MW), derates (138.7 MW) and an increase in exports (1.6 MW).

At the beginning of the new delivery year on June 1, 2019, RPM installed capacity was 187,322.6 MW, an increase of 1,944.6 MW or 1.0 percent from the May 31, 2019, level of 185,378.0 MW.

Table 5-3 Installed capacity (By fuel source): January 1, May 31, June 1, and September 30, 2019[39]

	01-Jan-19		31-May-19		01-Jun-19		30-Sep-19	
	MW	Percent	MW	Percent	MW	Percent	MW	Percent
Coal	60,763.4	32.6%	58,833.6	31.7%	58,043.9	31.0%	57,877.0	31.0%
Gas	75,261.2	40.4%	75,770.8	40.9%	78,475.8	41.9%	78,477.3	42.1%
Hydroelectric	8,888.2	4.8%	8,873.9	4.8%	8,873.9	4.7%	8,873.9	4.8%
Nuclear	32,684.5	17.5%	33,000.7	17.8%	33,001.7	17.6%	32,297.9	17.3%
Oil	6,388.2	3.4%	6,342.2	3.4%	6,330.2	3.4%	6,331.6	3.4%
Solar	640.0	0.3%	686.2	0.4%	702.6	0.4%	757.4	0.4%
Solid waste	712.3	0.4%	712.3	0.4%	702.3	0.4%	695.6	0.4%
Wind	1,158.3	0.6%	1,158.3	0.6%	1,192.2	0.6%	1,192.2	0.6%
Total	186,496.1	100.0%	185,378.0	100.0%	187,322.6	100.0%	186,502.9	100.0%

36 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.

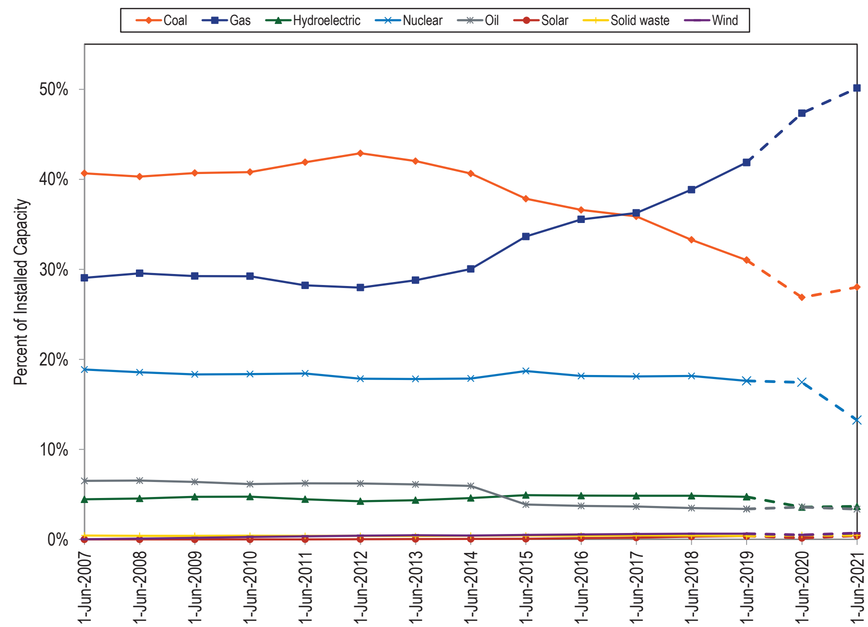
37 Unless otherwise specified, the capacity described in this section is the summer installed capacity rating of all PJM generation capacity resources, as entered into the Capacity Exchange system, regardless of whether the capacity cleared in the RPM auctions.

38 Wind resources accounted for 1,192.2 MW, and solar resources accounted for 757.4 MW of installed capacity in PJM on September 30, 2019. PJM administratively reduces the capabilities of all wind generators to 14.7 percent for wind farms in mountainous terrain and 17.6 percent for wind farms in open terrain, and solar generators to 42.0 percent for ground mounted fixed panel, 60.0 percent for ground mounted tracking panel, and 38.0 percent for other than ground mounted solar arrays, 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," Appendix B.3 Calculation Procedure, Rev. 14 (Aug. 1, 2019).

39 The reported ICAP MW for May 31, 2019, and June 1, 2019, were revised from the 2019 Quarterly State of the Market Report for PJM: January through June.

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, 2019, as well as the expected installed capacity for the next two delivery years, based on the results of all auctions held through September 30, 2019.[40] On June 1, 2007, coal comprised 40.7 percent of the installed capacity, reached a maximum of 42.9 percent in 2012, decreased to 31.0 percent on June 1, 2019 and is projected to decrease to 28.2 percent by June 1, 2021. The share of gas increased from 29.1 percent in 2007 to 41.9 percent in 2019 and is projected to increase to 50.3 percent in 2021.

Figure 5-1 Percent of installed capacity (By fuel source): June 1, 2007 through June 1, 2021



40 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 5-4 shows the RPM installed capacity on January 1, 2019, through September 30, 2019, for the top five generation capacity resource owners, excluding FRR committed MW.

Table 5-4 Installed capacity by parent company: January 1, May 31, June 1, and September 30, 2019[41]

	01-Jan-19			31-May-19			01-Jun-19			30-Sep-19		
Parent Company	ICAP (MW)	Percent of Total ICAP	Rank	ICAP (MW)	Percent of Total ICAP	Rank	ICAP (MW)	Percent of Total ICAP	Rank	ICAP (MW)	Percent of Total ICAP	Rank
Exelon Corporation	22,819.1	13.3%	1	22,789.4	13.3%	1	22,691.5	13.1%	1	21,984.0	12.8%	1
Dominion Resources, Inc.	20,388.9	11.8%	2	20,180.7	11.8%	2	20,143.7	11.6%	2	20,198.5	11.7%	2
FirstEnergy Corp.	14,644.0	8.5%	3	12,495.3	7.3%	3	12,489.3	7.2%	3	12,489.3	7.3%	3
Vistra Energy Corp.	12,082.3	7.0%	4	12,082.0	7.1%	4	12,187.0	7.0%	4	12,187.0	7.1%	4
Talen Energy Corporation	10,959.3	6.4%	5	10,964.0	6.4%	5	10,964.6	6.3%	5	10,964.6	6.4%	5

The sources of funding for generation owners can be categorized as one of two types: market and nonmarket. Market funding is from private investors bearing the investment risk without guarantees or support from any public sources, subsidies or guaranteed payment by ratepayers. Providers of market funding rely entirely on market revenues. Nonmarket funding is from guaranteed revenues, including cost of service rates for a regulated utility and subsidies. Table 5-5 shows the RPM installed capacity on January 1, 2019, to September 30, 2019, by funding type.

Table 5-5 Installed capacity by funding type: January 1, May 31, June 1, and September 30, 2019

	01-Jan-19		31-May-19		01-Jun-19		30-Sep-19	
Funding Type	ICAP (MW)	Percent of Total ICAP	ICAP (MW)	Percent of Total ICAP	ICAP (MW)	Percent of Total ICAP	ICAP (MW)	Percent of Total ICAP
Market	153,676.9	82.4%	152,777.4	82.4%	154,892.6	82.7%	154,018.1	82.6%
Nonmarket	32,819.2	17.6%	32,600.6	17.6%	32,430.0	17.3%	32,484.8	17.4%
Total	186,496.1	100.0%	185,378.0	100.0%	187,322.6	100.0%	186,502.9	100.0%

41 The reported ICAP MW for May 31, 2019, and June 1, 2019, were revised from the 2019 Quarterly State of the Market Report for PJM: January through June.

Fuel Diversity

Figure 5-2 shows the fuel diversity index (FDI_c) for RPM installed capacity.[42] 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.[43] 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.[44] The average FDI_c for the first nine months of 2019 decreased 0.8 percent from the first nine months of 2018. Figure 5-2 also includes the expected FDI_c through June 2021 based on cleared 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. There are 16 capacity resources with installed capacity totaling 12,017 MW identified as being at risk of retirement.[45] Generation owners that intend to retire a generator are required by the tariff to notify PJM at least 90 days in advance

42 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.

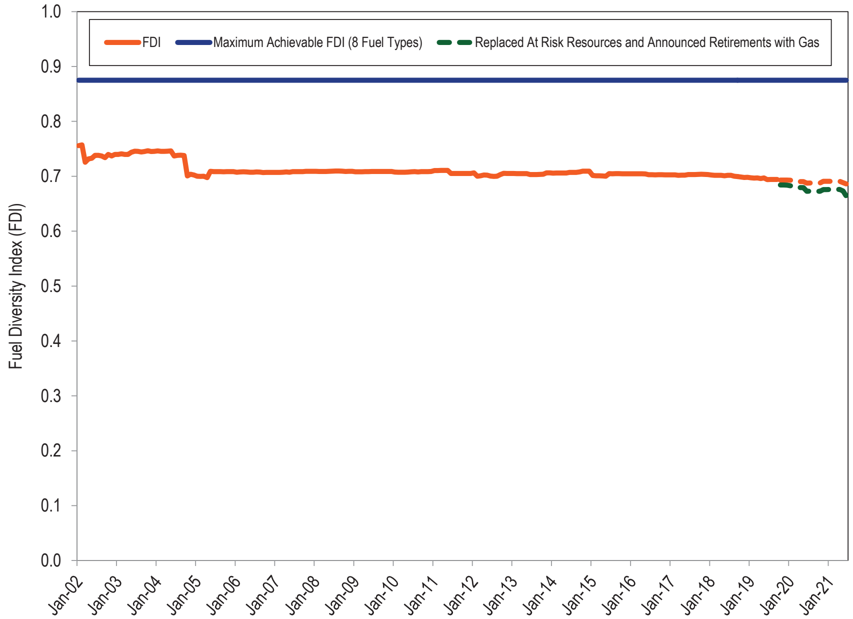
43 On April 1, 2002, the PJM Region expanded with the addition of Allegheny Power System under a set of agreements known as "PJM-West." See page 4 in the 2002 State of the Market Report for PJM for additional details.

44 See the 2018 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.

45 See the 2018 State of the Market Report for PJM, Section 7: Net Revenue, Units at Risk. The list of at risk units has been updated to reflect the subsidies included in Ohio HB 6 which was passed by the Ohio legislature on July 23, 2019 <https://www.legislature.ohio.gov/legislation/legislation-summary?id=GA133-HB-6>.

of the retirement.[46] There are 8,093.7 MW of generation that have a requested retirement date after September 30, 2019.[47] Generation owners of three of the at risk capacity resources have provided notice of their intent to deactivate the generators. The dashed green line in Figure 5-2 shows the FDI_c calculated assuming that the capacity that cleared in an RPM auction from the at risk resources and other resources with deactivation notices is replaced by gas generation.[48] The FDI_c under these assumptions would decrease by 1.9 percent on average from the expected FDI_c for the period October 1, 2019, through June 1, 2021.

Figure 5-2 Fuel Diversity Index for installed capacity: January 1, 2002 through June 1, 2021



46 See OATT Part V § 113.1.
47 See PJM Future Deactivations, <https://www.pjm.com/planning/services-requests/gen-deactivations.aspx> (Accessed October 1, 2019).
48 For this analysis resources for which PJM has received deactivation notifications were replaced with gas capacity beginning on the projected retirement date listed in the deactivation data. At risk resources that have not notified PJM regarding deactivation were replaced with gas capacity beginning on October 1, 2019.

RPM Capacity Market

The RPM Capacity Market, implemented June 1, 2007, is a forward-looking, annual, locational market, with a must-offer requirement for Existing Generation Capacity Resources and mandatory participation by load, with performance incentives, that includes clear market power mitigation rules and that permits the direct participation of demand-side resources.

Annual base auctions are held in May for delivery years that are three years in the future. Effective January 31, 2010, First, Second, and Third Incremental Auctions are conducted 20, 10, and three months prior to the delivery year.[49] In the first nine months of 2019, the 2019/2020 RPM Third Incremental Auction, the 2020/2021 RPM Second Incremental Auction, and the 2021/2022 RPM First Incremental Auction were conducted.[50]

Market Structure

Supply

Table 5-6 shows generation capacity changes since the implementation of the Reliability Pricing Model through the 2018/2019 Delivery Year. The 21,718.6 MW increase was the result of new generation capacity resources (29,002.4 MW), reactivated generation capacity resources (1,349.5 MW), uprates (6,507.3 MW), integration of external zones (21,802.5 MW), a net increase in capacity imports (183.0 MW), a net decrease in capacity exports (2,306.5 MW), offset by deactivations (36,104.0 MW) and derates (3,328.6 MW).

Table 5-7 shows the calculated RPM reserve margin and reserve in excess of the defined installed reserve margin (IRM) for June 1, 2016, through June 1, 2021, and accounts for cleared capacity, replacement capacity, and deficiency MW for all auctions held and the most recent peak load forecast for each delivery year. The completion of the replacement process using cleared buy bids from RPM incremental auctions includes two transactions. The first step is for the entity to submit and clear a buy bid in an RPM incremental auction.

49 See PJM Interconnection, L.L.C., Letter Order in Docket No. ER10-366-000 (January 22, 2010).
50 FERC granted PJM's request for waiver of its Open Access Transmission Tariff to delay the 2022/2023 RPM Base Residual Auction from May 2019 to August 2019. See 164 FERC ¶ 61,153 (2018). FERC subsequently denied PJM's motion seeking clarification of the June 29, 2018, Order (163 FERC ¶ 61,236) and directed PJM not to run the 2022/2023 BRA in August 2019. See 168 FERC ¶ 61,051 (2019).

The next step is for the entity to complete a separate replacement transaction using the cleared buy bid capacity. Without an approved early replacement transaction requested for defined physical reasons, replacement capacity transactions can be completed only after the EFORds for the delivery year are finalized, on November 30 in the year prior to the delivery year, but before the start of the delivery day. The calculated reserve margins for June 1, 2020, and June 1, 2021, do not account for cleared buy bids that have not been used in replacement capacity transactions. The projected reserve margins for June 1, 2020, and June 1, 2021, account for projected replacement capacity using cleared buy bids by applying the rate at which historical buy bids have been used.

Future Changes in Generation Capacity[51]

As shown in Table 5-6, for the period from the introduction of the RPM capacity market design in the 2007/2008 Delivery Year through the 2018/2019 Delivery Year, internal installed capacity decreased by 2,573.4 MW after accounting for new capacity resources, reactivations, and uprates (36,859.2 MW) and capacity deactivations and derates (39,432.6 MW).

For the current and future delivery years (2019/2020 through 2021/2022), new generation capacity is defined as capacity that cleared an RPM auction for the first time in the specified DY. Based on expected completion rates of cleared new generation capacity (6,055.6 MW) and pending deactivations (5,977.8 MW), PJM capacity is expected to increase by 77.8 MW for the 2019/2020 through 2021/2022 Delivery Years.

Table 5-6 Generation capacity changes: 2007/2008 through 2018/2019[52]

	ICAP (MW)								
	New	Reactivations	Uprates	Integration	Net Change in Capacity Imports	Net Change in Capacity Exports	Deactivations	Derates	Net Change
2007/2008	45.0	0.0	691.5	0.0	70.0	15.3	380.0	417.0	(5.8)
2008/2009	815.4	238.3	987.0	0.0	473.0	(9.9)	609.5	421.0	1,493.1
2009/2010	406.5	0.0	789.0	0.0	229.0	(1,402.2)	108.4	464.3	2,254.0
2010/2011	153.4	13.0	339.6	0.0	137.0	367.7	840.6	223.5	(788.8)
2011/2012	3,096.4	354.5	507.9	16,889.5	(1,183.3)	(1,690.3)	2,542.0	176.2	18,637.1
2012/2013	1,784.6	34.0	528.1	47.0	342.4	95.0	5,536.0	317.8	(3,212.7)
2013/2014	198.4	58.0	372.8	2,746.0	934.3	17.9	2,786.9	288.3	1,216.4
2014/2015	2,276.8	20.7	530.2	0.0	2,335.7	177.3	4,915.6	360.3	(289.8)
2015/2016	4,291.8	90.0	449.0	0.0	511.4	(117.8)	8,338.2	215.8	(3,094.0)
2016/2017	3,679.3	532.0	419.2	0.0	575.6	722.9	659.4	206.7	3,617.1
2017/2018	4,127.3	5.0	562.1	0.0	(1,025.1)	(695.1)	2,657.4	148.5	1,558.5
2018/2019	8,127.5	4.0	330.9	2,120.0	(3,217.0)	212.7	6,730.0	89.2	333.5
Total	29,002.4	1,349.5	6,507.3	21,802.5	183.0	(2,306.5)	36,104.0	3,328.6	21,718.6

51 For more details on future changes in generation capacity, see "PJM Generation and Funding Sources 2007/2008 through 2021/2022 Delivery Years," <http://www.monitoringanalytics.com/reports/Reports/2019/IMM_PJM_Generation_Capacity_and_Funding_Sources_20072008_through_20212022_Delivery_Years_20190912.pdf> (September 12, 2019).

52 The calculation of capacity changes were revised from the **2019 Quarterly State of the Market Report for PJM: January through June**. The capacity changes in this report are calculated based on June 1 through May 31. The capacity changes were previously calculated based on June 2 through June 1.

Table 5-7 RPM reserve margin: June 1, 2016, to June 1, 2021[53] [54]

	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		Projected Replacement Capacity using Cleared Buy Bids UCAP (MW)	Projected Reserve Margin
										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	0.0	22.3%
01-Jun-17	163,872.0	153,230.1	12,837.5	0.0	140,392.6	16.6%	5.94%	174,220.7	24.1%	7.5%	10,522.9	0.0	24.1%
01-Jun-18	161,242.6	152,407.9	12,732.9	0.0	139,675.0	16.1%	6.07%	171,662.5	22.9%	6.8%	9,499.8	0.0	22.9%
01-Jun-19	162,276.1	151,643.5	12,284.2	0.0	139,359.3	16.0%	6.08%	172,781.2	24.0%	8.0%	11,124.4	0.0	24.0%
01-Jun-20	167,273.9	151,155.1	11,930.9	558.0	138,666.2	15.9%	6.04%	178,026.7	28.4%	12.5%	17,312.6	5,299.2	24.3%
01-Jun-21	162,632.9	151,832.3	11,982.6	510.0	139,339.7	15.8%	6.01%	173,032.1	24.2%	8.4%	11,676.8	1,906.3	22.7%

Sources of Funding[55]

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 and reactivated generation capacity from the 2007/2008 DY through the 2018/2019 DY totaled 30,351.9 MW (82.3 percent of all additions), with 22,277.9 MW from market funding and 8,074.0 MW from nonmarket funding. Uprates to existing generation capacity from the 2007/2008 DY through the 2018/2019 DY totaled 6,507.3 MW (17.7 percent of all additions), with 5,028.7 MW from market funding and 1,478.6 MW from nonmarket funding. In summary, of the 36,859.2 MW of additional capacity from new, reactivated, and uprated generation that cleared in RPM auctions for the 2007/2008 through 2018/2019 delivery years, 27,306.6 MW (74.1 percent) were based on market funding.

Of the 7,171.2 MW of the additional generation capacity (new resources, reactivated resources, and uprates) that cleared in RPM auctions for the 2019/2020 through 2021/2022 delivery years, 4,418.3 MW are not yet in service. Of those 4,418.3 MW that have not yet gone into service, 4,329.9 MW have market funding and 88.4 MW have nonmarket funding. Applying the historical completion rates, 74.8 percent of all the projects in development are expected to go into service (3,236.6 MW of the 4,329.9 MW of market funded projects; 66.1 MW of the 88.4 MW of nonmarket funded projects). Together, 3,302.7 MW of the 4,418.3 MW of new generation capacity that cleared MW in RPM and are not yet in service are expected to go into service through the 2021/2022 Delivery Year.

Of the 2,752.9 MW of the additional generation capacity that cleared in RPM auctions for the 2019/2020 through 2021/2022 delivery years and are already in service, 2,684.8 MW (97.5 percent) are based on market funding and 68.1 MW (2.5 percent) are based on nonmarket funding. In summary, 7,014.7 MW (97.8 percent) of the additional generation capacity (2,684.8 MW in service and 4,329.9 MW not yet in service) that cleared in RPM auctions for the 2019/2020 through 2021/2022 delivery years are based on market funding. Capacity additions based on nonmarket funding are 156.5 MW (2.2 percent) of proposed generation that cleared at least one RPM auction for the 2019/2020 through 2021/2022 delivery years.

53 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.

54 These reserve margin calculations do not consider Fixed Resource Requirement (FRR) load.

55 For more details on sources of funding for generation capacity, see "PJM Generation Capacity and Funding Sources 2007/2008 through 2021/2022 Delivery Years," <http://www.monitoringanalytics.com/reports/Reports/2019/IMM_PJM_Generation_Capacity_and_Funding_Sources_20072008_through_20212022_Delivery_Years_20190912.pdf> (September 12, 2019).

Demand

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:

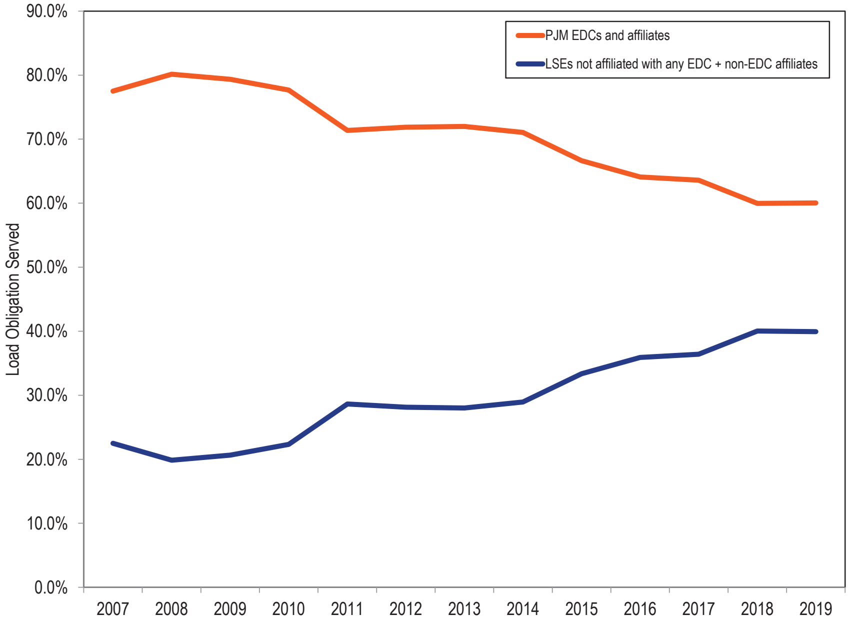
- **PJM EDC.** EDCs with a franchise service territory within the PJM footprint. This sector includes traditional utilities, electric cooperatives, municipalities and power agencies.
- **PJM EDC Generating Affiliate.** Affiliate companies of PJM EDCs that own generating resources.
- **PJM EDC Marketing 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, 2019, PJM EDCs and their affiliates maintained a large market share of load obligations under RPM, together totaling 60.1 percent (Table 5-8), up from 60.0 percent on June 1, 2018. The combined market share of LSEs not affiliated with any EDC and of non-PJM EDC affiliates was 39.9 percent, down from 40.0 percent on June 1, 2018. 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, 2019, 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 60.1 percent on June 1, 2019. 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 39.9 percent on June 1, 2019. Prior to the 2012/2013 Delivery Year, obligation was defined as cleared and make whole MW in the Base Residual Auction and the Second Incremental Auction plus ILR forecast obligations. Effective with the 2012/2013 Delivery Year, obligation is defined as the sum of the unforced capacity obligations satisfied through all RPM auctions for the delivery year.

Table 5-8 Capacity market load obligation served: June 1, 2019

	2018		2019		Change	
	Obligation (MW)	Percent of total obligation	Obligation (MW)	Percent of total obligation	Obligation (MW)	Percent of total obligation
PJM EDCs and Affiliates	113,202.4	60.0%	113,416.3	60.1%	213.8	0.1%
LSEs not affiliated with any EDC + non EDC Affiliates	75,585.7	40.0%	75,445.0	39.9%	(140.7)	(0.1%)
Total	188,788.1	100.0%	188,861.3	100.0%	73.2	0.0%

Figure 5-3 Capacity market load obligation served: June 1, 2007 through June 1, 2019



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 2021/2022 RPM Base Residual Auction, EMAAC had 4,352.6 MW of CTRs with a total value of $40,877,295, PSEG had 4,990.5 MW of CTRs with a total value of $70,238,159, ATSI had 6,402.8 MW of CTRs with a total value of $73,219,252, ComEd had 1,527.9 MW of CTRs with a total value of $30,978,820, and BGE had 5,125.6 MW of CTRs with a total value of $112,812,971.[56]

EMAAC had 40.0 MW of customer funded ICTRs with a total value of $375,658, PSEG had 41.0 MW of customer funded ICTRs with a total value of $577,050, BGE had 65.7 MW of customer funded ICTRs with a total value of $1,446,024, and ComEd had 1,097.0 MW of customer funded ICTRs with a total value of $22,242,498.

EMAAC had 948.0 MW of ICTRs due to Incremental Rights-Eligible Required Transmission Enhancements with a value of $8,903,095. PSEG had 499.4 MW of ICTRs due to Incremental Rights-Eligible Required Transmission Enhancements with a value of $7,028,755. BGE had 306.0 MW of ICTRs due to Incremental Rights-Eligible Required Transmission Enhancements with a value of $6,734,907.

Market Concentration

Auction Market Structure

As shown in Table 5-9, in the 2020/2021 RPM Second Incremental Auction, all participants in the total PJM market as well as the LDA RPM markets failed

56 The values of capacity transfer rights values were revised from the values reported in previous 2018 and 2019 state of the market reports.

the three pivotal supplier (TPS) test.[57] In the 2021/2022 RPM First Incremental Auction, two participants in the EMAAC LDA market passed the TPS test. 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.[58] [59] [60]

In applying the market structure test, the relevant supply for the RTO market includes all supply offered at less than or equal to 150 percent of the RTO cost-based clearing price. The relevant supply for the constrained LDA markets includes the incremental supply inside the constrained LDAs which was offered at a price higher than the unconstrained clearing price for the parent LDA market and less than or equal to 150 percent of the cost-based clearing price for the constrained LDA. The relevant demand consists of the MW needed inside the LDA to relieve the constraint.

Table 5-9 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 (RSI_x). The RSI_x 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 RSI_x 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 RSI_x 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.

57 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.
58 See OATT Attachment DD § 6.5.
59 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).
60 Effective January 31, 2011, the RPM rules related to market power mitigation were changed, including revising the definition for planned generation capacity resource and creating a new definition for existing generation capacity resource for purposes of the must-offer requirement and market power mitigation, and treating a proposed increase in the capability of a generation capacity resource the same in terms of mitigation as a planned generation capacity resource. See 134 FERC ¶ 61,065 (2011).

Table 5-9 RSI results: 2018/2019 through 2021/2022 RPM Auctions[61]

RPM Markets	$RSI_{1, 1.05}$	RSI_3	Total Participants	Failed RSI_3 Participants
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
2018/2019 Third Incremental Auction				
RTO	0.88	0.65	71	71
EMAAC	0.00	0.00	3	3
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
2019/2020 Second Incremental Auction				
RTO	0.61	0.48	38	38
BGE	0.00	0.00	1	1
2019/2020 Third Incremental Auction				
RTO	0.70	0.59	72	72
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
2020/2021 First Incremental Auction				
RTO	0.47	0.42	47	47
2020/2021 Second Incremental Auction				
RTO	0.40	0.56	34	34
2021/2022 Base Residual Auction				
RTO	0.80	0.68	122	122
EMAAC	0.71	0.22	14	14
PSEG	0.20	0.01	5	5
ATSI	0.01	0.00	2	2
ComEd	0.08	0.02	5	5
BGE	0.23	0.00	3	3
2021/2022 First Incremental Auction				
RTO	0.57	0.48	26	26
EMAAC	0.00	0.82	5	3
PSEG	0.00	0.00	1	1
PSEG North	0.00	0.00	2	2
BGE	0.00	0.00	1	1

61 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.[62]

Locational Deliverability Areas are shown in Figure 5-4, Figure 5-5 and Figure 5-6.

Figure 5-4 Map of locational deliverability areas

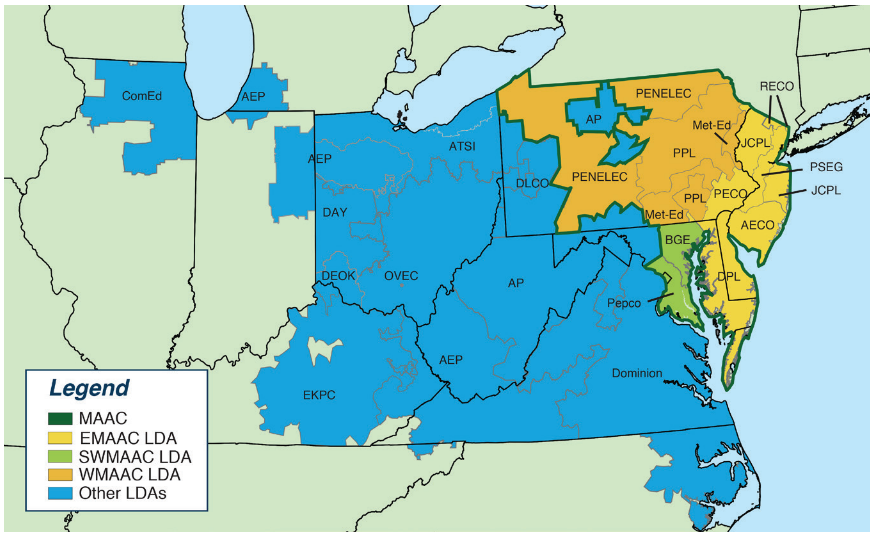


Figure 5-5 Map of RPM EMAAC subzonal LDAs

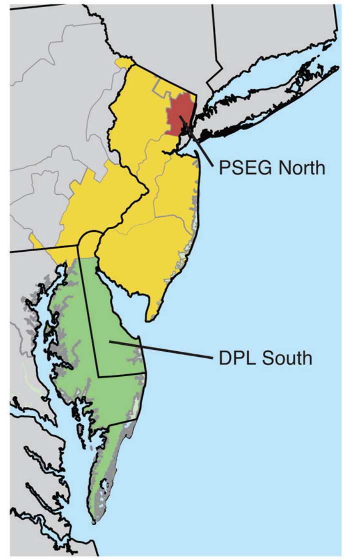
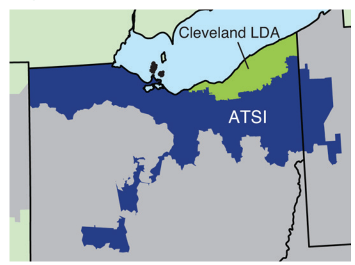


Figure 5-6 Map of RPM ATSI subzonal LDA



62 For definitions of the RPM Locational Deliverability Areas see 2018 State of the Market Report for PJM, Volume 2: Section 5 Capacity Market, at Locational Deliverability Areas (LDAs). <http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2018/2018-som-pjm-sec5.pdf>

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.[63]

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. 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 Years, 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.[64] 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.[65]

Effective May 9, 2017, enhanced pseudo tie requirements for external generation capacity resources were implemented, including a transition period with deliverability requirements for existing pseudo tie resources that have previously cleared an RPM auction. The rule changes include: defining coordination with other Balancing Authorities when conducting pseudo tie studies; establishing an electrical distance requirement; establishing a market-to-market flowgate test to establish limits on the number of coordinated flowgates PJM must add in order to accommodate a new pseudo-tie; a model consistency requirement; the requirement for the capacity market seller to provide written acknowledgement from the external Balancing Authority Areas that such Pseudo-Tie does not require tagging and that firm allocations associated with any coordinated flowgates applicable to the external Generation Capacity Resource under any agreed congestion management process then in effect between PJM and such Balancing Authority Area will be allocated to PJM; the requirement for the capacity market seller to obtain long-term firm point to point transmission service for transmission outside PJM with rollover rights and to obtain network external designated transmission service for transmission within PJM; establishing an operationally deliverable standard; and modifying the nonperformance penalty definition for external generation capacity resources to assess performance at sub-regional transmission organization granularity.

As shown in Table 5-10, of the 4,470.4 MW of imports offered in the 2021/2022 RPM Base Residual Auction, 4,051.8 MW cleared. Of the cleared imports, 1,909.9 MW (47.1 percent) were from MISO.

63 OATT Attachment DD § 5.6.6(b).
64 147 FERC ¶ 61,060 (2014).
65 151 FERC ¶ 61,208 (2015).

Table 5-10 RPM imports: 2007/2008 through 2021/2022 RPM Base Residual Auctions

	UCAP (MW)					
Base Residual	MISO		Non-MISO		Total Imports	
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
2021/2022	2,308.4	1,909.9	2,162.0	2,141.9	4,470.4	4,051.8

Demand Resources

As shown in Table 5-11, Table 5-12, and Table 5-13, capacity in the RPM load management programs was 11,042.8 MW for June 1, 2019, as a result of cleared capacity for demand resources and energy efficiency resources in RPM auctions for the 2019/2020 Delivery Year (13,231.6 MW) less replacement capacity (2,188.8 MW).

Table 5-11 RPM load management statistics by LDA: June 1, 2017 to June 1, 2021[66] [67] [68] [69]

		UCAP (MW)														
		RTO	MAAC	EMAAC	SWMAAC	DPL South	PSEG	PSEG North	Pepco	ATSI	ATSI Cleveland	ComEd	BGE	PPL	DAY	DEOK
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)		
	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	11,435.4	4,361.9	1,707.2	1,226.4	86.8	389.9	139.2	559.3	1,034.3	287.2	1,895.2	667.1	716.2		
	EE cleared	2,296.3	706.8	315.9	317.6	9.2	102.0	45.2	186.1	184.4	33.2	807.4	131.5	43.1		
	DR net replacements	(3,182.4)	(1,268.4)	(584.3)	(199.5)	(52.4)	(150.9)	(43.6)	(25.6)	(261.0)	(136.7)	(430.0)	(173.9)	(220.0)		
	EE net replacements	248.8	163.0	45.5	107.6	1.1	22.4	9.1	(8.9)	14.7	4.7	29.0	116.5	5.4		
	RPM load management	10,798.1	3,963.3	1,484.3	1,452.1	44.7	363.4	149.9	710.9	972.4	188.4	2,301.6	741.2	544.7		
01-Jun-19	DR cleared	10,703.1	3,878.9	1,659.2	817.0	91.3	381.2	176.5	554.6	1,047.0	333.9	1,759.9	262.4	741.4		
	EE cleared	2,528.5	821.4	395.3	301.7	7.8	134.5	52.8	170.0	204.8	41.7	792.9	131.7	72.7		
	DR net replacements	(2,138.8)	(1,004.2)	(468.8)	(129.0)	(40.9)	(141.5)	(86.6)	(74.8)	(130.3)	(123.1)	(143.0)	(54.2)	(208.9)		
	EE net replacements	(50.0)	(24.1)	4.7	3.3	(0.2)	2.7	9.1	2.2	3.4	0.0	0.0	1.1	(20.4)		
	RPM load management	11,042.8	3,672.0	1,590.4	993.0	58.0	376.9	151.8	652.0	1,124.9	252.5	2,409.8	341.0	584.8		
01-Jun-20	DR cleared	9,231.7	2,823.2	1,168.9	481.1	72.6	339.0	152.7	234.6	853.0	227.1	1,644.7	246.5	615.6	225.2	184.7
	EE cleared	2,653.8	932.8	515.7	309.6	14.8	184.3	75.2	144.6	256.0	56.8	775.8	165.0	61.5	60.8	85.0
	DR net replacements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	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
	RPM load management	11,885.5	3,756.0	1,684.6	790.7	87.4	523.3	227.9	379.2	1,109.0	283.9	2,420.5	411.5	677.1	286.0	269.7
01-Jun-21	DR cleared	11,415.5	3,454.1	1,381.5	624.9	66.3	410.5	188.6	345.9	1,196.8	272.8	2,073.7	279.0	697.7	227.7	220.5
	EE cleared	3,137.6	1,090.3	660.5	274.5	13.6	244.4	73.9	137.7	202.2	47.5	787.3	136.8	86.6	61.3	93.5
	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
	RPM load management	14,553.1	4,544.4	2,042.0	899.4	79.9	654.9	262.5	483.6	1,399.0	320.3	2,861.0	415.8	784.3	289.0	314.0

66 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.
67 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.
68 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.
69 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 5-12 RPM commitments, replacements, and registrations for demand resources: June 1, 2007 to June 1, 2021[70 71 72]

	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	11,435.4	0.0	(3,182.4)	8,253.0	(1.0)	8,252.0	8,512.0	1.091	9,282.4
01-Jun-19	10,703.1	0.0	(2,138.8)	8,564.3	(0.4)	8,563.9	9,229.9	1.090	10,056.0
01-Jun-20	9,231.7	0.0	0.0	9,231.7	0.0	9,231.7	0.0	1.089	0.0
01-Jun-21	11,415.5	0.0	0.0	11,415.5	0.0	11,415.5	0.0	1.088	0.0

Table 5-13 RPM commitments and replacements for energy efficiency resources: June 1, 2007 to June 1, 2021[73 74]

	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	2,296.3	0.0	248.8	2,545.1	0.0	2,545.1
01-Jun-19	2,528.5	0.0	(50.0)	2,478.5	0.0	2,478.5
01-Jun-20	2,653.8	0.0	0.0	2,653.8	0.0	2,653.8
01-Jun-21	3,137.6	0.0	0.0	3,137.6	0.0	3,137.6

70 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.
71 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.
72 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.
73 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.
74 Effective with the 2019/2020 Delivery Year, available capacity from an EE Resource can be used to replace only EE Resource commitments. This rule change and related EE add back rule changes were endorsed at the December 17, 2015, meeting of the PJM Markets and Reliability Committee.

Market Conduct

Offer Caps and Offer Floors

Market power mitigation measures were applied to capacity resources such that the sell offer was set equal to the defined offer cap when the capacity market seller failed the market structure test for the auction, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, would have increased the market clearing price.[75]

2020/2021 RPM Second Incremental Auction

As shown in Table 5-14, 464 generation resources submitted Capacity Performance offers in the 2020/2021 RPM Second Incremental Auction. Unit specific offer caps were calculated for six generation resources (1.3 percent), five of which were unit-specific with an APIR component. Of the 464 generation resources, 419 generation resources had the net CONE times B offer cap (90.3 percent), three Planned Generation Capacity Resource had an uncapped offer (0.6 percent), and the remaining 36 generation resources were price takers (7.8 percent). Market power mitigation was applied to the Capacity Performance sell offers of zero generation resources.

2021/2022 RPM First Incremental Auction

As shown in Table 5-14, 301 generation resources submitted Capacity Performance offers in the 2021/2022 RPM First Incremental Auction. Unit specific offer caps were calculated for zero generation resources (0.0 percent). Of the 301 generation resources, 285 generation resources had the net CONE times B offer cap (94.7 percent), nine Planned Generation Capacity Resource had an uncapped offer (3.0 percent), four generation resources had uncapped planned uprates plus net CONE times B offer cap for the existing portion of the units (1.3 percent), one generation resource had uncapped planned uprate and price taker for the existing portion of the unit (0.3 percent), and the remaining two generation resources were price takers (0.7 percent). Market power mitigation was applied to the Capacity Performance sell offers of zero generation resources.

75 For an explanation of offer caps, offer floors, and the minimum offer price rule (MOPR), see 2018 State of the Market Report for PJM, Volume 2, Section 5 Capacity Market, at Offer Caps and Offer Floors. <http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2018/2018-som-pjm-sec5.pdf>.

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 5-15, of the 75.0 ICAP MW of MOPR Unit-Specific Exception requests for the 2020/2021 RPM Second Incremental Auction, requests for 75.0 MW were granted. Of the 1,390.0 MW of MOPR Unit-Specific Exception requests for the 2021/2022 RPM First Incremental Auction, requests for 1,390.0 MW were granted.

Table 5-14 ACR statistics: RPM Auctions conducted in third quarter, 2019

	2020/2021 Second Incremental Auction		2021/2022 First Incremental Auction	
Offer Cap/Mitigation Type	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered
Default ACR	NA	NA	NA	NA
Unit specific ACR (APIR)	2	0.4%	0	0.0%
Unit specific ACR (APIR and CPQR)	3	0.6%	0	0.0%
Unit specific ACR (non-APIR)	1	0.2%	0	0.0%
Unit specific ACR (non-APIR and CPQR)	0	0.0%	0	0.0%
Opportunity cost input	0	0.0%	0	0.0%
Default ACR and opportunity cost	NA	NA	NA	NA
Net CONE times B	419	90.3%	285	94.7%
Offer cap of 1.1 times BRA clearing price elected	NA	NA	NA	NA
Uncapped planned uprate and default ACR	NA	NA	NA	NA
Uncapped planned uprate and opportunity cost	0	0.0%	0	0.0%
Uncapped planned uprate and Net CONE times B	0	0.0%	4	1.3%
Uncapped planned uprate and price taker	0	0.0%	1	0.3%
Uncapped planned uprate and 1.1 times BRA clearing price elected	NA	NA	NA	NA
Uncapped planned generation resources	3	0.6%	9	3.0%
Existing generation resources as price takers	36	7.8%	2	0.7%
Total Generation Capacity Resources offered	464	100.0%	301	100.0%

Table 5-15 MOPR statistics: RPM Auctions conducted in third quarter, 2019[76]

		Number of Requests	ICAP (MW)			UCAP (MW)	
		(Company-Plant Level)	Requested	Granted	Offered	Offered	Cleared
2020/2021 Second Incremental Auction	Unit-Specific Exception	3	75.0	75.0	10.0	9.6	0.0
	Other MOPR Screened Generation Resources	0	0.0	0.0	166.2	160.3	0.0
	Total	3	75.0	75.0	176.2	169.9	0.0
2021/2022 First Incremental Auction	Unit-Specific Exception	7	1,390.0	1,390.0	1,242.7	1,199.1	279.3
	Other MOPR Screened Generation Resources	0	0.0	0.0	138.6	136.4	0.0
	Total	7	1,390.0	1,390.0	1,381.3	1,335.5	279.3

76 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 are not reported as a result of PJM confidentiality rules.

Replacement Capacity[77]

Table 5-16 shows the committed and replacement capacity for all capacity resources for June 1 of each year from 2007 through 2021. The 2020 through 2021 numbers are not final.

Table 5-16 RPM commitments and replacements for all Capacity Resources: June 1, 2007 to June 1, 2021

	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	(625.3)	165,982.5
01-Jun-18	175,996.0	0.0	(12,057.8)	163,938.2	(150.5)	163,787.7
01-Jun-19	177,064.2	0.0	(12,300.3)	164,763.9	(9.3)	164,754.6
01-Jun-20	170,537.8	0.0	(610.1)	169,927.7	0.0	169,927.7
01-Jun-21	165,770.5	0.0	0.0	165,770.5	0.0	165,770.5

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 5-17 shows RPM clearing prices for all RPM auctions held through the first nine months of 2019, and Table 5-18 shows the RPM cleared MW for all RPM auctions held through the first nine months of 2019.

Figure 5-8 shows the RPM cleared MW weighted average prices for each LDA for the current delivery year and all results for auctions for future delivery years that have been held through the first nine months of 2019. A summary of these weighted average prices is given in Table 5-19.

Table 5-20 shows RPM revenue by resource type for all RPM auctions held through the first nine months of 2019 with $9.4 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 5-21 shows RPM revenue by calendar year for all RPM auctions held through the first nine months of 2019. In 2017, RPM revenue was $8.8 billion. In 2018, RPM revenue was $10.3 billion.

Table 5-22 shows the RPM annual charges to load. For the 2018/2019 Delivery Year, RPM annual charges to load were $11.0 billion. For the 2019/2020 Delivery Year, annual charges to load are $7.0 billion.

77 For more details on replacement capacity, see "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2019," <http://www.monitoringanalytics.com/reports/Reports/2019/IMM_Analysis_of_Replacement_Capacity_for_RPM_Commitments_June_1_2007_to_June_1_2019_20190913.pdf> (September 13, 2019).

Table 5-17 Capacity market clearing prices: 2007/2008 through 2021/2022 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 5-17 Capacity market clearing prices: 2007/2008 through 2021/2022 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
2018/2019 Third Incremental Auction	Base Capacity	$14.29	$14.29	$14.29	$14.29	$19.30	$14.29	$5.00	$19.30	$19.30	$14.29	$14.29	$14.29	$3.50
2018/2019 Third Incremental Auction	Base Capacity DR/EE	$14.29	$14.29	$14.29	$14.29	$19.30	$14.29	$5.00	$19.30	$19.30	$14.29	$14.29	$14.29	$3.50
2018/2019 Third Incremental Auction	Capacity Performance	$34.99	$34.99	$34.99	$34.99	$34.99	$34.99	$34.99	$34.99	$34.99	$34.99	$34.99	$34.99	$34.99
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
2019/2020 First Incremental Auction	Base Capacity	$15.00	$15.00	$15.00	$15.00	$22.22	$15.00	$22.22	$22.22	$22.22	$15.00	$15.00	$15.00	$15.00
2019/2020 First Incremental Auction	Base Capacity DR/EE	$15.00	$15.00	$15.00	$15.00	$22.22	$15.00	$22.22	$22.22	$22.22	$15.00	$15.00	$15.00	$15.00
2019/2020 First Incremental Auction	Capacity Performance	$51.33	$51.33	$51.33	$51.33	$58.55	$51.33	$58.55	$58.55	$58.55	$51.33	$51.33	$51.33	$51.33
2019/2020 Second Incremental Auction	Base Capacity	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$32.14
2019/2020 Second Incremental Auction	Base Capacity DR/EE	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$32.14
2019/2020 Second Incremental Auction	Capacity Performance	$32.87	$32.87	$32.87	$32.87	$32.87	$32.87	$32.87	$32.87	$32.87	$32.87	$32.87	$32.87	$55.00
2019/2020 Third Incremental Auction	Base Capacity	$21.35	$21.35	$21.35	$21.35	$21.35	$21.35	$21.35	$21.35	$21.35	$21.35	$21.35	$21.35	$21.35
2019/2020 Third Incremental Auction	Base Capacity DR/EE	$21.35	$21.35	$21.35	$21.35	$21.35	$21.35	$21.35	$21.35	$21.35	$20.00	$21.35	$21.35	$21.35
2019/2020 Third Incremental Auction	Capacity Performance	$28.35	$28.35	$28.35	$28.35	$28.35	$28.35	$28.35	$28.35	$28.35	$28.35	$28.35	$28.35	$28.35
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
2020/2021 First Incremental Auction	Capacity Performance	$42.90	$42.90	$42.90	$42.90	$42.90	$42.90	$42.90	$42.90	$42.90	$42.90	$42.90	$42.90	$42.90
2020/2021 Second Incremental Auction	Capacity Performance	$20.25	$20.25	$20.25	$20.25	$20.25	$20.25	$20.25	$20.25	$20.25	$20.25	$20.25	$20.25	$20.25
2021/2022 BRA	Capacity Performance	$140.00	$140.00	$140.00	$140.00	$165.73	$140.00	$165.73	$204.29	$204.29	$140.00	$171.33	$195.55	$200.30
2021/2022 First Incremental Auction	Capacity Performance	$23.00	$23.00	$23.00	$23.00	$25.00	$23.00	$25.00	$45.00	$219.00	$23.00	$23.00	$23.00	$60.00

Table 5-18 Capacity market cleared MW: 2007/2008 through 2021/2022 RPM Auctions[78]

		UCAP (MW)															
Delivery Year	Auction	RTO	MAAC+APS	MAAC	EMAAC	SWMAAC	DPL South	PSEG	PSEG North	Pepco	ATSI	ATSI Cleveland	ComEd	BGE	PPL	DAY	DEOK	Total
2007/2008	BASE	88,410.2	.	.	30,797.8	10,201.2	.	.	.	.	.	.	.	.	.	.	.	129,409.2
2008/2009	BASE	88,745.1	.	.	30,231.3	10,621.2	.	.	.	.	.	.	.	.	.	.	.	129,597.6
2008/2009	THIRD	719.5	.	.	292.1	20.6	.	.	.	.	.	.	.	.	.	.	.	1,032.2
2009/2010	BASE	59,684.1	30,982.5	.	31,650.6	9,914.6	.	.	.	.	.	.	.	.	.	.	.	132,231.8
2009/2010	THIRD	503.1	178.7	.	353.8	762.8	.	.	.	.	.	.	.	.	.	.	.	1,798.4
2010/2011	BASE	68,777.4	.	51,019.9	.	10,873.4	1,519.7	.	.	.	.	.	.	.	.	.	.	132,190.4
2010/2011	THIRD	1,313.1	.	373.6	.	127.9	31.2	.	.	.	.	.	.	.	.	.	.	1,845.8
2011/2012	BASE	132,264.5	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	132,264.5
2011/2012	FIRST	361.1	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	361.1
2011/2012	THIRD	1,557.0	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	1,557.0
2012/2013	BASE	70,679.4	.	22,777.6	22,644.7	11,643.5	1,354.1	3,672.1	3,582.5	.	.	.	.	.	.	.	.	136,353.9
2012/2013	FIRST	452.2	.	16.1	560.4	38.7	167.8	319.9	133.6	.	.	.	.	.	.	.	.	1,688.7
2012/2013	SECOND	539.1	.	143.8	102.9	4.0	0.1	24.3	23.6	.	.	.	.	.	.	.	.	837.8
2012/2013	THIRD	1,871.9	.	215.0	170.2	16.4	56.3	37.5	36.2	.	.	.	.	.	.	.	.	2,403.5
2013/2014	BASE	85,103.4	.	23,562.4	23,203.9	6,450.4	1,612.4	3,859.7	4,173.4	4,791.7	.	.	.	.	.	.	.	152,757.3
2013/2014	FIRST	1,719.5	.	128.5	167.8	2.0	1.3	238.7	124.2	5.1	.	.	.	.	.	.	.	2,387.1
2013/2014	SECOND	1,143.7	.	109.6	125.9	24.4	61.7	34.1	17.3	480.0	.	.	.	.	.	.	.	1,996.7
2013/2014	THIRD	1,449.0	.	404.1	301.2	1.8	9.7	1.1	4.7	531.8	.	.	.	.	.	.	.	2,703.4
2014/2015	BASE	82,798.7	.	23,497.9	23,527.6	5,509.5	1,551.8	3,765.5	3,812.3	5,614.6	.	.	.	.	.	.	.	150,077.9
2014/2015	FIRST	2,590.2	.	605.5	69.0	764.5	10.3	31.8	143.3	24.5	.	.	.	.	.	.	.	4,239.1
2014/2015	SECOND	2,000.4	.	215.1	271.7	159.6	13.7	5.0	0.9	243.1	.	.	.	.	.	.	.	2,909.5
2014/2015	THIRD	2,517.4	.	247.9	645.7	142.1	61.8	65.4	282.1	15.4	.	.	.	.	.	.	.	3,977.8
2015/2016	BASE	87,870.2	.	21,713.1	24,567.7	4,857.1	1,722.1	3,076.8	3,632.4	6,129.5	10,669.1	.	.	.	.	.	.	164,238.0
2015/2016	FIRST	1,523.6	.	855.2	92.8	654.8	.	23.9	268.3	1.7	777.4	.	.	.	.	.	.	4,197.7
2015/2016	SECOND	865.3	.	70.7	48.5	430.6	2.3	3.6	6.6	5.3	346.8	.	.	.	.	.	.	1,779.7
2015/2016	THIRD	1,908.0	.	464.1	71.2	340.9	12.5	29.5	70.1	5.6	402.1	.	.	.	.	.	.	3,304.0
2016/2017	BASE	22,136.2	.	17,491.2	15,181.3	4,988.1	1,577.0	2,587.9	3,693.7	5,786.3	4,155.0	2,752.8	.	.	.	.	.	80,349.5
2016/2017	CP TRANSITION	74,359.3	.	6,219.4	8,373.9	1,039.0	170.8	1.6	1.4	308.0	4,526.0	97.2	.	.	.	.	.	95,096.6
2016/2017	FIRST	1,032.3	.	304.2	417.0	132.9	0.5	409.0	7.5	8.7	295.3	2.1	.	.	.	.	.	2,609.5
2016/2017	SECOND	126.9	.	4.0	30.5	32.9	0.0	10.7	6.7	0.0	16.4	.	.	.	.	.	.	228.1
2016/2017	THIRD	790.1	.	180.6	264.0	22.7	11.4	22.8	84.6	71.9	11.2	6.0	.	.	.	.	.	1,465.3
2017/2018	BASE	19,385.3	.	5,132.3	10,218.5	733.6	792.9	2,217.5	3,893.2	2,938.8	2,896.8	911.7	8,616.1	2,488.8	4,411.9	.	.	64,637.4
2017/2018	CP TRANSITION	48,074.6	.	10,128.4	14,993.6	1,670.7	891.0	2.1	1.7	3,165.9	5,898.3	1,636.9	18,116.2	1,391.5	6,223.6	.	.	112,194.5
2017/2018	FIRST	173.6	.	8.8	31.1	.	7.0	151.4	3.1	31.6	10.1	0.3	73.2	3.1	111.3	.	.	604.6
2017/2018	SECOND	783.5	.	90.3	111.2	.	2.9	27.7	33.0	59.5	76.6	24.3	20.9	34.1	4.5	.	.	1,268.5
2017/2018	THIRD	314.3	.	105.6	205.1	16.3	40.8	82.2	76.0	94.4	141.5	14.6	125.3	209.1	26.9	.	.	1,452.1
2018/2019	BASE	67,273.7	.	14,294.6	24,039.7	2,405.1	1,728.5	2,132.8	3,168.0	5,478.7	7,913.5	2,258.1	23,320.4	3,296.9	9,565.5	.	.	166,875.5
2018/2019	FIRST	260.5	.	831.3	178.5	.	29.0	38.2	27.9	58.7	582.5	27.9	468.6	4.5	37.7	.	.	2,545.3
2018/2019	SECOND	580.7	.	148.0	515.2	.	5.6	26.7	22.9	117.9	81.1	37.9	338.2	5.6	498.2	.	.	2,378.0
2018/2019	THIRD	1,433.2	.	253.2	372.8	27.6	67.1	101.3	199.9	229.5	245.1	16.4	1,156.4	50.0	44.7	.	.	4,197.2
2019/2020	BASE	69,128.4	.	13,101.5	23,715.8	2,406.7	1,598.5	2,249.7	3,228.9	6,248.4	8,202.1	2,089.0	22,971.4	2,739.5	9,649.6	.	.	167,329.5
2019/2020	FIRST	823.8	.	249.4	78.7	0.0	11.7	10.6	28.8	43.6	96.9	50.6	711.4	31.9	157.7	.	.	2,295.1
2019/2020	SECOND	473.0	.	160.4	229.4	20.0	21.2	18.8	44.8	41.9	229.7	33.9	105.8	87.5	146.2	.	.	1,612.6
2019/2020	THIRD	2,037.4	.	529.7	286.9	3.4	2.4	159.2	23.2	80.6	232.8	221.4	867.4	254.8	1,127.8	.	.	5,827.0
2020/2021	BASE	61,372.9	.	15,454.5	22,895.5	2,138.9	1,647.2	2,124.2	2,975.4	5,953.1	8,068.0	1,857.9	23,960.3	2,339.1	10,356.9	1,527.6	2,437.8	165,109.2
2020/2021	FIRST	1,307.6	.	331.0	176.6	32.5	38.9	5.4	32.0	65.3	389.4	277.5	644.4	38.7	83.4	81.9	20.3	3,524.8
2020/2021	SECOND	447.4	.	206.9	302.9	21.6	28.4	29.5	48.8	35.4	249.7	116.5	194.6	138.7	30.7	21.4	31.5	1,903.8
2021/2022	BASE	61,395.2	.	16,679.9	22,286.8	2,220.2	1,673.8	2,237.7	3,134.1	6,013.2	6,762.4	1,248.1	22,358.1	1,980.6	11,253.8	1,637.4	2,746.1	163,627.3
2021/2022	FIRST	238.8	.	200.4	119.0	0.0	15.3	18.3	79.1	207.9	507.0	232.3	360.4	48.7	27.2	1.2	87.6	2,143.2

78 The MW values in this table refer to rest of LDA or RTO values, which are net of nested LDA values.

Table 5-19 Weighted average clearing prices by zone: 2018/2019 through 2021/2022

	Weighted Average Clearing Price ($ per MW-day)			
LDA	2018/2019	2019/2020	2020/2021	2021/2022
RTO				
AEP	$158.20	$93.63	$75.44	$139.59
APS	$158.20	$93.63	$75.44	$139.59
ATSI	$148.42	$92.97	$73.41	$160.97
Cleveland	$158.68	$89.17	$69.47	$148.05
ComEd	$199.02	$188.90	$183.04	$192.81
DAY	$158.20	$93.63	$74.10	$139.91
DEOK	$158.20	$93.63	$127.74	$136.38
DLCO	$158.20	$93.63	$75.44	$139.59
Dominion	$158.20	$93.63	$75.44	$139.59
EKPC	$158.20	$93.63	$75.44	$139.59
MAAC				
EMAAC				
AECO	$214.31	$112.48	$184.46	$164.94
DPL	$214.31	$112.48	$184.46	$164.94
DPL South	$211.38	$115.95	$181.80	$164.46
JCPL	$214.31	$112.48	$184.46	$164.94
PECO	$214.31	$112.48	$184.46	$164.94
PSEG	$210.92	$110.56	$185.11	$202.91
PSEG North	$211.71	$116.03	$183.68	$204.63
RECO	$214.31	$112.48	$184.46	$164.94
SWMAAC				
BGE	$141.58	$88.20	$81.66	$195.66
Pepco	$144.90	$90.59	$85.16	$136.09
WMAAC				
Met-Ed	$152.65	$93.81	$84.32	$138.61
PENELEC	$152.65	$93.81	$84.32	$138.61
PPL	$147.90	$88.53	$85.50	$139.80

Table 5-20 RPM revenue by type: 2007/2008 through 2021/2022[79] [80]

				Coal		Gas		Hydroelectric		Nuclear		Oil	
	Demand Resources	Energy Efficiency Resources	Imports	Existing	New/repower/ reactivated	Existing	New/repower/ reactivated	Existing	New/repower/ reactivated	Existing	New/repower/ reactivated	Existing	New/repower/ reactivated
2007/2008	$5,537,085	$0	$22,225,980	$1,019,060,206	$0	$1,625,158,046	$3,516,075	$209,490,444	$0	$996,085,233	$0	$339,272,020	$0
2008/2009	$35,349,116	$0	$60,918,903	$1,835,059,769	$0	$2,115,862,522	$9,784,064	$287,838,147	$12,255	$1,322,601,837	$0	$375,774,257	$4,837,523
2009/2010	$65,762,003	$0	$56,517,793	$2,409,315,953	$1,854,781	$2,551,967,501	$30,168,831	$364,731,344	$11,173	$1,517,723,628	$0	$447,358,085	$5,676,582
2010/2011	$60,235,796	$0	$106,046,871	$2,648,278,766	$3,168,069	$2,829,039,737	$58,065,964	$442,410,730	$19,085	$1,799,258,125	$0	$440,593,115	$4,339,539
2011/2012	$55,795,785	$139,812	$185,421,273	$1,586,775,249	$28,330,047	$1,721,272,563	$98,448,693	$278,529,660	$0	$1,079,386,338	$0	$263,061,402	$967,887
2012/2013	$264,387,897	$11,408,552	$13,260,822	$1,014,858,378	$7,568,127	$1,256,600,367	$76,633,409	$179,117,374	$11,998	$762,719,550	$0	$248,107,065	$2,772,987
2013/2014	$558,715,114	$21,598,174	$31,804,645	$1,741,613,525	$12,950,135	$2,154,401,813	$167,844,235	$308,853,673	$25,708	$1,346,223,419	$0	$385,720,626	$5,670,399
2014/2015	$681,315,139	$42,308,549	$135,573,409	$1,935,468,356	$57,078,818	$2,176,442,220	$205,555,569	$333,941,614	$6,649,774	$1,464,950,862	$0	$319,758,617	$4,106,697
2015/2016	$903,496,003	$66,652,986	$260,806,674	$2,902,870,267	$63,682,708	$2,676,692,075	$535,039,154	$389,540,948	$15,478,144	$1,850,033,226	$0	$397,556,965	$5,947,275
2016/2017	$466,952,356	$68,709,670	$244,091,507	$2,137,545,515	$72,217,195	$2,217,027,225	$667,098,133	$283,613,426	$13,927,638	$1,483,759,630	$0	$261,495,016	$4,030,823
2017/2018	$515,145,457	$86,147,605	$218,710,769	$2,452,687,763	$62,790,145	$2,550,970,172	$984,733,791	$348,972,234	$15,219,121	$1,694,447,711	$0	$276,148,715	$3,888,126
2018/2019	$637,742,320	$103,105,796	$263,475,004	$2,637,322,434	$77,072,397	$2,992,482,882	$1,444,760,231	$416,075,805	$15,382,098	$2,004,607,689	$0	$339,771,633	$2,922,855
2019/2020	$375,353,169	$92,569,666	$84,207,557	$1,679,065,727	$47,569,776	$1,960,634,807	$1,061,191,651	$250,290,590	$6,311,022	$1,283,332,540	$0	$187,076,264	$1,818,114
2020/2021	$345,185,064	$97,323,679	$74,259,155	$1,320,801,488	$36,115,158	$2,081,124,566	$1,147,013,042	$209,105,260	$7,737,607	$1,423,094,666	$0	$214,870,056	$1,441,013
2021/2022	$633,862,672	$169,757,227	$130,201,888	$2,080,004,418	$66,345,247	$2,677,241,436	$1,680,485,131	$295,309,520	$11,589,480	$1,186,655,901	$0	$255,731,483	$2,453,445

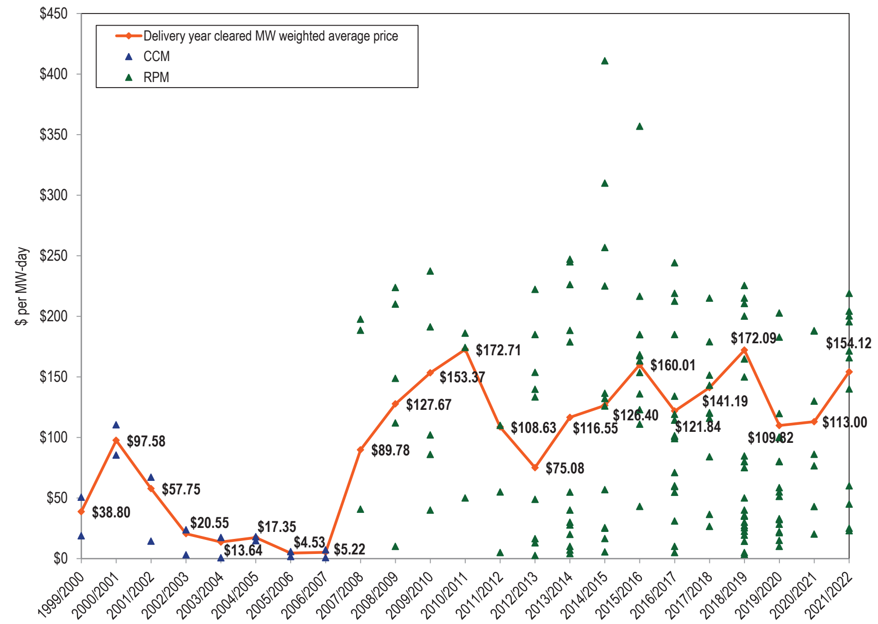
	Solar		Solid waste		Wind		
	Existing	New/repower/ reactivated	Existing	New/repower/ reactivated	Existing	New/repower/ reactivated	Total revenue
2007/2008	$0	$0	$31,512,230	$0	$430,065	$0	$4,252,287,381
2008/2009	$0	$0	$35,011,991	$0	$1,180,153	$2,917,048	$6,087,147,586
2009/2010	$0	$0	$42,758,762	$523,739	$2,011,156	$6,836,827	$7,503,218,157
2010/2011	$0	$0	$40,731,606	$413,503	$1,819,413	$15,232,177	$8,449,652,496
2011/2012	$0	$66,978	$25,636,836	$261,690	$1,072,929	$9,919,881	$5,335,087,023
2012/2013	$0	$1,246,337	$26,840,670	$316,420	$812,644	$5,052,036	$3,871,714,635
2013/2014	$0	$3,523,555	$43,943,130	$1,977,705	$1,373,205	$13,538,988	$6,799,778,047
2014/2015	$0	$3,836,582	$34,281,137	$1,709,533	$1,524,551	$32,766,219	$7,437,267,646
2015/2016	$0	$7,064,983	$35,862,368	$6,179,607	$1,829,269	$42,994,253	$10,161,726,902
2016/2017	$0	$7,057,256	$32,648,789	$6,380,604	$1,144,873	$26,189,042	$7,993,888,695
2017/2018	$0	$10,899,883	$34,771,100	$9,036,976	$1,529,251	$40,577,901	$9,306,676,719
2018/2019	$0	$16,928,323	$38,243,467	$9,658,138	$1,166,553	$54,226,228	$11,054,943,851
2019/2020	$610,166	$12,246,100	$21,332,647	$5,326,702	$1,296,846	$46,582,019	$7,116,815,360
2020/2021	$1,490	$7,631,833	$26,917,827	$5,428,707	$25,124	$35,868,550	$7,033,944,282
2021/2022	$0	$30,521,295	$31,939,133	$7,757,690	$2,089,282	$63,485,513	$9,325,430,761

79 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.
80 The results for the ATSI Integration Auctions are not included in this table.

Table 5-21 RPM revenue by calendar year: 2007 through 2022[81]

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	$159.31	177,680.6	365	$10,331,688,133
2019	$135.58	176,503.3	365	$8,734,613,179
2020	$111.68	173,203.0	366	$7,079,628,476
2021	$137.11	167,395.9	365	$8,377,445,944
2022	$154.12	165,770.5	151	$3,857,917,931

Figure 5-7 History of capacity prices: 1999/2000 through 2021/2022[82]



81 The results for the ATSI Integration Auctions are not included in this table.

82 The 1999/2000 through 2006/2007 capacity prices are CCM combined market, weighted average prices. The 2007/2008 through 2021/2022 capacity prices are RPM weighted average prices. The CCM data points plotted are cleared MW weighted average prices for the daily and monthly markets by delivery year. The RPM data points plotted are RPM resource clearing prices. For the 2014/2015 and subsequent delivery years, only the prices for Annual Resources or Capacity Performance Resources are plotted.

Figure 5-8 Map of RPM capacity prices: 2018/2019 through 2021/2022

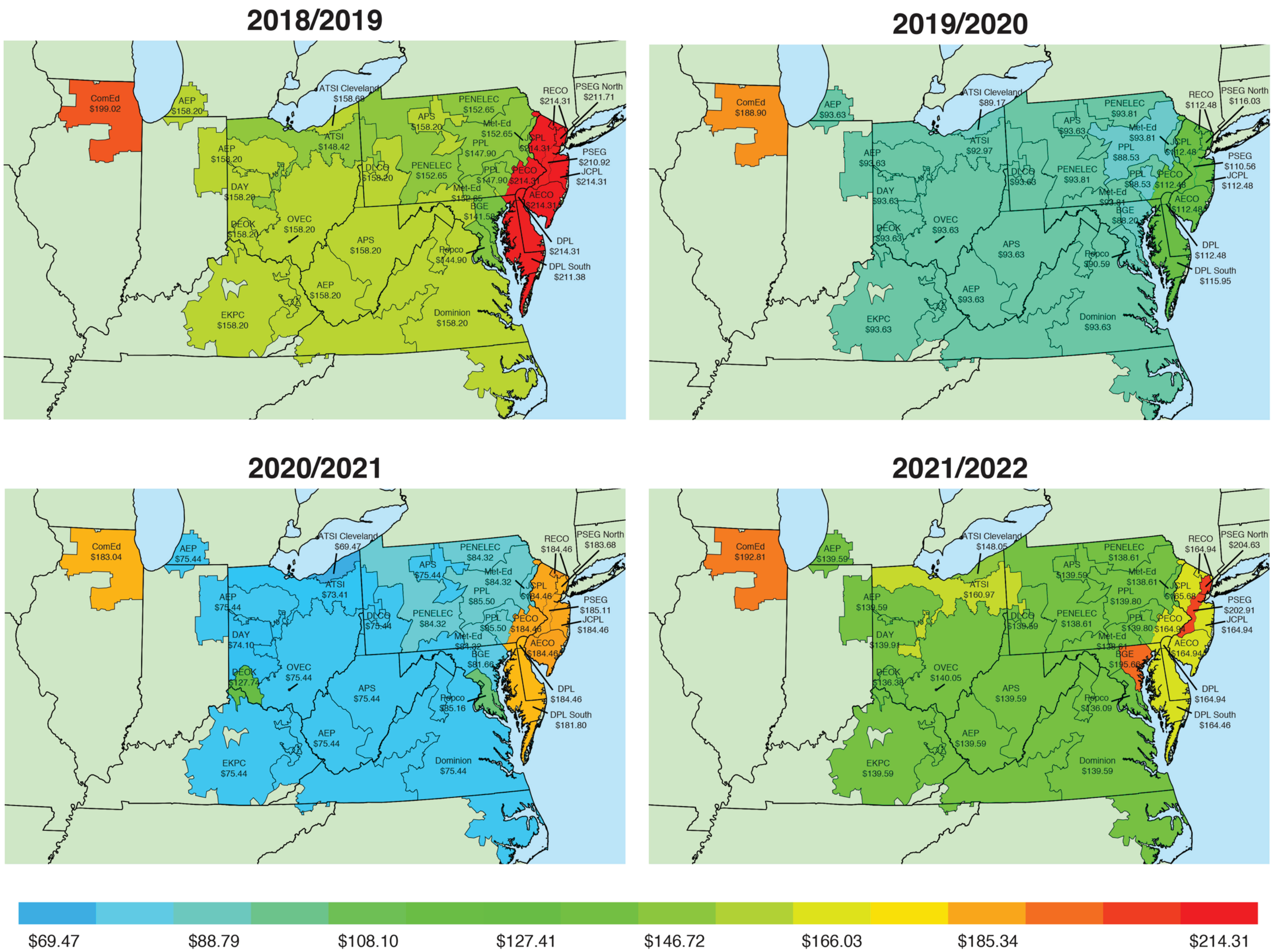


Table 5-22 RPM cost to load: 2018/2019 through 2021/2022 RPM Auctions[83] [84] [85]

	Net Load Price ($ per MW-day)	UCAP Obligation (MW)	Annual Charges
2018/2019			
Rest of RTO	$164.70	80,837.7	$4,859,734,465
Rest of MAAC	$218.98	31,118.9	$2,487,249,930
BGE	$158.20	7,701.4	$444,710,759
DPL	$219.29	4,463.7	$357,277,053
ComEd	$212.03	24,752.4	$1,915,591,298
Pepco	$156.90	7,329.2	$419,746,111
PPL	$155.11	8,300.9	$469,969,694
Total		164,504.2	$10,954,279,310
2019/2020			
Rest of RTO	$98.07	89,185.9	$3,201,364,940
Rest of EMAAC	$115.58	24,415.1	$1,032,810,556
BGE	$97.79	7,595.2	$271,828,430
ComEd	$192.56	24,985.1	$1,760,892,086
Pepco	$92.90	7,330.3	$249,230,694
PSEG	$115.83	11,281.1	$478,247,326
Total		164,792.8	$6,994,374,033
2020/2021			
Rest of RTO	$77.03	69,245.7	$1,946,798,301
Rest of MAAC	$86.84	29,695.1	$941,190,229
EMAAC	$175.11	35,335.5	$2,258,533,907
ComEd	$184.91	24,785.1	$1,672,785,387
DEOK	$103.66	5,186.4	$196,224,895
Total		164,247.8	$7,015,532,719
2021/2022			
Rest of RTO	$140.45	82,239.3	$4,216,042,632
Rest of EMAAC	$162.79	23,992.8	$1,425,620,686
ATSI	$157.96	14,427.1	$831,805,815
BGE	$161.73	7,412.6	$437,575,603
ComEd	$193.26	24,662.6	$1,739,734,117
PSEG	$185.16	11,007.1	$743,903,582
Total		163,741.4	$9,394,682,433

83 The RPM annual charges are calculated using the rounded, net load prices as posted in the PJM RPM Auction results.
84 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.
85 The Net Load Prices and obligation MW for 2020/2021 and 2021/2022 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.[86] 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.[87] [88]

Table 5-23 shows units that have provided RMR service to PJM.

86 OATT Part V.
87 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.").
88 For an explanation of the RMR rules, see 2018 State of the Market Report for PJM, Volume 2, Section 5: Capacity Market, at Reliability Must Run (RMR) Service. <http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2018/2018-som-pjm-sec5.pdf>.

Table 5-23 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	30-Apr-19
Yorktown 1	Dominion Virginia Power	159.0	Deactivation Avoidable Cost Rate	ER17-750	06-Jan-17	08-Mar-19
Yorktown 2	Dominion Virginia Power	164.0	Deactivation Avoidable Cost Rate	ER17-750	06-Jan-17	08-Mar-19
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

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 5-24 shows the capacity factors by unit type in the first nine months of 2018 and 2019. In the first nine months of 2019, nuclear units had a capacity factor of 93.8 percent, compared to 94.0 percent in the first nine months of 2018; combined cycle units had a capacity factor of 66.0 percent in the first nine months of 2019, compared to a capacity factor of 62.2 percent in the first nine months of 2018; all steam units had a capacity factor of 37.3 percent in the first nine months of 2019, compared to 41.6 percent in the first nine months of 2018; coal units had a capacity factor of 42.4 percent in the first nine months of 2019, compared to 47.5 percent in the first nine months of 2018.

Table 5-24 Capacity factor (By unit type (GWh)): January through September, 2018 and 2019[89][90]

	2018 (Jan-Sep)		2019 (Jan-Sep)		
Unit Type	Generation (GWh)	Capacity Factor	Generation (GWh)	Capacity Factor	Change in 2019 from 2018
Battery	10.6	0.6%	15.1	0.7%	0.1%
Combined Cycle	175,780.0	62.2%	211,909.2	66.0%	3.8%
Single Fuel	144,728.4	65.7%	180,345.5	71.7%	6.0%
Dual Fuel	31,051.6	49.8%	31,563.7	45.4%	(4.4%)
Combustion Turbine	15,077.5	8.0%	12,153.3	6.4%	(1.6%)
Single Fuel	9,916.5	7.1%	8,255.5	5.9%	(1.2%)
Dual Fuel	5,161.0	10.3%	3,897.8	7.6%	(2.7%)
Diesel	264.1	11.4%	200.3	7.8%	(3.6%)
Single Fuel	255.1	12.5%	196.3	8.5%	(3.9%)
Dual Fuel	9.0	3.3%	4.0	1.5%	(1.8%)
Diesel (Landfill gas)	1,332.4	51.6%	1,240.4	48.8%	(2.8%)
Fuel Cell	168.8	84.8%	163.1	80.8%	(4.0%)
Nuclear	214,603.2	94.0%	210,542.6	93.8%	(0.2%)
Pumped Storage Hydro	5,723.9	17.3%	4,597.2	13.9%	(3.4%)
Run of River Hydro	8,466.9	43.5%	8,818.5	44.7%	1.2%
Solar	1,706.4	19.6%	2,218.6	21.0%	1.4%
Steam	197,444.7	41.6%	165,357.5	37.3%	(4.3%)
Biomass	4,916.7	63.0%	4,511.4	61.4%	(1.6%)
Coal	186,816.7	47.5%	155,939.5	42.4%	(5.1%)
Single Fuel	182,058.5	49.0%	153,068.2	44.3%	(4.7%)
Dual Fuel	4,758.2	21.7%	2,871.3	13.1%	(8.6%)
Natural Gas	5,346.5	38.7%	4,807.9	42.2%	3.5%
Single Fuel	552.7	45.2%	354.1	50.8%	5.6%
Dual Fuel	4,793.9	25.0%	4,453.8	23.4%	(1.6%)
Oil	364.8	1.6%	98.6	0.7%	(0.9%)
Wind	15,120.1	27.0%	16,973.8	28.1%	1.1%
Total	635,701.4	48.9%	634,192.3	48.3%	(0.6%)

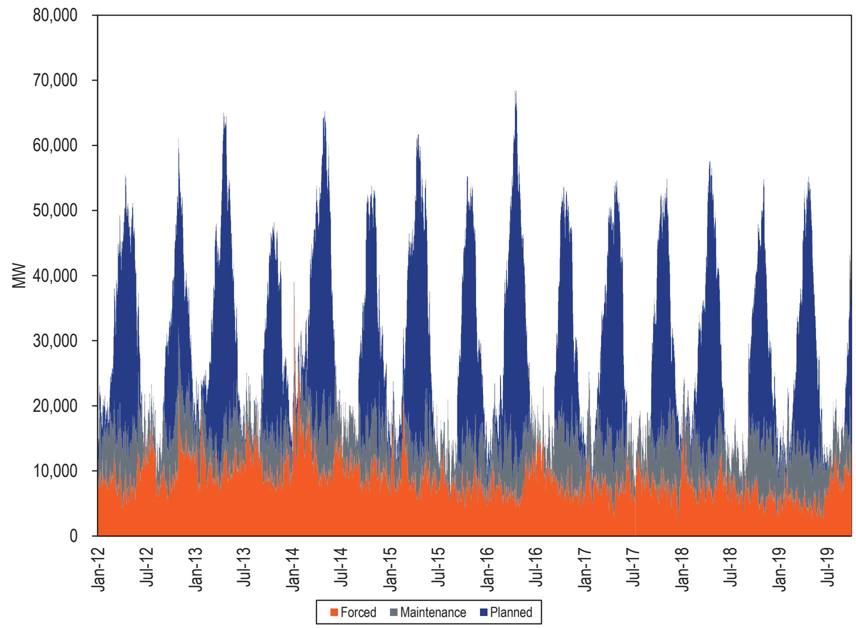
89 The capacity factors in this table are based on nameplate capacity values, and are calculated based on when the units come on line.

90 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.

Generator Performance Factors

Generator outages fall into three categories: planned, maintenance, and forced. The MW on outage vary throughout the year. For example, the MW on planned outage are generally highest in the spring and fall, as shown in Figure 5-9, due to restrictions on planned outages during the winter and summer. The effect of the seasonal variation in outages can be seen in the monthly generator performance metrics in Figure 5-9.

Figure 5-9 Outages (MW): 2012 through September 2019



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 5-25.

Figure 5-10 Equivalent outage and availability factors: 2007 to 2019

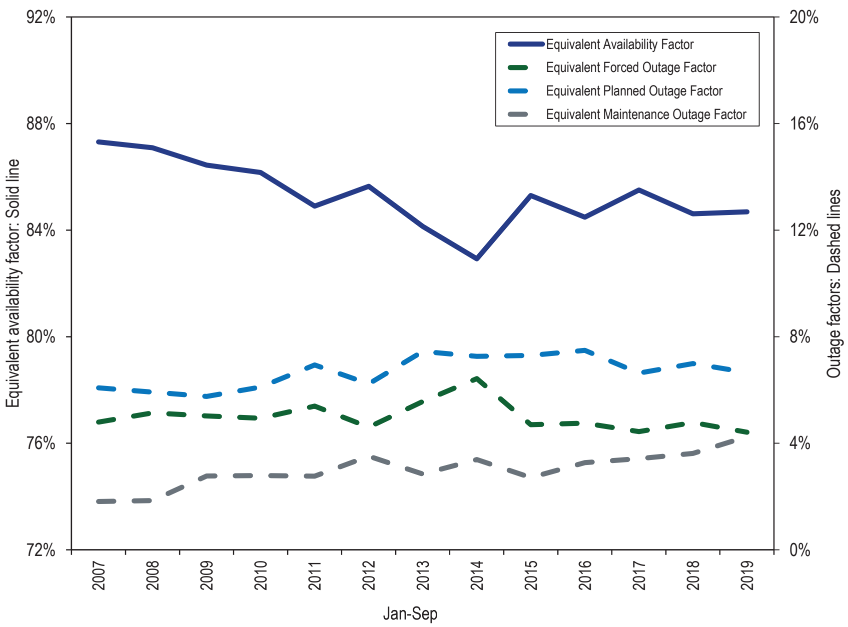


Table 5-25 EFOF, EPOF, EMOF and EAF by unit type: January through September, 2007 through 2019

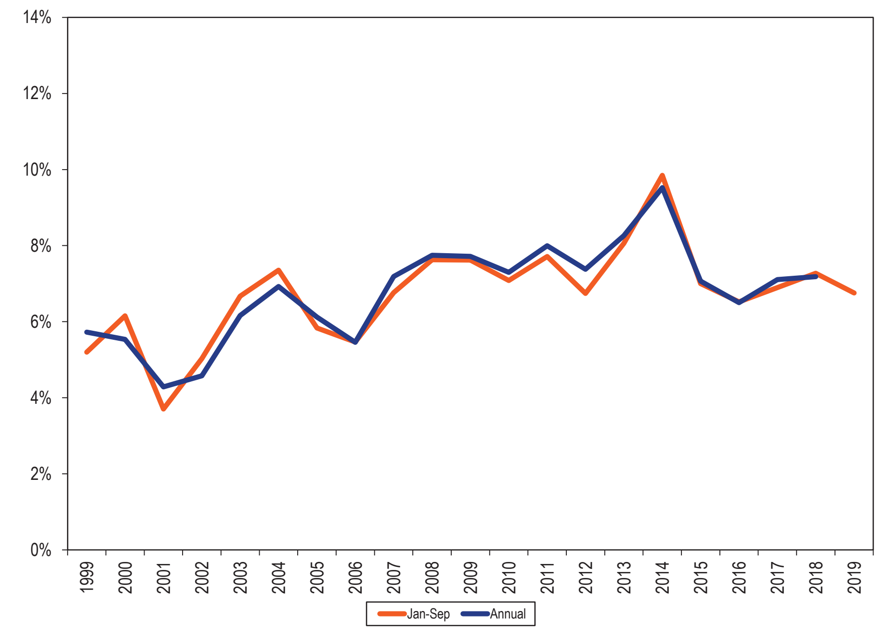
	Coal				Combined Cycle				Combustion Turbine				Diesel				Hydroelectric				Nuclear				Other			
Jan-Sep	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF
2007	7.1%	8.6%	2.5%	81.8%	2.2%	5.2%	1.3%	91.2%	5.0%	2.1%	2.0%	90.9%	10.8%	0.7%	1.8%	86.7%	1.3%	5.4%	1.6%	91.8%	1.1%	3.8%	0.3%	94.7%	6.6%	7.7%	2.5%	83.2%
2008	8.2%	6.6%	2.4%	82.8%	2.1%	5.0%	1.4%	91.5%	3.0%	3.7%	1.9%	91.4%	9.8%	1.2%	1.2%	87.9%	1.6%	6.8%	1.7%	89.9%	0.9%	5.2%	0.6%	93.3%	8.6%	8.5%	2.5%	80.5%
2009	6.7%	7.1%	3.5%	82.7%	3.4%	5.1%	3.5%	88.0%	1.4%	2.6%	2.0%	94.1%	6.7%	0.3%	1.2%	91.8%	2.1%	8.9%	2.3%	86.7%	4.2%	4.2%	0.7%	90.9%	7.9%	7.7%	4.6%	79.8%
2010	7.7%	7.8%	4.2%	80.3%	2.6%	6.0%	3.1%	88.3%	1.9%	2.0%	1.5%	94.5%	4.7%	0.6%	0.8%	93.9%	0.8%	8.4%	2.1%	88.8%	1.9%	4.4%	0.5%	93.1%	8.2%	7.7%	3.3%	80.7%
2011	8.5%	8.0%	3.9%	79.6%	2.4%	7.0%	2.1%	88.5%	1.9%	3.2%	1.5%	93.4%	3.8%	0.0%	1.9%	94.3%	1.6%	13.2%	2.0%	83.2%	2.2%	5.8%	1.5%	90.5%	8.8%	7.7%	3.3%	80.3%
2012	7.2%	7.6%	5.8%	79.5%	2.5%	6.4%	1.8%	89.3%	2.0%	2.2%	1.5%	94.2%	3.9%	0.1%	1.7%	94.4%	3.5%	4.9%	1.8%	89.8%	1.4%	6.1%	0.9%	91.6%	7.2%	7.3%	5.0%	80.5%
2013	8.4%	9.5%	4.4%	77.7%	1.9%	8.5%	2.6%	87.0%	5.1%	3.1%	1.3%	90.5%	5.5%	0.3%	1.4%	92.8%	2.1%	6.5%	1.6%	89.7%	1.2%	5.6%	0.8%	92.4%	9.5%	8.9%	4.2%	77.4%
2014	9.8%	8.0%	5.3%	77.0%	2.8%	8.7%	2.1%	86.4%	7.4%	3.1%	1.5%	88.1%	14.0%	0.5%	2.3%	83.2%	2.0%	8.9%	3.0%	86.1%	1.8%	5.9%	0.9%	91.5%	7.4%	12.0%	6.0%	74.6%
2015	8.0%	7.6%	4.1%	80.3%	2.1%	8.3%	1.7%	87.9%	3.0%	3.8%	1.8%	91.4%	8.4%	0.4%	2.3%	88.9%	2.3%	7.9%	1.5%	88.3%	1.2%	4.9%	1.3%	92.7%	6.7%	15.1%	4.0%	74.2%
2016	8.5%	8.1%	5.7%	77.7%	3.0%	8.6%	1.7%	86.7%	2.3%	4.1%	2.2%	91.4%	5.4%	0.2%	2.5%	91.9%	2.1%	6.7%	2.7%	88.4%	2.1%	4.6%	1.1%	92.2%	5.2%	15.5%	3.6%	75.7%
2017	9.8%	8.1%	6.4%	75.7%	1.9%	7.9%	1.6%	88.6%	1.2%	4.0%	1.7%	93.0%	5.8%	0.2%	1.7%	92.3%	2.2%	5.3%	2.9%	89.6%	0.6%	5.0%	0.6%	93.9%	4.5%	7.9%	5.3%	82.3%
2018	10.4%	9.4%	6.8%	73.5%	1.5%	7.9%	1.2%	89.4%	2.1%	4.3%	1.5%	92.2%	6.0%	0.9%	2.7%	90.4%	2.2%	5.3%	3.1%	89.4%	0.8%	4.5%	0.5%	94.2%	5.2%	8.0%	7.5%	79.3%
2019	9.0%	7.8%	8.3%	74.9%	1.6%	8.0%	1.7%	88.8%	1.5%	5.2%	1.5%	91.8%	6.4%	1.0%	2.3%	90.2%	1.3%	5.4%	3.6%	89.7%	0.9%	4.7%	1.3%	93.1%	8.4%	7.9%	7.0%	76.7%

Generator Forced Outage Rates

The most fundamental forced outage rate metric is 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.[91] The EFORd metric includes all forced outages, regardless of the reason for those outages.

The average PJM EFORd in the first nine months of 2019 was 6.8 percent, an increase from 7.3 percent fin the first nine months of 2018. Figure 5-11 shows the average EFORd since 1999 for all units in PJM.[92]

Figure 5-11 Trends in the equivalent demand forced outage rate (EFORd): 1999 through 2019



91 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.
92 The universe of units in PJM changed as the PJM footprint expanded and as units retired from and entered PJM markets. See the 2018 State of the Market Report for PJM, Appendix A: "PJM Geography" for details.

Table 5-26 shows the class average EFORd by unit type.

Table 5-26 EFORd data for different unit types: January through September, 2007 through 2019

	Jan-Sep												
	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Coal	8.1%	9.2%	8.3%	9.1%	10.6%	9.5%	10.6%	12.1%	9.4%	10.3%	12.5%	13.3%	12.3%
Combined Cycle	3.7%	3.5%	4.8%	3.6%	3.1%	3.1%	2.6%	4.6%	2.8%	3.6%	2.4%	2.2%	2.0%
Combustion Turbine	11.4%	11.2%	8.9%	8.7%	7.5%	6.6%	10.3%	17.2%	9.7%	5.6%	5.3%	6.8%	5.1%
Diesel	12.3%	10.8%	8.8%	6.7%	9.8%	5.1%	6.1%	15.0%	9.7%	7.3%	7.1%	6.6%	7.0%
Hydroelectric	1.9%	2.5%	2.7%	1.3%	2.2%	5.1%	3.2%	3.1%	3.1%	2.9%	3.1%	2.8%	1.7%
Nuclear	1.2%	1.0%	4.3%	2.1%	2.4%	1.5%	1.3%	2.0%	1.2%	2.3%	0.6%	0.8%	1.0%
Other	10.8%	15.2%	14.3%	11.9%	13.9%	10.8%	16.6%	14.3%	13.1%	9.7%	13.0%	12.0%	14.9%
Total	6.8%	7.6%	7.6%	7.1%	7.7%	6.7%	8.1%	9.8%	7.0%	6.5%	6.9%	7.3%	6.8%

Other Forced Outage Rate Metrics

Under the capacity performance modifications to RPM, effective with the 2018/2019 Delivery Year, neither XEFORd nor EFORp are relevant.

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.[93] On a system wide basis, the resultant lost equivalent availability from the forced outages is equal to the equivalent forced outage factor (EFOF).

PJM EFOF was 4.4 percent in the first nine months of 2019. This means there was 4.4 percent lost availability because of forced outages. Table 5-27 shows that forced outages for boiler tube leaks, at 15.3 percent of the systemwide EFOF, were the largest single contributor to EFOF.

93 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.

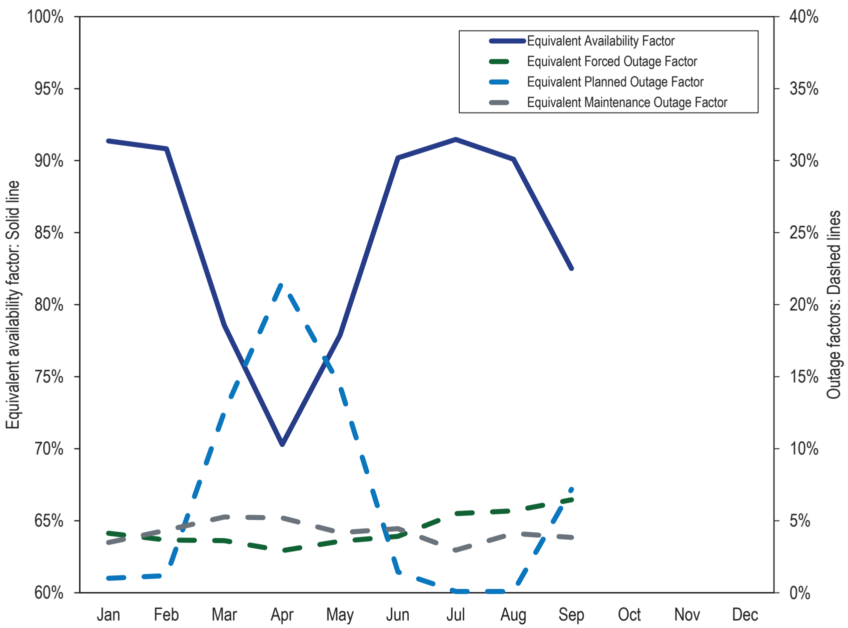
Table 5-27 Contribution to EFOF by unit type by cause: January through September, 2019

	Coal	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Other	System
Boiler Tube Leaks	20.6%	7.7%	0.0%	0.0%	0.0%	0.0%	6.7%	15.3%
Unit Testing	12.1%	3.8%	5.1%	33.9%	33.8%	7.0%	2.2%	9.8%
Economic	0.0%	1.8%	10.4%	1.6%	5.1%	0.0%	45.1%	7.9%
Boiler Air and Gas Systems	9.4%	0.1%	0.0%	0.0%	0.0%	0.0%	9.6%	7.8%
Miscellaneous (Pollution Control Equipment)	10.9%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	7.3%
Boiler Fuel Supply from Bunkers to Boiler	7.8%	0.3%	0.0%	0.0%	0.0%	0.0%	0.5%	5.3%
Electrical	3.6%	2.9%	22.9%	3.1%	3.1%	11.4%	1.8%	4.5%
Feedwater System	5.0%	1.1%	0.0%	0.0%	0.0%	16.4%	1.9%	4.4%
Wet Scrubbers	6.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	4.0%
Auxiliary Systems	3.4%	2.3%	12.8%	0.0%	0.1%	6.3%	0.1%	3.3%
High Pressure Turbine	0.7%	0.0%	0.0%	0.0%	0.0%	1.0%	16.6%	3.1%
Miscellaneous (Generator)	2.1%	2.0%	7.1%	4.7%	4.4%	3.5%	1.0%	2.3%
Boiler Piping System	2.1%	5.2%	0.0%	0.0%	0.0%	0.0%	0.4%	1.8%
Controls	0.5%	3.4%	1.6%	21.3%	2.2%	10.9%	1.9%	1.5%
Exciter	0.9%	9.3%	1.0%	0.6%	0.7%	5.4%	0.3%	1.5%
Intermediate Pressure Turbine	2.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.4%
Valves	0.8%	7.0%	0.0%	0.0%	0.0%	0.0%	1.9%	1.3%
Slag and Ash Removal	1.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.6%	1.2%
Miscellaneous (Steam Turbine)	0.6%	1.9%	0.0%	0.0%	0.0%	13.8%	0.1%	1.1%
All Other Causes	9.9%	51.3%	39.1%	35.0%	50.6%	24.3%	9.2%	15.2%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Performance by Month

On a monthly basis, unit availability as measured by the equivalent availability factor is shown in Figure 5-12.

Figure 5-12 Monthly generator performance factors: 2019



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 the first nine months of 2019, total demand response revenue decreased by $41.5 million, 9.5 percent, from $435.1 million in the first nine months of 2018 to $393.7 million in the first nine months of 2019. Emergency demand response revenue accounted for 98.8 percent of all demand response revenue, economic demand response for 0.2 percent, demand response in the Synchronized Reserve Market for 0.3 percent and demand response in the regulation market for 0.3 percent.

  Total emergency demand response revenue decreased by $37.3 million, 8.8 percent, from $426.3 million in the first nine months of 2018 to $389.0 million in the first nine months of 2019. This decreased consisted entirely of capacity market revenue.[2]

  Economic demand response revenue decreased by $1.5 million, 65.3 percent, from $2.3 million in the first nine months of 2018 to $0.8 million in the first nine months of 2019.[3] Demand response revenue in the Synchronized Reserve Market decreased by $2.1 million, 50.1 percent, from $4.2 million in the first nine months of 2018 to $2.1 million in the first nine months of 2019. Demand response revenue in the regulation market decreased by $0.5 million, 20.9 percent, from $2.3 million in the first nine months of 2018 to $1.8 million in the first nine months of 2019.

- **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 2018 and the first nine months of 2019. The HHI for economic resource reductions increased by 535 points from 7541 in the first nine months 2018 to 8076 in the first nine months of 2019. The ownership of emergency demand response resources was moderately concentrated in the first nine months of 2019. The HHI for emergency demand response committed MW was 1808 for the 2018/2019 Delivery Year and 1838 for the 2019/2020 Delivery Year. In the 2018/2019 Delivery Year, the four largest companies owned 78.1 percent of all committed demand response UCAP MW. In the 2019/2020 Delivery Year, the four largest companies owned 78.8 percent of all committed demand response UCAP MW.

- **Limited Locational Dispatch of Demand Resources.** Beginning with the 2014/2015 Delivery Year, demand resources that are not Capacity Performance, 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

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 October 15, 2019 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," § 11.2.2, Rev. 82 (July 25, 2019).

improve market efficiency. The goal should be nodal dispatch of demand resources with no advance notice required, as is the case for generation resources. With full implementation of the Capacity Performance rules in the capacity market starting with the 2020/2021 Delivery Year, PJM will be able to individually dispatch demand resources with no advanced notice, although PJM does not know the nodal location of demand resources.

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 September 30, 2019.

- 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. First reported 2013. Status: Not adopted.)
- The MMU recommends that the demand resources be treated as economic resources, 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 Interval. (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, if demand resources remain in the capacity market, 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 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 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.)

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

- The MMU recommends that PJM adopt the ISO-NE five-minute metering requirements in order to ensure that operators have the necessary information for reliability and that market payments to demand resources be calculated based on interval meter data at the site of the demand reductions.[6] (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends limited, extended summer and annual demand response event compliance be calculated on an hourly basis for noncapacity performance resources and on a five minute basis for all capacity performance resources and that the penalty structure reflect five minute compliance. (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.)

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 there be only one demand response product in the capacity market, with an obligation to respond when called for any hour of the delivery 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. First reported 2017. Status: Partially adopted.)
- The MMU recommends that PRD be required to respond during a PAI to be consistent with all CP resources. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends that the limits imposed on the pre-emergency and emergency demand response share of the Synchronized Reserve Market be eliminated. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that 30 minute pre-emergency and emergency demand response be considered to be 30 minute reserves. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that energy efficiency MW not be included in the PJM capacity market and that PJM should ensure that the impact of EE measures on the load forecast is incorporated immediately rather than with the existing lag. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that demand reductions based entirely on behind the meter generation be capped at the lower of economic maximum or actual generation output. (Priority: High. First reported Q2, 2019. Status: Not adopted.)

7 PJM's Capacity Performance design requires resources to respond when called for any hour of the delivery year.

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 how customers value 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. Demand resources do not have a must offer requirement into the day-ahead energy market, are able to offer above $1,000 per MWh without providing a fuel cost policy, or any rationale for the offer. PJM automatically triggers a PAI when demand resources are dispatched and demand resources do not have telemetry requirements similar to other Capacity Performance 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 interval (PAI) under the Capacity Performance design, both serve as a significant disincentive to calling on demand resources and mean that demand resources are underused. 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 with 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 Interval (PAI) will be measured on a five-minute 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 MMU peak shaving proposal at the Summer-Only Demand Response Senior Task Force (SODRSTF) is an example of how to create a demand side product that is on the demand side of the market and not on the supply side.[8] The MMU proposal was based on the BGE load forecasting program and Pennsylvania Act 129 Utility Program.[9] [10] Under the MMU proposal, participating load would inform PJM prior to an RPM auction of the MW participating, the months and hours of participation and the temperature humidity index (THI) threshold at which load would be reduced. PJM would reduce the load forecast used in the RPM auction based on the designated reductions. Load would agree to curtail demand to at or below a defined FSL, less than the customer PLC, when the THI exceeds a defined level or load exceeds a specified threshold. By relying on metered load and the PLC, load can reduce its demand for capacity and that reduction can be verified without complicated and inaccurate metrics to estimate load reductions. Under PJM's weakened version of the program, performance will be measured under the current economic demand response CBL rules which means relying on load estimates rather than actual metered load.[11] PJM's proposal includes only a THI curtailment trigger and not an overall load curtailment trigger.

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

8 See the MMU package within the *SODRSTF Matrix*, <http://www.pjm.com/-/media/committees-groups/task-forces/sodrstf/20180802/20180802-item-04-sodrstf-matrix.ashx>.

9 *Advance signals that can be used to foresee demand response days*, BGE, <https://www.pjm.com/-/media/committees-groups/task-forces/sodrstf/20180309/20180309-item-05-bge-load-curtailment-programs.ashx> (Accessed March 6, 2019).

10 *Pennsylvania ACT 129 Utility Program*, CPower, <https://www.pjm.com/-/media/committees-groups/task-forces/sodrstf/20180413/20180413-item-03-pa-act-129-program.ashx> (Accessed March 6, 2019).

11 The PJM proposal from the SODRSTF weakened the proposal but was approved at the October 25, 2018 Members Committee meeting and PJM filed Tariff changes on December 7, 2018. See "Peak Shaving Adjustment Proposal," Docket No. ER19-511-000 (December 7, 2018).

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.

The current PRD rules do not align with the definition of capacity under the Capacity Performance construct despite PJM's attempt to create alignment.[12] The PJM proposed rule changes do not require reductions during PAI unless LMP is above the specified price threshold. PJM incorrectly values PRD capacity and measured performance.[13] Similar to emergency and pre-emergency demand response, PJM would limit the nominated MW for PRD resources to the lower of the Peak Load Contribution (PLC) minus the Firm Service Level (FSL) times the loss factor (LF) or the Winter Peak Load (WPL) multiplied by the Zonal Winter Weather Adjustment Factor (ZWWAF) minus the winter Firm Service Level (wFSL) times the loss factor for each zone.

$$PRD\ Value = Min\{(PLC - FSL * LF), (WPL * ZWWAF - wFSL)\} * zonal\ loss\ factor$$

Use of the WPL would artificially limit the amount of MW that can participate as PRD if the WPL is less than the PLC. The Commission rejected PJM's filing regarding PRD on June 27, 2019 for these reasons.[14]

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 participate in the capacity market and energy market.[15] 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 and the resource has environmental restrictions that limit the resource's ability to operate only in emergency conditions.[16] Under current rules, PJM will declare an emergency if pre-emergency or emergency demand response is dispatched. In all demand response programs, CSPs are companies that sign up 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.

12 See "Proposed Amendments to Price Response Demand Rules," Docket No. ER19-1012- (February 7, 2019).
13 See "Comments of the Independent Market Monitor for PJM," Docket No. ER19-1012 (February 28, 2019).
14 See 167 FERC ¶ 61,268 (June 27, 2019).
15 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.
16 OA Schedule 1 § 8.5.

PRD does not receive direct 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.[17] PRD does not have to respond during performance assessment intervals (PAI) 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 PAI to be consistent with all CP resources. PRD first cleared the capacity market in the BRA for the 2020/2021 Delivery Year, and cleared for the 2021/2022 Delivery Year.[18]

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. 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.

17 The Demand Response Subcommittee (DRS) is currently working to align PRD with the CP designed products.

18 There were a total of 558 MW of cleared PRD in the 2020/2021 Delivery Year. See PJM Auction Results, <https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2020-2021-base-residual-auction-results.ashx?la=en>.

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.

Order No. 719 required PJM and other RTOs to amend their market rules to accept bids from aggregators of retail customers of utilities unless the laws or regulations of the relevant electric retail regulatory authority ("RERRA") do not permit the customers aggregated in the bid to participate.[19] PJM implemented rules that require PJM to verify with EDCs that no law or regulation of a RERRA prohibits an end use customers' participation.[20] EDCs and their end use customers are categorized as small and large based on whether the EDC distributed more or less than 4 million MWh in the previous fiscal year. End use customers within a large EDC must provide verification of any other contractual obligations or laws or regulations that prohibit participation, but end use customers within a small EDC do not need to

19 *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).

20 The evidence supplied by LDCs 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.

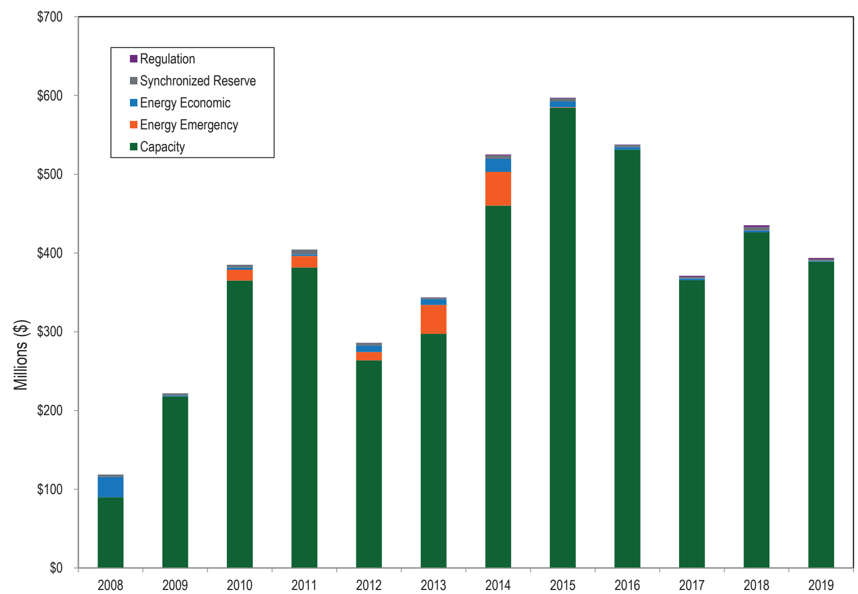
provide additional verification.[21] RERRAs have permitted EDCs, in a number of cases, to participate in the PJM Economic Load Response Program. There are 188 active RERRAs within PJM.

Figure 6-1 shows all revenue from PJM demand response programs by market for the first nine months of 2008 through 2019. Since the implementation of the RPM Capacity Market on June 1, 2007, the capacity market (demand resources) has been the primary source of demand response revenue.[22] In the first nine months of 2019, total demand response revenue decreased by $41.5 million, 9.5 percent, from $435.1 million in the first nine months of 2018 to $393.7 million in the first nine months of 2019. Total emergency demand response revenue decreased by $37.3 million, 8.8 percent, from $426.3 million in the first nine months of 2018 to $389.0 million in the first nine months of 2019. This decrease consisted entirely of capacity market revenue.[23] In the first nine months of 2019, demand resource revenue, which includes capacity and emergency energy revenue, accounted for 98.8 percent of all revenue received by demand response providers, the economic program for 0.2 percent, synchronized reserve for 0.5 percent and the regulation market for 0.5 percent.

Economic demand response revenue decreased by $1.5 million, 65.3 percent, from $2.3 million in the first nine months of 2018 to $0.8 million in the first nine months of 2019.[24] Demand response revenue in the Synchronized Reserve Market decreased by $2.1 million, 50.1 percent, from $4.2 million in the first nine months of 2018 to $2.1 million in the first nine months of 2019. Demand response revenue in the regulation market decreased by $0.5 million, 20.9 percent, from $2.3 million in the first nine months of 2018 to $1.8 million in the first nine months of 2019.

Lower demand resource revenues were in part a result of lower capacity market prices in the 2019/2020 RPM auction. The capacity revenue in 2018 is from 2017/2018 RPM and 2018/2019 RPM auction clearing prices and the capacity revenue in 2019 is from 2018/2019 RPM and 2019/2020 RPM auction clearing prices. The annual RTO capacity market prices decreased $64.77 per MW-day from $164.77 in the 2018/2019 Delivery Year to $100.00 in the 2019/2020 Delivery Year, a 39.3 percent increase.

Figure 6-1 Demand response revenue by market: January through September, 2008 through 2019



Economic Program

FERC Order No. 831 requires all energy offers above $1,000 per MWh to provide supporting documentation.[25] 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."[26] Demand resources participate in both the

21 PJM Operating Agreement Schedule 1 § 1.5A.3.1.
22 This includes both capacity market revenue and emergency energy revenue for capacity resources.
23 The total credits and MWh for demand resources were calculated as of October 15, 2019 and may change as a result of continued PJM billing updates. There was no emergency energy revenue in the first nine months of 2019.
24 Economic credits are synonymous with revenue received for reductions under the economic load response program.
25 157 FERC ¶ 61,115 (2016).
26 *Id.* at 8.

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 No. 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, 2015, through September 30, 2019. Registration is a prerequisite for CSPs to participate in the economic program. The monthly average number of registrations for economic demand response decreased and the monthly average registered MW increased in the first nine months of 2019 compared to the first nine months of 2018. Average monthly registrations decreased by 83, 18.3 percent, from 455 in the first nine months of 2018 to 372 in the first nine months of 2019. Average monthly registered MW increased by 218 MW, 8.4 percent, from 2,604 MW in the first nine months of 2018 to 2,822 MW in the first nine months of 2019.

Table 6-2 Economic program registrations on the last day of the month: 2015 through 2019[27]

	2015		2016		2017		2018		2019	
Month	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW
Jan	1,078	2,960	838	2,557	871	2,603	537	2,570	374	2,652
Feb	1,076	2,956	835	2,557	842	2,578	537	2,628	370	2,640
Mar	1,075	2,949	834	2,556	850	2,576	519	2,641	378	2,648
Apr	1,076	2,938	832	2,556	897	2,574	501	2,624	366	2,595
May	980	2,846	829	2,545	977	2,626	471	2,615	372	3,193
Jun	871	2,614	518	2,500	577	1,305	397	2,576	370	2,769
Jul	870	2,609	519	2,421	589	1,548	374	2,591	376	2,900
Aug	869	2,609	805	2,569	590	1,541	382	2,609	361	2,888
Sep	867	2,608	831	2,608	588	1,663	378	2,580	378	3,112
Oct	858	2,568	822	2,564	574	1,660	382	2,584		
Nov	851	2,566	820	2,564	559	1,662	381	2,581		
Dec	850	2,566	807	2,561	556	1,659	392	2,671		
Avg	974	2,788	774	2,547	706	2,000	438	2,606	372	2,822

Most economic demand response resources are registered in the emergency demand response program. Resources registered in both programs do not need to register for the same amount of MW. There are 144 registrations and 991 nominated MW in the economic program, or 183 registrations and 573 nominated MW in the emergency program.

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, but are not required to offer any MW. Table 6-3 shows the sum of peak economic MW dispatched by registration each month from January 1, 2010, through September 30, 2019. 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 increased by 63 MW, 8.4 percent, from 755 MW in the first nine months of 2018 to 818 MW in the first nine months of 2019.[28] The peak dispatched MW in the first nine months of 2019, 770 MW, were 2,052 MW less than the average MW registered in the first nine months of 2019, 2,801 MW.

27 Data for years 2010 through 2014 are available in the *2018 State of the Market Report for PJM.*

28 The total credits and MWh numbers for demand resources were calculated as of October 15, 2019 and may change as a result of continued PJM billing updates.

Table 6-3 Sum of peak MW reductions for all registrations per month: 2010 through September 2019

	Sum of Peak MW Reductions for all Registrations per Month									
Month	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Jan	183	132	110	193	446	169	139	123	142	88
Feb	121	89	101	119	307	336	128	83	70	58
Mar	115	81	72	127	369	198	120	111	71	38
Apr	111	80	108	133	146	143	118	54	71	41
May	172	98	143	192	151	161	131	169	70	22
Jun	209	561	954	433	483	833	121	240	105	26
Jul	999	561	1,631	1,088	665	1,362	1,316	936	518	770
Aug	794	161	952	497	358	272	249	141	581	28
Sep	276	84	451	530	795	816	263	140	112	8
Oct	118	81	242	168	214	136	150	88	69	
Nov	111	86	165	155	166	127	116	81	54	
Dec	114	88	98	168	155	122	147	83	11	
Annual	1,202	840	1,942	1,486	1,739	1,858	1,451	1,217	758	818

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.[29] The zonal allocation is shown in Table 6-13.

Table 6-4 shows the total MW reductions made by participants in the economic program and the total credits paid for these reductions in the first nine months of 2010 through 2019. The average credits per MWh paid decreased by $11.05 per MWh, 20.9 percent, from $52.76 per MWh in the first nine months of 2018 to $41.71 per MWh in the first nine months of 2019. The PJM real-time load-weighted, average LMP was 30.0 percent lower in the first nine months of 2019 than in the first nine months of 2018, $27.60 per MWh versus $39.43 per MWh. Curtailed energy for the economic program decreased by 25,207 MWh, 56.3 percent, from 44,735 MWh in the first nine months of 2018 to 19,528 MWh in the first nine months of 2019. Total credits paid for economic DR in the first nine months of 2018 decreased by $1.5 million, 65.5 percent, from $2.4 million in the first nine months of 2018 to $0.8 million in the first nine months of 2019.

Table 6-4 Credits paid to the PJM economic program participants: January through September, 2010 through 2019

(Jan-Sep)	Total MWh	Total Credits	$/MWh
2010	58,280	$2,677,937	$45.95
2011	15,376	$1,943,507	$126.40
2012	121,381	$8,172,654	$67.33
2013	105,299	$7,387,658	$70.16
2014	118,007	$16,510,733	$139.91
2015	103,721	$7,355,263	$70.91
2016	67,516	$3,032,039	$44.91
2017	49,331	$2,167,590	$43.94
2018	44,735	$2,360,007	$52.76
2019	19,528	$814,484	$41.71

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.[30] 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.[31] 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 January 1, 2010 through September 30, 2019.

29 "PJM Manual 28: Operating Agreement Accounting," § 11.2.2, Rev. 82 (July 25, 2019).

30 PJM. "Manual 11: Energy & Ancillary Services Market Operations," § 10.4.5, Rev. 107 (Sep. 26, 2019).

31 FERC Order No. 831.

Figure 6-2 Economic program credits and MWh by month: 2010 through September 2019

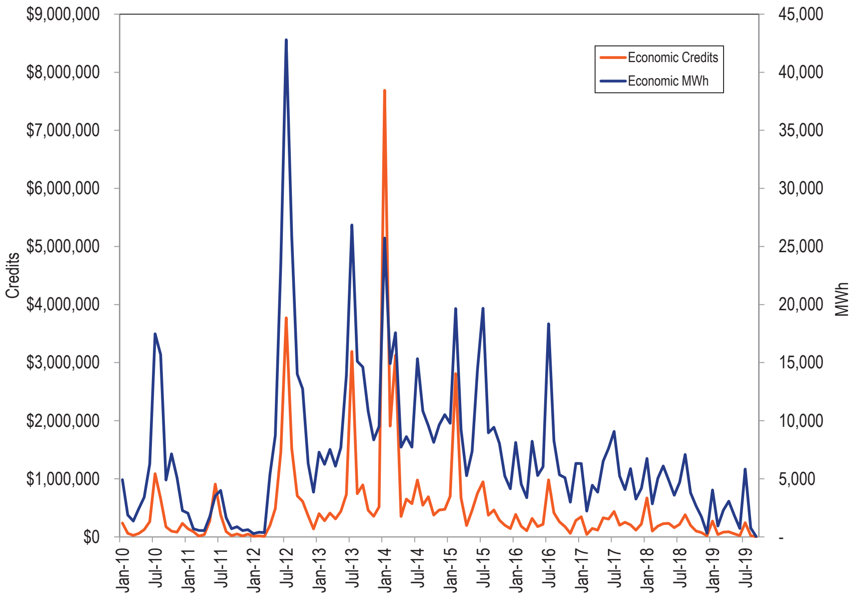


Table 6-5 shows performance for the first nine months of 2018 and 2019 in the economic program by control zone. Total reductions under the economic program decreased by 25,207 MWh, 56.3 percent, from 44,735 MW in the first nine months of 2018 to 19,528 MW in the first nine months of 2019. Total revenue under the economic program decreased by $1.5 million, 64.8 percent, from $2.3 million in the first nine months of 2018 to $0.8 million in the first nine months of 2019.[32]

32 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: January through September, 2018 and 2019

	Credits			MWh Reductions			Credits per MWh Reduction		
Zones	2018 (Jan-Sep)	2019 (Jan-Sep)	Percent Change	2018 (Jan-Sep)	2019 (Jan-Sep)	Percent Change	2018 (Jan-Sep)	2019 (Jan-Sep)	Percent Change
AECO	$0.00	$1,353.78	NA	115	41	(64.5%)	NA	$33.27	NA
AEP	$931.88	$3,848.34	313.0%	19	86	349.7%	$48.98	$44.98	(8.2%)
APS	$53,209.17	$70.19	(99.9%)	967	2	(99.8%)	$55.02	$42.15	(23.4%)
ATSI	$941,309.96	$9,355.23	(99.0%)	18,659	157	(99.2%)	$50.45	$59.71	18.4%
BGE	$152,018.22	$96,681.98	(36.4%)	2,692	2,352	(12.6%)	$56.47	$41.11	(27.2%)
ComEd	$172,215.00	$5,068.30	(97.1%)	4,685	176	(96.2%)	$36.76	$28.73	(21.8%)
DAY	$0.00	$0.00	NA	0	0	NA	NA	NA	NA
DEOK	$0.00	$2,922.39	NA	341	53	(84.4%)	NA	$55.16	NA
Dominion	$38,249.51	$267.33	(99.3%)	177	4	(97.9%)	$216.31	$71.78	(66.8%)
DPL	$0.00	$4,916.92	NA	(183)	150	(182.2%)	NA	$32.74	NA
DLCO	$0.00	$0.00	NA	0	0	NA	NA	NA	NA
JCPL	$250,025.99	$16,793.13	(93.3%)	3,612	338	(90.6%)	$69.22	$49.66	(28.3%)
Met-Ed	$38,665.88	$29,103.14	(24.7%)	821	664	(19.2%)	$47.09	$43.86	(6.9%)
OVEC	$0.00	$0.00	NA	0	0	NA	NA	NA	NA
PECO	$48,523.81	$125,165.86	157.9%	696	2,133	206.4%	$69.71	$58.68	(15.8%)
PENELEC	$122,502.06	$112,801.68	(7.9%)	4,000	3,464	(13.4%)	$30.62	$32.56	6.3%
Pepco	$0.00	$10,392.56	NA	(164)	313	(291.5%)	NA	$33.18	NA
PPL	$126,224.03	$143,383.61	13.6%	1,118	2,297	105.4%	$112.86	$62.43	(44.7%)
PSEG	$372,007.61	$252,359.64	(32.2%)	7,179	7,436	3.6%	$51.82	$33.94	(34.5%)
Total	$2,315,883.13	$814,484.08	(64.8%)	44,735	19,664	(56.0%)	$51.77	$41.42	(20.0%)

Table 6-6 shows total settlements submitted for the first nine months of 2010 through 2019. A settlement is counted for every day on which a registration is dispatched in the economic program.

Table 6-6 Settlements submitted in the economic program: January through September, 2010 through 2019

(Jan-Sep)	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Number of Settlements	3,367	703	5,334	2,358	2,425	1,851	1,524	1,417	1,263	875

Table 6-7 shows the number of CSPs, and the number of participants in their portfolios, submitting settlements for the first nine months of 2010 through 2019. The number of active participants decreased by seven, 12.1 percent, from 58 in the first nine months of 2018 to 51 in the first nine months of 2019. All participants must be registered through a CSP.

Table 6-7 Participants and CSPs submitting settlements in the economic program by year: January through September, 2010 through 2019

(Jan-Sep)	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Active CSPs	16	15	22	20	16	18	12	13	13	12
Active Participants	257	203	428	273	154	114	58	72	58	51

The ownership of economic demand response resources was highly concentrated in 2018 through September 2019.[33] Table 6-8 shows the average hourly HHI for each month and the average hourly HHI for January 1, 2018 through September 30, 2019. Table 6-8 also lists the share of reductions provided by, and the share of credits claimed by the four largest companies in each year. In the first nine months of 2019, 79.8 percent of all economic DR reductions and 72.3 percent of economic DR revenue were attributable to the four largest companies. The HHI for economic demand response increased by 535 from 7541 for the first nine months of 2018 to 8076 for the first nine months of 2019.

Table 6-8 Average hourly MWh HHI and market concentration in the economic program: January 2018 through September 2019[34]

	Average Hourly MWh HHI			Top Four Companies Share of Reduction			Top Four Companies Share of Credit		
Month	2018	2019	Percent Change	2018	2019	Change in Percent	2018	2019	Change in Percent
Jan	6576	6884	4.7%	92.3%	82.1%	10.2%	88.6%	78.1%	10.5%
Feb	8304	9382	13.0%	99.2%	94.7%	4.5%	99.1%	90.7%	8.4%
Mar	7498	7758	3.5%	96.1%	99.3%	(3.3%)	95.7%	99.1%	(3.4%)
Apr	6828	7457	9.2%	97.3%	99.4%	(2.1%)	97.2%	99.8%	(2.6%)
May	6688	7875	17.8%	98.3%	99.9%	(1.6%)	97.9%	99.9%	(2.0%)
Jun	8375	9623	14.9%	97.4%	99.9%	(2.5%)	96.2%	99.9%	(3.7%)
Jul	8256	8035	(2.7%)	90.2%	88.8%	1.4%	90.3%	86.1%	4.2%
Aug	7588	9364	23.4%	90.0%	99.9%	(9.9%)	89.3%	99.9%	(10.6%)
Sep	9306	9890	6.3%	97.4%			96.9%		
Oct	6805			95.6%			93.9%		
Nov	7038			91.6%			91.8%		
Dec	8082								
Total	7541	8076	7.1%	84.9%	79.9%	(5.0%)	84.5%	72.3%	(12.2%)

Table 6-9 shows average MWh reductions and credits by hour for the first nine months of 2018 and 2019. In the first nine months of 2018, 88.1 percent of reductions and 85.8 percent of credits occurred in hours ending 0900 to 2100, and in the first nine months of 2019, 89.2 percent of reductions and 85.5 percent of credits occurred in hours ending 0900 to 2100.

Table 6-9 Hourly frequency distribution of economic program MWh reductions and credits: January through September, 2018 and 2019

	MWh Reductions			Program Credits		
Hour Ending (EPT)	2018 (Jan-Sep)	2019 (Jan-Sep)	Percent Change	2018 (Jan-Sep)	2019 (Jan-Sep)	Percent Change
1 through 6	1,270	522	(59%)	$92,768	$31,808	(66%)
7	1,031	264	(74%)	$65,777	$17,158	(74%)
8	1,683	471	(72%)	$97,804	$29,217	(70%)
9	2,114	786	(63%)	$101,228	$32,979	(67%)
10	2,341	908	(61%)	$103,253	$33,546	(68%)
11	2,485	1,004	(60%)	$112,382	$38,085	(66%)
12	2,668	1,048	(61%)	$117,939	$33,185	(72%)
13	2,621	1,094	(58%)	$125,559	$37,501	(70%)
14	3,397	1,431	(58%)	$155,813	$50,468	(68%)
15	3,464	1,479	(57%)	$173,739	$51,749	(70%)
16	3,588	1,672	(53%)	$193,752	$59,574	(69%)
17	4,272	1,985	(54%)	$235,971	$77,238	(67%)
18	4,078	1,996	(51%)	$220,545	$102,582	(53%)
19	3,080	1,706	(45%)	$173,300	$73,861	(57%)
20	2,863	1,264	(56%)	$145,088	$52,278	(64%)
21	2,437	1,186	(51%)	$127,545	$53,341	(58%)
22	862	537	(38%)	$46,977	$24,961	(47%)
23 through 24	482	309	(36%)	$26,446	$14,954	(43%)
Total	44,735	19,664	(56%)	$2,315,883	$814,484	(65%)

Table 6-10 shows the distribution of economic program MWh reductions and credits by ranges of real-time zonal, load-weighted, average LMP in the first nine months of 2018 and 2019. In the first nine months of 2019, 1.0 percent of MWh reductions and 3.9 percent of program credits occurred during hours when the applicable zonal LMP was higher than $175 per MWh.

33 All HHI calculations in this section are at the parent company level. Parent companies may own one CSP or multiple CSPs.
34 December 2018 and September 2019 reduction and credit share percent are redacted based on confidentiality rules.

Table 6-10 Frequency distribution of economic program zonal, load-weighted, average LMP (By hours): January through September, 2018 and 2019

	MWh Reductions			Program Credits		
LMP	2018 (Jan-Sep)	2019 (Jan-Sep)	Percent Change	2018 (Jan-Sep)	2019 (Jan-Sep)	Percent Change
$0 to $25	3,876	4,282	10%	$69,164	$107,730	56%
$25 to $50	26,579	11,758	(56%)	$971,020	$431,293	(56%)
$50 to $75	6,238	2,052	(67%)	$360,293	$125,601	(65%)
$75 to $100	3,376	722	(79%)	$269,879	$55,223	(80%)
$100 to $125	1,449	394	(73%)	$142,668	$36,529	(74%)
$125 to $150	1,077	136	(87%)	$120,499	$11,657	(90%)
$150 to $175	563	124	(78%)	$69,726	$14,682	(79%)
> $175	1,578	196	(88%)	$312,632	$31,768	(90%)
Total	44,735	19,664	(56%)	$2,315,883	$814,484	(65%)

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.[35] 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 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 for the historical test from August 2010 through July 2011, and April 2012, when Order No. 745 was implemented in PJM, through September 2019. The NBT threshold price has never exceeded the lowest historical test result of $34.07 per MWh.

Table 6-11 Net benefits test threshold prices: August 2010 through September 2019

	Historical Test ($/MWh)	Net Benefits Test Threshold Price ($/MWh)								
Month	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Jan		$40.27		$25.72	$29.51	$29.63	$23.67	$32.60	$26.27	$29.44
Feb		$40.49		$26.27	$30.44	$26.52	$26.71	$31.57	$24.65	$23.49
Mar		$38.48		$25.60	$34.93	$24.99	$22.10	$30.56	$25.50	$22.15
Apr		$36.76	$25.89	$26.96	$32.59	$24.92	$19.93	$30.45	$25.56	$22.36
May		$34.68	$23.46	$27.73	$32.08	$23.79	$20.69	$29.77	$25.52	$21.01
Jun		$35.09	$23.86	$28.44	$31.62	$23.80	$20.62	$27.14	$23.59	$20.20
Jul		$36.78	$22.99	$29.42	$31.62	$23.03	$20.73	$24.42	$23.57	$19.76
Aug	$35.57		$24.47	$28.58	$29.85	$23.17	$23.24	$22.75	$23.53	$19.57
Sep	$34.07		$24.93	$28.80	$29.83	$21.69	$24.70	$21.51	$22.23	$18.19
Oct	$38.10		$25.96	$29.13	$30.20	$21.48	$26.50	$21.70	$23.84	
Nov	$36.83		$25.63	$31.63	$29.17	$22.28	$29.27	$26.41	$23.89	
Dec	$37.04		$25.97	$28.82	$29.01	$22.31	$29.71	$29.16	$26.35	
Average	$36.32	$37.51	$24.80	$28.09	$30.91	$23.97	$23.99	$27.34	$24.54	$21.80

Table 6-12 shows the number of hours that at least one zone in PJM had day-ahead LMP or real-time LMP higher than the NBT threshold price. In the first nine months of 2019, the highest zonal LMP in PJM was higher than the NBT threshold price 5,630 hours out of 6,551 hours, or 85.9 percent of all hours. Reductions occurred in 1,949 hours, 34.6 percent, of those 5,630 hours in the first nine months of 2019. The last three columns illustrate how often

35 "PJM Manual 11: Energy & Ancillary Services Market Operations," §10.3.1, Rev. 107 (Sep. 26, 2019).

economic demand response activity occurred when LMPs exceeded NBT threshold prices for January 1, 2018 through October 31, 2019. There are no economic payments when demand response occurs and zonal LMP is below the NBT threshold. Demand response reductions occurred in 0.05 percent (1 hour) of the hours in which LMP was below the NBT threshold price in the first nine months of 2019, and none of the hours in which LMP was below the NBT threshold price in 2018.

Table 6-12 Hours with price higher than NBT and DR occurrences in those hours: 2018 through September 2019

	Number of Hours		Number of Hours with LMP Higher than NBT			Percent of NBT Hours with DR		
Month	2018	2019	2018	2019	Percent Change	2018	2019	Percent Change
Jan	744	744	665	503	(24.4%)	62.9%	51.9%	(11.0%)
Feb	672	672	485	582	20.0%	44.7%	22.9%	(21.9%)
Mar	743	743	713	711	(0.3%)	58.3%	40.5%	(17.8%)
Apr	720	720	663	559	(15.7%)	73.8%	55.1%	(18.7%)
May	744	744	611	579	(5.2%)	62.7%	45.1%	(17.6%)
Jun	720	720	503	488	(3.0%)	64.0%	25.2%	(38.8%)
Jul	744	744	549	744	35.5%	74.0%	46.9%	(27.0%)
Aug	744	744	560	744	32.9%	72.5%	28.6%	(43.9%)
Sep	720	720	643	720	12.0%	64.2%	1.8%	(62.4%)
Oct	744		699			50.9%		
Nov	721		702			43.9%		
Dec	744		627			12.1%		
Total	8,760	6,551	7,420	5,630	(24.1%)	56.7%	34.6%	(22.1%)

Economic DR revenues are paid by real-time loads and real-time scheduled exports as an uplift charge. Table 6-13 shows the sum of real-time DR charges and day-ahead DR charges paid in each zone and paid by exports. Real-time loads in AEP paid the highest DR charges in the first nine months of 2019.

Table 6-13 Zonal DR charge: January through September, 2019

Zone	January	February	March	April	May	June	July	August	September	Total
AECO	$3,107	$402	$813	$712	$370	$251	$3,794	$304	$1	$5,655
AEP	$43,073	$6,115	$12,606	$14,331	$8,719	$3,283	$33,639	$3,595	$5	$88,128
APS	$18,269	$2,567	$5,104	$5,370	$3,330	$1,253	$12,897	$1,379	$2	$35,893
ATSI	$20,920	$3,150	$6,706	$7,709	$4,429	$1,672	$18,840	$1,934	$3	$44,587
BGE	$12,438	$1,635	$3,148	$3,355	$2,170	$924	$9,829	$976	$1	$23,670
ComEd	$18,936	$4,237	$8,395	$9,312	$5,596	$2,441	$30,921	$3,069	$3	$48,916
DAY	$6,000	$837	$1,776	$2,122	$1,188	$480	$4,974	$527	$1	$12,403
DEOK	$7,798	$1,224	$2,557	$2,943	$1,869	$762	$7,784	$828	$1	$17,153
Dominion	$36,308	$4,935	$9,651	$10,745	$7,510	$2,882	$29,996	$3,041	$5	$72,029
DPL	$7,438	$901	$1,691	$1,522	$706	$447	$6,093	$489	$1	$12,704
DLCO	$4,108	$623	$1,264	$1,464	$965	$366	$3,953	$418	$1	$8,790
EKPC	$4,559	$614	$1,299	$1,289	$817	$318	$3,477	$360	$1	$8,897
JCPL	$7,427	$911	$1,989	$1,863	$883	$566	$8,636	$681	$1	$13,639
Met-Ed	$5,815	$775	$1,522	$1,530	$814	$387	$4,433	$438	$1	$10,843
OVEC	$38	$6	$13	$13	$8	$3	$25	$3	$0	$81
PECO	$14,213	$1,755	$3,650	$3,583	$1,471	$903	$12,546	$1,012	$2	$25,575
PENELEC	$5,304	$860	$1,751	$1,940	$1,071	$410	$4,328	$454	$1	$11,336
Pepco	$11,147	$1,511	$2,897	$3,118	$2,155	$880	$9,303	$929	$1	$21,707
PPL	$15,052	$2,006	$4,004	$3,848	$1,699	$887	$10,966	$1,017	$2	$27,495
PSEG	$15,476	$1,711	$3,783	$3,709	$1,753	$1,034	$14,582	$1,206	$2	$27,467
RECO	$424	$59	$125	$136	$66	$42	$567	$47	$0	$852
Exports	$14,962	$1,827	$4,862	$5,507	$3,388	$990	$10,143	$1,029	$2	$31,536
Total	$272,811	$38,661	$79,605	$86,121	$50,976	$21,182	$241,725	$23,737	$35	$549,357

Table 6-14 shows the total zonal DR charge per MWh of real-time load and exports in the first nine months of 2019.

Table 6-14 Zonal DR charge per MWh of load and exports: January through September 2019

Zone	January	February	March	April	May	June	July	August	September	Zonal Average
AECO	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004
AEP	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004
APS	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004
ATSI	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003
BGE	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004
ComEd	$0.002	$0.002	$0.002	$0.002	$0.002	$0.002	$0.002	$0.002	$0.002	$0.002
DAY	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004
DEOK	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003
Dominion	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004
DPL	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004
DLCO	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003
EKPC	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003
JCPL	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004
Met-Ed	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004
OVEC	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003
PECO	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004
PENELEC	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003
Pepco	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004
PPL	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004
PSEG	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004
RECO	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004
Exports	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004
Monthly Average	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004

Table 6-15 shows the monthly day-ahead and real-time DR charges and the per MWh DR charges for 2018 through September 2019. The day-ahead DR charges decreased by $0.2 million, 32.3 percent, from $0.8 million in the first nine months of 2018 to $0.5 million in the first nine months of 2019. The real-time DR charges decreased $1.2 million, 79.9 percent, from $1.6 million in the first nine months of 2018 to $0.3 million in the first nine months of 2019.

Table 6-15 Monthly day-ahead and real-time economic DR charge: 2018 through September 2019

	Day-ahead DR Charge			Real-time DR Charge		
Month	2018	2019	Percent Change	2018	2019	Percent Change
Jan	$287,093	$150,139	(47.7%)	$381,071	$122,303	(67.9%)
Feb	$22,479	$22,811	1.5%	$77,584	$15,850	(79.6%)
Mar	$58,245	$71,143	22.1%	$125,482	$8,462	(93.3%)
Apr	$85,711	$84,808	(1.1%)	$140,688	$1,313	(99.1%)
May	$87,376	$47,488	(45.7%)	$143,598	$3,488	(97.6%)
Jun	$56,538	$18,261	(67.7%)	$101,014	$2,921	(97.1%)
Jul	$45,087	$81,306	80.3%	$153,191	$160,418	4.7%
Aug	$60,540	$19,893	(67.1%)	$308,315	$3,844	(98.8%)
Sep	$29,144	$0	(100.0%)	$152,727	$35	(100.0%)
Oct	$57,842			$40,317		
Nov	$32,131			$42,017		
Dec	$9,890			$6,369		
Total	$832,077	$495,849	(40.4%)	$1,672,373	$318,635	(80.9%)

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 in the 2020/2021 Delivery Year 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.[36] With the implementation of Capacity Performance, a performance assessment interval (PAI) occurs when emergency or pre-emergency is dispatched. PJM effectively eliminated the difference between pre-emergency and emergency by making both trigger a PAI. 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.[37]

The HHI for demand resources showed that ownership was highly concentrated for the 2018/2019 and 2019/2020 delivery years, with an HHI value of 1807 and 1838. In the 2018/2019 Delivery Year, the four largest companies contributed 78.1 percent of all committed demand resources UCAP MW and 78.8 percent of all committed demand resources UCAP MW in the 2019/2020 Delivery Year.

Table 6-16 shows the HHI value for committed UCAP MW by LDA by delivery year. The HHI values are calculated by the committed UCAP MW in each delivery year for demand resources.

36 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.

37 See "Complaint and Motion to Consolidate of the Independent Market Monitor for PJM," Docket No. EL14-20-000 (January 28, 2014), "Comments of the Independent Market Monitor for PJM," Docket No. ER15-852-000 (February 13, 2015).

Table 6-16 HHI value for committed UCAP MW by LDA by delivery year: 2018/2019 and 2019/2020 delivery years[38]

Delivery Year	LDA	Committed UCAP MW	HHI Value	HHI Concentration
2018/2019	RTO	3,387.6	2018	High
	MAAC	447.5	2473	High
	EMAAC	1,315.5	2156	High
	PSEG	143.4	2252	High
	PS-NORTH	95.6	2924	High
	PEPCO	533.7	5464	High
	ATSI	622.8	2573	High
	ATSI-CLEVELAND	150.5	4050	High
	COMED	1,938.6	2438	High
	BGE	493.2	5597	High
	PPL	496.2	2264	High
	DPL-SOUTH	500.4	8707	High
2019/2020	RTO	3,576.3	2018	High
	MAAC	463.8	2473	High
	EMAAC	900.3	2156	High
	PSEG	149.8	2252	High
	PS-NORTH	89.9	2924	High
	PEPCO	479.8	5464	High
	ATSI	705.9	2573	High
	ATSI-CLEVELAND	210.8	4050	High
	COMED	2,016.5	2438	High
	BGE	208.2	5597	High
	PPL	532.5	2264	High
	DPL-SOUTH	50.4	8707	High

Table 6-17 shows the committed demand response UCAP MW by delivery year. Total committed demand response UCAP MW in PJM increased by 257.6 MW, or 3.0 percent, from 8,727.0 MW in the 2018/2019 Delivery Year to 8,984.6 MW in the 2019/2020 Delivery Year. The DR percent of capacity increased by 0.1 percent, from 4.9 percent in the 2018/2019 Delivery Year to 5.0 percent in the 2019/2020 Delivery Year.

Table 6-17 Committed demand response UCAP MW for PJM: 2011/2012 through 2019/2020 delivery year

Delivery Year	DR Cleared MW UCAP	DR Percent of Capacity MW UCAP
2011/2012	2,509.1	1.4%
2012/2013	7,632.4	4.4%
2013/2014	8,218.3	4.6%
2014/2015	8,665.9	4.8%
2015/2016	11,340.2	6.4%
2016/2017	8,862.6	5.0%
2017/2018	8,458.4	4.6%
2018/2019	8,727.0	4.9%
2019/2020	8,984.6	5.0%

Table 6-18 shows zonal monthly capacity market revenue to demand resources for the first nine months of 2019. Capacity market revenue decreased in the first nine months of 2019 by $37.3 million, 8.8 percent, from $426.3 million in the first nine months of 2018 to $389.0 million in the first nine months of 2019. Lower demand resource revenues were in part a result of lower capacity market prices in the 2019/2020 RPM auction. The capacity revenue in the first nine months of 2018 is from 2017/2018 RPM and 2018/2019 RPM auction clearing prices and the capacity revenue in the first nine months of 2019 is from 2018/2019 RPM and 2019/2020 RPM auction clearing prices. The annual capacity market prices decreased $64.77 per MW-day from $164.77 in the 2018/2019 Delivery Year to $100.00 in the 2019/2020 Delivery Year, a 39.3 percent increase.

38 The RTO LDA refers to the rest of RTO.

Table 6-18 Zonal monthly capacity revenue: January through September, 2019

Zone	January	February	March	April	May	June	July	August	September	Total
AECO	$1,063,052	$960,176	$1,063,052	$1,028,760	$1,063,052	$436,515	$451,066	$451,066	$436,515	$6,953,251
AEP, EKPC	$7,363,738	$6,651,118	$7,363,738	$7,126,198	$7,363,738	$3,867,902	$3,996,832	$3,996,832	$3,867,902	$51,597,996
APS	$4,638,234	$4,189,373	$4,638,234	$4,488,614	$4,638,234	$2,285,119	$2,361,289	$2,361,289	$2,285,119	$31,885,504
ATSI	$4,254,499	$3,842,773	$4,254,499	$4,117,257	$4,254,499	$2,344,392	$2,422,538	$2,422,538	$2,344,392	$30,257,388
BGE	$1,471,812	$1,329,378	$1,471,812	$1,424,334	$1,471,812	$630,148	$651,153	$651,153	$630,148	$9,731,748
ComEd	$11,763,628	$10,625,212	$11,763,628	$11,384,156	$11,763,628	$9,639,882	$9,961,211	$9,961,211	$9,639,882	$96,502,438
DAY	$1,082,665	$977,891	$1,082,665	$1,047,740	$1,082,665	$533,882	$551,678	$551,678	$533,882	$7,444,747
DEOK	$996,130	$899,730	$996,130	$963,997	$996,130	$608,291	$628,567	$628,567	$608,291	$7,325,835
DLCO	$3,841,793	$3,470,007	$3,841,793	$3,717,864	$3,841,793	$1,760,122	$1,818,792	$1,818,792	$1,760,122	$25,871,078
Dominion	$2,760,840	$2,493,662	$2,760,840	$2,671,780	$2,760,840	$1,133,435	$1,171,216	$1,171,216	$1,133,435	$18,057,265
DPL	$1,229,930	$1,110,904	$1,229,930	$1,190,255	$1,229,930	$599,460	$619,442	$619,442	$599,460	$8,428,752
JCPL	$1,324,124	$1,195,983	$1,324,124	$1,281,410	$1,324,124	$605,867	$626,062	$626,062	$605,867	$8,913,624
Met-Ed	$1,527,708	$1,379,865	$1,527,708	$1,478,427	$1,527,708	$775,740	$801,598	$801,598	$775,740	$10,596,093
OVEC	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
PECO	$3,342,110	$3,018,680	$3,342,110	$3,234,300	$3,342,110	$1,582,953	$1,635,718	$1,635,718	$1,582,953	$22,716,652
PENELEC	$1,811,449	$1,636,148	$1,811,449	$1,753,015	$1,811,449	$830,090	$857,760	$857,760	$830,090	$12,199,210
Pepco	$806,881	$728,796	$806,881	$780,853	$806,881	$142,570	$147,322	$147,322	$142,570	$4,510,076
PPL	$2,314,965	$2,090,936	$2,314,965	$2,240,289	$2,314,965	$1,801,961	$1,862,026	$1,862,026	$1,801,961	$18,604,095
PSEG	$2,521,890	$2,277,836	$2,521,890	$2,440,539	$2,521,890	$1,157,439	$1,196,021	$1,196,021	$1,157,439	$16,990,965
RECO	$48,971	$44,232	$48,971	$47,392	$48,971	$30,889	$31,919	$31,919	$30,889	$364,154
Total	$54,164,419	$48,922,701	$54,164,419	$52,417,179	$54,164,419	$30,766,656	$31,792,211	$31,792,211	$30,766,656	$388,950,870

Table 6-19 shows the amount of energy efficiency (EE) resources in PJM on June 1 for the 2012/2013 through 2018/2019 delivery years. EE resources may participate in PJM without restrictions imposed by a state unless the Commission authorizes a state to impose restrictions.[39] Only Kentucky has been authorized by the Commission.[40] Energy efficiency resources are offered in the PJM Capacity Market. The total MW of energy efficiency resources committed increased by 20.2 percent from 2,117.9 MW in the 2017/2018 Delivery Year to 2,545.1 MW in the 2018/2019 Delivery Year.[41]

Table 6-19 Energy efficiency resources (MW): June 1, 2012 to June 1, 2018

	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
01-Jun-18	2,545.1

Figure 6-3 shows the amount of installed EE MW in PJM by technology for the 2018/2019 and 2019/2020 delivery years. An installed EE resource may participate as a capacity resource for up to a maximum of four consecutive delivery years.[42] The lighting category consists of more efficient lighting technology installed, HVAC consists of more efficient HVAC technology installed, new construction consists of more efficient equipment than the industry average for individual components, appliances consists of more efficient appliances and prescriptive consists of more efficient equipment procured by an incentive program for lighting, HVAC or appliances. 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. Prescriptive energy efficiency MW comprise 87.2 percent of all energy efficiency MW in the 2018/2019 Delivery Year and 86.5 percent in the 2019/2020 Delivery Year. The measurement and verification method for prescriptive energy efficiency projects relies on unverified assumptions and is too imprecise to rely on as a source of capacity comparable to capacity from a power plant.

39 *See* 161 FERC ¶ 61,245 at P 57 (2017); 107 FERC ¶ 61,272 at P 8 (2008).

40 The Commission made an exception for Kentucky when it determined that RERRAs must obtain FERC approval prior to excluding EE, explaining that "the Commission accepted such condition at the time the Kentucky Commission approved the integration of Kentucky Power into PJM." 161 FERC ¶ 61,245 at P 67.

41 See the *2018 State of the Market Report for PJM*, Vol. 2, Section 5: Capacity Market, Table 5-13.

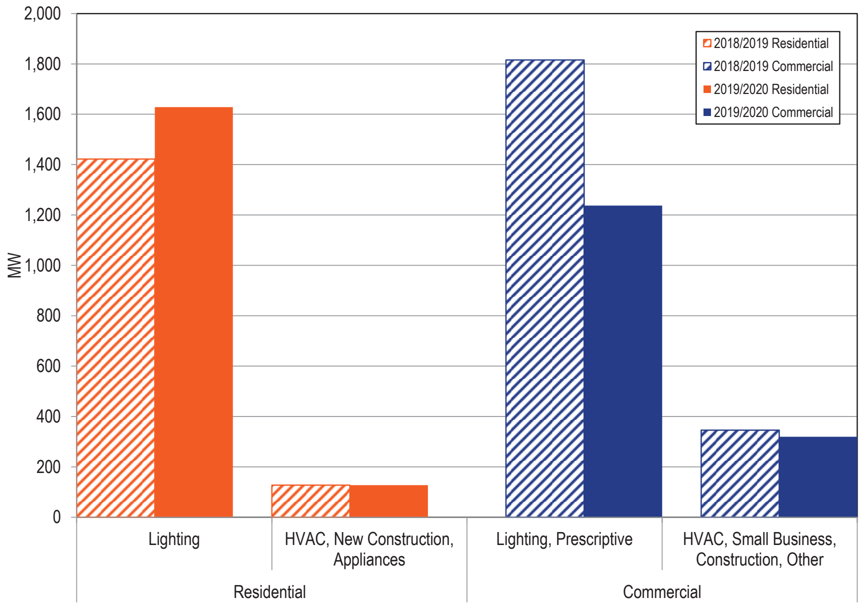
42 PJM. "Manual 18: Capacity Market," § 4.4, Rev. 42 (July 25, 2019).

All EE resources must submit pre and post installation M&V plans that include the variables that affect the project's electrical demand, baseline consumption, post installation consumption, and specifications of the equipment or types of equipment used in the project. The nonprescriptive measurement and verification methods do not use full metering but rely on samples and assumptions and only for limited periods.[43] The nominated EE value is the expected average demand reduction during: the peak hours ending 15:00 EPT through 18:00 EPT for June 1 through August 31; and the peak hours ending 8:00 EPT through 9:00 EPT and 19:00 EPT through 20:00 EPT for all days between January 1 and February 28, of the relevant delivery year.[44] The calculated MW are offered in PJM's Capacity Market as EE. The installed EE resources for the 2018/2019 Delivery Year include any installed EE resource between June 1, 2014 and May 31, 2018, and installed EE resources for the 2019/2020 Delivery Year include any installed EE resources between June 1, 2015 and May 31, 2019.

The MMU recommends that energy efficiency MW not be included in the PJM capacity market. The measurement and verification protocols for energy efficiency are too imprecise to rely on as a source of capacity. Energy efficiency measures reduce energy usage and capacity usage directly. The reduced market payments are the appropriate compensation. PJM should ensure that the impact of EE measures on the load forecast is incorporated immediately rather than with the existing lag.

43 PJM. "Manual 18B: Energy Efficiency Measurement & Verification," § 2.2 Rev. 3 (November 17, 2016).
44 PJM. "Manual 18B: Energy Efficiency Measurement & Verification," § 1.1 Rev. 3 (November 17, 2016).

Figure 6-3 Installed energy efficiency MW by type: 2018/2019 and 2019/2020 delivery years



FERC accepted PJM's proposed 30 minute lead time as a phased in approach on May 9, 2014, effective on June 1, 2015.[45] 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.[46] 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.[47] 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.[48] Once a location is granted a longer lead time,

45 See 147 FERC ¶ 61,103 (2014).
46 See PJM Interconnection, L.L.C., Docket No. ER14-135-000 (October 20, 2014).
47 See "PJM Manual 18: Capacity Market," § 4.3.1, Rev. 42 (July 25, 2019).
48 "PJM Manual 18: PJM Capacity Market," § 4.3.1, Rev. 42 (July 25, 2019).

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 6-20 shows the amount of nominated MW and locations by product type and lead time for the 2018/2019 Delivery Year. PJM approved 3,022 locations, or 20.6 percent of all locations, which have 3,944.1 nominated MW, or 43.9 percent of all nominated MW, for exceptions to the 30 minute lead time rule for the 2018/2019 Delivery Year.[49]

Table 6-20 Nominated MW and locations by product type and lead time: 2018/2019 Delivery Year

	Pre-Emergency MW					Emergency MW					
Lead Type	Limited	Annual	Base	Capacity Performance	Pre-Emergency Total	Limited	Annual	Base	Capacity Performance	Emergency Total	Total
Quick Lead (30 Minutes)	311.9	6.8	4,179.5	305.2	4,803.3	0.2	0.0	221.6	18.9	240.7	5,044.0
Short Lead (60 Minutes)	23.2	0.0	367.8	65.5	456.5	0.0	0.0	26.4	0.0	26.4	483.0
Long Lead (120 Minutes)	122.8	0.0	2,666.4	527.7	3,316.9	0.0	0.0	144.2	0.0	144.2	3,461.1
Total	457.8	6.8	7,213.6	898.4	8,576.7	0.2	0.0	392.3	18.9	411.4	8,988.1
	Pre-Emergency Locations					Emergency Locations					
Lead Type	Limited	Annual	Base	Capacity Performance	Pre-Emergency Total	Limited	Annual	Base	Capacity Performance	Emergency Total	Total
Quick Lead (30 Minutes)	167	2	10,154	732	11,055	4	0	518	57	579	11,634
Short Lead (60 Minutes)	12	0	297	30	339	0	0	42	0	42	381
Long Lead (120 Minutes)	33	0	2,010	379	2,422	0	0	219	0	219	2,641
Total	212	2	12,461	1,141	13,816	4	0	779	57	840	14,656

Table 6-21 shows the amount of nominated MW and locations by product type and lead time for the 2019/2020 Delivery Year. PJM approved 3,106 locations, or 20.9 percent of all locations, which have 3,902.1 nominated MW, or 40.6 percent of all nominated MW, for exceptions to the 30 minute lead time rule for the 2019/2020 Delivery Year.

Table 6-21 Nominated MW and locations by product type and lead time: 2019/2020 Delivery Year

	Pre-Emergency MW			Emergency MW			
Lead Type	Base	Capacity Performance	Pre-Emergency Total	Base	Capacity Performance	Emergency Total	Total
Quick Lead (30 Minutes)	5,298.4	159.1	5,457.5	238.4	17.7	256.1	5,713.6
Short Lead (60 Minutes)	326.7	36.3	363.0	27.2	0.0	27.2	390.3
Long Lead (120 Minutes)	2,933.8	428.2	3,362.0	148.3	1.4	149.8	3,511.8
Total	8,558.9	623.6	9,182.6	414.0	19.1	433.1	9,615.7
	Pre-Emergency Locations			Emergency Locations			
Lead Type	Base	Capacity Performance	Pre-Emergency Total	Base	Capacity Performance	Emergency Total	Total
Quick Lead (30 Minutes)	10,886	356	11,242	514	26	540	11,782
Short Lead (60 Minutes)	288	8	296	53	0	53	349
Long Lead (120 Minutes)	2,048	425	2,473	281	3	284	2,757
Total	13,222	789	14,011	848	29	877	14,888

49 For analysis of the 2017/2018 Delivery Year, *see 2018 Quarterly State of the Market Report: January through September*, Section 6: Demand Response, at Emergency and Pre-Emergency Programs. <http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2018/2018q3-som-pjm-sec6.pdf>.

There are two different ways to measure load reductions of demand resources. The Firm Service Level (FSL) method, applied to the summer, measures the difference between a customer's peak load contribution (PLC) and real-time load, multiplied by the loss factor (LF).[50] 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.[51] With the introduction of the Winter Peak Load (WPL) concept, effective for the 2017/2018 Delivery Year, both the FSL and GLD methods are modified for the non-summer period. The FSL method measures compliance during the non-summer period as the difference between a customer's WPL multiplied by the Zonal Winter Weather Adjustment Factor (ZWWAF) and the LF, rather than the PLC, and real-time load, multiplied by the LF. PJM calculates and posts on the PJM website the ZWWAF as the zonal winter weather normalized peak divided by the zonal average of the five coincident peak loads in December through February.[52] The Winter Peak Load is adjusted up for transmission and distribution line loss factors because one MW of load would be served by more than one MW of generation to account for transmission losses. The Winter Peak Load is normalized based on the winter conditions during the five coincident peak loads in winter using the ZWWAF to account for an extreme temperatures or a mild winter. The GLD method measures compliance during the non-summer period as the minimum of: the comparison load minus real-time load multiplied by the loss factor; or the WPL multiplied by the ZWWAF and the LF, rather than the PLC, minus the real-time load multiplied by the LF.[53]

The Capacity Market is an annual market. A Capacity Performance resource has an annual commitment. Load is allocated capacity obligations based on the annual peak load which is a summer load. The amount of MW allocated to load does not vary based on winter demand. 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.[54] LSEs generally allocate capacity costs to customers based on the five coincident peak method.[55] The allocation of capacity costs to customers uses 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 FSL and GLD equations for calculating load reductions are:

$$FSL\ Compliance_{Summer} = PLC - (Load \cdot LF)$$

$$FSL\ Compliance_{Non-Summer} = (WPL \cdot ZWWAF \cdot LF) - (Load \cdot LF)$$

$$GLD\ Compliance_{Summer} = Minimum\{(comparison\ load - Load) \cdot LF; PLC - (Load \cdot LF)\}$$

$$GLD\ Compliance_{Non-Summer} = Minimum\{(comparison\ load - Load) \cdot LF; (WPL \cdot ZWWAF \cdot LF) - (Load \cdot LF)\}$$

Table 6-22 shows the MW registered by measurement and verification method and by technology type for the 2018/2019 Delivery Year. For the 2018/2019 Delivery Year, 99.7 percent use the FSL method and 0.3 percent use the GLD measurement and verification method.

50 Real-time load is hourly metered load.
51 135 FERC ¶ 61,212.
52 "PJM Manual 18: PJM Capacity Market," § 4.3.7, Rev. 42 (July 25, 2019).
53 "PJM Manual 18: PJM Capacity Market," § 8.7A, Rev.42 (July 25, 2019).
54 OATT Attachment DD.5.11.
55 OATT Attachment M-2.

Table 6-22 Reduction MW by each demand response method: 2018/2019 Delivery Year

	Technology Type								
Measurement and Verification Method	On-site Generation MW	HVAC MW	Refrigeration MW	Lighting MW	Manufacturing MW	Water Heating MW	Batteries and Plug Load MW	Total	Percent by type
Firm Service Level	1,056.4	2,857.5	178.8	849.5	3,856.2	116.6	45.7	8,960.6	99.7%
Guaranteed Load Drop	0.8	8.8	0.0	0.7	16.4	0.1	0.5	27.4	0.3%
Total	1,057.2	2,866.3	178.8	850.2	3,872.6	116.6	46.2	8,988.0	100.0%
Percent by method	11.8%	31.9%	2.0%	9.5%	43.1%	1.3%	0.5%	100.0%	

Table 6-23 shows the MW registered by measurement and verification method and by technology type for the 2019/2020 Delivery Year. For the 2019/2020 Delivery Year, 99.7 percent use the FSL method and 0.3 percent use the GLD measurement and verification method.

Table 6-23 Reduction MW by each demand response method: 2019/2020 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	1,053.1	3,239.0	187.8	940.3	3,923.8	122.5	51.1	9,517.6	99.7%
Guaranteed Load Drop	0.4	12.3	0.0	1.4	15.1	0.1	0.3	29.5	0.3%
Total	1,053.5	3,251.2	187.8	941.8	3,938.8	122.6	51.4	9,547.1	100.0%
Percent by method	11.0%	34.1%	2.0%	9.9%	41.3%	1.3%	0.5%	100.0%	

Table 6-24 shows the fuel type used in the onsite generators for the 2018/2019 Delivery Year in the emergency and pre-emergency programs. During the 2018/2019 Delivery Year, 1,057.2 MW of the 8,988.0 MW of nominated MW, 11.8 percent, used onsite generation. Of the 1,057.2 MW, 82.7 percent of MW are diesel and 17.3 percent of MW are natural gas, gasoline, oil, propane or waste products. For the 2018/2019 Delivery Year, there was 354.5 MW of the 411.4 MW, 86.2 percent, registered with an onsite generator in the emergency program.

Table 6-24 Onsite generation fuel type (MW): 2018/2019 Delivery Year

	2018/2019	
Fuel Type	MW	Percent
Diesel	874.4	82.7%
Natural Gas, Gasoline, Oil, Propane, Waste Products	182.8	17.3%
Total	1,057.2	100.0%

Table 6-25 shows the fuel type used in the onsite generators for the 2019/2020 Delivery Year in the emergency and pre-emergency programs. During the 2019/2020 Delivery Year, 1,053.5 MW of the 9,547.1 MW of nominated MW, 11.0 percent, used onsite generation. Of the 1,053.5 MW, 85.9 percent of MW are diesel and 14.1 percent of MW are natural gas, gasoline, oil, propane or waste products. For the 2019/2020 Delivery Year, there were 284.9 MW of the 433.1 MW, 65.7 percent, registered with an onsite generator in the emergency program.

Table 6-25 Onsite generation fuel type (MW): 2019/2020 Delivery Year

	2019/2020	
Fuel Type	MW	Percent
Diesel	905.3	85.9%
Natural Gas, Gasoline, Oil, Propane, Waste Products	148.2	14.1%
Total	1,053.5	100.0%

Emergency and Pre-Emergency Event Reported Compliance

Subzonal dispatch became mandatory for emergency demand resources in the 2014/2015 Delivery Year, if the subzone was defined by PJM no later than the day before the dispatch.[56] PJM does not measure compliance when demand response is dispatched in a subzone created on the same day as the dispatch. There are thirteen dispatchable subzones in PJM effective September 21, 2018: 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.[57] Effective with the 2020/2021 Delivery Year, PJM will procure a single capacity product, Capacity Performance, which does not require predefined subzones for mandatory dispatch.[58]

PJM can remove a defined subzone, and make changes to the 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.[59] 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 20 closed loop interface definitions, 11 (55 percent) were created for the purpose of allowing emergency DR to set price.[60] 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, ATSI-CLEVELAND and BGE LDAs.

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 limited, extended summer and annual 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.

Capacity Performance demand resources currently estimate five minute compliance with an hourly interval meter during PAIs. To accurately measure compliance on a five minute basis, a five minute interval meter is required. All other Capacity Performance resources require five minute interval meters, and demand resources should be no different. Limited, extended summer and annual demand resources are paid based on the average performance by registration for the duration of a demand response event. Each capacity performance demand response product should measure compliance on a five minute basis to accurately report reductions during demand response events. The current rules for limited, extended summer and annual demand response use the average reduction for the duration of an event. The average duration across multiple hours does not provide an accurate metric for each

56 OATT Attachment DD, Section 11.
57 See "Load Management Subzones," <http://www.pjm.com/~/media/markets-ops/demand-response/subzone-definition-workbook.ashx> (Accessed February 25, 2019).
58 OATT Attachment DD, Section 10A.
59 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).
60 See the *2018 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.

five minute interval of the event and is inconsistent with the measurement of generation resources. Measuring compliance on a five minute basis would provide accurate information to the PJM system. The MMU recommends limited, extended summer and annual demand response event compliance be calculated on an hourly basis for noncapacity performance resources and on a five minute basis for all capacity performance resources and that the penalty structure reflect five minute compliance.[61]

Annual and capacity performance demand response currently assign annual reduction capability by registration, which is measured as the lower of the summer and winter reduction capability. Starting with the 2019/2020 Delivery Year, CSPs will assign the annual reduction capability by portfolio rather than registration, which is measured as the lower of the summer and winter reduction capability by portfolio.[62] Allowing CSPs to aggregate to the portfolio level further weakens the locational aspect of registered demand resources and artificially inflates the level of demand response. For example, imagine a CSP has two registrations in a zonal portfolio, with one registration capable of reducing 5 MW in summer and 2 MW in winter, and the second registration capable of reducing 1 MW in summer and 5 MW in winter. Before the 2019/2020 Delivery Year, the first registration would have an annual capability of 2 MW and the second registration would have an annual capability of 1 MW resulting in a 3 MW total reduction capability. After the 2019/2020 Delivery Year, individual registration capability is ignored resulting in the portfolio capability of 6 MW in summer and 7 MW in winter. This creates a 6 MW total reduction capability within the zone. Without any change to either registration, the CSP was able to add 3 MW to their annual reduction capability. The locational availability of demand resources, at a nodal level, will vary. This treatment is unique to demand resources.

Under the capacity performance design of the PJM Capacity Market, compliance for potential penalties will be measured for DR only during performance assessment intervals (PAI).[63] When pre-emergency or emergency demand response is dispatched, a PAI is triggered for PJM. PJM cannot dispatch pre-emergency or emergency demand response without triggering a PAI and measuring compliance. Before PJM created PAI to measure compliance, pre-emergency demand response could be dispatched without calling an emergency event. As a result, PJM now effectively 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 interval (PAI) for CP compliance. Emergencies should be triggered only when PJM has exhausted all economic resources including demand response resources. Table 6-26 shows the amount of nominated demand response MW, the required reserve margin and actual reserve margin as of June 1, for 2017, 2018 and 2019. There are 8,988.1 nominated MW of demand response for the 2018/2019 Delivery Year, which is 40.0 percent of the required reserve margin and 28.1 percent of the actual reserve margin on June 1, 2018.[64] There are 9,547.1 nominated MW of demand response for the 2019/2020 Delivery Year, which is 42.8 percent of the required reserve margin and 24.2 percent of the actual reserve margin on June 1, 2019.

Table 6-26 Demand response nominated MW compared to reserve margin: June 1, 2017 through 2019

	Demand Response Nominated MW	Required Reserve Margin	Demand Response Percent of Required Reserve Margin	Actual Reserve Margin	Demand Response Percent of Actual Reserve Margin
01-Jun-17	9,154.7	23,305.2	39.3%	33,828.1	27.1%
01-Jun-18	8,998.1	22,487.7	40.0%	31,987.5	28.1%
01-Jun-19	9,547.1	22,297.5	42.8%	39,401.6	24.2%

PJM will dispatch demand resources by zone or subzone for limited, extended summer and annual demand resources, or within a PAI area for Capacity Performance resources. When PJM dispatches all demand resources in multiple connecting zones, PJM further degrades the nodal design of electricity markets. PJM allows compliance to be measured across zones within a compliance aggregation area (CAA) or Emergency Action Area

61 "PJM Manual 18: Capacity Market," § 8.7A, Rev. 42 (July 25, 2019).
62 The seasonal DR registration aggregation received endorsement at the September 27, 2018 MRC meeting, <https://www.pjm.com/-/media/committees-groups/committees/mc/20180927/20180927-consent-agenda-item-b-seasonal-dr-registration-aggregation-draft-oatt-revisions.ashx>.
63 OATT § 1 (Performance Assessment Hour).
64 *2018 State of the Market Report for PJM*, Volume 2, Section 5: Capacity, Table 5-7.

(EAA).[65] [66] A CAA, or EAA, 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. 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. With full implementation of capacity performance, demand response will be dispatched by registrations within an area for which an Emergency Action is declared by PJM. PJM does not have the nodal location of each registration, meaning PJM will need to guess as to the useful demand response registration by registered location. 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.

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.[67]

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.

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

65 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.

66 PJM. "Manual 18: Capacity Market," § 8.7.2, Rev. 42 July 25, 2019).

67 OA Schedule 1 § 8.9.

a zero MW reduction value.[68] 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.[69] The CBL must use the RRMSE test to verify that it is a good approximation for real-time load usage. The MMU recommends the RRMSE test be required for all demand resources with a CBL.

The CBL for a customer is an estimate of what load would have been if the customer had not responded to LMP and reduced load. The difference between the CBL and real-time load is the energy reduction. When load responds to LMP by using a behind the meter generator, the energy reduction should be capped at the generation output. Any additional energy reduction is a result of inaccuracy in the CBL estimate rather than an actual reduction. The MMU recommends that demand reductions based entirely on behind the meter generation be capped at the lower of economic maximum or actual generation output.

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."[70] 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.[71] The registered customers that are bankrupt and the amount of registered MW cannot be released for reasons of confidentiality.

The metering requirement for demand resources is outdated, and has not kept up with the changes to PJM's market design. PJM moved to five minute settlements, but the metering requirement for demand resources remained at an hourly interval meter. It is impossible to measure energy usage on a five minute basis using an hourly interval meter. PJM will estimate real-time usage by prorating the hourly interval meter and assume if load is less than the CBL, that the reduction occurred during the required dispatch window. The meter

68 OA Schedule 1 § 8.9.
69 157 FERC ¶ 61,067 (2016).
70 OA Schedule 1 § 8.2.
71 There was one proposal from PJM, one proposal from a market participant and one proposal from the MMU. See *Approved Minutes from the Market Implementation Committee*, <http://www.pjm.com/-/media/committees-groups/committees/mic/20170607/20170607-minutes.ashx>.

reading is not telemetered to PJM in real time. The resource is allowed up to 60 days to report the data to PJM. 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 so that they can accurately measure compliance.[72]

When demand resources are not dispatched during a mandatory response window, each CSP must test their portfolio to the levels of capacity commitment.[73] 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. Given that demand resources are now an annual product, multiple tests are required to ensure reduction capability year round. 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 6-27 shows the test penalties by delivery year by product type for the 2015/2016 Delivery Year through the 2018/2019 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. 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.[74] There were 98.2 percent of nominated MW for the 2017/2018 Delivery Year and 98.8 percent of nominated MW for the 2018/2019 Delivery Year registered under the full program option. There were 1.8 percent of nominated MW for the 2017/2018 Delivery Year and 1.2 percent of nominated MW for the 2018/2019 Delivery Year registered as capacity only option. Demand resources clear the capacity market like all other capacity resources and the dispatch of demand resources should not trigger a scarcity event. 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

Table 6-27 Test penalties by delivery year by product type: 2015/2016 through 2018/2019

	2015/2016			2016/2017			2017/2018			2018/2019		
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	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	$631,665	0.0	$179.80	$2,100
Extended Summer	1.9	$163.70	$113,835	7.3	$138.14	$370,290	10.5	$142.86	$547,928			
Annual	3.7	$184.67	$250,621	4.8	$137.45	$241,406	16.3	$144.00	$855,940			
Base DR and EE										16.3	$186.80	$1,110,134
Capacity Performance				2.1	$160.80	$124,310	0.6	$181.80	$40,146			
Total	102.0	$166.02	$6,200,711	63.1	$160.72	$3,703,163	41.3	$137.54	$2,075,678	16.3	$186.79	$1,112,234

72 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.

73 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. 42 (July 25, 2019).

74 *Id.*

per MWh minimum dispatch price and an associated shutdown cost. 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. FERC has stated clearly that demand resources in the capacity market must verify costs above $1,000 per MWh, unless they are capacity only. "We clarify, however, that reforms adopted in this Final Rule, which provide that resources are eligible to submit cost-based incremental energy offers in excess of $1,000/MWh and require that those offers be verified, do not apply to capacity-only demand response resources that do not submit incremental energy offers in energy markets."[75] PJM interprets the scarcity pricing rules to allow a maximum DR energy price of $1,849 per MWh for the 2017/2018 Delivery Year and the 2018/2019 Delivery Year.[76] [77] Demand resources registered with the full option should be required to verify energy offers in excess of $1,000 per MWh. PJM does not require such verification.[78] The MMU recommends that the maximum offer for demand resources be the same as the maximum offer for generation resources.

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.[79]

Table 6-28 shows the distribution of registrations and associated MW in the emergency full option across ranges of minimum dispatch prices for the 2018/2019 Delivery Year. The majority of participants, 76.8 percent of locations and 53.9 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 2018/2019 Delivery Year, 2.3 percent of locations and 4.0 percent of nominated MW have a dispatch price between $0 and $1,000 per MWh, and 97.7 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 $1,000 to $1,275 per MWh strike prices had the highest average at $173.97 per location and $130.17 per nominated MW.

Table 6-28 Distribution of registrations and associated MW in the full option across ranges of minimum dispatch: 2018/2019 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-$1,000	338	2.3%	350.6	4.0%	$69.18	$55.03
$1,000-$1,275	2,666	18.4%	3,355.9	37.9%	$173.97	$130.17
$1,275-$1,550	361	2.5%	380.6	4.3%	$51.11	$48.48
$1,550-$1,849	11,159	76.8%	4,775.2	53.9%	$51.43	$120.18
Total	14,524	100.0%	8,862.3	100.0%	$74.33	$121.81

Table 6-29 shows the distribution of registrations and associated MW in the emergency full option across ranges of minimum dispatch prices for the 2019/2020 Delivery Year. The majority of participants, 75.3 percent of locations and 56.7 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 2019/2020 Delivery Year, 3.6 percent of locations and 3.6 percent of nominated MW have a dispatch price between $0 and $1,000 per MWh, and 96.4 percent of locations and 96.4 percent of nominated MW have a dispatch price above $1,000 per MWh. The shutdown cost of resources with $1,000 to $1,275 per MWh strike prices had the highest average at $181.51 per location and $141.57 per nominated MW.

75 161 FERC ¶ 61,153 (2017).
76 139 FERC ¶ 61,057 (2012).
77 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.
78 OATT Attachment K Appendix Section 1.10.1A Day-ahead Energy Market Scheduling (d) (x).
79 "PJM Manual 15: Cost Development Guidelines," § 8.1, Rev. 32 (May 13, 2019).

Table 6-29 Distribution of registrations and associated MW in the full option across ranges of minimum dispatch: 2019/2020 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-$1,000	530	3.6%	339.5	3.6%	$46.98	$86.48
$1,000-$1,275	2,761	18.8%	3,397.5	35.9%	$181.51	$141.57
$1,275-$1,550	350	2.4%	364.9	3.9%	$57.49	$55.14
$1,550-$1,849	11,073	75.3%	5,370.6	56.7%	$49.77	$102.62
Total	14,714	100.0%	9,472.5	100.0%	$74.57	$115.84

Distributed Energy Resources

Distributed Energy Resources (DER) are not well defined, but generally include small scale generation directly connected to the grid, generation connected to distribution level facilities and behind the meter generation.[80] For example, Table 6-24 shows the fuel mix of behind the meter generation participating as emergency demand response in the 2018/2019 Delivery Year. Clear rules for defining DERs and for defining the ways in which DERs will interact with the wholesale power markets do not yet exist, although the development of those rules is under active discussion.[81] [82] DERs should be treated like other resources. Creating preferential treatment for DERs could create an incentive to move resources behind the meter in a manner inconsistent with efficiency and competitive markets. FERC directed that DER aggregation be as geographically broad as technically feasible.[83]

The current demand response rules appropriately restrict demand response from injecting power into the grid and receiving demand response revenue. At the January 30, 2019, Demand Response Subcommittee meeting, PJM without a stakeholder process or FERC approval, decided to allow some economic DR payments when DR injects power into the grid. PJM's test compares the total benefits of running the generator which includes generation payments and assumed retail rate savings against the total cost of the generator. If the total cost of the generator is greater than the benefits, then the resource would receive economic DR payments while injecting. The use of a retail rate in calculating wholesale power market benefits raises significant issues analogous to net metering that require discussion and tariff changes. PJM should not include retail rate benefits in the definition of demand response without approval of FERC.

Aggregation to a single node is technically feasible. Allowing DER aggregation across nodes is not necessary and is not consistent with the nodal market design. Getting the rules correct at the beginning of DER development is essential to the active and effective participation of DER in the wholesale power markets in a manner that enhances rather than undercuts the efficiency and competitiveness of the power markets.

80 Some energy storage facilities may be DERs. The February 15, 2018, FERC Order No. 841 requires that energy storage resources have access to capacity, energy and ancillary service markets. 162 FERC ¶ 61,127, at P 1 (2018).
81 In PJM, the Distributed Energy Resources Subcommittee (DERSC) is currently discussing these issues. *Distributed Energy Resources Subcommittee*, PJM, <http://www.pjm.com/committees-and-groups/subcommittees/ders.aspx>.
82 See "Notice of Technical Conference," Docket No. RM18-9-000 and AD18-10-000 (February 15, 2018); "Technical Conference Distributed Energy Resources," Docket No. RM18-9-000 and AD18-10-000 (April 10, 2018).
83 162 FERC ¶ 32,718 at P 139 (2016).

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 (NP), solar, and wind generating units.

Overview

Net Revenue

- Energy net revenues are significantly affected by energy prices and fuel prices. Energy prices were significantly lower in the first nine months of 2019 than in the first nine months of 2018 largely as a result of lower gas prices.
- In the first nine months of 2019, average energy market net revenues decreased by 52 percent for a new CT, 36 percent for a new CC, 82 percent for a new CP, 32 percent for a new nuclear plant, 74 percent for a new DS, 29 percent for a new on shore wind installation, 29 percent for a new off shore wind installation and 19 percent for a new solar installation compared to the first nine months of 2018.
- The relative prices of fuel varied during the first nine months of 2019. As a result, the marginal cost of the new CC was consistently below that of the new CP in 2019, and the marginal cost of the new CT was above that of the new CP in January.
- Nuclear unit revenue is a combination of energy market revenue and capacity market revenue. Negative prices do not have a significant impact on nuclear unit revenue. Since 2014, negative prices have affected nuclear plants' annual revenues by an average of 0.1 percent.[1]

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 CCs for three representative locations shows that CC units that entered the PJM markets in 2007 have not covered 100 percent of their total costs, including the return on and of capital, on a cumulative basis. The analysis also shows that theoretical new entrant Theoretical new entrant CCs that entered the PJM markets in 2012 have covered their total costs on a cumulative basis in the BGE Zone but have not covered 100 percent of total costs in the PSEG or ComEd zones. Energy market revenues alone were not sufficient to cover total costs in any scenario, which demonstrates the critical role of the capacity market revenue in covering total costs.

1 Analysis is based on actual unit generation and received energy market and capacity market revenues. Negative prices in the DA and RT market were set to zero for the comparison.

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. CC units that entered the PJM markets in 2007 have not covered 100 percent of their total costs, including the return on and of capital, on a cumulative basis. CCs that entered the PJM markets in 2012 have covered their total costs on a cumulative basis in the BGE Zone but have not covered 100 percent of total costs in the PSEG or ComEd zones. Energy market revenues alone were not sufficient to cover total costs in any scenario, which demonstrates the critical role of the capacity market revenue in covering total costs.

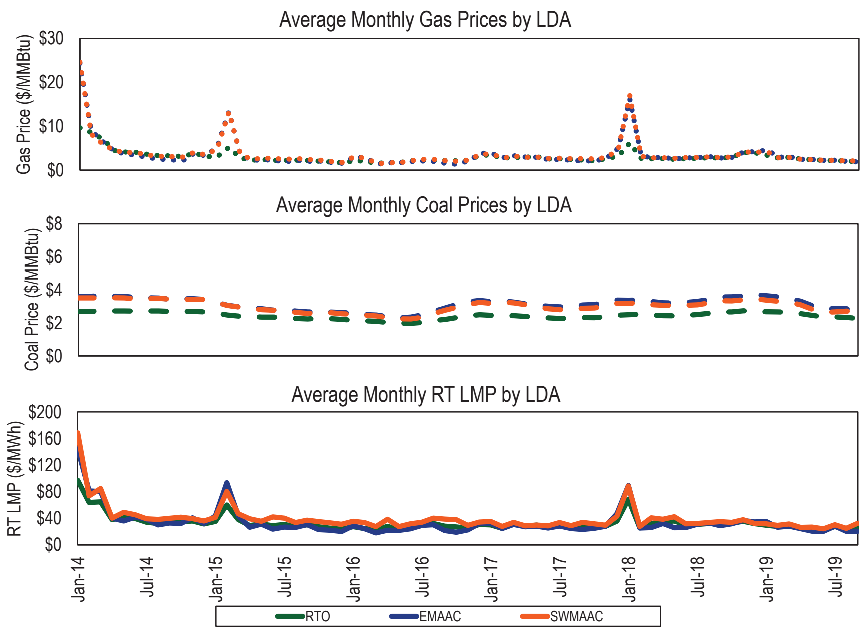
Net Revenue

When compared to annualized fixed costs and avoidable 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 short run marginal 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. Net revenues cover fixed costs, which include a return on investment, depreciation and income taxes, and avoidable costs, which include long term and intermediate term operation and maintenance expenses. Net revenue is the contribution to total fixed and avoidable costs received by generators from all PJM markets.

In a perfectly competitive, energy only market in long run equilibrium, net revenue from the energy market would be expected to equal the total of all annualized fixed and avoidable 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 and avoidable costs. In PJM, the energy, capacity and ancillary service markets are all significant sources of revenue to cover the fixed and avoidable 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 and avoidable 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 30.0 percent lower in the first nine months of 2019 than in the first nine months of 2018, $27.60 per MWh versus $39.43 per MWh. Eastern and western natural gas prices decreased in the first nine months of 2019. The price of Northern Appalachian coal was 5.2 percent lower; the price of Central Appalachian coal was 2.8 percent lower; the price of Powder River Basin coal was 0.06 percent higher; the price of eastern natural gas was 39.6 percent lower; and the price of western natural gas was 12.7 percent lower (Figure 7-1).

Figure 7-1 Energy market net revenue factor trends: 2014 through September 2019



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. Spreads are lower in the first nine months of 2019 as a result of lower energy prices.

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): 2014 through September 2019

	BGE			ComEd			PSEG			Western Hub		
	Spark	Dark	Quark	Spark	Dark	Quark	Spark	Dark	Quark	Spark	Dark	Quark
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
2018	$15.64	$25.17	$41.16	$12.42	$26.62	$29.27	$7.61	$12.35	$34.23	$15.83	$21.05	$37.04
2019 (Jan-Sep)	$16.22	$15.57	$28.49	$11.07	$21.55	$23.15	$9.40	$4.16	$23.11	$13.00	$12.23	$25.15

Table 7-2 Peak hour spread standard deviation ($/MWh): 2014 through September 2019

	BGE			ComEd			PSEG			Western Hub		
	Spark	Dark	Quark	Spark	Dark	Quark	Spark	Dark	Quark	Spark	Dark	Quark
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
2018	$50.5	$36.9	$36.9	$17.0	$18.0	$17.9	$51.9	$33.3	$33.2	$42.3	$30.5	$30.4
2019 (Jan-Sep)	$27.3	$27.5	$27.3	$19.9	$19.9	$19.9	$20.9	$23.7	$24.1	$21.8	$21.5	$21.5

Figure 7-2 shows the hourly spark spread, Figure 7-3 shows the hourly dark spread, and Figure 7-4 shows the hourly quark spread for peak hours for BGE, ComEd, PSEG, and Western Hub.

Figure 7-2 Hourly spark spread (gas) for peak hours ($/MWh): 2018 through September 2019[2]

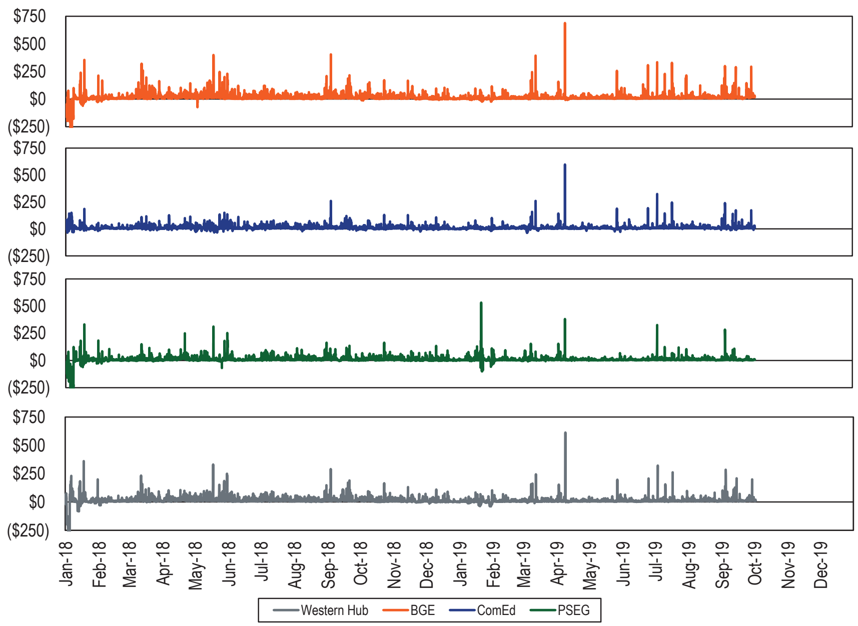
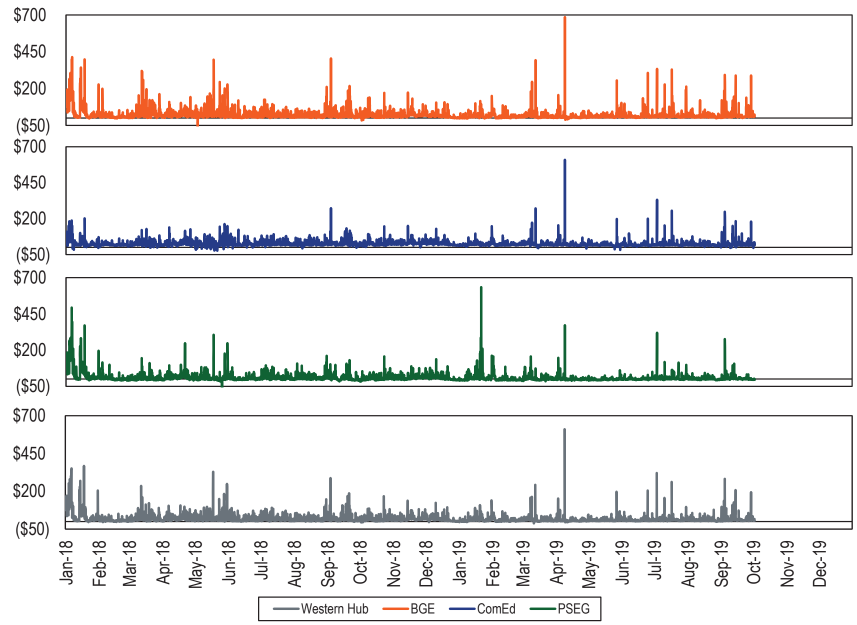


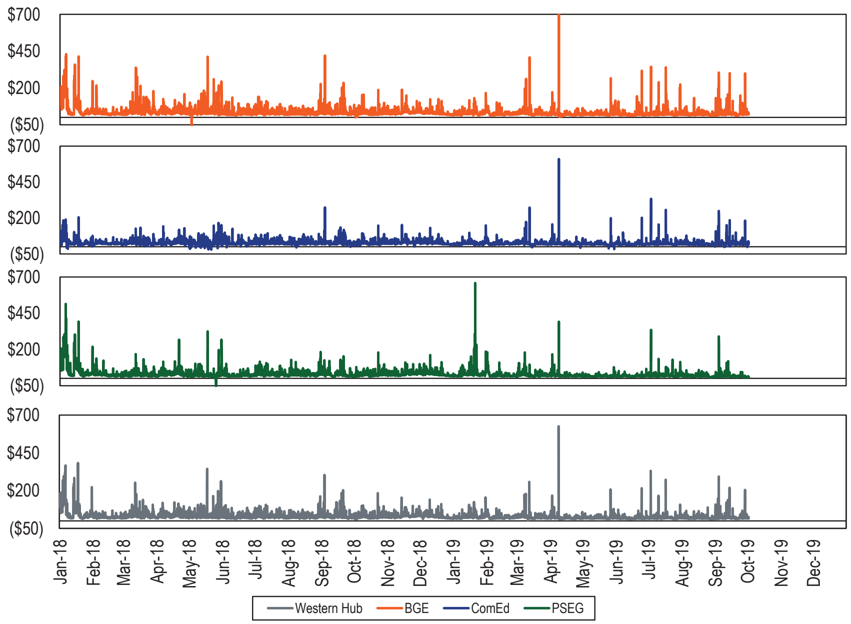
Figure 7-3 Hourly dark spread (coal) for peak hours ($/MWh): 2018 through September 2019[3]



2 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.

3 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): 2018 through September 2019[4]



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.

The analysis in this quarterly report includes only energy revenues unless explicitly stated. The analysis in the annual state of the market report includes revenues from all PJM markets.

4 Quark spreads use a heat rate of 10,000 Btu/kWh, zonal hourly LMPs, and daily uranium prices.

Analysis of energy market net revenues for a new entrant includes seven power plant configurations:

- The CT plant has an installed capacity of 360.1 MW and consists of one GE Frame 7HA.02 CT, equipped with evaporative coolers and selective catalytic reduction (SCR) for NO_x reduction.
- 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.
- 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 on shore wind installation consists of 37 Siemens 2.7 MW wind turbines totaling 99.9 MW installed capacity.
- The off shore wind installation consists of 43 Siemens 7.0 MW wind turbines totaling 301.0 MW installed capacity.
- The solar installation consists of a 35.5 acre ground mounted solar farm totaling 10 MW of AC installed capacity.

Net revenue calculations for the CT, CC and CP include the hourly effect of actual local ambient air temperature on plant heat rates and generator output for each of the three plant configurations.[5] [6] Plant heat rates account for the efficiency changes and corresponding cost changes resulting from ambient air temperatures.

5 Hourly ambient conditions supplied by DTN.
6 Heat rates provided by Pasteris Energy, Inc. No-load costs are included in the dispatch price since each unit type is dispatched at full load for every economic hour resulting in a single offer point.

CO_2, NO_x and SO_2 emission allowance costs are included in the hourly plant dispatch cost, the short run marginal cost. CO_2, NO_x and SO_2 emission allowance costs were obtained from daily spot cash prices.[7]

A forced outage rate for each class of plant was calculated from PJM data and incorporated into all revenue calculations.[8] In addition, each CT, CC, CP, and DS plant was assumed to take a continuous 14 day planned annual outage in the fall season.

Zonal net revenues reflect zonal fuel costs based on locational fuel indices and zone specific delivery charges.[9] The delivered fuel cost for natural gas reflects the zonal, daily delivered price of natural gas and is from published commodity daily cash prices, with a basis adjustment for transportation costs.[10] The delivered cost of coal reflects the zone specific, delivered price of coal and was developed from the published prompt-month prices, adjusted for rail transportation costs.[11]

Short run marginal cost includes fuel costs, emissions costs, and the short run marginal component of VOM costs.[12] [13] Average short run marginal costs are shown, including all components, in Table 7-3 and the short run marginal component of VOM is also shown separately.

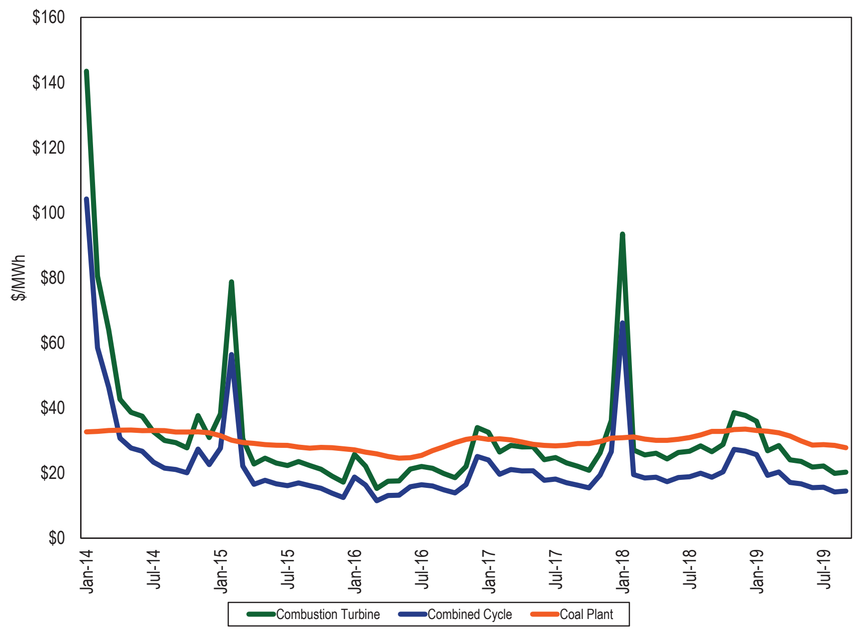
Table 7-3 Average short run marginal costs: 2019

Unit Type	Short Run Marginal Costs ($/MWh)	Heat Rate (Btu/kWh)	VOM ($/MWh)
CT	$24.76	9,241	$0.38
CC	$17.63	6,296	$1.39
CP	$30.33	9,250	$4.16
DS	$149.64	9,660	$0.25
Nuclear	$8.50	NA	$3.00
Wind	$0.00	NA	$0.00
Wind (off shore)	$0.00	NA	$0.00
Solar	$0.00	NA	$0.00

7 CO_2, NO_x and SO_2 emission daily prompt prices obtained from Evolution Markets, Inc.
8 Outage figures obtained from the PJM eGADS database.
9 Startup fuel burns and emission rates provided by Pasteris Energy, Inc. Startup station power consumption costs were obtained from the station service rates published quarterly by PJM and netted against the MW produced during startup at the preceding applicable hourly LMP. All starts associated with combined cycle units are assumed to be hot starts.
10 Gas daily cash prices obtained from Platts.
11 Coal prompt prices obtained from Platts.
12 Fuel costs are calculated using the daily spot price and may not equal what participants actually paid.
13 VOM rates provided by Pasteris Energy, Inc.

A comparison of the monthly average short run marginal cost of the theoretical CT, CC and CP plants since 2014, shows that, on average, the short run marginal costs of the CC plant have been less than those of the CP plant but 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: 2014 through September 2019



The net revenue measure does not include the potentially significant contribution from the explicit or implicit sale of the option value of physical units or from bilateral agreements to sell output at a price other than the PJM day-ahead or real-time energy market prices, e.g., a forward price.

Gas prices, coal prices, and energy prices are reflected in new entrant run hours. Table 7-4 shows the average run hours by a new entrant unit.

Table 7-4 Average run hours: January through September, 2014 through 2019

Jan-Sep	CT	CC	CP	DS	Nuclear
2014	3,550	6,076	5,364	149	6,576
2015	4,664	6,277	4,744	128	6,576
2016	5,208	6,446	4,082	39	6,600
2017	3,790	6,394	3,538	25	6,576
2018	4,176	6,346	3,822	111	6,576
2019	4,210	6,347	3,970	110	6,576

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.

New entrant CT plant energy market net revenues were lower across all zones as a result of lower energy prices (Table 7-5).

Table 7-5 Energy net revenue for a new entrant gas fired CT under economic dispatch: January through September, 2014 through 2019 (Dollars per installed MW-year)[14 15]

Zone	2014 (Jan-Sep)	2015 (Jan-Sep)	2016 (Jan-Sep)	2017 (Jan-Sep)	2018 (Jan-Sep)	2019 (Jan-Sep)	Change in 2019 from 2018
AECO	$70,291	$41,814	$48,435	$22,948	$27,422	$21,251	(23%)
AEP	$64,588	$55,063	$50,081	$27,247	$68,355	$33,736	(51%)
APS	$86,998	$86,557	$54,420	$32,488	$69,756	$18,475	(74%)
ATSI	$47,314	$47,988	$48,357	$28,655	$80,782	$35,095	(57%)
BGE	$84,875	$60,674	$82,780	$33,327	$48,822	$26,630	(45%)
ComEd	$29,986	$25,143	$31,020	$18,633	$30,583	$19,000	(38%)
DAY	$42,462	$44,119	$46,688	$27,795	$76,816	$38,746	(50%)
DEOK	$38,812	$41,410	$44,531	$26,522	$85,230	$35,126	(59%)
DLCO	$37,358	$62,998	$64,564	$35,542	$52,279	$23,743	(55%)
Dominion	$56,788	$51,349	$57,727	$28,766	$53,481	$28,123	(47%)
DPL	$56,255	$28,069	$25,508	$11,148	$22,397	$13,864	(38%)
EKPC	$57,355	$43,284	$43,488	$22,698	$51,626	$27,612	(47%)
JCPL	$71,528	$40,965	$43,643	$26,583	$28,326	$20,257	(28%)
Met-Ed	$69,297	$72,808	$64,489	$44,115	$40,101	$23,938	(40%)
PECO	$71,223	$71,492	$61,121	$35,226	$36,142	$19,291	(47%)
PENELEC	$116,333	$120,664	$80,204	$42,743	$77,782	$30,839	(60%)
Pepco	$61,877	$39,578	$42,603	$21,116	$39,895	$16,338	(59%)
PPL	$182,403	$139,815	$65,767	$39,806	$79,855	$21,883	(73%)
PSEG	$87,014	$83,251	$65,437	$40,729	$40,962	$21,497	(48%)
RECO	$63,584	$46,476	$47,818	$27,903	$30,502	$21,377	(30%)
PJM	$58,381	$60,176	$53,434	$29,700	$52,056	$24,841	(52%)

14 The energy net revenues presented for the PJM area in this section represent the zonal average energy net revenues.
15 Energy net revenues presented for 2018 have been updated since the 2017 State of the Market Report for a one CT configuration and updated gas pipelines.

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.[16] If the unit was not already committed day ahead, it was run in real time in standalone profitable blocks of at least four hours, or any profitable hours bordering the profitable day-ahead or real-time block.

New entrant CC plant energy market net revenues were lower in all zones as a result of lower energy prices (Table 7-6).

Table 7-6 Energy net revenue for a new entrant CC under economic dispatch: January through September, 2014 through 2019 (Dollars per installed MW-year)[17]

Zone	2014 (Jan-Sep)	2015 (Jan-Sep)	2016 (Jan-Sep)	2017 (Jan-Sep)	2018 (Jan-Sep)	2019 (Jan-Sep)	Change in 2019 from 2018
AECO	$121,349	$70,652	$64,666	$44,271	$56,680	$47,947	(15%)
AEP	$104,577	$88,253	$70,759	$50,215	$103,001	$65,063	(37%)
APS	$148,258	$134,825	$91,312	$61,663	$114,032	$55,382	(51%)
ATSI	$77,890	$80,718	$69,506	$50,924	$114,505	$66,264	(42%)
BGE	$150,000	$108,367	$121,090	$64,426	$92,328	$66,460	(28%)
ComEd	$45,859	$47,649	$49,605	$34,123	$52,475	$41,334	(21%)
DAY	$70,963	$77,411	$68,527	$51,240	$111,681	$70,837	(37%)
DEOK	$62,724	$72,609	$65,471	$48,360	$118,841	$66,349	(44%)
DLCO	$70,582	$84,560	$81,638	$56,362	$85,949	$51,149	(40%)
Dominion	$101,049	$86,641	$80,724	$52,875	$85,317	$59,337	(30%)
DPL	$100,664	$49,225	$44,126	$20,673	$39,983	$22,308	(44%)
EKPC	$92,252	$75,371	$63,371	$44,587	$85,519	$57,575	(33%)
JCPL	$124,951	$70,098	$59,894	$47,934	$57,600	$47,513	(18%)
Met-Ed	$116,448	$99,480	$77,701	$63,170	$71,192	$51,875	(27%)
PECO	$121,634	$100,332	$74,419	$55,185	$69,409	$45,499	(34%)
PENELEC	$170,957	$142,791	$93,144	$62,907	$110,869	$61,253	(45%)
Pepco	$113,395	$84,032	$80,067	$48,103	$79,132	$51,316	(35%)
PPL	$230,845	$155,954	$78,573	$59,161	$107,557	$48,083	(55%)
PSEG	$148,398	$114,531	$79,368	$60,900	$75,305	$49,894	(34%)
RECO	$116,172	$74,623	$63,734	$49,431	$59,414	$49,518	(17%)
PJM	$100,026	$90,906	$73,885	$51,325	$84,540	$53,748	(36%)

16 All starts associated with combined cycle units are assumed to be warm starts.
17 The energy net revenues presented for the PJM area in this section represent the zonal average energy net revenues.

New Entrant Coal Plant

Energy market net revenue was calculated for a new CP plant economically dispatched by PJM. It was assumed that the CP plant had a minimum run time of eight hours. The unit was first committed day ahead in profitable blocks of at least eight hours, including start costs. If the unit was not already committed day-ahead, it was run in real time in standalone profitable blocks of at least eight hours, or any profitable hours bordering the profitable day-ahead or real-time block.

New entrant CP plant energy market net revenues were lower in all zones as a result of lower energy prices (Table 7-7).

Table 7-7 Energy net revenue for a new entrant CP: January through September, 2014 through 2019 (Dollars per installed MW-year)[18]

Zone	2014 (Jan-Sep)	2015 (Jan-Sep)	2016 (Jan-Sep)	2017 (Jan-Sep)	2018 (Jan-Sep)	2019 (Jan-Sep)	Change in 2019 from 2018
AECO	$131,596	$54,527	$11,879	$3,943	$35,368	$4,501	(87%)
AEP	$117,847	$52,683	$35,998	$31,393	$63,550	$15,002	(76%)
APS	$116,610	$47,439	$14,212	$14,508	$47,300	$5,504	(88%)
ATSI	$130,705	$55,126	$31,610	$31,773	$65,491	$12,454	(81%)
BGE	$185,723	$89,340	$49,389	$14,740	$57,606	$9,532	(83%)
ComEd	$116,836	$41,435	$24,899	$25,209	$31,649	$13,229	(58%)
DAY	$121,566	$52,225	$30,072	$30,000	$63,376	$14,633	(77%)
DEOK	$110,745	$47,447	$27,536	$27,216	$70,476	$12,882	(82%)
DLCO	$101,866	$42,795	$27,650	$28,579	$65,333	$11,215	(83%)
Dominion	$167,089	$94,905	$45,927	$21,565	$68,664	$15,285	(78%)
DPL	$177,820	$78,651	$23,431	$10,077	$52,327	$10,861	(79%)
EKPC	$107,225	$40,350	$23,192	$22,041	$42,350	$9,097	(79%)
JCPL	$136,459	$54,165	$8,829	$5,114	$36,256	$4,036	(89%)
Met-Ed	$167,833	$74,430	$20,340	$16,746	$51,860	$8,835	(83%)
PECO	$126,952	$51,862	$9,813	$3,965	$34,922	$4,320	(88%)
PENELEC	$138,961	$66,476	$24,546	$12,549	$45,964	$8,347	(82%)
Pepco	$131,026	$45,357	$11,577	$3,484	$35,362	$4,449	(87%)
PPL	$126,181	$50,594	$7,864	$4,175	$34,327	$2,786	(92%)
PSEG	$189,944	$83,789	$14,428	$8,309	$42,718	$6,034	(86%)
RECO	$184,321	$83,981	$13,726	$8,137	$41,777	$7,127	(83%)
PJM	$155,324	$60,379	$22,846	$16,176	$49,334	$9,007	(82%)

18 The energy net revenues presented for the PJM area in this section represent the zonal average energy net revenues.

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 but output reflects the class average capacity factor.[19]

New entrant nuclear plant energy market net revenues were lower in all zones as a result of lower energy prices (Table 7-8).

Table 7-8 Energy net revenue for a new entrant nuclear plant: January through September, 2014 through 2019 (Dollars per installed MW-year)[20]

Zone	2014 (Jan-Sep)	2015 (Jan-Sep)	2016 (Jan-Sep)	2017 (Jan-Sep)	2018 (Jan-Sep)	2019 (Jan-Sep)	Change in 2019 from 2018
AECO	$318,327	$182,864	$100,509	$112,487	$161,428	$105,112	(35%)
AEP	$242,376	$157,290	$115,624	$125,598	$166,806	$120,684	(28%)
APS	$267,710	$179,549	$120,462	$126,758	$178,460	$120,656	(32%)
ATSI	$255,630	$161,290	$117,548	$129,129	$178,057	$122,784	(31%)
BGE	$358,983	$234,151	$171,017	$143,326	$204,098	$137,467	(33%)
ComEd	$212,862	$127,948	$104,359	$113,413	$120,706	$103,262	(14%)
DAY	$245,407	$157,890	$116,719	$129,499	$175,271	$127,790	(27%)
DEOK	$233,889	$152,894	$113,752	$126,286	$182,572	$123,027	(33%)
DLCO	$225,045	$148,138	$113,268	$125,623	$177,676	$120,271	(32%)
Dominion	$310,819	$205,428	$133,883	$135,713	$195,500	$127,976	(35%)
DPL	$342,411	$203,171	$122,376	$121,360	$181,011	$115,460	(36%)
EKPC	$230,087	$145,439	$109,279	$120,677	$152,067	$117,443	(23%)
JCPL	$322,332	$181,602	$95,371	$116,681	$162,205	$104,597	(36%)
Met-Ed	$306,649	$174,877	$96,836	$121,092	$161,483	$108,590	(33%)
PECO	$310,861	$176,913	$93,961	$112,179	$159,554	$101,804	(36%)
PENELEC	$279,885	$173,810	$109,127	$120,076	$166,270	$114,456	(31%)
Pepco	$346,530	$216,882	$146,478	$138,477	$197,133	$131,718	(33%)
PPL	$307,624	$175,288	$94,319	$114,737	$154,860	$100,637	(35%)
PSEG	$343,219	$192,002	$98,694	$118,563	$166,453	$106,846	(36%)
RECO	$337,323	$193,237	$98,486	$119,419	$167,186	$110,307	(34%)
PJM	$289,899	$177,033	$113,603	$123,555	$170,440	$116,044	(32%)

New Entrant Diesel

Energy market net revenue was calculated for a DS plant economically dispatched by PJM in real time.

New entrant DS plant energy market net revenues were lower in all zones except ComEd and EKPC as a result of lower energy prices (Table 7-9).

Table 7-9 Energy market net revenue for a new entrant DS: January through September, 2014 through 2019 (Dollars per installed MW-year)

Zone	2014 (Jan-Sep)	2015 (Jan-Sep)	2016 (Jan-Sep)	2017 (Jan-Sep)	2018 (Jan-Sep)	2019 (Jan-Sep)	Change in 2019 from 2018
AECO	$33,271	$12,274	$2,425	$805	$10,318	$1,927	(81%)
AEP	$14,711	$3,752	$838	$1,343	$4,256	$2,213	(48%)
APS	$18,342	$7,286	$917	$1,201	$6,850	$1,956	(71%)
ATSI	$14,371	$3,524	$1,989	$1,670	$7,193	$1,959	(73%)
BGE	$50,553	$15,851	$7,257	$2,328	$13,089	$3,371	(74%)
ComEd	$11,536	$2,186	$643	$1,275	$727	$1,706	135%
DAY	$14,518	$3,500	$913	$1,579	$3,942	$2,306	(41%)
DEOK	$13,670	$2,932	$1,302	$3,010	$6,698	$2,193	(67%)
DLCO	$13,221	$2,999	$2,299	$1,412	$8,226	$1,852	(77%)
Dominion	$43,380	$11,318	$2,212	$1,809	$14,957	$2,687	(82%)
DPL	$38,181	$16,308	$3,446	$1,978	$14,403	$6,334	(56%)
EKPC	$14,728	$2,774	$858	$902	$1,957	$2,063	5%
JCPL	$33,367	$13,235	$877	$1,109	$11,479	$1,851	(84%)
Met-Ed	$32,412	$13,087	$893	$2,601	$11,321	$1,528	(87%)
PECO	$32,768	$12,569	$869	$1,054	$10,146	$1,930	(81%)
PENELEC	$16,281	$6,515	$883	$1,254	$5,627	$1,268	(77%)
Pepco	$52,189	$11,575	$2,964	$1,768	$12,720	$2,910	(77%)
PPL	$33,369	$13,225	$779	$1,653	$9,070	$935	(90%)
PSEG	$32,944	$12,837	$938	$1,110	$10,637	$2,211	(79%)
RECO	$30,429	$13,930	$981	$1,120	$9,863	$2,174	(78%)
PJM	$29,787	$9,084	$1,714	$1,549	$8,674	$2,269	(74%)

19 The annual class average capacity factor was applied to total energy market net revenues.
20 The energy net revenues presented for the PJM area in this section represent the zonal average energy net revenues.

New Entrant On Shore Wind Installation

Energy market net revenues for an on shore wind installation 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. The unit is credited with wind RECs for its generation and is assumed to have taken a 1603 payment instead of either the Investment Tax Credit (ITC) or Production Tax Credit (PTC).[21]

On shore wind energy market net revenues were lower as a result of lower energy prices.

Table 7-10 Energy market net revenue for an on shore wind installation (Dollars per installed MW-year): January through September, 2014 through 2019

Zone	2014 (Jan-Sep)	2015 (Jan-Sep)	2016 (Jan-Sep)	2017 (Jan-Sep)	2018 (Jan-Sep)	2019 (Jan-Sep)	Change in 2019 from 2018
AEP	$88,356	$56,224	$45,232	$47,693	$68,562	$49,142	(28%)
APS	$78,949	$54,305	$40,911	$52,480	$70,730	$41,920	(41%)
ComEd	$73,547	$46,817	$40,030	$48,207	$47,023	$44,843	(5%)
PENELEC	$102,811	$68,435	$42,209	$51,037	$70,326	$40,524	(42%)

New Entrant Off Shore Wind Installation

Energy market net revenues for an off shore wind installation were calculated by assuming the unit received the average annual zonal RT LMP and operated at a 45 percent capacity factor. 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).

Off shore wind energy market net revenues were lower as a result of lower energy prices.

21 The 1603 payment is a direct payment of 30 percent of the project cost.

Table 7-11 Energy market net revenue for an off shore wind installation (Dollars per installed MW-year): January through September, 2014 through 2019

	2014 (Jan-Sep)	2015 (Jan-Sep)	2016 (Jan-Sep)	2017 (Jan-Sep)	2018 (Jan-Sep)	2019 (Jan-Sep)	Change in 2019 from 2018
AECO	$168,494	$108,246	$72,635	$78,368	$102,218	$72,559	(29%)

New Entrant Solar Installation

Energy market net revenues for a solar installation were calculated hourly assuming the unit was generating at the average hourly capacity factor of operating solar units in the zone if 75 percent of existing solar units in the zone were generating at greater than or equal to 25 percent capacity factor in that hour. The unit is credited with SRECs for its generation and is assumed to have taken a 1603 payment instead of either the Investment Tax Credit (ITC) or Production Tax Credit (PTC).[22]

Solar energy market net revenues were lower as a result of lower energy prices.

Table 7-12 Energy market net revenue for a solar installation (Dollars per installed MW-year): January through September, 2014 through 2019

Zone	2014 (Jan-Sep)	2015 (Jan-Sep)	2016 (Jan-Sep)	2017 (Jan-Sep)	2018 (Jan-Sep)	2019 (Jan-Sep)	Change in 2019 from 2018
AECO	$47,486	$36,239	$28,970	$27,106	$30,300	$23,286	(23%)
Dominion	-	-	$58,531	$56,985	$57,095	$44,177	(23%)
DPL	-	-	$33,857	$33,891	$41,838	$32,451	(22%)
JCPL	$44,422	$28,870	$23,576	$22,744	$24,559	$19,270	(22%)
PSEG	$42,209	$31,519	$26,908	$25,002	$26,040	$24,447	(6%)

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 CCs for three representative locations shows that CC units that entered the PJM markets in 2007 have not covered 100 percent of their total costs, including the return on and of capital, on a cumulative basis. The analysis also shows that theoretical new entrant

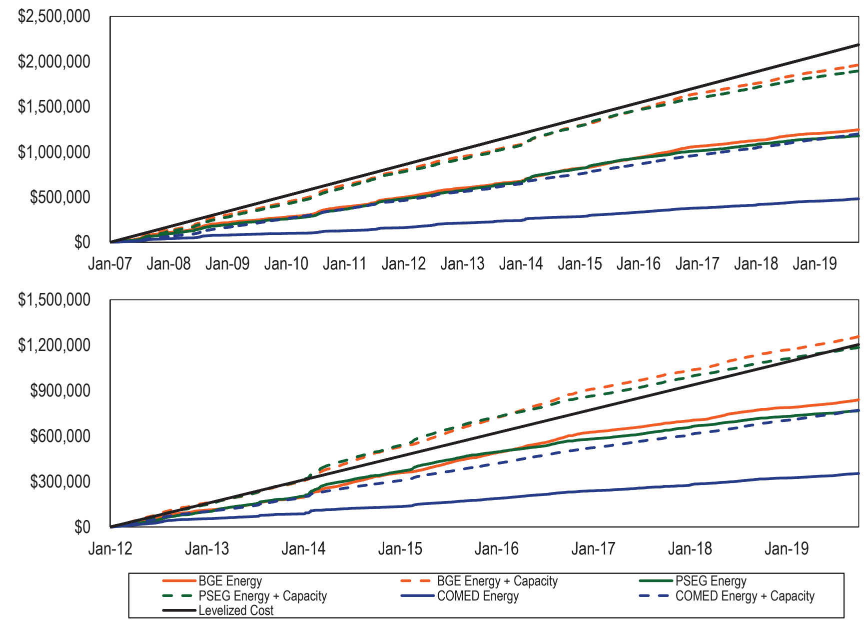
22 The 1603 payment is a direct payment of 30 percent of the project cost.

CCs that entered the PJM markets in 2012 have covered their total costs on a cumulative basis in the BGE Zone but have not covered 100 percent of total costs in the PSEG or ComEd zones. Energy market revenues alone were not sufficient to cover total costs in any scenario, which demonstrates the critical role of the 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.

Figure 7-6 compares cumulative energy market net revenues and energy market net revenues plus capacity market revenues to cumulative levelized costs for a new entrant CC that began operation on January 1, 2007, and new entrant CC that began operation on January 1, 2012. 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.

Figure 7-6 Historical new entrant CC revenue adequacy: January 2007 through September 2019 and January 2012 through September 2019[23]



23 The gas pipeline pricing points used in this analysis are Zone 6 non-NY for BGE, Chicago City Gate for ComEd, and Texas Eastern M3 for PSEG.

Assumptions used for this analysis are shown in Table 7-13.

Table 7-13 Assumptions for analysis of new entry in 2007 and 2012

	2007 CC	2012 CC
Project Cost	$658,598,000	$665,995,000
Fixed O&M ($/MW-Year)	$20,016	$20,126
End of Life Value	$0	$0
Loan Term	20 years	20 years
Percent Equity (%)	50%	50%
Percent Debt (%)	50%	50%
Loan Interest Rate (%)	7%	7%
Federal Income Tax Rate (%)	35%	35%
State Income Tax Rate (%)	9%	9%
General Escalation (%)	2.5%	2.5%
Technology	GE Frame 7FA.04	GE Frame 7FA.05
ICAP (MW)	601	655
Depreciation MACRS 150% declining balance	20 years	20 years

Nuclear Net Revenue Analysis

The analysis of nuclear plants includes annual avoidable costs and incremental capital expenditures from the Nuclear Energy Institute (NEI) based on NEI's calculations of average costs for all U.S. nuclear plants.[24 25] The analysis includes the most recent operating cost data and incremental capital expenditure data published by NEI, for 2018. This is likely to result in conservatively high costs for the forward looking analysis. NEI average operating costs have decreased since their peak in 2012 (14.0 percent decrease from 2012 through 2018 for all plants including single and multiple unit plants). NEI average incremental capital expenditures have decreased since their peak in 2012 (46 percent decrease from 2012 through 2018 for all plants including single and multiple unit plants). NEI's incremental capital expenditures peaked in 2012 as a result of regulatory requirements following the 2011 accident at the Fukushima nuclear plant in Japan.

24 Operating costs from: Nuclear Energy Institute (September, 2019). "Nuclear Costs in Context," <https://www.nei.org/resources/reports-briefs/nuclear-costs-in-context>. Individual plants may vary from the average due to factors such as geographic location, local labor costs, the timing of refueling outages and other unit specific factors. This is the most current NEI data available.

25 The NEI costs for Hope Creek were treated as that of a two unit configuration because the unit is located in the same area as Salem 1 & 2. The net surplus of Hope Creek is sensitive to the accuracy of this assumption.

The results for nuclear plants are sensitive to small changes in PJM energy and capacity prices, both actual and forward prices.[26] When gas prices are high and LMPs are high as a result, net revenues to nuclear plants increase. In 2014, the polar vortex resulted in a significant increase in net revenues to nuclear plants. When gas prices are low and LMPs are low as a result, net revenues to nuclear plants decrease. 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.[27] In 2018, high gas prices and high LMPs resulted in a significant increase in net revenues for nuclear plants in PJM. Energy prices in 2018 were significantly higher than in 2017. Forward prices for 2019 are lower than 2018 prices. The result is that nuclear plant net revenues based on the three year forward period prices are lower than 2018 net revenues. The results for nuclear plants are also sensitive to changes in costs and whether unit costs are less than or greater than the benchmark NEI data.

Table 7-14 includes the publicly available data on energy market prices, Table 7-15 and Table 7-16 show capacity market prices and Table 7-17 shows nuclear cost data for the 16 nuclear plants in PJM in addition to Oyster Creek, which retired September 17, 2018, and Three Mile Island, which retired September 20, 2019.[28] The analysis excludes Cook nuclear units. Cook nuclear units are designated FRR and receive cost of service revenues and are not subject to PJM market revenues.[29]

For nuclear plants, all calculations are based on publicly available data in order to avoid revealing confidential information. Nuclear unit revenue is based on day-ahead LMP at the relevant node. Nuclear unit capacity revenue assumes that the unit cleared its full unforced capacity at the BRA locational clearing price. Unforced capacity is determined using the annual class average EFORd rate.

26 A change in the capacity market price of $24 per MW-day translates into a change in capacity revenue of $1.00 per MWh for a nuclear power plant operating in every hour. A change in the capacity market price of $24 per MW-day translates into a change in capacity revenue of $1.06 per MWh for a nuclear power plant operating at a capacity factor of 0.942 percent.

27 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*.

28 Installed capacity is from NEI, "Map of U.S. Nuclear Plants," <https://www.nei.org/resources/map-of-us-nuclear-plants>.

29 See "Resources Designated in 2021/2022 FRR Capacity Plans as of May 1, 2018," <https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2021-2022/2021-2022-resources-designated-in-frr-plans.ashx?la=en>.

Table 7-14 Nuclear unit day ahead LMP: 2008 through 2018

	ICAP	Average DA LMP ($/MWh)										
	(MW)	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Beaver Valley	1,808	$49.46	$31.51	$35.59	$37.43	$30.34	$34.24	$41.86	$30.35	$27.07	$29.11	$36.35
Braidwood	2,337	$48.10	$27.76	$31.48	$32.02	$27.51	$30.26	$37.34	$25.97	$24.30	$24.99	$27.11
Byron	2,300	$47.61	$23.98	$28.49	$28.09	$24.25	$29.22	$35.05	$21.00	$17.94	$23.79	$26.96
Calvert Cliffs	1,708	$78.63	$41.05	$51.27	$46.53	$35.19	$40.27	$57.88	$40.30	$32.64	$31.57	$38.79
Davis Besse	894	-	-	-	$39.68	$31.68	$36.10	$47.21	$31.94	$27.80	$28.85	$34.44
Dresden	1,797	$48.76	$28.27	$32.73	$33.07	$28.42	$31.82	$39.22	$27.45	$25.89	$26.35	$28.25
Hope Creek	1,172	$73.34	$39.43	$48.03	$45.52	$33.07	$37.43	$51.99	$32.41	$23.20	$26.78	$32.93
LaSalle	2,271	$47.96	$27.71	$31.53	$31.93	$27.56	$30.94	$37.88	$26.28	$23.95	$24.71	$27.19
Limerick	2,242	$73.49	$39.49	$48.23	$45.27	$33.09	$37.28	$51.71	$32.65	$23.37	$26.99	$33.08
North Anna	1,892	$75.14	$39.89	$50.59	$45.47	$33.87	$38.55	$53.37	$38.05	$30.50	$31.27	$38.44
Oyster Creek	608	$75.49	$40.43	$49.29	$46.74	$33.69	$38.62	$52.85	$33.10	$23.79	$27.52	$34.03
Peach Bottom	2,347	$73.09	$39.32	$47.70	$44.73	$32.81	$37.37	$51.52	$31.98	$23.07	$26.76	$32.63
Perry	1,240	-	-	$36.99	$38.76	$31.68	$36.69	$46.14	$32.77	$27.84	$29.91	$37.24
Quad Cities	1,819	$47.28	$24.81	$27.53	$26.79	$20.43	$25.94	$30.71	$19.47	$18.04	$23.09	$25.54
Salem	2,328	$73.41	$39.51	$48.02	$45.50	$33.06	$37.40	$51.96	$32.37	$23.18	$26.76	$32.90
Surry	1,676	$71.96	$39.02	$49.30	$45.01	$33.62	$37.98	$51.75	$37.91	$30.08	$31.08	$38.50
Susquehanna	2,520	$69.96	$38.24	$45.95	$44.78	$32.10	$36.76	$50.93	$32.47	$23.66	$27.14	$32.42
Three Mile Island	803	$72.46	$39.11	$46.72	$44.15	$32.43	$36.83	$50.47	$30.94	$22.96	$27.12	$31.76

Table 7-15 BRA capacity market clearing prices ($/MW-Day): 2008 through 2021[30]

	ICAP	BRA Capacity Price ($/MW-Day)														
	(MW)	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22
Beaver Valley	1,808	$41	$112	$102	$174	$110	$16	$28	$126	$136	$59	$120	$165	$100	$77	$140
Braidwood	2,337	$41	$112	$102	$174	$110	$16	$28	$126	$136	$59	$120	$215	$203	$188	$196
Byron	2,300	$41	$112	$102	$174	$110	$16	$28	$126	$136	$59	$120	$215	$203	$188	$196
Calvert Cliffs	1,708	$189	$210	$237	$174	$110	$133	$226	$137	$167	$119	$120	$165	$100	$86	$140
Davis Besse	894	-	-	-	-	$109	$20	$28	$126	$357	$114	$120	$165	$100	$77	$171
Dresden	1,797	$41	$112	$102	$174	$110	$16	$28	$126	$136	$59	$120	$215	$203	$188	$196
Hope Creek	1,172	$198	$149	$191	$174	$110	$140	$245	$137	$167	$119	$120	$225	$120	$188	$166
LaSalle	2,271	$41	$112	$102	$174	$110	$16	$28	$126	$136	$59	$120	$215	$203	$188	$196
Limerick	2,242	$198	$149	$191	$174	$110	$140	$245	$137	$167	$119	$120	$225	$120	$188	$166
North Anna	1,892	$41	$112	$102	$174	$110	$16	$28	$126	$136	$59	$120	$165	$100	$77	$140
Oyster Creek	608	$198	$149	$191	$174	$110	$140	$245	$137	$167	$119	$120	$225	$120	$188	-
Peach Bottom	2,347	$198	$149	$191	$174	$110	$140	$245	$137	$167	$119	$120	$225	$120	$188	$166
Perry	1,240	-	-	-	-	$109	$20	$28	$126	$357	$114	$120	$165	$100	$77	$171
Quad Cities	1,819	$41	$112	$102	$174	$110	$16	$28	$126	$136	$59	$120	$215	$203	$188	$196
Salem	2,328	$198	$149	$191	$174	$110	$140	$245	$137	$167	$119	$120	$225	$120	$188	$166
Surry	1,676	$41	$112	$102	$174	$110	$16	$28	$126	$136	$59	$120	$165	$100	$77	$140
Susquehanna	2,520	$41	$112	$191	$174	$110	$133	$226	$137	$167	$119	$120	$165	$100	$86	$140
Three Mile Island	803	$41	$112	$191	$174	$110	$133	$226	$137	$167	$119	$120	$165	$100	$86	$140

30 Oyster Creek retired September 17, 2018. Exelon. "Oyster Creek Generating Station Retires from Service," (September 17, 2018) <http://www.exeloncorp.com/newsroom/oyster-creek-retires>. Three Mile Island retired September 20, 2019. Exelon. "Three Mile Island Generating Station Unit 1 Retires from Service After 45 Years," (September 20, 2019) <https://www.exeloncorp.com/newsroom/three-mile-island-generating-station-unit-1-retires>.

Table 7-16 Nuclear unit capacity market revenue ($/MWh): 2008 through 2021[31 32]

	ICAP	Capacity Revenue ($/MWh)													
	(MW)	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Beaver Valley	1,808	$3.57	$4.50	$6.23	$5.87	$2.41	$1.01	$3.70	$5.75	$3.96	$4.17	$6.42	$5.56	$3.79	$4.99
Braidwood	2,337	$3.57	$4.50	$6.23	$5.87	$2.41	$1.01	$3.70	$5.75	$3.96	$4.17	$7.71	$9.12	$8.52	$8.44
Byron	2,300	$3.57	$4.50	$6.23	$5.87	$2.41	$1.01	$3.70	$5.75	$3.96	$4.17	$7.71	$9.12	$8.52	$8.44
Calvert Cliffs	1,708	$8.73	$9.59	$8.64	$5.87	$5.38	$8.21	$7.53	$6.74	$6.04	$5.26	$6.42	$5.57	$4.03	$5.16
Davis Besse	894	NA	NA	NA	NA	$2.49	$1.08	$3.70	$11.40	$9.33	$5.17	$6.42	$5.56	$3.79	$5.80
Dresden	1,797	$3.57	$4.50	$6.23	$5.87	$2.41	$1.01	$3.70	$5.75	$3.96	$4.17	$7.71	$9.12	$8.52	$8.44
Hope Creek	1,172	$7.33	$7.37	$7.82	$5.87	$5.54	$8.81	$7.87	$6.74	$6.04	$5.26	$7.98	$7.17	$7.00	$7.67
LaSalle	2,271	$3.57	$4.50	$6.23	$5.87	$2.41	$1.01	$3.70	$5.75	$3.96	$4.17	$7.71	$9.12	$8.52	$8.44
Limerick	2,242	$7.33	$7.37	$7.82	$5.87	$5.54	$8.81	$7.87	$6.74	$6.04	$5.26	$7.98	$7.17	$7.00	$7.67
North Anna	1,892	$3.57	$4.50	$6.23	$5.87	$2.41	$1.01	$3.70	$5.75	$3.96	$4.17	$6.42	$5.56	$3.79	$4.99
Oyster Creek	608	$7.33	$7.37	$7.82	$5.87	$5.54	$8.81	$7.87	$6.74	$6.04	$5.26	NA	NA	NA	NA
Peach Bottom	2,347	$7.33	$7.37	$7.82	$5.87	$5.54	$8.81	$7.87	$6.74	$6.04	$5.26	$7.98	$7.17	$7.00	$7.67
Perry	1,240	NA	NA	NA	NA	$2.49	$1.08	$3.70	$11.40	$9.33	$5.17	$6.42	$5.56	$3.79	$5.80
Quad Cities	1,819	$3.57	$4.50	$6.23	$5.87	$2.41	$1.01	$3.70	$5.75	$3.96	$4.17	$7.71	$9.12	$8.52	$8.44
Salem	2,328	$7.33	$7.37	$7.82	$5.87	$5.54	$8.81	$7.87	$6.74	$6.04	$5.26	$7.98	$7.17	$7.00	$7.67
Surry	1,676	$3.57	$4.50	$6.23	$5.87	$2.41	$1.01	$3.70	$5.75	$3.96	$4.17	$6.42	$5.56	$3.79	$4.99
Susquehanna	2,520	$3.57	$6.72	$7.82	$5.87	$5.38	$8.21	$7.53	$6.74	$6.04	$5.26	$6.42	$5.56	$4.03	$5.16
Three Mile Island	803	$3.57	$6.72	$7.82	$5.87	$5.38	$8.21	$7.53	$6.74	$6.04	$5.26	$6.42	$5.56	$4.03	$5.16

Table 7-17 Nuclear unit costs: 2008 through 2018[33]

	ICAP	NEI Costs ($/MWh)										
	(MW)	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Beaver Valley	1,808	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07
Braidwood	2,337	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07
Byron	2,300	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07
Calvert Cliffs	1,708	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07
Davis Besse	894	$35.31	$39.36	$41.23	$45.45	$47.41	$44.16	$44.32	$44.51	$41.39	$42.66	$42.00
Dresden	1,797	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07
Hope Creek	1,172	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07
LaSalle	2,271	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07
Limerick	2,242	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07
North Anna	1,892	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07
Oyster Creek	608	$35.31	$39.36	$41.23	$45.45	$47.41	$44.16	$44.32	$44.51	$41.39	$42.66	$42.00
Peach Bottom	2,347	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07
Perry	1,240	$35.31	$39.36	$41.23	$45.45	$47.41	$44.16	$44.32	$44.51	$41.39	$42.66	$42.00
Quad Cities	1,819	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07
Salem	2,328	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07
Surry	1,676	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07
Susquehanna	2,520	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07
Three Mile Island	803	$35.31	$39.36	$41.23	$45.45	$47.41	$44.16	$44.32	$44.51	$41.39	$42.66	$42.00

31 Capacity revenue calculated by adjusting the BRA Capacity Price for calendar year, by the class average EFORd, and by the 2018 class average capacity factor of 0.942 percent. Class average capacity factor is from **2018 State of the Market Report for PJM**, Volume 2, Section 5: Capacity Market.

32 Oyster Creek retired September 17, 2018. Exelon. "Oyster Creek Generating Station Retires from Service," (September 17, 2018) <http://www.exeloncorp.com/newsroom/oyster-creek-retires>. Three Mile Island retired September 20, 2019. Exelon. "Three Mile Island Generating Station Unit 1 Retires from Service After 45 Years," (September 20, 2019) <https://www.exeloncorp.com/newsroom/three-mile-island-generating-station-unit-1-retires>.

33 Oyster Creek retired on September 17, 2018. Exelon. "Oyster Creek Generating Station Retires from Service," (September 17, 2018) <http://www.exeloncorp.com/newsroom/oyster-creek-retires>. Three Mile Island retired September 20, 2019. Exelon. "Three Mile Island Generating Station Unit 1 Retires from Service After 45 Years," (September 20, 2019) <https://www.exeloncorp.com/newsroom/three-mile-island-generating-station-unit-1-retires>.

Table 7-18 shows the surplus or shortfall in $/MWh for the 16 nuclear plants in PJM and Oyster Creek and Three Mile Island calculated using this cost data and historic LMPs.[34] In 2016, 13 nuclear plants, with a total capacity of 25,075 MW, in addition to Oyster Creek and Three Mile Island, did not recover all their fuel costs, operating costs, and capital expenditures. In 2017, seven nuclear plants with a total capacity of 12,658 MW, in addition to Oyster Creek and Three Mile Island, did not recover all their fuel costs, operating costs, and capital expenditures. In 2018, one nuclear plant, with a total capacity of 894 MW, in addition to Oyster Creek and Three Mile Island, did not recover all its fuel costs, operating costs, and capital expenditures. The surplus or shortfall assumes that the unit cleared its full unforced capacity at the BRA locational clearing price.[35] Unforced capacity is determined using the annual class average EFORd rate.

Some nuclear plants did not clear the capacity market primarily as a result of decisions by plant owners about how to offer the plants. Three Mile Island did not clear the 2018/2019 Auction[36] and Three Mile Island, Quad Cities, and a portion of Byron's capacity did not clear the 2019/2020 Auction.[37] Three Mile Island and Quad Cities did not clear the 2020/2021 Auction.[38] Three Mile Island, Dresden, and most of Byron did not clear the 2021/2022 Auction.[39] Beaver Valley, Davis Besse, and Perry did not clear the 2021/2022 Auction.[40]

Nuclear unit revenue is a combination of energy market revenue and capacity market revenue. Negative prices do not have a significant impact on nuclear unit revenue. Since 2014, negative prices have affected nuclear plants' annual revenues by an average of 0.1 percent. Negative LMPs reduced nuclear plant net revenues by an average of 0.0 percent and a maximum of 0.6 percent in 2014, an average of 0.2 percent and a maximum of 1.2 percent in 2015, an average of 0.1 percent and a maximum of 0.7 percent in 2016, an average of 0.0 percent and a maximum of 0.6 percent in 2017, and an average of 0.0 percent and a maximum of 0.0 percent in 2018 and the first nine months of 2019.[41]

Table 7-18 Nuclear unit surplus (shortfall) based on public data: 2008 through 2018[42]

	ICAP	Surplus (Shortfall) ($/MWh)										
	(MW)	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Beaver Valley	1,808	$26.3	$6.3	$10.5	$8.8	($3.3)	$1.4	$11.7	$3.2	($0.6)	$2.4	$13.7
Braidwood	2,337	$24.9	$2.5	$6.4	$3.4	($6.1)	($2.6)	$7.2	($1.2)	($3.4)	($1.7)	$5.7
Byron	2,300	$24.5	($1.3)	$3.4	($0.6)	($9.4)	($3.6)	$4.9	($6.1)	($9.7)	($2.9)	$5.6
Calvert Cliffs	1,708	$60.6	$20.9	$28.6	$17.9	$4.5	$14.6	$31.6	$14.1	$7.1	$5.9	$16.1
Davis Besse	894	NA	NA	NA	NA	($13.2)	($7.0)	$6.6	($1.2)	($4.3)	($8.6)	($1.1)
Dresden	1,797	$25.6	$3.0	$7.6	$4.4	($5.2)	($1.0)	$9.1	$0.3	($1.8)	($0.4)	$6.9
Hope Creek	1,172	$54.0	$17.0	$24.5	$16.9	$2.6	$12.4	$26.0	$6.3	($2.4)	$1.2	$11.8
LaSalle	2,271	$24.8	$2.5	$6.4	$3.3	($6.1)	($1.9)	$7.7	($0.9)	($3.7)	($2.0)	$5.8
Limerick	2,242	$54.1	$17.1	$24.7	$16.6	$2.6	$12.2	$25.7	$6.5	($2.2)	$1.4	$12.0
North Anna	1,892	$52.0	$14.6	$25.5	$16.8	$0.2	$5.7	$23.2	$10.9	$2.8	$4.6	$15.8
Oyster Creek	608	$47.5	$8.4	$15.9	$7.2	($8.2)	$3.3	$16.4	($4.7)	($11.6)	($9.9)	NA
Peach Bottom	2,347	$53.7	$16.9	$24.2	$16.1	$2.3	$12.3	$25.5	$5.8	($2.5)	$1.1	$11.5
Perry	1,240	NA	NA	NA	NA	($13.2)	($6.4)	$5.5	($0.3)	($4.2)	($7.6)	$1.7
Quad Cities	1,819	$24.1	($0.4)	$2.4	($1.8)	($13.2)	($6.9)	$0.6	($7.7)	($9.6)	($3.6)	$4.2
Salem	2,328	$54.0	$17.1	$24.5	$16.9	$2.6	$12.4	$26.0	$6.2	($2.4)	$1.1	$11.8
Surry	1,676	$48.8	$13.8	$24.2	$16.4	($0.0)	$5.1	$21.6	$10.8	$2.4	$4.4	$15.8
Susquehanna	2,520	$46.8	$15.2	$22.4	$16.1	$1.4	$11.1	$24.6	$6.3	($1.9)	$1.5	$9.8
Three Mile Island	803	$40.7	$6.5	$13.3	$4.6	($9.6)	$0.9	$13.7	($6.8)	($12.4)	($10.3)	($3.8)

In order to evaluate the expected viability of nuclear plants, analysis was performed based on forward energy market prices for 2019, 2020 and 2021 and known capacity market prices for 2019, 2020 and 2021. 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.

34 Analysis excludes Catawba 1 which is pseudo tied to PJM.
35 Installed capacity is from NEI. "Maps of U.S. Nuclear Plants," <https://www.nei.org/resources/map-of-us-nuclear-plants>.
36 Exelon. "Exelon Announces Outcome of 2019-2020 PJM Capacity Auction," (May 25, 2016) <http://www.exeloncorp.com/newsroom/pjm-auction-results-2016>.
37 Exelon. "Exelon Announces Outcome of 2019-2020 PJM Capacity Auction," (May 25, 2016) <http://www.exeloncorp.com/newsroom/pjm-auction-results-2016>.
38 Exelon. "Exelon Announces Outcome of 2020-2021 PJM Capacity Auction," (May 24, 2017) <http://www.exeloncorp.com/newsroom/pjm-auction-results-release-2017>.
39 Exelon. "Exelon Announces Outcome of 2021-2022 PJM Capacity Auction," (May 24, 2018) <http://www.exeloncorp.com/newsroom/exelon-announces-outcome-of-2021-2022-pjm-capacity-auction>.
40 PRNewswire. "FirstEnergy Solutions Comments on Results of PJM Capacity Auction," (May 24, 2018) <https://www.prnewswire.com/news-releases/firstenergy-solutions-comments-on-results-of-pjm-capacity-auction-300654549.html>.
41 Analysis is based on actual unit generation and received energy market and capacity market revenues. Negative prices in the DA and RT market were set to zero for comparison. Results round to 0.0 percent.
42 This table has changed slightly from previous versions because of the capacity factor adjustment made when converting capacity revenues in $/MW-Day to $/MWh.

Table 7-19 shows PJM energy prices (LMP), capacity prices (BRA), and annual fuel, operating and capital expenditures for the 2019 through 2021 period. The LMPs are based on forward prices with a basis adjustment for the specific plant locations.[43] Forward prices are as of October 1, 2019. The capacity prices are known based on PJM capacity auction results. The 2019 energy prices include actual day-ahead market prices through September 30, 2019, and forward prices for October through December 2019. The 2019 energy prices decreased by an average of $0.28 per MWh or 0.6 percent as a result of a decline in actual energy prices and forward prices. The 2020 forward prices for Western Hub increased $2.41 per MWh or 8.9 percent and 2021 forward prices increased $1.82 per MWh or 6.9 percent since July 1, 2019.

Table 7-19 Forward prices in PJM energy and capacity markets and annual costs[44 45]

	ICAP	Average Forward LMP ($/MWh)			Capacity Revenue ($/MWh)			2018 NEI Costs ($/MWh)		
	(MW)	2019	2020	2021	2019	2020	2021	Fuel	Operating	Capital
Beaver Valley	1,808	$26.92	$30.32	$29.14	$5.56	$3.79	$4.99	$6.01	$17.44	$5.62
Braidwood	2,337	$23.56	$24.12	$23.19	$9.12	$8.52	$8.44	$6.01	$17.44	$5.62
Byron	2,300	$23.22	$24.11	$23.18	$9.12	$8.52	$8.44	$6.01	$17.44	$5.62
Calvert Cliffs	1,708	$28.23	$30.81	$29.62	$5.57	$4.03	$5.16	$6.01	$17.44	$5.62
Davis Besse	894	$26.94	$29.44	$28.33	$5.56	$3.79	$5.80	$5.84	$27.82	$8.34
Dresden	1,797	$24.24	$25.03	$24.07	$9.12	$8.52	$8.44	$6.01	$17.44	$5.62
Hope Creek	1,172	$23.93	$26.68	$25.62	$7.17	$7.00	$7.67	$6.01	$17.44	$5.62
LaSalle	2,271	$23.48	$24.12	$23.19	$9.12	$8.52	$8.44	$6.01	$17.44	$5.62
Limerick	2,242	$24.09	$26.73	$25.67	$7.17	$7.00	$7.67	$6.01	$17.44	$5.62
North Anna	1,892	$27.78	$30.43	$29.26	$5.56	$3.79	$4.99	$6.01	$17.44	$5.62
Peach Bottom	2,347	$23.22	$26.56	$25.50	$7.17	$7.00	$7.67	$6.01	$17.44	$5.62
Perry	1,240	$27.60	$30.94	$29.72	$5.56	$3.79	$5.80	$5.84	$27.82	$8.34
Quad Cities	1,819	$22.39	$22.89	$22.00	$9.12	$8.52	$8.44	$6.01	$17.44	$5.62
Salem	2,328	$23.91	$26.66	$25.60	$7.17	$7.00	$7.67	$6.01	$17.44	$5.62
Surry	1,676	$27.23	$30.27	$29.11	$5.56	$3.79	$4.99	$6.01	$17.44	$5.62
Susquehanna	2,520	$22.46	$26.10	$25.06	$5.56	$4.03	$5.16	$6.01	$17.44	$5.62

Table 7-20 shows the surplus or shortfall that would be received net of avoidable costs and incremental capital expenditures by year, based on forward prices, on a per MWh basis. The fuel and operating costs are the 2018 NEI fuel, operating, and capital costs. Plants may have operating costs higher or lower than the NEI average. Table 7-21 shows the total dollar surplus or shortfall and adjusts energy revenues and operating costs using the annual class average capacity factor.

Changes in forward energy market prices can significantly affect expected profitability of nuclear plants in PJM. The current analysis, based on forward prices for energy and known forward prices for capacity, shows that two plants, Davis Besse and Perry, would not cover their annual avoidable costs. These two plants are single unit sites which have higher operating costs per MWh than multiple unit plants and show an average annual shortfall of $8.12 per MWh. In March 2018, Davis Besse and Perry requested deactivation in 2021 but reversed the decision based on new subsidies in Ohio. Susquehanna shows a shortfall in 2019 and a surplus in 2020 and 2021. Susquehanna has reduced its operating costs and is not operating at a loss when the unit specific information is accounted for.[46]

43 Forward prices on October 1, 2019. Forward prices are reported for PJM trading hubs which are 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 2018 data.
44 Oyster Creek retired on September 17, 2018. Exelon. "Oyster Creek Generating Station Retires from Service," (September 17, 2018) <http://www.exeloncorp.com/newsroom/oyster-creek-retires>. Three Mile Island retired September 20, 2019. Exelon. "Three Mile Island Generating Station Unit 1 Retires from Service After 45 Years," (September 20, 2019) <https://www.exeloncorp.com/newsroom/three-mile-island-generating-station-unit-1-retires>.
45 This table has changed slightly from previous versions because of the capacity factor adjustment made when converting capacity revenues in $/MW-Day to $/MWh.
46 Talen Energy Investor Day, February 12, 2019.

Table 7-20 Nuclear unit forward annual surplus (shortfall) ($/MWh)[47]

	Surplus (Shortfall) ($/MWh)		
	2019	2020	2021
Beaver Valley	$3.41	$5.04	$5.06
Braidwood	$3.61	$3.57	$2.57
Byron	$3.27	$3.56	$2.56
Calvert Cliffs	$4.73	$5.77	$5.71
Davis Besse	($9.50)	($8.78)	($7.87)
Dresden	$4.29	$4.48	$3.44
Hope Creek	$2.03	$4.61	$4.23
LaSalle	$3.53	$3.57	$2.57
Limerick	$2.19	$4.66	$4.28
North Anna	$4.27	$5.15	$5.18
Peach Bottom	$1.33	$4.49	$4.11
Perry	($8.84)	($7.28)	($6.48)
Quad Cities	$2.44	$2.34	$1.38
Salem	$2.02	$4.59	$4.21
Surry	$3.72	$4.99	$5.03
Susquehanna	($1.04)	$1.06	$1.15

Table 7-21 Nuclear unit forward annual surplus (shortfall) ($ in millions)[48]

	Surplus (Shortfall) ($ in millions)		
	2019	2020	2021
Beaver Valley	$50.9	$75.4	$75.4
Braidwood	$69.7	$69.1	$49.5
Byron	$62.1	$67.7	$48.5
Calvert Cliffs	$66.7	$81.6	$80.5
Davis Besse	($70.1)	($64.9)	($58.1)
Dresden	$63.5	$66.6	$51.0
Hope Creek	$19.6	$44.7	$40.9
LaSalle	$66.1	$67.1	$48.1
Limerick	$40.6	$86.5	$79.1
North Anna	$66.7	$80.6	$80.8
Peach Bottom	$25.7	$87.2	$79.6
Perry	($90.4)	($74.7)	($66.3)
Quad Cities	$36.6	$35.2	$20.7
Salem	$38.7	$88.4	$80.8
Surry	$51.5	$69.2	$69.5
Susquehanna	($21.7)	$22.1	$23.9

47 Oyster Creek retired on September 17, 2018. Exelon. "Oyster Creek Generating Station Retires from Service," (September 17, 2018) <http://www.exeloncorp.com/newsroom/oyster-creek-retires>. Three Mile Island retired September 20, 2019. Exelon. "Three Mile Island Generating Station Unit 1 Retires from Service After 45 Years," (September 20, 2019) <https://www.exeloncorp.com/newsroom/three-mile-island-generating-station-unit-1-retires>.

48 Oyster Creek retired on September 17, 2018. Exelon. "Oyster Creek Generating Station Retires from Service," (September 17, 2018) <http://www.exeloncorp.com/newsroom/oyster-creek-retires>. Three Mile Island retired September 20, 2019. Exelon. "Three Mile Island Generating Station Unit 1 Retires from Service After 45 Years," (September 20, 2019) <https://www.exeloncorp.com/newsroom/three-mile-island-generating-station-unit-1-retires>

Environmental and Renewable Energy Regulations

Environmental requirements and renewable energy mandates have a significant impact on PJM markets.

The investments required for environmental compliance have resulted in higher offers in the Capacity Market, and in making the investments in some cases when those offers clear, and in the retirement of units in some cases when those offers do not clear.

Environmental requirements and initiatives at both the federal and state levels 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 resources. Renewable energy credit (REC) markets created by state programs, and federal tax credits have significant impacts on PJM wholesale markets. But state renewables programs in PJM are not coordinated with one another, are generally not consistent with the PJM market design or PJM prices, have widely differing objectives, have widely differing implied prices of carbon and are not transparent on pricing and quantities. The effectiveness of state renewables programs would be enhanced if they were coordinated with one another and with PJM markets, and increased transparency.

Overview

Federal Environmental Regulation

- **MATS.** 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] All coal steam units in PJM are compliant with the state and federal emissions limits established by MATS.
- **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]
- **NSR.** On August 1, 2019, the EPA proposed to reform the New Source Review (NSR) permitting program.[3] NSR requires new projects and existing projects receiving major overhauls that significantly increase emissions to obtain permits under State Implementation Programs.
- **RICE.** Stationary reciprocating internal combustion engines (RICE) are electrical generation facilities like diesel engines typically used for backup, emergency or supplemental power. RICE must be tested annually.[4] Emergency stationary RICE participating in demand response programs are allowed to operate for up to 100 hours/calendar year providing emergency demand response during periods when there is a NERC declared Energy Emergency Alert Level 2 or there is a five percent voltage/frequency deviations, and for an unlimited time during emergency situations.
- **Greenhouse Gas Emissions.** On June 19, 2019, the EPA repealed the Clean Power Plan[5] and replaced it with the Affordable Clean Energy (ACE) rule, which establishes guidelines for states to develop plans to address greenhouse gas emissions from existing coal fired power plants.[6] Under the ACE Rule some states may permit more CO_2 emissions than under the Clean Power Plan.

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 (Feb. 16, 2012).

2 CAA § 110(a)(2)(D)(i)(I).

3 *Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NNSR): Project Emissions Accounting*, EPA Docket No. EPA–HQ–OAR–2018–0048; FRL–9997–95–OAR, 84 Fed. Reg. 39244 (Aug. 9, 2019).

4 See 40 CFR § 63.6640(f).

5 *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units*, EPA-HQ-OAR-2013-0602, Final Rule *mimeo* (Aug. 3, 2015) (Clean Power Plan). The Clean Power Plan never took effect because it was subject to a stay issued by the U.S. Supreme Court.

6 See *Repeal of the Clean Power Plan; Emission Guidelines for Greenhouse Gas Emissions From Existing Electric Utility Generating Units; Revisions to Emission Guidelines Implementing Regulations*, EPA Docket No. EPA–HQ–OAR–2017–0355, et al., 84 Fed. Reg. 32520 (July 8, 2019).

- **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.[7]
- **Coal Ash.** The EPA administers the Resource Conservation and Recovery Act (RCRA), which governs the disposal of solid and hazardous waste.[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. New Jersey is rejoining.[9] Virginia and Pennsylvania are preparing to join.[10] [11] The auction price in the September 4, 2019, auction for the 2018/2020 compliance period was $5.02 per ton. The clearing price is equivalent to a price of $5.73 per metric tonne, the unit used in other carbon markets. The price decreased by $0.60 per ton, 7.5 percent, from $5.62 per ton from June 5, 2019, to $5.02 per ton for September 4, 2019.
- **Carbon Price.** If the price of carbon were $50.00 per metric tonne, the short run marginal costs would increase by $24.52 per MWh for a new combustion turbine (CT) unit, $16.71 per MWh for a new combined cycle (CC) unit and $43.15 per MWh for a new coal plant (CP).

State Renewable Portfolio Standards

- **RPS.** In PJM, nine of 14 jurisdictions have enacted legislation requiring 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 September 30, 2019, Delaware, Illinois, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, and Washington, D.C. had renewable portfolio standards. Virginia and Indiana had voluntary renewable portfolio standards. Kentucky, Tennessee and West Virginia did not have renewable portfolio standards.
- **RPS Cost.** The cost of complying with RPS, as reported by the states, was $3.4 billion over the four year period from 2014 through 2017, or an average annual RPS compliance cost of $840.4 million.[12]

Emissions Controls in PJM Markets

- **Regulations.** 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.
- **Emissions Controls.** As of September 30, 2019, 93.5 percent of coal steam MW had some type of flue-gas desulfurization (FGD) technology to reduce SO_2 emissions, while 99.6 percent of coal steam MW had some type of particulate control, and 93.6 percent of fossil fuel fired capacity in PJM had NO_X emission control technology. All coal steam units in PJM are compliant with the state and federal emissions limits established by MATS.

Renewable Generation

- **Renewable Generation.** Total wind and solar generation was 3.1 percent of total generation in PJM for the first nine months of 2019. Tier I generation was 4.6 percent of total generation in PJM and Tier II generation was 2.2 percent of total generation in PJM for the first nine months of 2019. Only Tier I generation is renewable.

7 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).

8 42 U.S.C. §§ 6901 *et seq.*

9 Executive Order 7; see *Regional Greenhouse Gas Initiative*, State of New Jersey Department of Environmental Protection <http://www.state.nj.us/dep/aqes/rggi.html>.

10 See Regulation for Emissions Trading, 9 VAC 5-140. The Virginia Air Pollution Control Board is developing the regulation and considering public comments.

11 Executive Order – 2019-07- Commonwealth Leadership in Addressing Climate Change through Electric Sector Emissions Reductions, Tom Wolf, Governor, October 3, 2019, <https://www.governor.pa.gov/newsroom/executive-order-2019-07-commonwealth-leadership-in-addressing-climate-change-through-electric-sector-emissions-reductions/>.

12 The actual PJM RPS compliance cost exceeds the reported $3.4 billion since this total does not include a value for Delaware in 2014, a value for Pennsylvania in 2017, does not include any data for 2018 or 2019, and does not include any RPS compliance cost for North Carolina.

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.)
- The MMU recommends that the Commission reconsider its disclaimer of jurisdiction over RECs markets because, given market changes since that decision, it is clear that RECs materially affect jurisdictional rates. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that states consider the development of a multistate framework for RECs markets, for potential agreement on carbon pricing including the distribution of carbon revenues, and for coordination with PJM wholesale markets. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that jurisdictions with a renewable portfolio standard make the price and quantity data on supply and demand more transparent. (Priority: Low. First reported 2018. Status: Not adopted.)
- The MMU recommends that load and generation located at separate nodes be treated as separate resources. (Priority: High. First reported Q2, 2019. 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.[13] The MMU recommends that the Commission reconsider its disclaimer of jurisdiction over RECs markets because, given market changes since that decision, it is clear that RECs materially affect jurisdictional rates.

RECs clearly affect prices in the PJM wholesale power market. Some resources are not economic except for the ability to purchase or sell RECs. RECs provide out of market payments to qualifying renewable resources, primarily wind and solar. The credits provide an incentive to make negative energy offers and more generally provide an incentive to enter the market, to remain in the market and 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 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 the PJM RTO 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. The MMU recommends that PJM states consider the development of a multistate framework for REC markets, for potential agreement on carbon pricing, and for coordination with PJM wholesale markets.

REC markets are not consistently or adequately transparent. Data on REC prices, clearing quantities and markets are not publicly available for all PJM states. The provision of more complete data would facilitate competition to provide energy from renewable sources.

The economic logic of RPS programs and the associated REC and SREC prices is not always clear. The price of carbon implied by REC prices ranges from $5.64 per tonne in Washington, D.C. to $31.78 per tonne in Pennsylvania. The price of carbon implied by SREC prices ranges from $48.08 per tonne in

13 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.").

Pennsylvania to $789.17 per tonne in Washington, D.C. The effective prices for carbon compare to the RGGI clearing price in September 2019 of $5.73 per tonne and to the social cost of carbon which is estimated in the range of $50 per tonne.[14] The impact on the cost of generation from a new combined cycle unit of an $800 per tonne carbon price would be $267.30 per MWh.[15] The impact of a $50 per tonne carbon price would be $16.71 per MWh. This wide range of implied carbon prices is not consistent with an efficient, competitive, least cost approach to the reduction of emissions.

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 offers 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 ensures 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 to limit carbon output, for example by incorporating a consistent 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 consistent carbon price would be the most efficient way to implement that decision. The states in PJM could agree, if they decided it was in their interests, with the appropriate information, on a carbon price and on how to allocate the revenues from a carbon price that would make all states better off. The MMU continues to recommend that PJM provide modeling information to the states adequate to inform such a decision making process. A carbon price would also be an alternative to specific subsidies to individual nuclear power plants and to the current wide range of implied carbon prices embedded in RPS programs 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. The use of inconsistent implied carbon prices by state is also inconsistent with an efficient market and inconsistent with the least cost approach to meeting state environmental goals.

The annual average cost of complying with RPS over the four year period from 2014 through 2017 for the eight jurisdictions that had RPS and reported compliance costs was $840.4 million, or a total of $3.4 billion over four years.[16] The RPS compliance cost for 2016, the most recent year for which there is complete data for all jurisdictions except North Carolina, was $986 million. RPS costs are payments by customers to the sellers of qualifying resources.

If all the PJM states participated in a regional carbon market, the estimated revenue returned to the states/customers from selling carbon allowances would be approximately $2.1 billion per year assuming a five percent reduction below 2018 emission levels and a carbon price equal to the latest RGGI auction clearing price. If only the current RPS states participated in a regional carbon market, the estimated revenue returned to the states/customers from selling carbon allowances would be about $1.2 billion. The costs of a carbon price are the impact on energy market prices, net of the revenue returned to states/customers.

14 "Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis – Under Executive Order 12899," Interagency Working Group on the Social Cost of Greenhouse Gases, United States Government, (Aug. 2016), <https://19january2017snapshot.epa.gov/sites/production/files/2016-12/documents/sc_co2_tsd_august_2016.pdf>.

15 The cost impact calculation assumes a heat rate of 6.296 MMBtu per MWh and a carbon emissions rate of 0.053070 tonne per MMBtu. The $800 per tonne carbon price represents an upper bound on the 2019 REC and SREC prices in the PJM jurisdictions with RPS. Additional cost impacts are provided in Table 8-16.

16 The actual PJM RPS compliance cost exceeds the reported $3.4 billion since this total does not include a value for Delaware in 2014, a value for Pennsylvania in 2017, does not include any data for 2018 or 2019, and does not include any RPS compliance cost for North Carolina.

Federal Environmental Regulation

The U.S. Environmental Protection Agency (EPA) administers the Clean Air Act (CAA), the Clean Water Act (CWA) and Resource Conservation and Recovery Act (RCRA), all of which address pollution created by electric power production. The administration of these statutes is relevant to the operation of PJM markets.[17]

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.[18] [19]

The CWA 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.

The Resource Conservation and Recovery Act (RCRA) regulates the disposal of solid and hazardous waste.[20]

The EPA's actions have affected 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.

CAA: NESHAP/MATS

Section 112 of the CAA requires the EPA to promulgate emissions control standards, known as the National Emission Standards for Hazardous Air Pollutants (NESHAP), from both new and existing area and major sources. On December 21, 2011, the U.S. Environmental Protection Agency (EPA) issued its Mercury and Air Toxics Standards rule (MATS), which applies the CAA maximum achievable control technology (MACT) requirement to new or modified sources of emissions of mercury and arsenic, acid gas, nickel, selenium and cyanide.

17 For more details, see the *2018 State of the Market Report for PJM*, Vol. II, Appendix I: "Environmental and Renewable Energy Regulations."
18 42 U.S.C. § 7401 et seq. (2000).
19 The EPA defines a "major source" 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.
20 42 U.S.C. §§ 6901 *et seq.*

On December 27, 2018, the EPA issued a proposed revised Supplemental Cost Finding for the MATS, and the risk and technology review required by the CAA.[21] The EPA determined the cost to coal and oil fired power plants of complying with the MATS rule ranged from $7.4 to $9.6 billion annually.[22] The EPA determined the quantifiable benefits attributable to regulating hazardous air pollutant (HAP) emissions ranged from $4 to $6 million annually.[23] The EPA determined, in accordance with a decision of the U.S. Supreme Court, that based on analysis of costs versus benefits it is not "appropriate and necessary" to regulate HAP emissions from power plants under Section 112 of the Clean Air Act.[24] [25] The immediate practical effect is limited because the emission standards and other requirements of the 2012 MATS rule remain in place and the list of coal and oil fired power plants regulated under Section 112 of the Act remains in place.[26]

CAA: NAAQS/CSAPR

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). 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. Implementation was delayed in the courts, but CSAPR is now fully effective. 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. The CSAPR covers 28

21 See *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units—Reconsideration of Supplemental Finding and Residual Risk and Technology Review*, Docket No. EPA-HQ-OAR-2018-0794, 84 Fed. Reg. 2670 (Feb. 7, 2019).
22 *Id.* at 2676.
23 *Id.*
24 Michigan v. EPA, 135 S.Ct. 2699 (2015).
25 84 Fed. Reg. at 2676-2678.
26 *Id.* at 2768. EPA explains (*id.*): "Under D.C. Circuit case law, the EPA's determination that a source category was listed in error does not by itself remove a source category from the CAA section 112(c)(1) list—even EGUs, notwithstanding their special treatment under CAA section 112(n). *New Jersey* v. *EPA*, 517 F.3d 574 (D.C. Cir. 2008)."

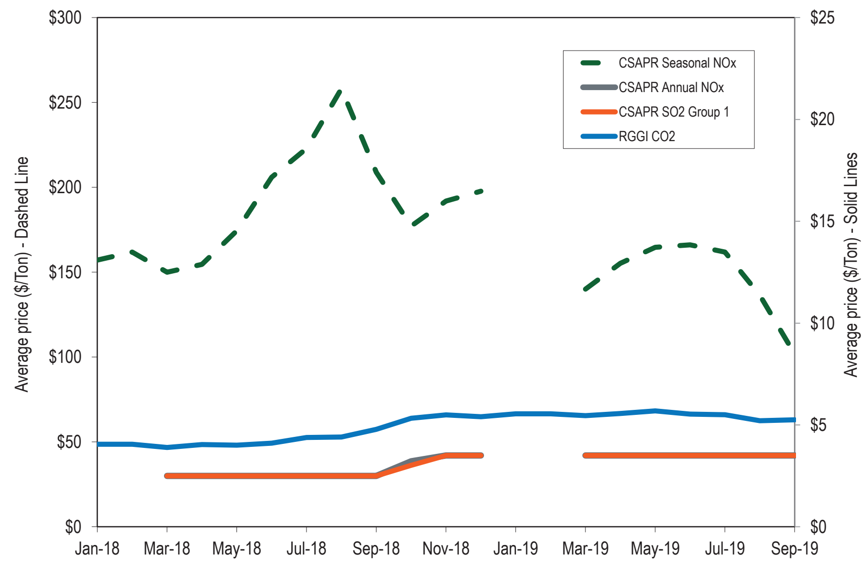
states, including all of the PJM states except Delaware, and also excluding the District of Columbia. The Cross-State Air Pollution Rule ("CSAPR") is a federal emissions trading program designed to address the CAA's requirement that each state prohibit emissions that significantly interfere with the ability of another state to meet NAAQS. CSAPR emissions prices may be compared with RGGI emissions prices.

Section 126 of the CAA permits a downwind state to file a petition with the EPA to regulate the emissions from particular resources in another state. On October 5, 2018, EPA denied petitions filed under this provision filed by Delaware and Maryland.[27]

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, 2018 through September 30, 2019. Figure 8-1 also shows the average, monthly settled price for the Regional Greenhouse Gas Initiative (RGGI) CO_2 allowances.

In the first nine months of 2019, CSAPR annual NO_X prices were 40.0 percent higher than in the first nine months of 2018. The CSAPR Seasonal NO_X price hit a peak of $258.15 in August 2018.

Figure 8-1 Spot monthly average emission price comparison: January 2018 through September 2019



CAA: NSR

Parts C and D of Title I of the CAA provide for New Source Review (NSR) in order to prevent new projects and projects receiving major modifications from increasing emissions in areas currently meeting NAAQS or inhibiting progress in areas that do not.[28] NSR requires permits before construction commences.

On August 1, 2019, EPA proposed to reform the New Source Review (NSR) permitting program.[29] Under a revised NSR rule, both emissions increases and decreases from a major modification would be considered in the first prong of the NSR applicability test.

NSR review applies a two prong analysis to projects at facilities such as power plants, some of which involve multiple units and combinations of new and

27 See *Response to Clean Air Act Section 126(b) Petitions From Delaware and Maryland*, EPA Docket No. EPA-HQ-OAR-2018-0295, 83 Fed. Reg. 50444 (Oct. 5, 2018). Delaware filed a petition requesting that the EPA regulate emissions from the Brunner Island coal plant in Pennsylvania, the Harrison coal plant in West Virginia, the Homer City coal plant in Pennsylvania and the Conemaugh coal plant in Pennsylvania. Maryland filed a petition requesting that the EPA regulate 36 generating units at coal plants located in Indiana, Kentucky, Ohio, Pennsylvania and West Virginia. U.S. Court of Appeals for the D.C. Circuit Case No. 18-1285.

28 42 U.S.C § 7470 et seq.

29 *Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NNSR): Project Emissions Accounting*, EPA Docket No. EPA-HQ-OAR-2018-0048; FRL-9997-95-OAR, 84 Fed. Reg. 39244 (Aug. 9, 2019).

existing units. The first analytical prong provides for consideration of whether a modification would cause a "significant emission increase" of a regulated NSR pollutant. The second prong considers whether any identified increase is also a "significant net emission increase." No permit is required if there is a negative determination under either prong.

The proposed rule changes apply to the first prong. The rule clarifies that under the first prong, a project's decreased as well as increased emissions are considered.[30] Consideration of decreased emissions makes this prong easier to satisfy and thereby avoid the need for a permit and associated investments in pollution controls.

The ACE rule as proposed on August 21, 2018, also included changes to NSR regulations.[31] These proposed NSR changes have been deferred to a separate future action.[32] As proposed, these NSR changes would apply to new units or existing units receiving major modifications. Under these proposed NSR changes, only modifications that increase a plant's hourly rate of emissions would be deemed major and require a two pronged NSR analysis. Modifications that increased a plant's annual run time and annual emissions but not the hourly emissions rate would not require an NSR analysis.

CAA: RICE

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). 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). The RICE Rules apply to emissions such as formaldehyde, acrolein, acetaldehyde, methanol, CO, NO_X, volatile organic compounds (VOCs) and PM. The regulatory regime for RICE is complicated, and the applicable requirements turn on whether the engine is an "area source" or "major source," and the starter mechanism for the engine (compression ignition or spark ignition). EPA regulations allow RICE to operate for only 100 hours per year, of which 50 hours must be during emergencies (Energy Emergency Alert Level 2).[33]

CAA: Greenhouse Gas Emissions

The EPA regulates CO_2 as a pollutant using CAA provisions that apply to pollutants not subject to NAAQS.[34] [35]

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."[36] 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.[37] Although the decision applies only to the Department of Energy's regulations of manufacturers, it bolsters the ability of the EPA and state regulators to rely on Social Cost of Carbon analyses.

On September 20, 2013, the EPA proposed national limits on the amount of CO_2 that new power plants would be allowed to emit.[38] [39] The proposed rule

30 See E. Scott Pruitt, EPA Memorandum re Project Emissions Accounting Under New Source Review Preconstruction Permitting Program (March 13, 2018).
31 82 Fed. Reg. 48035.
32 84 Fed. Reg. 32520, 32521.

33 See 40 CFR § 63.6640(f).
34 See CAA § 111.
35 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 (Dec. 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.
36 See Zero Zone, Inc., et al., v. U.S. Dept. of Energy, et al., Case Nos. 14-2147, et al., Slip Op. (Aug. 8, 2016).
37 *Id.*
38 *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>.
39 79 Fed. Reg. 1352 (Jan. 8, 2014).

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 June 19, 2019, the EPA repealed the prior administration's Clean Power Plan[40] and replaced it with the Affordable Clean Energy (ACE) rule.[41] The ACE rule establishes emission guidelines pursuant to which states must develop plans to address greenhouse gas emissions from existing coal fired power plants.

The ACE Rule (i) defines the "best system of emission reduction" (BSER) for existing power plants as on-site, heat-rate efficiency improvements and (ii) lists "candidate technologies" that states can use to establish standards of performance and incorporate into their plans.[42] [43]

The ACE Rule replaces the Clean Power Plan's use of national greenhouse gas emissions limits with the application of emission reduction measures at the power plant. The ACE Rule allows states to establish standards of performance based on a proposed list of candidate technologies to achieve the BSER standard.[44] As a result, the impact on coal fired generation depends upon actions taken in their host state. Under the ACE Rule some states may permit more CO_2 emissions than under the Clean Power Plan.

The EPA finalized regulations governing implementation of ACE and any future emission guidelines issued under Section 111(d) of the CAA. The regulations clarify "that states have broad discretion in establishing and applying emissions standards consistent with the BSER." The implementing regulations also coordinate state and federal deadlines: A state must issue State Implementation Plans (SIP) by June 19, 2022; if no SIP issues, the EPA must issue a Federal Implementation Plan (FIP) by June 19, 2024. The EPA will accept or reject a state's SIP within 12 months after timely receipt, and, if a state's SIP is rejected, issue an FIP for such state within two years.

CWA: WOTUS Definition and Effluents

The Clean Water Act (CWA) applies to the navigable waters, which are defined as waters of the United States (WOTUS).[45] On June 17, 2017, the EPA issued a rulemaking to rescind the definition of WOTUS proposed in the 2015 Clean Water Rule.[46] 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.[47] The U.S. Supreme Court reversed the stay, but the EPA amended the 2015 Clean Water Rule to establish an applicability date of February 6, 2020.[48] 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 new applicability date, 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.[49]

On December 11, 2018, the EPA and Department of the Army proposed a replacement definition of "waters of the United States."[50] The proposed definition would replace both the approaches used before and after the 2015 Rule. The proposed rule includes "waters within the ordinary meaning of the term, such as oceans, rivers, streams, lakes, ponds, and wetlands."[51] The proposed rule excludes "features that flow only in response to precipitation; groundwater, including groundwater drained through subsurface drainage systems; certain ditches; prior converted cropland; artificially irrigated areas that would revert to upland if artificial irrigation ceases; certain artificial lakes

40 *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units*, EPA-HQ-OAR-2013-0602, Final Rule *mimeo* (Aug. 3, 2015) (Clean Power Plan). The Clean Power Plan never took effect because it was subject to a stay issued by the U.S. Supreme Court.

41 See *Repeal of the Clean Power Plan; Emission Guidelines for Greenhouse Gas Emissions From Existing Electric Utility Generating Units; Revisions to Emission Guidelines Implementing Regulations*, EPA Docket No. EPA–HQ–OAR–2017–0355, et al., 84 Fed. Reg. 32520 (July 8, 2019) ("ACE Rule").

42 See CAA § 111(d).

43 *Id.*

44 Candidate technologies include: Neural network/intelligent sootblowers, boiler feed pumps, air heater and duct leakage control, variable frequency drives, blade path upgrade (steam turbine), redesign/replace economizer, and improved operating and maintenance practices.

45 33 U.S.C. 1251 et seq.; 33 U.S.C. § 1362(7) ("The term "navigable waters" means the waters of the United States, including the territorial seas.").

46 80 Fed. Reg. 37054 (June 29, 2015).

47 The stay was issued by the U.S. Court of Appeals for the Sixth Circuit on October 9, 2015.

48 *See Definition of "Waters of the United States"—Addition of an Applicability Date to 2015 Clean Water Rule*, Final Rule, EPA Docket No. EPA-HQ-OW-2017-0644, 83 Fed. Reg. 5200 (Feb. 6, 2018); National Assoc. of Mfg. v Dept. of Defense, No. 16-299 (S. Ct. Jan. 22, 2018).

49 Rapanos v. U.S., 547 U.S. 715 (2006).

50 See *Revised Definition of "Waters of the United States,"* EPA Docket No. EPA–HQ–OW–2018–0149, 84 Fed. Reg. 4154 (Feb. 14, 2019).

51 *Id.* at 4155.

and ponds constructed in upland; water-filled depressions created in upland incidental to mining or construction activity; storm water control features excavated or constructed in upland to convey, treat, infiltrate, or store storm water run-off; wastewater recycling structures constructed in upland; and waste treatment systems."[52] The new rule would specifically exclude from EPA jurisdiction waters that are now included.

The EPA issues effluent limitation guidelines ("ELGs") under the CWA, which apply a Best Available Technology Economically Available ("BAT") to identified waste streams.[53] The BAT standard requires the best technology, subject to cost considerations. On September 30, 2015, EPA issued a rule updating the standard for certain waste streams from steam power plants.[54] On April 12, 2019, the U.S. Court of Appeals for the Fifth Circuit vacated BAT standards for two identified categories, legacy wastewater (wastewater created, as determined by the permitting authority, between November 1, 2020 and December 31, 2023) and combustion residual leachate (wastewater percolating through landfills and impoundments).[55] The Court determined that reliance on impoundments for both categories is not BAT, and remanded to the EPA the determination of BATs consistent with the CWA.[56]

Water cooling systems at steam electric power generating stations are subject to regulation under the CWA. EPA regulations of discharges from steam electric power generating stations are set forth in the Generating Effluent Guidelines and Standards in 1974. These standards were amended most recently in 2015.

Section 301(a) of the CWA prohibits the point source discharge of pollutants to a water of the United States, unless authorized by permit. 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.

52 *Id.*
53 *See* 33 U.S.C. § 1311, 1314, 1362(11).
54 *See Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category*, 80 Fed. Reg. 67,838 (Nov. 3, 2015).
55 *See Southwestern Electric Power Co., et al. v. EPA*, Slip. Op. 15-60821.
56 *Id.* at 3.

NPDES permits must satisfy the more stringent of a technology based standard, known at Best Technology Available (BTA), or water quality standards. In contrast to the BAT standard, the BTA standard requires the best technology without regard to cost. NDPES permits include limits designed to prevent discharges that would cause or contribute to violations of water quality standards. Water quality standards include thermal limits.

PJM states are authorized to issue NPDES permits, with the exception of the District of Columbia. Pennsylvania, Delaware, Indiana and Illinois are partially authorized; the balance of PJM states are fully authorized.

The CWA regulates intakes in addition to discharges.

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).[57]

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.

57 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).

RCRA: Coal Ash

The EPA administers the Resource Conservation and Recovery Act (RCRA), which governs the disposal of solid and hazardous waste.[58]

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.[59] 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 8-1 describes the criteria and anticipated implementation dates.

58 42 U.S.C. §§ 6901 *et seq.*

59 *See Hazardous and Solid Waste Management System; Disposal of Coal Combustion Residuals From Electric Utilities*, 80 Fed. Reg. 21302 (April 17, 2015).

Table 8-1 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

On March 1, 2018, the EPA proposed a rule amending the CCRR.[60] Effective August 9, 2018, the EPA approved (i) revised groundwater protections standards for constituents without an established MCL, (ii) alternative performance standards and (iii) extended deadlines for placement of waste

60 EPA Press Release, *EPA Proposes First of Two Rules to Amend Coal Ash Disposal Regulations, Saving Up To $100M Per Year in Compliance Costs* <https://www.epa.gov/newsreleases/epa-proposes-first-two-rules-amend-coal-ash-disposal-regulations-saving-100m-year> (March 1, 2018).

in CCR units closing for cause in certain situations.[61] EPA indicated that additional revisions will be considered in a future rulemaking.

State Environmental Regulation

States have in some cases enacted emissions regulations more stringent or potentially more stringent than federal requirements:[62]

- **New Jersey HEDD.** 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. 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.
- **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). MPS and CPS establish standards that are more stringent and take effect earlier than comparable Federal regulations, such as the EPA's MATS.

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.[63]

Delaware and Maryland are the only PJM states that are currently members of RGGI. Other PJM states have expressed interest in joining RGGI. New Jersey, a founding member of RGGI opted out in 2011. New Jersey will rejoin RGGI in 2020.[64] The Virginia Air Pollution Control Board approved a regulation that would allow Virginia to join RGGI. However subsequent budget legislation prevents Virginia's participation.[65] Pennsylvania Governor Tom Wolf issued an executive order on October 3, 2019, directing the Pennsylvania Department of Environmental Protection (DEP) to join RGGI.[66] The order stipulates that the DEP is to present a rulemaking package to the Pennsylvania Environmental Quality Board by July 31, 2020.[67]

PJM has initiated a task force to investigate the issues associated with the introduction of a carbon price in the PJM energy market.[68]

Table 8-2 shows the RGGI CO_2 auction clearing prices and quantities for the 2008/2011 compliance period auctions, the 2012/2014 compliance period auctions, the 2015/2018 compliance period and the 2018/2020 compliance period auctions held as of September 4, 2019, in short tons and metric tonnes.[69] Prices for auctions held September 4, 2019, were $5.20 per allowance (equal to one short ton of CO_2), above the current price floor of $2.21 for RGGI auctions.[70] 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 $5.62 in June 2019.

61 See *Hazardous and Solid Waste Management System: Disposal of Coal Combustion Residuals From Electric Utilities; Amendments to the National Minimum Criteria (Phase One, Part One)*, EPA Docket No. EPA-HQ-OLEM-2017-0286, 83 Fed. Reg. 36435 (July 30, 2018).
62 For more details, see the *2018 State of the Market Report for PJM*, Volume II, Appendix I: "Environmental and Renewable Energy Regulations."
63 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>.
64 "Statement on New Jersey Greenhouse Gas Rule," RGGI Inc., (June 17, 2019) <https://www.rggi.org/news-releases/rggi-releases>.
65 "Statement Regarding Virginia State Budget," RGGI Inc., (May 6, 2019), <https://www.rggi.org/news-releases/rggi-releases>.
66 Executive Order – 2019-07- Commonwealth Leadership in Addressing Climate Change through Electric Sector Emissions Reductions, Tom Wolf, Governor, October 3, 2019, <https://www.governor.pa.gov/newsroom/executive-order-2019-07-commonwealth-leadership-in-addressing-climate-change-through-electric-sector-emissions-reductions/>
67 *Id.*
68 PJM. Carbon Pricing Senior Task Force (CPSTF) (July 2019) <https://www.pjm.com/committees-and-groups/task-forces/cpstf.aspx>.
69 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.
70 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 8-2 RGGI CO_2 allowance auction prices and quantities in short tons and metric tonnes: 2009/2011, 2012/2014, 2015/2018, and 2018/2020 Compliance Periods[71]

	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
March 14, 2018	$3.79	13,553,767	13,553,767	$4.18	12,295,774	12,295,774
June 13, 2018	$4.02	13,771,025	13,771,025	$4.43	12,492,867	12,492,867
September 9, 2018	$4.50	13,590,107	13,590,107	$4.96	12,328,741	12,328,741
December 5, 2018	$5.35	13,360,649	13,360,649	$5.90	12,120,580	12,120,580
March 13, 2019	$5.27	12,883,436	12,883,436	$5.81	11,687,660	11,687,660
June 5, 2019	$5.62	13,221,453	13,221,453	$6.19	11,994,304	11,994,304
September 4, 2019	$5.20	13,116,447	13,116,447	$5.73	11,899,044	11,899,044

71 See Regional Greenhouse Gas Initiative, "Auction Results," <http://www.rggi.org/market/co2_auctions/results> (Accessed October 17, 2019).

RGGI auctions have generated approximately $2.8 billion in auction revenue since 2009 and almost all of the auction revenue has been returned to the participating states.[72] The RGGI states have spent approximately 55 percent of this revenue on energy efficiency, 17 percent on clean and renewable energy, 11 percent on greenhouse gas abatements and 11 percent on direct bill assistance.[73]

Table 8-3 Estimated CO_2 allowance revenue at September 2019 RGGI price level[74 75 76]

		Estimated CO_2 allowance revenue ($ millions), carbon price $5.20 per short ton					
Jurisdiction	2018 power generation CO_2 emissions (short tons)	5 percent reduction below 2018 emission levels	10 percent reduction below 2018 emission levels	15 percent reduction below 2018 emission levels	20 percent reduction below 2018 emission levels	25 percent reduction below 2018 emission levels	50 percent reduction below 2018 emission levels
Delaware	2,820,304.7	$13.9	$13.2	$12.5	$11.7	$11.0	$7.3
Illinois	34,918,315.6	$172.5	$163.4	$154.3	$145.3	$136.2	$90.8
Indiana	49,202,850.2	$243.1	$230.3	$217.5	$204.7	$191.9	$127.9
Kentucky	29,989,896.2	$148.2	$140.4	$132.6	$124.8	$117.0	$78.0
Maryland	17,167,736.9	$84.8	$80.3	$75.9	$71.4	$67.0	$44.6
Michigan	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
New Jersey	15,521,984.9	$76.7	$72.6	$68.6	$64.6	$60.5	$40.4
North Carolina	302,169.7	$1.5	$1.4	$1.3	$1.3	$1.2	$0.8
Ohio	88,921,973.3	$439.3	$416.2	$393.0	$369.9	$346.8	$231.2
Pennsylvania	81,414,231.3	$402.2	$381.0	$359.9	$338.7	$317.5	$211.7
Tennessee	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Virginia	34,399,627.4	$169.9	$161.0	$152.0	$143.1	$134.2	$89.4
Washington, D.C.	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
West Virginia	64,849,471.6	$320.4	$303.5	$286.6	$269.8	$252.9	$168.6
Total	419,508,561.7	$2,072.4	$1,963.3	$1,854.2	$1,745.2	$1,636.1	$1,090.7

If all PJM states joined RGGI, the total RGGI revenue to the PJM states would be significant. The estimated allowance revenue for PJM states based on 2018 CO_2 emission levels and the RGGI clearing price for the June 2019 auction ranges from $1.1 billion per year to $2.1 billion per year depending on associated reductions in carbon emission levels (Table 8-3).[77] Table 8-3 shows the estimated carbon allowance revenue for each PJM state based on the latest RGGI auction price and reductions below 2018 CO_2 emission levels ranging from five to 50 percent. CO_2 emissions for the PJM states were approximately five times the total CO_2 emissions for the nine RGGI states.[78] A power plant owner must acquire an allowance for each ton of CO_2 emissions and the revenue values in Table 8-3 are computed by multiplying the carbon price by the emission cap level which is expressed as a reduction below the 2018 actual emissions level. States that participate in RGGI choose their emission cap. For example, New Jersey has chosen an emission cap of 18,000,000 short tons for reentry into RGGI in 2020, 5.3 percent below New Jersey's 2018 CO_2 emissions level; the New Jersey emission cap will be reduced by 540,000 short tons each year through 2030.[79]

The RGGI emissions cap is the sum of CO_2 allowances issued by each state. Table 8-4 shows the RGGI emission cap history. Compliance with the RGGI allowance obligation is evaluated at the end of each three year period which is called the control period. The first control period began in 2009. RGGI is currently in the second year of the fourth control period.

In 2014, RGGI began adjusting the emission cap to account for banked allowances from previous control periods.[80] At the end of the first control period, 57,449,495 banked allowances were held by market participants.[81] The cap adjustment for banked allowances was spread over a seven year period beginning in 2014 with the RGGI cap being reduced each year by one-seventh of the banked allowances. An additional reduction of 593 allowances per year, applying only to the Connecticut allowance

72 "The Economic Impacts of the Regional Greenhouse Gas Initiative on Nine Northeast and Mid-Atlantic States" at 2, Analysis Group, April 17, 2018.

73 *The Investment of RGGI Proceeds in 2016*, The Regional Greenhouse Gas Initiative, September 2018, <https://www.rggi.org/sites/default/files/Uploads/Proceeds/RGGI_Proceeds_Report_2016.pdf>.

74 The 2018 CO_2 emissions data is from the EPA Continuous Emission Monitoring System (CEMS) from generators located within the PJM footprint.

75 Power generation companies subject to a RGGI emission cap can offset up to 3.3 percent of their allowance obligation by undertaking certain greenhouse gas emission reduction projects. The allowance revenue values in Table 8-3 do not reflect offset allowances.

76 Emissions for the PJM states includes all power generators located in the state and is not limited to generators participating in the PJM energy markets.

77 This assumes that the PJM states would implement their RGGI rules consistent with the current RGGI states where owners of fossil fuel generators are required to purchase emission allowances in a regional centralized auction or purchase allowances in a secondary market.

78 Based on 2018 CO_2 emissions data from the EPA Continuous Emission Monitoring System (CEMS).

79 "Governor Murphy Announces Adoption of Rules Returning New Jersey to Regional Greenhouse Gas Initiative," State of New Jersey, Governor Phil Murphy Press Release, June 17, 2019 <https://nj.gov/governor/news/news/562019/approved/news_archive.shtml>.

80 A banked allowance is an allowance acquired during a previous control period that was not used to fulfill a RGGI allowance obligation.

81 "First Control Period Interim Adjustment for Banked Allowances Announcements," Regional Greenhouse Gas Initiative (Jan. 13, 2014), <https://www.rggi.org/sites/default/files/Uploads/Design-Archive/2012-Review/Adjustments/2014_01_13_FCP_Adjustment.pdf>.

budget, brings the overall cap adjustment to 8,207,664 allowances per year.[82] A second cap adjustment, corresponding to banked allowances for 2012 and 2013, began in 2015 with an adjustment of 13,683,744 allowances per year and will be in place through 2020.[83] The RGGI clearing price since 2014 has been on average 99.1 percent higher than the prices prior to the emission cap adjustments.

Table 8-4 RGGI emissions cap history[84 85]

	Control Period	RGGI Average Clearing Price ($ per short ton)	RGGI Cap (short tons)	Percent Change	RGGI Adjusted Cap (short tons)	Percent Change
2009		$2.77	188,000,000		188,000,000	
2010	1st	$1.93	188,000,000	0.0%	188,000,000	0.0%
2011		$1.89	188,000,000	0.0%	188,000,000	0.0%
2012		$1.93	165,000,000	(12.2%)	165,000,000	(12.2%)
2013	2nd	$2.92	165,000,000	0.0%	165,000,000	0.0%
2014		$4.72	91,000,000	(44.8%)	82,792,336	(49.8%)
2015		$6.10	88,725,000	(2.5%)	66,833,592	(19.3%)
2016	3rd	$4.47	86,506,875	(2.5%)	64,615,467	(3.3%)
2017		$3.42	84,344,203	(2.5%)	62,452,795	(3.3%)
2018		$4.41	82,235,598	(2.5%)	60,344,190	(3.4%)
2019	4th	$5.36	80,179,708	(2.5%)	58,288,301	(3.4%)
2020			78,175,215	(2.5%)	56,283,807	(3.4%)

If higher carbon prices were implemented in PJM, the associated revenues flowing to states would also increase. Table 8-5 shows the estimated allowance revenue for PJM states for carbon prices ranging from $10 per short ton to $50 per short ton and for emissions reductions ranging from five percent to 50 percent. Allowance revenues to states would be $19.9 billion if the carbon price were $50 per short ton and emission levels were five percent below 2018 levels. Allowance revenues to states would be $2.1 billion if the carbon price were $10 per short ton and emission levels were 50 percent below 2018.

82 Id at 2. Due to rounding, the adjustment is 8,207,664 allowances for years 2014 through 2018, and 8,207,663 allowances for the remaining two years.
83 "Second Control Period Interim Adjustment for Banked Allowances Announcement," Regional Greenhouse Gas Initiative (March 17, 2014), <https://www.rggi.org/sites/default/files/Uploads/Design-Archive/2012-Review/Adjustments/2014_03_17_SCP_Adjustment.pdf>.
84 See Regional Greenhouse Gas Initiative, "Elements of RGGI" and "Auction Results," <https://www.rggi.org/> (Accessed June 25, 2019).
85 The RGGI cap for 2020 does not reflect emissions for New Jersey.

Table 8-5 Estimated CO_2 allowance revenue at various carbon prices

	Estimated CO_2 allowance revenue ($ millions)					
Jurisdiction	5 percent reduction below 2018 emission levels	10 percent reduction below 2018 emission levels	15 percent reduction below 2018 emission levels	20 percent reduction below 2018 emission levels	25 percent reduction below 2018 emission levels	50 percent reduction below 2018 emission levels
	Carbon Price ($ per short ton)				$10.00	
Delaware	$26.8	$25.4	$24.0	$22.6	$21.2	$14.1
Illinois	$331.7	$314.3	$296.8	$279.3	$261.9	$174.6
Indiana	$467.4	$442.8	$418.2	$393.6	$369.0	$246.0
Kentucky	$284.9	$269.9	$254.9	$239.9	$224.9	$149.9
Maryland	$163.1	$154.5	$145.9	$137.3	$128.8	$85.8
Michigan	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
New Jersey	$147.5	$139.7	$131.9	$124.2	$116.4	$77.6
North Carolina	$2.9	$2.7	$2.6	$2.4	$2.3	$1.5
Ohio	$844.8	$800.3	$755.8	$711.4	$666.9	$444.6
Pennsylvania	$773.4	$732.7	$692.0	$651.3	$610.6	$407.1
Tennessee	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Virginia	$326.8	$309.6	$292.4	$275.2	$258.0	$172.0
Washington, D.C.	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
West Virginia	$616.1	$583.6	$551.2	$518.8	$486.4	$324.2
Total	$3,985.3	$3,775.6	$3,565.8	$3,356.1	$3,146.3	$2,097.5
	Carbon Price ($ per short ton)				$25.00	
Delaware	$67.0	$63.5	$59.9	$56.4	$52.9	$35.3
Illinois	$829.3	$785.7	$742.0	$698.4	$654.7	$436.5
Indiana	$1,168.6	$1,107.1	$1,045.6	$984.1	$922.6	$615.0
Kentucky	$712.3	$674.8	$637.3	$599.8	$562.3	$374.9
Maryland	$407.7	$386.3	$364.8	$343.4	$321.9	$214.6
Michigan	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
New Jersey	$368.6	$349.2	$329.8	$310.4	$291.0	$194.0
North Carolina	$7.2	$6.8	$6.4	$6.0	$5.7	$3.8
Ohio	$2,111.9	$2,000.7	$1,889.6	$1,778.4	$1,667.3	$1,111.5
Pennsylvania	$1,933.6	$1,831.8	$1,730.1	$1,628.3	$1,526.5	$1,017.7
Tennessee	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Virginia	$817.0	$774.0	$731.0	$688.0	$645.0	$430.0
Washington, D.C.	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
West Virginia	$1,540.2	$1,459.1	$1,378.1	$1,297.0	$1,215.9	$810.6
Total	$9,963.3	$9,438.9	$8,914.6	$8,390.2	$7,865.8	$5,243.9
	Carbon Price ($ per short ton)				$50.00	
Delaware	$134.0	$126.9	$119.9	$112.8	$105.8	$70.5
Illinois	$1,658.6	$1,571.3	$1,484.0	$1,396.7	$1,309.4	$873.0
Indiana	$2,337.1	$2,214.1	$2,091.1	$1,968.1	$1,845.1	$1,230.1
Kentucky	$1,424.5	$1,349.5	$1,274.6	$1,199.6	$1,124.6	$749.7
Maryland	$815.5	$772.5	$729.6	$686.7	$643.8	$429.2
Michigan	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
New Jersey	$737.3	$698.5	$659.7	$620.9	$582.1	$388.0
North Carolina	$14.4	$13.6	$12.8	$12.1	$11.3	$7.6
Ohio	$4,223.8	$4,001.5	$3,779.2	$3,556.9	$3,334.6	$2,223.0
Pennsylvania	$3,867.2	$3,663.6	$3,460.1	$3,256.6	$3,053.0	$2,035.4
Tennessee	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Virginia	$1,634.0	$1,548.0	$1,462.0	$1,376.0	$1,290.0	$860.0
Washington, D.C.	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
West Virginia	$3,080.3	$2,918.2	$2,756.1	$2,594.0	$2,431.9	$1,621.2
Total	$19,926.7	$18,877.9	$17,829.1	$16,780.3	$15,731.6	$10,487.7

Table 8-6 shows the estimated impact of three different carbon prices on PJM load-weighted LMP. For example, if the carbon price were $5.00 per tonne, the PJM load-weighted average LMP in the first nine months of 2019 would have increased by 5.9 percent.[86]

Table 8-6 Estimated impact of Carbon price on LMP January through September 2018 and 2019

	2018 (Jan - Sep)				2019 (Jan - Sep)		
Scenario	Carbon Price ($/Metric Ton)	Actual LMP ($/MWh)	Estimated LMP ($/MWh)	Percent Change	Actual LMP ($/MWh)	Estimated LMP ($/MWh)	Percent Change
Scenario 1	$5.00	$39.43	$41.11	4.2%	$27.60	$29.24	5.9%
Scenario 2	$10.00	$39.43	$42.94	8.9%	$27.60	$31.05	12.5%
Scenario 3	$15.00	$39.43	$44.78	13.5%	$27.60	$32.85	19.0%

State Renewable Portfolio Standards

Nine of 14 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 requirements are known as renewable portfolio standards, or RPS. In PJM jurisdictions that have adopted an RPS, load serving entities are 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 are penalized with alternative compliance payments.

Renewable energy sources replenish naturally in a short period of time but are flow limited and include solar, geothermal, wind, biomass and hydropower from flowing water. Renewable energy sources are virtually inexhaustible in duration but limited in the amount of energy that is available per unit of time. Nonrenewable energy sources do not replenish in a short period of time and include crude oil, natural gas, coal and uranium (nuclear energy).[87] Some state rules allow nonrenewable energy sources as part of their Renewable Portfolio Standard.

As of September 30, 2019, 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 noncompliance.

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 September 30, 2019, Virginia and Indiana had renewable portfolio standards that are voluntary and do not include penalties in the form of alternative compliance payments for underperformance. A voluntary standard including target shares was enacted by the Indiana legislature in 2011, but no load serving entities have volunteered to participate in the program.[88]

Three PJM states have no renewable portfolio standards. Kentucky and Tennessee have enacted no renewable portfolio standards. West Virginia had a voluntary standard, but it was repealed.[89]

How each state satisfies its renewable portfolio standard requirements should be more transparent. While some jurisdictions publish transparent information regarding total REC generation, how the standard is fulfilled and the total cost to the state, some jurisdictions do not provide the same level of detail and there can be a significant lag from the end of the compliance year to the publication of the information. Some states provide adequate information with respect to the total cost for the RPS, where the RECs originated that fulfill the RPS requirements, and if the state fulfilled the RPS goals. Pennsylvania and Maryland both provide more information than other states and serve as

86 The impact 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.

87 *Renewable Energy Explained*, U.S. Energy Information Administration, <https://www.eia.gov/energyexplained/index.php?page=renewable_home> (Accessed October 23, 2019).

88 See the Indiana Utility Regulatory Commission's "2019 Annual Report," at 35 (Oct. 2019) <https://www.in.gov/iurc/2981.htm>.

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

a model for other states. The MMU recommends that jurisdictions with a renewable portfolio standard make the compliance data and cost data available in a more complete and transparent manner.

Since a REC may be applied in years other than the year in which it was generated, each vintage of RECs for each state has a different price. For example, the Pennsylvania Alternative Energy Portfolio Standard allows an electric distribution company or generation supplier to retain RECs from the current reporting year for use toward satisfying their REC obligation in either of the two subsequent reporting years.[90]

Table 8-7 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. Table 8-8 summarizes recent rules changes in Ohio, Maryland, New Jersey, and Washington, D. C.

Table 8-7 Renewable and alternative energy standards of PJM jurisdictions: 2019 to 2030[91]

Jurisdiction with RPS	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Delaware	19.00%	20.00%	21.00%	22.00%	23.00%	24.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
Illinois	14.50%	16.00%	17.50%	19.00%	20.50%	22.00%	23.50%	25.00%	25.00%	25.00%	25.00%	25.00%
Maryland	23.20%	30.50%	30.80%	33.10%	35.40%	37.70%	40.00%	42.50%	45.50%	47.50%	49.50%	50.00%
Michigan	12.50%	12.50%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%
New Jersey	18.53%	23.50%	23.50%	24.50%	29.50%	37.50%	40.50%	43.50%	46.50%	49.50%	52.50%	52.50%
North Carolina	10.00%	10.00%	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%
Ohio	5.50%	5.50%	6.00%	6.50%	7.00%	7.50%	8.00%	8.50%	0.00%	0.00%	0.00%	0.00%
Pennsylvania	15.20%	15.70%	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%
Washington, D.C.	18.00%	20.00%	26.25%	32.50%	38.75%	45.00%	52.00%	59.00%	66.00%	73.00%	80.00%	87.00%
Jurisdiction with Voluntary Standard												
Indiana	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
Virginia	7.00%	7.00%	7.00%	12.00%	12.00%	12.00%	15.00%	15.00%	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											

The recent New Jersey legislation also included provisions promoting the development of solar power in the state.[92] The Board of Public Utilities is directed to develop and provide an orderly transition to a new or modified program to support distributed solar. The Board must also design a Community Solar Energy Pilot Program that would "permit customers of an electric public utility to participate in a solar energy project that is remotely located from their properties but is within their electric public utility service territory to allow for a credit to the customer's utility bill equal to the electricity generated that is attributed to the customer's participation in the solar energy project." The pilot program would convert into a permanent program within three years. The statute targets the development of 600 MW of electric storage by 2021 and 2,000 MW by 2030.

90 Pennsylvania General Assembly, "Alternative Energy Portfolio Standards Act – Enactment Act of Nov. 30, 2004, P.L. 1672, No. 213," Section (e)(6).
91 This shows the total standard of alternative resources in all PJM jurisdictions, including Tier I and Tier II.
92 N.J. S. 2314/A. 3723.

Table 8-8 Recent changes in RPS rules[93 94 95 96]

Jurisdiction	Legislation	Effective Date	Summary of changes
Ohio	House Bill 6	October 22, 2019	Reduced the RPS percent for each year beginning in 2020. The 2020 standard was reduced from 6.5 percent to 5.5 percent; the 2026 standard was reduced from 12.5 percent to 8.5 percent. The legislation also removed language that had previously indicated that the standard would remain at the 2026 level for each year after 2026. The solar carve out was removed for compliance year 2020 and beyond. Prior to the recent legislation, the solar carve out was 0.26 percent for 2020, increased to 0.50 percent for 2026, and remained at 0.50 percent for subsequent years.
Maryland	Clean Energy Jobs Act	May 25, 2019	Established a new Tier I target of 50.0 percent in 2030; previously the 2030 Tier I standard was 25.0 percent. The 2019 Tier I standard increased from 20.4 percent to 20.7. The solar carve out percent for 2019 increased from 1.95 percent to 5.50 percent. The solar carve out percent for 2030 increased from 2.5 percent to 14.5 percent. The 2.5 percent Tier II standard, scheduled to end in 2018, was extended through 2020.
Washington, D.C.	CleanEnergy DC Omnibus Amendment Act of 2018	March 22, 2019	Established a 100 percent Tier I renewable standard by 2032. Previously, the 2032 target was 50.0 percent. Tier I increases start in 2020, going from 20.0 percent to 26.25 percent. The 2020 solar carve out will increase from 1.58 percent to 2.175 percent. The 2041 target for the solar carve out is 10.0 percent.
New Jersey	Clean Energy Act	May 24, 2018	Established a 50.0 percent Class I renewable standard for the 2029/2030 compliance year, and an intermediate target of 35.0 percent Class I renewable standard for the 2024/2025 compliance year. Prior to this legislation, the target percent for Class I renewable was 17.9 percent for the 2020/2021 compliance year. The legislation also included an increase in the solar standard for 2018/2019 compliance year from 3.29 percent to 4.3 percent, and an increase to 5.1 percent for the 2020/2021 compliance year. The solar standard decreases to 4.9 percent in the 2023/2024 compliance year, and gradually decreases to 1.1 percent for the 2032/2033 compliance year.

New Jersey and Maryland have taken significant steps to promote offshore wind. Both states enacted legislation for offshore wind renewable energy credits (ORECs) in 2010.[97] On May 24, 2018, New Jersey enacted a statute directing the Board of Public Utilities to create an OREC program targeting installation of at least 3,500 MW of generation from qualified offshore wind projects by 2030 (plus 2,000 MW of energy storage capacity).[98] The New Jersey statute also reinstates certain tax incentives for offshore wind manufacturing activities. Governor Murphy has issue Executive Order No. 8, which call for full implementation of the statute. The BPU has initiated a proceeding considering the opening of an application window for qualified offshore wind projects.[99]

In 2017, the Maryland Public Service Commission announced two awards of ORECs to two commercial wind projects, Deepwater Wind's 120-MW Skipjack Wind Farm and U.S. Wind's 248-MW project. These project awards are the first under Maryland's 2010 OREC program.

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 jurisdictions with mandatory RPS, Maryland, New Jersey, Pennsylvania, and Washington, D.C. group the eligible technologies that must be used to comply with their RPS programs into Tier I and Tier II resources. Although there are minor differences across these four jurisdictions' definitions of Tier I resources, technologies that use solar photovoltaic, solar thermal, wind, ocean, tidal, biomass, low-impact hydro, and geothermal sources to produce electricity are classified as Tier I resources. Table 8-9 shows the Tier I standards for PJM states.[100] All eligible technologies for the RPS standards in Table 8-9 satisfy the EIA definition of renewable energy.[101]

93 See Ohio Legislature House, 133rd Assembly, Bill 6, "Ohio Clean Air Program," effective Date October 22, 2019, <https://www.legislature.ohio.gov/legislation/legislation-summary?id=GA133-HB-6>.
94 See Maryland State Legislature, Senate Bill 516, "Clean Energy Jobs" Passed May 25, 2019, <https://legiscan.com/md/text/sb516/2019>.
95 D.C. Law 22-257 "CleanEnergy DC Omnibus Amendment Act of 2018," Effective March 22, 2019, <https://code.dccouncil.us/dc/council/laws/22-257.html>.
96 See New Jersey CleanEnergy Program, RPS Background Info, <http://njcleanenergy.com/renewable-energy/program-activity-and-background-information/rps-background-info>.
97 See Offshore Wind Economic Development Act of 2010, P.L. 2010, c. 57, as amended, N.J.S.A. 48:3-87 to -87.2.
98 N.J. S. 2314/A. 3723.
99 BPU Docket No. QO18080851.
100 This includes New Jersey's Class I renewable standard.
101 *Renewable Energy Explained*, U.S. Energy Information Administration, <https://www.eia.gov/energyexplained/index.php?page=renewable_home> (Accessed October 17, 2019).

Table 8-9 Tier I renewable standards of PJM jurisdictions: 2019 to 2030

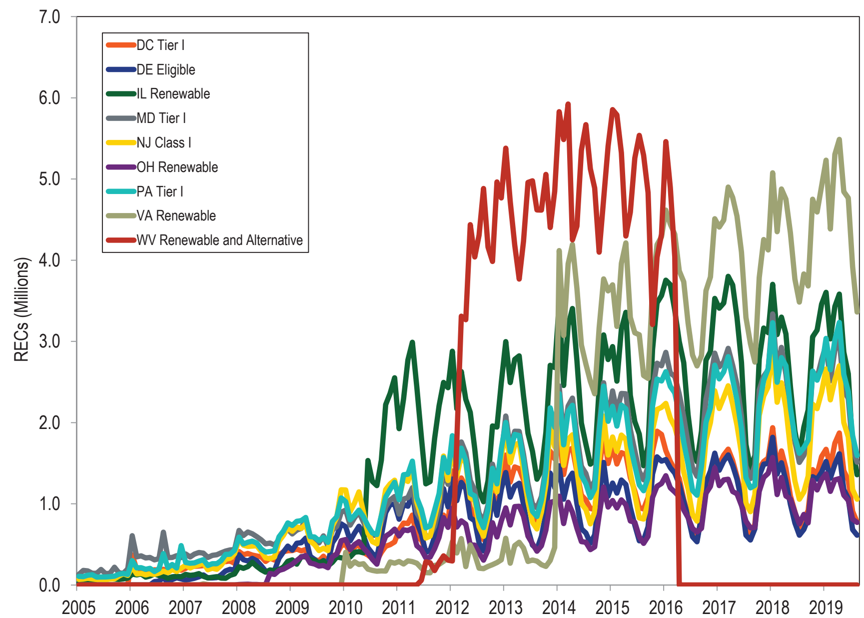
Jurisdiction with RPS	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Maryland	20.70%	28.00%	30.80%	33.10%	35.40%	37.70%	40.00%	42.50%	45.50%	47.50%	49.50%	50.00%
New Jersey	16.03%	21.00%	21.00%	22.00%	27.00%	35.00%	38.00%	41.00%	44.00%	47.00%	50.00%	50.00%
Pennsylvania	7.00%	7.50%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%
Washington, D.C.	17.50%	20.00%	26.25%	32.50%	38.75%	45.00%	52.00%	59.00%	66.00%	73.00%	80.00%	87.00%

Delaware, Illinois, Michigan, North Carolina, and Ohio do not classify the resources eligible for their RPS standards by tiers. In these states eligible technologies are largely but not completely renewable resources.[102]

RECs do not need to be used during the year in which they are generated. The result is that there may be multiple prices for a REC based on the year in which it was generated. RECs typically have a shelf life of five years during which they can be used to satisfy a state's RPS requirement. For example if a load serving entity (LSE) owns renewable generation and the renewable generation exceeds the LSE's RECs purchase obligation for the current year, the LSE can either sell the REC to another LSE or hold the REC for use in a subsequent year.

Figure 8-2 shows the number of RECs eligible monthly by state for January 1, 2005, through August 31, 2019.[103] REC eligibility by state is the number of RECs created in a month that the state could use to fulfil a state's RPS goal. One REC created during a month could be eligible for multiple states based on the RPS requirements. Table 8-18 describes the state's renewable portfolio standard's geographical restrictions governing the source of RECs to satisfy each state's standards. The figure includes Tier I or the equivalent REC type available in each state. Washington, D.C., Maryland, and Pennsylvania classify these RECs as Tier I, New Jersey classifies the RECs as Class I and Delaware, Illinois, Ohio, Virginia and West Virginia classify these RECs as renewable or eligible. West Virginia repealed its renewable portfolio standard, and Virginia has a voluntary renewable portfolio standard.

Figure 8-2 Number of RECs eligible monthly by state: January 2005 through August 2019[104]



The REC prices are the average price for each vintage of REC, defined by the year in which the associated power was generated, regardless of when the REC is consumed. REC prices are required to be publicly disclosed in Maryland, Pennsylvania and Washington, D.C., but in the other states REC prices are not publicly available.

102 Michigan's Public Act 342, effective April 20, 2017, removed nonrenewable technologies (e.g. coal gasification, industrial cogeneration, and coal with carbon capture) from the list of RPS eligible technologies.

103 Tier I REC volume obtained through PJM Environmental Information Services <https://www.pjm-eis.com/reports-and-events/public-reports.aspx> (Accessed October 17, 2019).

104 West Virginia eligible MW drop to 0 in 2016 with the repeal of the state's renewable portfolio standard.

Figure 8-3 shows the average Tier I REC price by jurisdiction from January 1, 2009, through September 30, 2019. Tier I REC prices are lower than SREC prices.

Figure 8-3 Average Tier I REC price by jurisdiction: January 2009 through September 2019

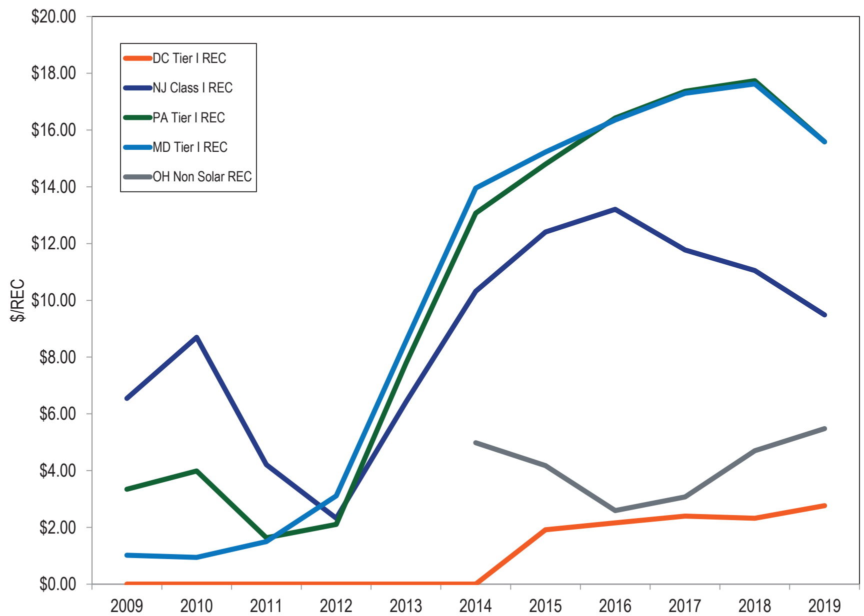
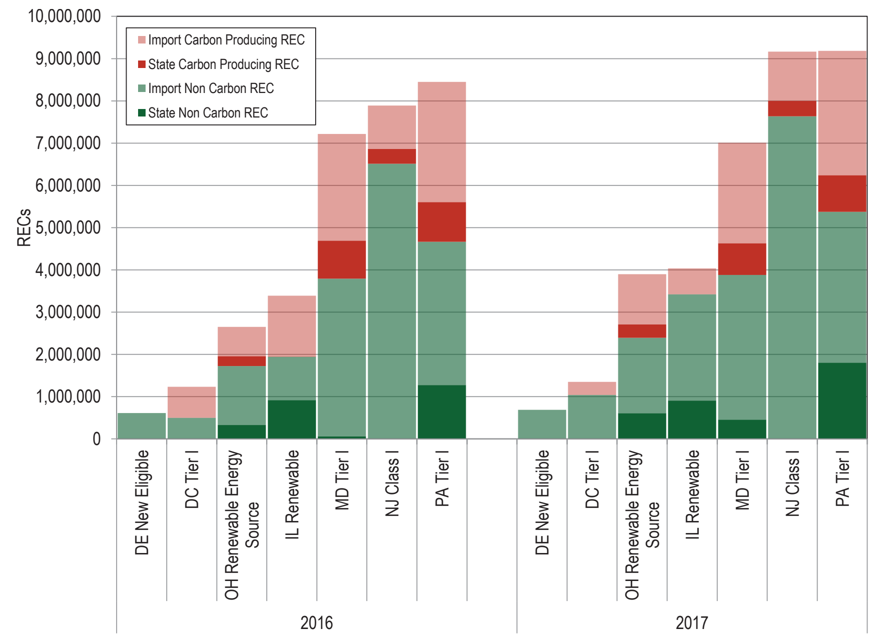


Figure 8-4 and Table 8-10 shows the fulfillment of Tier I equivalent RPS requirement for 2016 and 2017 by state and by import and internal RECs and by carbon producing and noncarbon producing RECs.[105] Depending on the state, the RPS requirement can be fulfilled by wind, solar, hydro ("Non Carbon REC") or with landfill gas, captured methane, wood, black liquor, etc. ("Carbon Producing REC"). States' Tier I requirements are not all carbon free. The DC New Eligible requirement is fulfilled by Non Carbon RECs, but all other state Tier I equivalent RPS requirements allow carbon producing RECs to fulfill the RPS requirements. Figure 8-4 shows the use of imported and local carbon producing RECs and imported and local non carbon RECs by state to meet the RPS requirements. Table 8-10 shows the percent of imported and local carbon producing RECs and imported and local noncarbon RECs by state used to meet the RPS requirements. For example, Pennsylvania met its Tier I target using 73.9 percent imported RECs for the 2016 compliance year, and using 44.8 percent carbon producing RECs for the 2016 compliance year.

Figure 8-4 State fulfillment of Tier I equivalent RPS: 2016 and 2017



105 Retired REC information obtained through PJM GATS <https://gats.pjm-eis.com/gats2/PublicReports/RPSRetiredCertificatesReportingYear> (Accessed October 23, 2019).

Table 8-10 State fulfillment of Tier I equivalent RPS: 2016 and 2017

Year	REC Type	State Non Carbon REC	Import Non Carbon REC	State Carbon Producing REC	Import Carbon Producing REC
2016	DE New Eligible	1.0%	99.0%	0.0%	0.0%
	DC Tier I	0.0%	40.5%	0.0%	59.5%
	OH Renewable Energy Source	12.3%	52.8%	8.7%	26.2%
	IL Renewable	27.1%	30.3%	0.1%	42.5%
	MD Tier I	0.8%	51.7%	12.5%	35.0%
	NJ Class I	0.0%	82.5%	4.5%	13.0%
	PA Tier I	15.1%	40.2%	11.1%	33.7%
2017	DE New Eligible	0.7%	99.3%	0.0%	0.0%
	DC Tier I	0.0%	77.2%	0.0%	22.8%
	OH Renewable Energy Source	15.6%	45.8%	8.1%	30.6%
	IL Renewable	22.5%	62.3%	0.0%	15.2%
	MD Tier I	6.5%	48.9%	10.7%	34.0%
	NJ Class I	0.1%	83.2%	3.9%	12.8%
	PA Tier I	19.6%	38.9%	9.4%	32.0%

Table 8-11 Additional renewable standards of PJM jurisdictions: 2019 to 2030

Jurisdiction	Type of Standard	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Illinois	Distributed Generation	0.15%	0.16%	0.18%	0.19%	0.21%	0.22%	0.24%	0.25%	0.25%	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%
Maryland	Off Shore Wind			1.37%	1.36%	2.03%	2.01%	2.01%	1.99%	1.98%	1.96%	1.96%	1.94%
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	0.14%	0.14%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%
North Carolina	Poultry Waste (in GWh)	900	900	900	900	900	900	900	900	900	900	900	900
Pennsylvania	Tier II Standard	8.20%	8.20%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
Washington, D.C.	Tier II Standard	0.50%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Table 8-11 shows the percent of retail electric load that must be served by Tier II or a specific type of resource under each PJM jurisdiction's RPS by year. Tier II resources are generally not renewable resources. Table 8-11 also shows specific technology requirements that PJM jurisdictions have added to their renewable portfolio standards. Except for the Maryland offshore wind and the North Carolina poultry waste standards, the standards shown in Table 8-11 are included in the total RPS requirements presented in Table 8-7. Illinois requires that a defined proportion of retail load be served by wind and solar resources, increasing from 9.75 percent of load served in 2018 to 18.75 percent in 2026. Maryland, New Jersey, Pennsylvania and Washington, D.C. all have Tier II or Class 2 standards, which allow specific nonrenewable 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. Maryland established a minimum standard for offshore wind in 2017 that takes effect in 2021 with a requirement that 1.37 percent of load be served by offshore wind. The standard increases to 2.03 percent in 2023.[106]

Figure 8-5 shows the number of Tier II RECs eligible monthly by state for January 1, 2005, through August 31, 2019.[107] The figure includes Tier II or the equivalent REC type available in each state. Washington, D.C., Maryland, and Pennsylvania classify these RECs as Tier II and New Jersey classifies the RECs as Class II.

106 Public Service Commission of Maryland, Offshore Wind Projects, Order No. 88192 (May 11, 2017) at 8, Table 2, <https://www.psc.state.md.us/wp-content/uploads/Order-No.-88192-Case-No.-9431-Offshore-Wind.pdf>.

107 Tier II REC volume obtained through PJM Environmental Information Services <https://www.pjm-eis.com/reports-and-events/public-reports.aspx> (Accessed October 17, 2019).

Figure 8-5 Number of Tier II RECs eligible monthly by state: January 2005 through August 2019

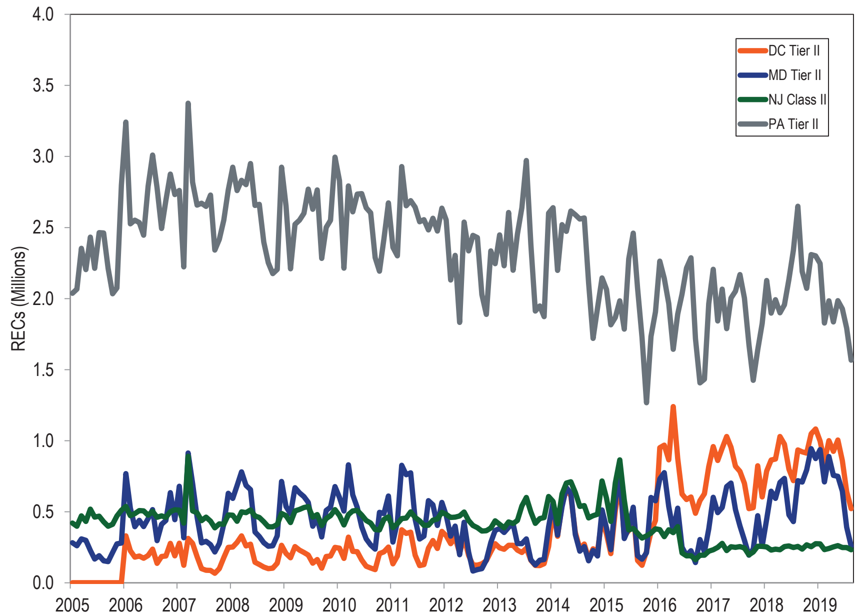
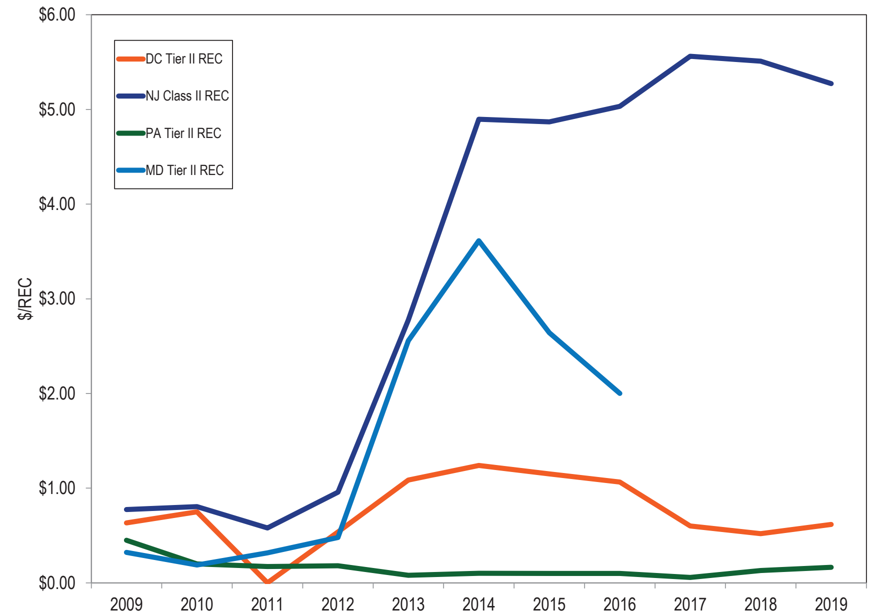


Figure 8-6 Average Tier II REC price by jurisdiction: January 2009 through September 2019



Tier II prices are lower than SREC and Tier I REC prices. Figure 8-6 shows the average Tier II REC price by jurisdiction for January 1, 2009 through September 30, 2019. Pennsylvania had the lowest average Tier II REC prices at $0.13 per REC while New Jersey had the highest average Tier II REC prices at $5.39 per REC.[108]

Some PJM jurisdictions have specific solar resource RPS requirements. These solar requirements are included in the total requirements shown in Table 8-9 but must be met by solar RECs (SRECs) only. Table 8-12 shows the percent of retail electric load that must be served by solar energy resources under each PJM jurisdiction's RPS by year. Delaware, Illinois, Maryland, New Jersey, North Carolina, Ohio, Pennsylvania, and Washington, D.C. 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. The New Jersey legislature in May 2018 increased the solar standard from 3.2 percent to 4.3 percent for 2018. The new solar standard is 5.1 percent for energy years 2020 through

108 Tier II REC price information obtained through Evomarkets <http://www.evomarkets.com> (Accessed October, 2019). There were not any reported cleared purchases for January 1, through September 30, 2019, for MD Tier II RECs.

2022 and the standard gradually decreases to 1.1 percent for 2032.[109] Maryland legislation in 2019 increased the solar carve out percentages. The new Maryland RPS solar carve out target, to be reached in 2030, increased from 2.5 percent to 14.5 percent. Ohio HB 6 removed the solar carve out from the Ohio RPS.

Table 8-12 Solar renewable standards by percent of electric load for PJM jurisdictions: 2019 to 2030

Jurisdiction with RPS	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Delaware	2.00%	2.25%	2.50%	2.75%	3.00%	3.25%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%
Illinois	0.87%	0.96%	1.05%	1.14%	1.23%	1.32%	1.41%	1.50%	1.50%	1.50%	1.50%	1.50%
Maryland	5.50%	6.00%	7.50%	8.50%	9.50%	10.50%	11.50%	12.50%	13.50%	14.50%	14.50%	14.50%
Michigan	No Minimum Solar Requirement											
New Jersey	4.90%	5.10%	5.10%	5.10%	4.90%	4.80%	4.50%	4.35%	3.74%	3.07%	2.21%	1.58%
North Carolina	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%
Ohio	0.22%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Pennsylvania	0.39%	0.44%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%
Washington, D.C.	1.85%	2.18%	2.50%	2.60%	2.85%	3.15%	3.45%	3.75%	4.10%	4.50%	4.75%	5.00%
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											

109 "Assembly, No. 3723" State of New Jersey, 218th Legislature (March 22, 2018), <http://www.njleg.state.nj.us/2018/Bills/A4000/3723_I1.PDF>.

Figure 8-7 shows the number of SRECs eligible monthly by state for January 1, 2005, through August 31, 2019.[110]

Figure 8-7 Number of SRECs eligible monthly by state: January 2005 through August 2019

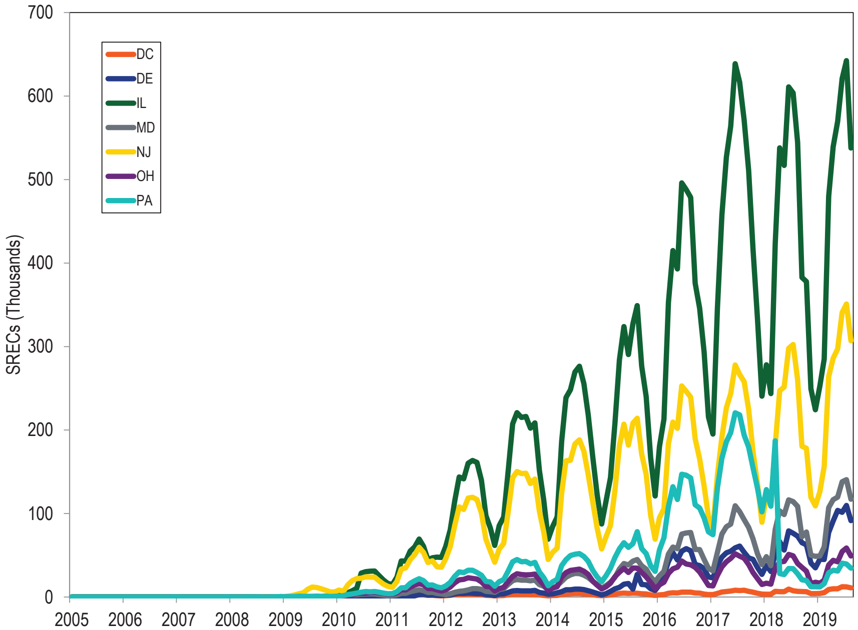


Figure 8-8 shows the average solar REC (SREC) price by jurisdiction for January 1, 2009, through September 30, 2019. The average NJ SREC prices dropped from $673 per SREC in 2009 to $194 per SREC in 2019. The limited supply of solar facilities in Washington, D.C. compared to the RPS requirement resulted in higher SREC prices. The average Washington, D.C. SREC price increased from $197 per SREC in 2011 to $387 per SREC in 2019.[111]

Figure 8-8 Average SREC price by jurisdiction: January 2009 through September 2019

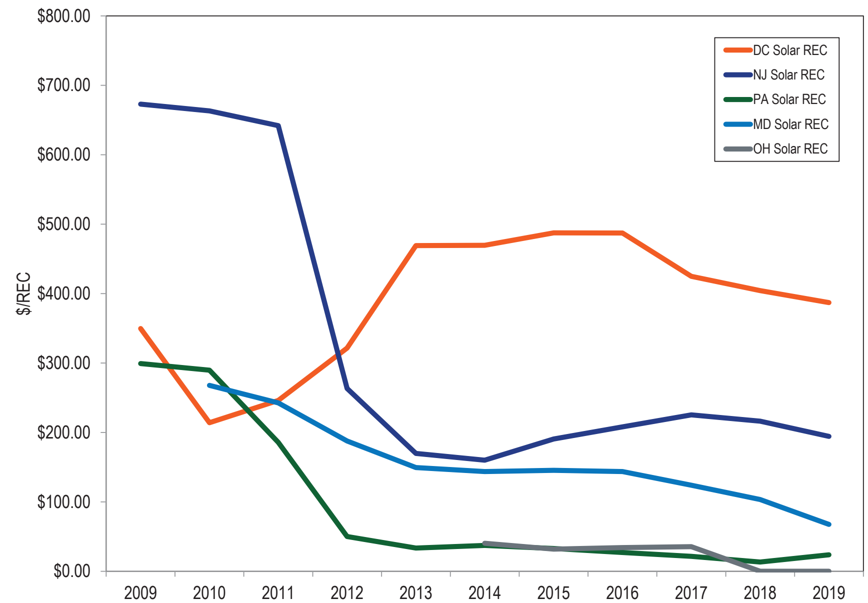


Figure 8-9 and Table 8-13 shows each the fulfillment of a solar requirement by state for 2016 and 2017, by source of SREC.[112] Depending on the state, the solar RPS requirement can be fulfilled by in state or out of state SRECs. The SRECs purchased in some states are imported from other PJM states and from non PJM states. Table 8-13 shows the percent of imported and local SRECs used to meet the RPS requirements. For example, Washington D.C. met its solar requirement using 50.2 percent imported SRECs for the 2016 compliance year.

110 SREC volume obtained through PJM Environmental Information Services <https://www.pjm-eis.com/reports-and-events/public-reports.aspx> (Accessed October 17, 2019).

111 Solar REC average price information obtained through Evomarkets, <http://www.evomarkets.com> (Accessed October 17, 2019).

112 Retired REC information obtained through PJM GATS <https://gats.pjm-eis.com/gats2/PublicReports/RPSRetiredCertificatesReportingYear> (Accessed October 23, 2019).

Figure 8-9 State fulfillment of Solar RPS: 2016 and 2017

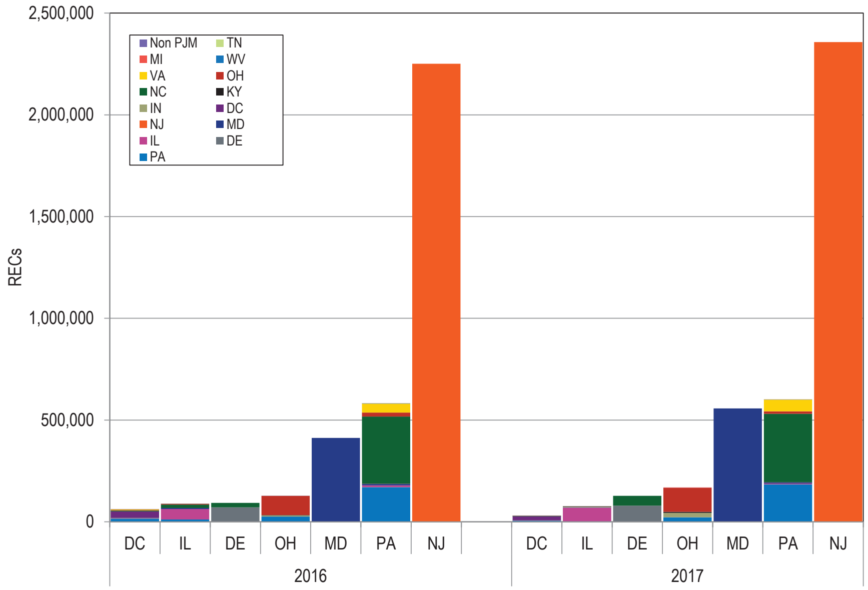
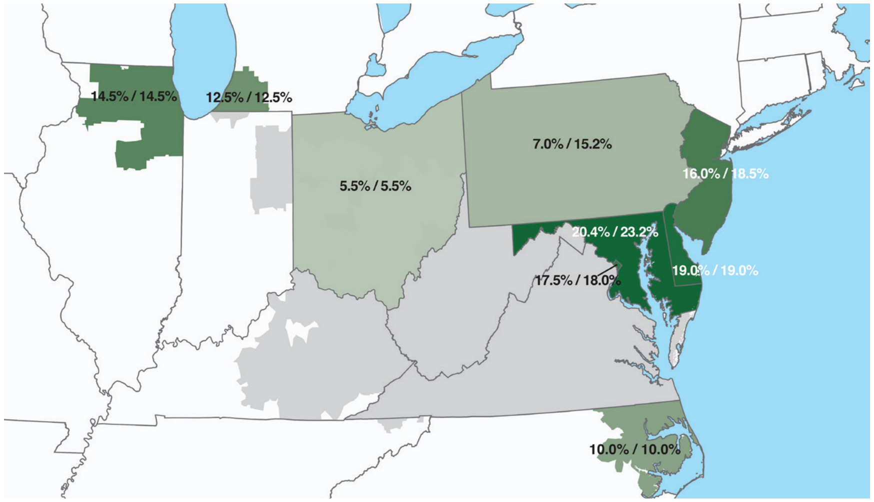


Table 8-13 State fulfillment of Solar RPS: 2016 and 2017

		State SREC	Import SREC
2016	DC Solar	49.8%	50.2%
	IL Solar Renewable	56.5%	43.5%
	DE Solar Eligible	76.5%	23.5%
	OH Solar Renewable Energy Source	73.3%	26.7%
	MD Solar	100.0%	0.0%
	PA Solar	29.1%	70.9%
	NJ Solar	100.0%	0.0%
2017	DC Solar	17.2%	82.8%
	IL Solar Renewable	87.6%	12.4%
	DE Solar Eligible	61.9%	38.1%
	OH Solar Renewable Energy Source	69.0%	31.0%
	MD Solar	100.0%	0.0%
	PA Solar	30.6%	69.4%
	NJ Solar	100.0%	0.0%

Figure 8-10 shows 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. For each state in Figure 8-10, the first number represents the RPS percent for Tier I or renewable energy resources; the second number represents the RPS percent for all eligible technologies which includes both renewable and alternative energy resources. States with higher percent requirements for renewable energy resources are shaded darker. Jurisdictions with no standards or with only voluntary RPS are shaded gray. Pennsylvania's RPS illustrates the need to differentiate between percent requirements for renewable and alternative energy resources. 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. As a result, the 15.2 percent number in Figure 8-10 overstates the percent of retail electric load in Pennsylvania that must be served by renewable energy resources. The 7.0 percent number in Figure 8-10 is a more accurate measure of the percent of retail electric load in Pennsylvania that must be served by renewable energy resources.

Figure 8-10 Map of retail electric load shares under RPS – Renewable / Alternative Energy resources: 2019[113]



Under the existing state renewable portfolio standards, approximately 10.3 percent of PJM load must be served by Tier I and Tier II renewable and alternative energy resources in 2019. In the first nine months of 2019, 6.8 percent of PJM generation was renewable and alternative energy resources, including carbon producing and noncarbon producing Tier I and Tier II generation as shown in Table 8-14. If the proportion of load among states remains constant, 17.5 percent of PJM load must be served by Tier I and Tier II renewable and alternative energy resources in 2029 under currently defined RPS rules. Approximately 8.2 percent of PJM load must be served by Tier I or renewable energy resources in 2019. In the first nine months of 2019, 4.6 percent of PJM generation was Tier I or renewable energy as shown in Table 8-14. If the proportion of load among states remains constant, 15.3 percent of PJM load must be served by Tier I or renewable energy resources in 2029 under defined RPS rules.

113 The standards in this chart include the Tier I standards used by some states in the PJM footprint, as well as the total alternative energy standard for states that do not classify eligible technologies into tiers.

In jurisdictions with an RPS, load serving entities must either generate power from eligible technologies identified in each jurisdiction's RPS or purchase RECs from resources classified as eligible technologies. Table 8-14 shows generation by jurisdiction and resource type for the first nine months of 2019. Wind output was 16,974.1 GWh of 29,029.2 Tier I GWh, or 58.5 percent, in the PJM footprint. As shown in Table 8-14, 42,695.1 GWh were generated by Tier I and Tier II resources, of which Tier I resources were 68.0 percent. Total wind and solar generation was 3.1 percent of total generation in PJM for the first nine months of 2019. Tier I generation was 4.6 percent of total generation in PJM and Tier II was 2.2 percent of total generation in PJM for the first nine months of 2019. Landfill gas, solid waste and waste coal were 10,682.5 GWh, or 25.0 percent of the total Tier I and Tier II.

Table 8-14 Tier I and Tier II generation by jurisdiction and renewable resource type (GWh): January through September, 2019

	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	29.9	0.0	0.0	0.0	29.9	0.0	0.0	0.0	0.0	29.9
Illinois	82.5	0.0	11.7	7,517.5	7,611.7	0.0	0.0	0.0	0.0	7,611.7
Indiana	14.7	36.5	10.9	3,872.3	3,934.5	0.0	0.0	0.0	0.0	3,934.5
Kentucky	0.0	265.6	0.0	0.0	265.6	0.0	0.0	0.0	0.0	265.6
Maryland	46.2	0.0	358.4	464.9	869.5	0.0	444.3	0.0	444.3	1,313.8
Michigan	16.1	51.4	5.3	0.0	72.8	0.0	0.0	0.0	0.0	72.8
New Jersey	191.0	23.9	578.4	10.7	804.1	231.6	987.6	0.0	1,219.2	2,023.3
North Carolina	0.0	609.0	676.9	372.2	1,658.0	0.0	0.0	0.0	0.0	1,658.0
Ohio	260.0	608.2	1.0	1,378.9	2,248.1	0.0	0.0	0.0	0.0	2,248.1
Pennsylvania	540.5	4,470.1	20.4	2,318.2	7,349.2	1,420.3	1,055.9	4,062.8	6,539.0	13,888.2
Tennessee	0.0	1,091.3	0.0	0.0	1,091.3	0.0	0.0	0.0	0.0	1,091.3
Virginia	400.8	466.3	527.7	0.0	1,394.8	2,945.3	688.8	1,132.6	4,766.6	6,161.4
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	32.0	628.4	0.0	1,039.3	1,699.6	0.0	0.0	696.7	696.7	2,396.3
Total	1,613.7	8,250.7	2,190.7	16,974.1	29,029.2	4,597.2	3,176.7	5,892.0	13,665.9	42,695.1
Percent of Renewable Generation	3.8%	19.3%	5.1%	39.8%	68.0%	10.8%	7.4%	13.8%	32.0%	100.0%
Percent of Total Generation	0.3%	1.3%	0.3%	2.7%	4.6%	0.7%	0.5%	0.9%	2.2%	6.8%

Figure 8-11 shows the average hourly output by fuel type for January 1 through September 30 of 2014 through 2019. 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.[114]

114 See the *2019 Quarterly State of the Market Report for PJM: January through June*, Section 3: Energy Market, Table 3-9.

Figure 8-11 Average hourly output by fuel type: January through September, 2014 through 2019

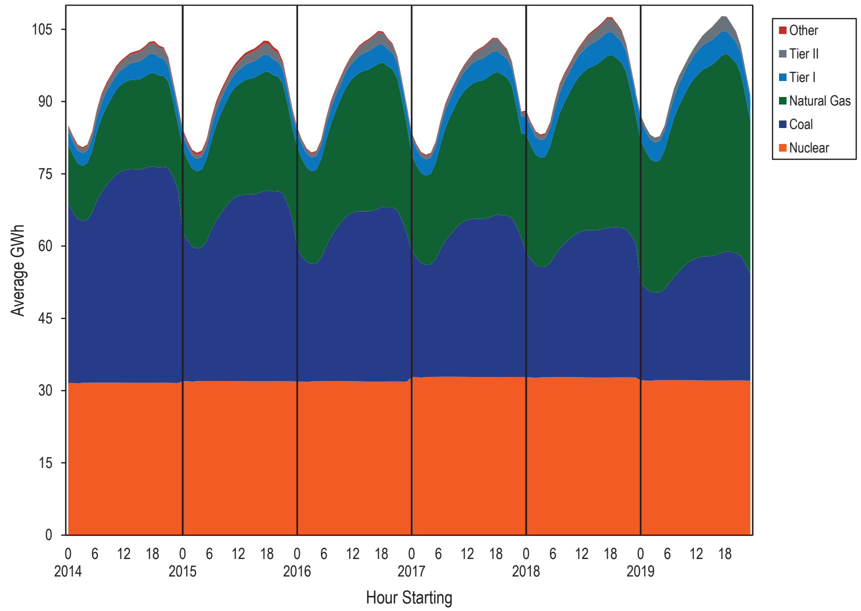


Table 8-15 shows the capacity of Tier I and Tier II resources in PJM by jurisdiction, as defined by primary fuel type. This capacity includes coal and natural gas units that qualify because they have a renewable fuel as an alternative fuel. For example, a coal generator that can also burn waste coal 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, 560.8 MW, or 28.6 percent of the total solar capacity. New Jersey's SREC prices were the highest in PJM at $673 per REC in 2009, and at $194 per REC in 2019. Wind resources are located primarily in western PJM, in Illinois and Indiana, which include 5,571.6 MW, or 63.0 percent of the total wind capacity.

Table 8-15 PJM renewable capacity by jurisdiction (MW): September 30, 2019

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	39.2	360.0	0.0	0.0	0.0	9.0	0.0	0.0	3,549.2	3,957.4
Indiana	0.0	8.0	0.0	0.0	0.0	8.2	10.1	0.0	0.0	2,022.5	2,048.8
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	22.3	0.0	69.0	0.0	494.4	204.3	128.2	0.0	190.0	1,108.2
Michigan	0.0	8.0	0.0	0.0	0.0	13.9	4.6	0.0	0.0	0.0	26.5
Missouri	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	146.0	146.0
New Jersey	0.0	77.7	0.0	0.0	453.0	11.0	560.8	162.0	0.0	4.5	1,268.9
North Carolina	0.0	0.0	0.0	0.0	0.0	465.0	655.6	0.0	0.0	208.0	1,328.6
Ohio	5,734.0	68.2	0.0	136.0	0.0	119.1	1.1	0.0	0.0	669.8	6,728.2
Pennsylvania	0.0	201.8	2,346.0	0.0	1,269.0	893.3	19.5	261.8	1,561.0	1,367.2	7,919.6
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	5,347.5	169.2	499.0	123.0	585.0	0.0	6,874.8
Washington, D.C.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
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	5,734.0	572.7	4,503.0	235.0	7,069.5	2,754.5	1,964.0	675.0	2,311.0	8,843.4	34,662.1

Table 8-16 shows renewable capacity registered in the PJM generation attribute tracking system (GATS). For example, roof top solar panels within the PJM footprint generate SRECs but are not PJM units. This includes solar capacity of 5,862.0 MW of which 2,280.2 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. There are 2,058.2 MW of capacity located in jurisdictions outside PJM that may qualify for specific renewable energy credits in some PJM jurisdictions. For example, there are 141.5 MW of capacity registered with GATS located in Alabama.

Table 8-16 Renewable capacity by jurisdiction, non-PJM units registered in GATS (MW), on September 30, 2019[115]

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	0.0	0.0	0.0	18.0	0.0	0.0	0.0	0.0	18.0
Delaware	0.0	0.0	2.2	0.0	0.0	0.0	116.1	0.0	2.1	120.4
Georgia	0.0	0.0	27.1	0.0	0.0	0.0	152.2	258.9	0.0	438.2
Illinois	0.0	21.4	93.8	0.0	5.5	0.0	142.7	0.0	300.3	563.7
Indiana	0.0	0.0	49.6	0.0	5.2	109.6	114.8	0.0	180.0	459.2
Iowa	0.0	0.0	1.6	0.0	0.0	0.0	3.2	0.0	336.8	341.6
Kentucky	600.0	162.2	18.6	0.0	0.4	0.0	37.0	93.0	0.0	911.2
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	0.0	0.0	0.0	952.8	15.0	0.3	1,045.8
Michigan	55.0	1.3	4.8	0.0	0.0	0.0	5.0	31.0	29.4	126.5
Missouri	0.0	0.0	5.6	0.0	0.0	0.0	61.5	0.0	451.0	518.1
New Jersey	0.0	0.0	48.3	0.0	11.6	0.0	2,280.2	0.0	4.8	2,344.9
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	1,068.5	151.5	0.0	1,650.4
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	6.6	30.8	52.0	14.2	32.4	219.7	92.8	47.4	496.0
Pennsylvania	109.7	31.7	45.2	93.0	16.6	5.0	374.8	8.6	3.3	687.8
South Carolina	0.0	0.0	30.8	0.0	0.0	0.0	91.3	0.0	0.0	122.1
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	28.6	11.3	0.0	3.1	0.0	166.7	287.6	0.0	497.3
Washington, D.C.	0.0	0.0	0.0	0.0	49.4	13.5	70.7	0.0	0.0	133.6
West Virginia	0.0	0.0	0.0	0.0	0.0	0.0	4.2	0.0	0.0	4.2
Wisconsin	0.0	9.0	0.0	0.0	0.0	0.0	0.3	44.6	0.0	53.9
Total	829.7	691.2	382.4	145.0	123.9	160.5	5,862.0	1,311.4	1,715.5	11,221.6

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.[116] 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.[117] 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 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.[118] 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.[119]

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 8-17 shows the REC tracking systems used by each state within the PJM footprint.

115 See PJM – EIS (Environmental Information Services), Generation Attribute Tracking System, "Renewable Generators Registered in GATS," <https://gats.pjm-eis.com/gats2/PublicReports/RenewableGeneratorsRegisteredinGATS> (Accessed October 17, 2019).

116 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).

117 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.").

118 See DSIRE, NC Clean Energy Technology Center. Delaware Renewable Portfolio Standard, <http://programs.dsireusa.org/system/program/detail/1231> (Accessed November 3, 2018).

119 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 8-17 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 8-18 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 each state's 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 to be sourced from resources located in Pennsylvania.

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.

Table 8-18 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 be purchased from resources located within Illinois or from resources located in adjacent states that meet certain public interest criteria.
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. 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.

Carbon Pricing

Table 8-19 shows the impact of a range of carbon prices on the cost per MWh of producing energy from three basic unit types.[120] [121] For example, if the price of carbon were $50.00 per tonne, the short run marginal costs would increase by $24.52 per MWh for a new combustion turbine (CT) unit, $16.71 per MWh for a new combined cycle (CC) unit and $43.15 per MWh for a new coal plant (CP).

Table 8-19 Carbon price per MWh by unit type

	Carbon Price per MWh						
Unit Type	Carbon $5/tonne	Carbon $10/tonne	Carbon $15/tonne	Carbon $50/tonne	Carbon $100/tonne	Carbon $200/tonne	Carbon $400/tonne
CT	$2.45	$4.90	$7.36	$24.52	$49.04	$98.08	$196.17
CC	$1.67	$3.34	$5.01	$16.71	$33.41	$66.83	$133.65
CP	$4.32	$8.63	$12.95	$43.15	$86.30	$172.60	$345.21

Table 8-19 also illustrates the effective cost of carbon included in the price of a REC or SREC. For example, the average price of an SREC in New Jersey was $194.32 per MWh through the third quarter of 2019. 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 tonne. 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 tonne, assuming that a MWh from a CT is avoided, is $24.52 per MWh.

120 Heat rates from: *2018 State of the Market Report for PJM*, Volume 2, Section 7: Net Revenue, Table 7-4.
121 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 July 24, 2018).

Applying this method to tier I REC and SREC price histories yields the implied carbon prices in Table 8-20. The carbon price implied by the 2019 average REC price in Washington, D.C. is $5.64 per tonne which is consistent with the most recent RGGI clearing price of $5.73 per tonne. All other carbon prices implied by renewable RECs are well above the RGGI clearing price, and the carbon prices implied by REC prices in Maryland and Pennsylvania are more consistent with the social cost of carbon which is estimated to be in the range of $50 per tonne.[122] The carbon prices implied by SREC prices have no apparent relationship to carbon prices implied by the REC clearing prices. Except for Pennsylvania, the carbon prices implied by SREC prices are significantly greater than the prices implied by REC prices in each jurisdiction and in most cases significantly higher than the social price of carbon.

Table 8-20 Implied carbon price based on REC and SREC prices: 2009 through 2019[123]

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Jurisdiction with Tier I or Class I REC	Carbon Price ($ per Metric Tonne) Implied by REC Prices										
Delaware					$34.15	$35.17	$31.91	$32.91	$10.26	$10.29	$13.34
Maryland	$2.07	$1.92	$3.06	$6.34	$17.46	$28.45	$31.04	$33.35	$35.26	$35.94	$31.78
New Jersey	$13.34	$17.74	$8.58	$4.74	$13.09	$21.04	$25.29	$26.93	$24.01	$22.53	$19.35
Ohio						$10.16	$8.52	$5.29	$6.27	$9.59	$11.17
Pennsylvania	$6.82	$8.13	$3.33	$4.29	$15.87	$26.66	$30.17	$33.49	$35.40	$36.17	$31.78
Washington, D.C.							$3.91	$4.40	$4.88	$4.73	$5.64
Jurisdiction with Solar REC	Carbon Price ($ per Metric Tonne) Implied by Solar REC Prices										
Delaware						$117.25	$85.40	$86.48	$35.70	$17.33	
Maryland		$546.11	$494.54	$382.57	$304.54	$292.70	$296.62	$292.64	$252.59	$210.76	$137.64
New Jersey	$1,372.37	$1,352.15	$1,309.00	$537.08	$345.94	$326.21	$388.73	$424.21	$459.21	$440.92	$396.23
Ohio						$82.32	$64.86	$69.53	$72.40		
Pennsylvania	$610.05	$590.57	$378.67	$101.80	$68.34	$75.90	$66.89	$55.06	$43.84	$27.09	$48.08
Washington, D.C.	$712.98	$436.28	$501.62	$655.52	$956.55	$957.46	$994.05	$993.49	$866.17	$824.43	$789.17
Regional Greenhouse Gas Initiative	CO_2 Allowance Price ($ per Metric Tonne)										
RGGI clearing price	$3.06	$2.12	$2.08	$2.13	$3.22	$5.21	$6.72	$4.93	$3.77	$4.86	$5.91

Alternative Compliance Payments

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 (ACPs), with varying standards, to cover any shortfall between the RECs required by the state and those the retail supplier actually purchased. The ACPs, which are penalties, function as a cap on the market value of RECs. In New Jersey, solar ACPs are currently $258.00 per MWh.[124] Pennsylvania requires that solar ACPs be 200 percent of the average market value of solar RECs sold in the RTO plus the value of any solar rebates. Figure 8-12 shows the historical relationship between SREC prices and ACP levels. The SREC price is represented by a solid line in the figure and the corresponding ACP level is represented by a dashed line. For each jurisdiction, the ACP is an upper bound for the price level. In Michigan and North Carolina, there are no defined values for ACPs. 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.

122 "Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis – Under Executive Order 12899," Interagency Working Group on the Social Cost of Greenhouse Gases, United States Government, (Aug. 2016), <https://19january2017snapshot.epa.gov/sites/production/files/2016-12/documents/sc_co2_tsd_august_2016.pdf>.
123 There were no trades in 2018 for Ohio SRECs available in the Evomarkets data.
124 N.J. S. 2314/A. 3723.

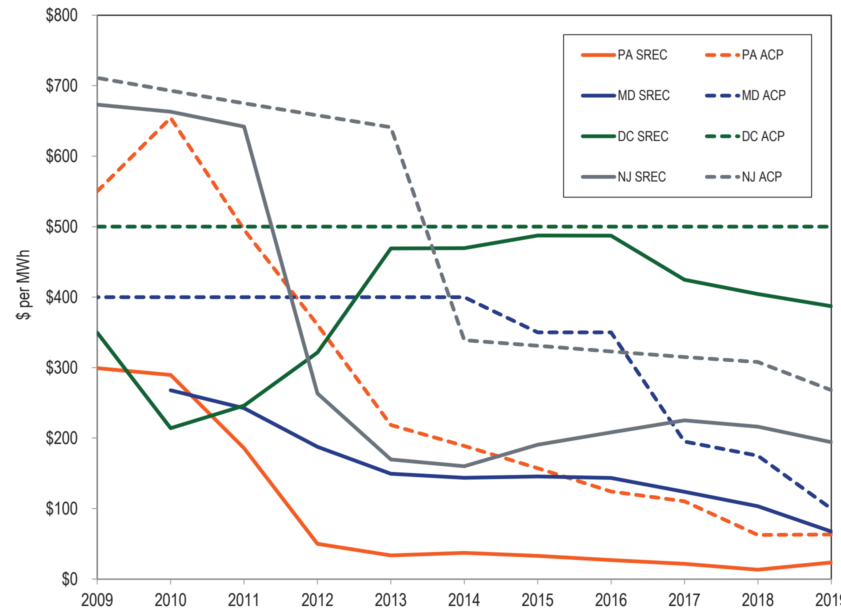
Table 8-21 shows the alternative compliance standards for RPS in PJM jurisdictions.

Table 8-21 Tier I, Tier II, and Solar alternative compliance payments in PJM jurisdictions: September 30, 2019[125 126 127]

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	$30.00	$15.00	$100.00
Michigan	No specific penalties		
New Jersey	$50.00		$258.00
North Carolina	No specific penalties: At the discretion of the NC Utility Commission		
Ohio	$52.62		$200.00
Pennsylvania	$45.00	$45.00	$62.62
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.

Figure 8-12 Comparison of SREC Price and Solar ACP: 2009 through 2019



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 Pennsylvania Public Utility Commission issued their 2017 compliance report for the Pennsylvania Alternative Energy Standards Act of 2004 during the first quarter of 2018.[128] Pennsylvania reported that the 20,634,311 credits retired during the compliance year exceeded the amount required by the standards by 1,995 credits. Not all suppliers met the required standard.

125 The Ohio standard alternative compliance payment (ACP) is updated annually <https://www.puco.ohio.gov/industry-information/industry-topics/acp-non-solar-alternative-compliance-payment-under-orc-492864/>. The Illinois Commerce Commission periodically publishes updates to the effective ACP amount <https://www.icc.illinois.gov/electricity/RPSCompliancePaymentNotices.aspx>. For updated Maryland ACPs, see Table 3 of the 2017 Renewable Energy Portfolio Standard Report <https://www.psc.state.md.us/commission-reports/>.

126 See DSIRE, "Database of State Incentives for Renewables & Efficiency, "Policies & Incentives by State," <http://www.dsireusa.org/> (Accessed February 21, 2019).

127 The entry for Pennsylvania reflects the solar ACP for the compliance year ending May 31, 2018. See "Pricing," <https://www.pennaeps.com/reports/> (Accessed July 16, 2019).

128 "2017 Annual Report – Alternative Energy Portfolio Standards Act of 2004," (March 2018), <http://www.pennaeps.com/reports/>.

Supplier obligations for six Tier I credits and 14 Tier II credits, were resolved through alternative compliance payments.

The Public Service Commission of the District of Columbia reported that 1,645,545 credits were retired during the 2017 compliance year and there was a significant increase in compliance payments.[129] Compliance payments were $26,571,010 for 2017, a 74.4 percent increase over the compliance payments for 2016. Solar standards contributed to the increase in compliance payments. Solar REC retirements in 2017 were 50.5 percent lower than solar REC retirements in 2016, with 30,765 solar RECs retired in 2017 and 62,173 retired in 2016.

The Public Service Commission of Maryland reported that "suppliers retired over 9.0 million RECs in 2017, slightly less than both the calculated obligation for the year and the 9.1 million RECs retired for compliance in 2016."[130] Alternative compliance payments totaled $55,032 for 2017 with the majority of payments "made in lieu of purchasing Tier 1 RECs to satisfy Industrial Load Process ("IPL") obligations."[131]

The Public Utilities Commission of Ohio reported that 3,919,366 nonsolar credits were retired in the 2017 compliance year, exceeding the credit obligation of 3,912,562 credits; and 175,829 solar credits were retired in the 2017 compliance year, exceeding the solar credit obligation of 175,185.[132] Retired non solar credits for 2017 exceeded the 2016 level by 46.1 percent, and retired solar credits for 2017 exceeded the 2016 level by 29.9 percent.

Delmarva Power is the only retail electric supplier that must file a compliance report with the Delaware Public Service Commission. Delmarva Power reported to the Delaware Public Service Commission that they satisfied their REC obligation of 670,488 credits for the compliance year ending May 31, 2019, with zero alternative compliance payments.[133] Delmarva Power satisfied their solar REC obligation of 124,073 credits with zero alternative compliance payments.

Prior to the 2017/2018 Delivery Year, the Illinois RPS had required electricity suppliers to satisfy at least 50 percent of their RPS obligation through alternative compliance payments. This requirement was removed for 2017/2018 Delivery Year and alternative compliance payments decreased to $151,027, a 99.8 percent reduction from the 2016-2017 level of alternative compliance payments.[134]

The North Carolina Utilities Commission reported that all electric power suppliers met or appear to have met the 2017 renewable energy portfolio standard, solar energy requirement, and poultry waste energy requirement.[135] [136] The implementation of the swine waste energy requirement has been delayed and electric power suppliers were not subject to the swine waste energy requirement for 2017.

The Michigan Public Service Commission reported that electric power suppliers met the 2017 renewable energy standards by retiring 10,218,115 RECs.[137]

New Jersey's Office of Clean Energy posted a summary of RPS compliance through the energy year ending May 31, 2018.[138] Electric power suppliers retired 9,166,102 class I RECs and 1,758,180 class II RECs. Alternative compliance payments were submitted for deficiencies of 24 class I credits and 9 class II credits. Electric power suppliers retired 2,357,814 solar RECs and there were no deficiencies requiring alternative compliance payments.

129 "Report on the Renewable Energy Portfolio Standard for Compliance Year 2018," Public Service Commission of the District of Columbia (May 1, 2019), <https://www.dcpsc.org/Utility-Information/Electric/Renewables/Renewable-Energy-Portfolio-Standard-Program.aspx>.

130 "Renewable Energy Portfolio Standard Report," Public Service Commission of Maryland (Nov. 2018) at 7, <https://www.psc.state.md.us/wp-content/uploads/FINAL-Renewable-Energy-Portfolio-Standard-Report-with-data-for-CY-2017.pdf>.

131 Id. at 8.

132 "Renewable Portfolio Standard Report to the General Assembly for Compliance Year 2017," Public Utilities Commission of Ohio (March 20, 2019), <https://www.puco.ohio.gov/industry-information/industry-topics/ohioe28099s-renewable-and-advanced-energy-portfolio-standard/>.

133 "Retail Electricity Supplier's RPS Compliance Report, Compliance Period: June 1, 2018–May 31, 2019," Delmarva Power, (Sept. 23, 2019), <https://depsc.delaware.gov/delawares-renewable-portfolio-standard-green-power-products/>

134 "Annual Report Fiscal Year 2018," Illinois Power Agency (Feb. 15, 2019) at 46, <https://www2.illinois.gov/sites/ipa/Pages/IPA_Reports.aspx>.

135 "Annual Report Regarding Renewable Energy and Energy Efficiency Portfolio Standard in North Carolina," North Carolina Utilities Commission, (Oct. 1, 2018), <https://www.ncuc.net/Reps/reps.html>.

136 Id. at 53. Compliance plan approvals are pending for one municipally-owned electric utility and one electric membership corporation (EMC).

137 "Report on the Implementation and Cost-Effectiveness of the P.A. 295 Renewable Energy Standard," Michigan Public Service Commission (Feb. 15, 2019), <https://www.michigan.gov/mpsc/0,9535,7-395-93309_93438_93459_94932---,00.html>.

138 See RPS Report Summary 2005-2018, New Jersey's Clean Energy Program (Dec. 31, 2018), <http://www.njcleanenergy.com/renewable-energy/program-updates/rps-compliance-reports>.

Table 8-22 shows the RPS compliance cost incurred by PJM jurisdictions as reported by the jurisdictions. The compliance costs are the cost of acquiring RECs plus the cost of any alternative compliance payments. The cost by type in Table 8-22 is an estimate based on average REC prices and assigning the reported alternative compliance payments to the solar standard. The cost of complying with RPS, as reported by the states, was $3.4 billion over the four year period from 2014 through 2017 for the eight jurisdictions that had RPS and reported compliance costs.[139] The average RPS compliance cost per year based on the reported compliance cost for the four year period from 2014 through 2017 was $840.4 million.

Table 8-22 RPS Compliance Cost[140 141 142 143 144 145 146 147 148 149]

Jurisdiction with RPS		2014	2015	2016	2017	2018
Delaware	Total RPS		$16,013,421	$18,409,631	$18,772,855	$18,341,916
	Solar		$7,070,254	$7,748,073	$7,105,726	$6,565,240
	Non-Solar		$8,943,167	$10,661,557	$11,667,129	$11,776,676
Illinois	Total RPS	$21,701,688	$24,817,068	$25,718,863	$25,919,372	$25,775,523
Maryland	Total RPS	$103,990,914	$126,727,632	$135,198,524	$72,009,070	
	Solar	$29,372,737	$39,055,714	$45,556,987	$21,275,664	
	Tier I	$70,630,620	$85,054,001	$88,200,121	$50,045,621	
	Tier II	$3,987,557	$2,617,917	$1,441,416	$687,785	
Michigan	Total RPS	$476,535	$0	$3,264,504	$3,961,262	
New Jersey	Total RPS	$395,782,297	$524,761,382	$593,441,037	$606,312,461	
	Solar	$322,504,920	$417,359,783	$481,540,738	$503,797,182	
	Class I	$66,071,749	$98,185,431	$100,910,465	$91,872,615	
	Class II	$7,205,628	$9,216,167	$10,989,834	$10,642,664	
Ohio	Total RPS	$42,581,477	$42,584,233	$37,631,481	$39,943,836	
	Solar	$17,666,730	$14,843,052	$11,564,584	$9,435,730	
	Non-Solar	$24,914,747	$27,741,181	$26,066,897	$30,508,106	
Pennsylvania	Total RPS	$86,184,477	$114,586,932	$125,041,911		
	Solar	$14,163,543	$19,227,690	$21,876,876		
	Tier I	$70,922,431	$94,339,032	$101,700,328		
	Tier II	$1,098,503	$1,020,210	$1,464,707		
Washington D.C.	Total RPS	$27,372,970	$38,540,633	$47,163,353	$42,678,813	$50,609,701
	Solar	$25,145,143	$36,526,662	$44,897,161	$38,571,061	$45,673,261
	Tier I	$2,140,860	$1,899,232	$2,132,072	$3,960,018	$4,809,857
	Tier II	$86,966	$114,738	$134,119	$147,734	$126,583
PJM	Total RPS	$678,090,358	$888,031,302	$985,869,304	$809,597,668	$94,727,139

139 The actual PJM RPS compliance cost exceeds the reported $3.4 billion since this total does not include a value for Delaware in 2014, a value for Pennsylvania in 2017, does not include any data for 2018 or 2019, and does not include any RPS compliance cost for North Carolina.
140 "Delmarva Power & Light's 2018 RPS Compliance Report," Delmarva Power (Sept. 23, 2019), <https://depsc.delaware.gov/delawares-renewable-portfolio-standard-green-power-products/>.
141 "Fiscal Year 2018 Annual Report," February 15, 2019, "Report on Costs and Benefits of Renewable Resource Procurement," April 1, 2016, Illinois Power Agency (IPA), <https://www2.illinois.gov/sites/ipa/Pages/IPA_Reports.aspx>. The compliance cost entry for Illinois represents the ComEd cost of RECs as given in Section 11, Table 2.
142 "Renewable Energy Portfolio Standard Report with Data for Calendar Year 2017," Public Service Commission of Maryland, November 2018, <https://www.psc.state.md.us/wp-content/uploads/FINAL-Renewable-Energy-Portfolio-Standard-Report-with-data-for-CY-2017.pdf>.
143 Appendix C in "Report on the Implementation and Cost-Effectiveness of the P.A. 295 Renewable Energy Standard," Michigan Public Service Commission, February 15, 2019, <https://www.michigan.gov/mpsc/0,9535,7-395-93309_93438_93459_94932---,00.html>. The compliance cost entry reflects the compliance cost of the Indiana Michigan Power Company, which is the only investor owned utilities whose service area is in the PJM footprint.
144 "RPS Report Summary 2005-2018," New Jersey's Clean Energy Program, December 31, 2018, <http://njcleanenergy.com/renewable-energy/program-updates/rps-compliance-reports>.
145 "Renewable Portfolio Standard Report to the General Assembly for Compliance Year 2017,"Public Utilities Commission of Ohio, March 20, 2019, <https://www.puco.ohio.gov/industry-information/industry-topics/ohioe28099s-renewable-and-advanced-energy-portfolio-standard/>.
146 "2017 Annual Report Alternative Energy Portfolio Standards Act of 2004," Pennsylvania Public Utility Commission, March 2018, <https://www.pennaeps.com/annual-reports/>.
147 "Report on the Renewable Energy Portfolio Standard for Compliance Year 2018," Public Service Commission of the District of Columbia, Executive Summary, May 1, 2019, <https://dcpsc.org/Orders-and-Regulations/PSC-Reports-to-the-DC-Council/Renewable-Energy-Portfolio-Standard.aspx>.
148 RPS compliance cost information for North Carolina is not available in the North Carolina Utilities Commission annual report on RPS compliance.
149 The reporting period for RPS compliance in Delaware, Illinois, New Jersey, and Pennsylvania corresponds to PJM capacity market delivery years, June 1 through May 31. The compliance cost amounts reported by these states were converted to calendar year by assuming the compliance cost was evenly spread across the months in the compliance year.

Emission Controlled Capacity and Emissions

Emission Controlled Capacity

Environmental regulations affect decisions about emission control investments in existing units, investment in new units and decisions to retire units lacking emission controls.[150] Most PJM units burning fossil fuels have installed emission control technology. All coal steam units in PJM are compliant with the state and federal emissions limits established by MATS.

Table 8-23 shows SO_2 emission controls by fossil fuel fired units in PJM.[151 152 153] Coal has the highest SO_2 emission rate, while natural gas and diesel oil have lower SO_2 emission rates.[154] Of the current 61,780.8 MW of coal capacity in PJM, 57,753.5 MW of capacity, 93.5 percent, has some form of FGD (flue-gas desulfurization) technology to reduce SO_2 emissions.

Table 8-23 SO_2 emission controls by fuel type (MW): September 30, 2019[155]

	SO_2 Controlled	No SO_2 Controls	Total	Percent Controlled
Coal	57,753.5	4,027.3	61,780.8	93.5%
Diesel Oil	0.0	4,976.6	4,976.6	0.0%
Natural Gas	0.0	57,390.0	57,390.0	0.0%
Other	136.0	3,219.7	3,355.7	4.1%
Total	57,889.5	69,613.6	127,503.1	45.4%

Table 8-24 shows NO_X emission controls by unit type in PJM. NO_X emission control technology is used by all fossil fuel fired unit types. Of the current fossil fuel fired units in PJM, 119,399.2 MW, 93.6 percent, of 127,503.1 MW of capacity in PJM, have emission controls for NO_X. While most units in PJM have NO_X emission controls, many of these controls may need to be upgraded in order to meet each state's emission compliance standards based on whether a state is part of CSAPR, CAIR, Acid Rain Program (ARP) or a combination of the three. The NO_X compliance standards of MATS require the use of selective catalytic reduction (SCRs) or selective non-catalytic reduction (SCNRs) for coal steam units, as well as SCRs or water injection technology for peaking combustion turbine units.[156]

Table 8-24 NO_X emission controls by fuel type (MW): As of September 30, 2019

	NO_x Controlled	No NO_x Controls	Total	Percent Controlled
Coal	61,249.3	531.5	61,780.8	99.1%
Diesel Oil	1,298.6	3,678.0	4,976.6	26.1%
Natural Gas	55,974.6	1,415.4	57,390.0	97.5%
Other	876.7	2,479.0	3,355.7	26.1%
Total	119,399.2	8,103.9	127,503.1	93.6%

Table 8-25 shows particulate emission controls by unit type in PJM. Almost all coal units (99.6 percent) in PJM have particulate controls, as well as a few natural gas units (4.9 percent) and units with other fuel sources (35.6 percent). Typically, technologies such as electrostatic precipitators (ESP) or fabric filters (baghouses) are used to reduce particulate matter from coal steam units.[157] Fabric filters work by allowing the flue gas to pass through a tightly woven fabric which filters out the particulates. In PJM, 61,535.8 MW out of 61,780.8 MW, 99.6 percent, of all coal steam unit MW, have some type of particulate emissions control technology, as of September 30, 2019. All coal steam units in PJM are compliant with the state and federal emissions limits established by MATS.[158] In order to achieve compliance with MATS, 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. Currently, 136 of the 151 coal steam units have baghouse or FGD technology installed, representing 55,437.5 MW out of the 61,780.8 MW total coal capacity, or 89.7 percent.

150 See EPA, "National Ambient Air Quality Standards (NAAQS)," <https://www.epa.gov/criteria-air-pollutants/naaqs-table> (Accessed July 25, 2019).
151 See EPA, "Air Market Programs Data," <http://ampd.epa.gov/ampd/> (Accessed October 17, 2019).
152 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. The most recent complete set of emissions data is from the second quarter of 2019.
153 The total MW are less than the 186,502.9 reported in Section 5: Capacity Market, because EPA data on controls could not be matched to some PJM units. "Air Markets Program Data," <http://ampd.epa.gov/ampd/QueryToolie.html> (Accessed October 17, 2019).
154 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 28, 2019).
155 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.
156 See EPA. "Mercury and Air Toxics Standards, Cleaner Power Plants," <https://www.epa.gov/mats/cleaner-power-plants#controls> (Accessed October 23, 2019).
157 See EPA. "Air Pollution Control Technology Fact Sheet," <https://www3.epa.gov/ttn/catc/dir1/ff-pulse.pdf> (Accessed October 23, 2019).
158 On April 14, 2016, the EPA issued a final finding regarding the Mercury and Air Toxics Standards. See EPA. "Regulatory Actions," <https://www.epa.gov/mats/regulatory-actions-final-mercury-and-air-toxics-standards-mats-power-plants> (Accessed October 23, 2019).

Table 8-25 Particulate emission controls by fuel type (MW): As of September 30, 2019

	Particulate Controlled	No Particulate Controls	Total	Percent Controlled
Coal	61,535.8	245.0	61,780.8	99.6%
Diesel Oil	0.0	4,976.6	4,976.6	0.0%
Natural Gas	2,786.0	54,604.0	57,390.0	4.9%
Other	1,195.5	2,160.2	3,355.7	35.6%
Total	65,517.3	61,985.8	127,503.1	51.4%

Emissions

Figure 8-13 shows the total CO_2 emissions and the CO_2 emissions per MWh within PJM for all CO_2 emitting units, for each quarter from 1999 to the second quarter of 2019. Figure 8-13 also shows the CO_2 emissions per MWh of total generation within PJM for each quarter from the third quarter of 2000 to the second quarter of 2019.[159] [160] For the period from 1999 through the second quarter of 2019, the minimum CO_2 produced per MWh was 0.72 short tons per MWh in the second quarter of 2019, and the maximum was 0.95 short tons per MWh in the first quarter of 2010. Total PJM generation decreased from 195,055.4 GWh in the second quarter of 2018 to 191,169.9 GWh in the second quarter of 2019, while CO_2 produced decreased from 95.6 million short tons in the second quarter of 2018 to 81.9 million short tons in the second quarter of 2019.[161] The reduction in total CO_2 emissions was primarily the result of a decrease in the use of coal and an increase in the use of natural gas for generation.

Figure 8-13 CO_2 emissions by quarter (millions of short tons), by PJM units: 1999 through 2019[162] [163]

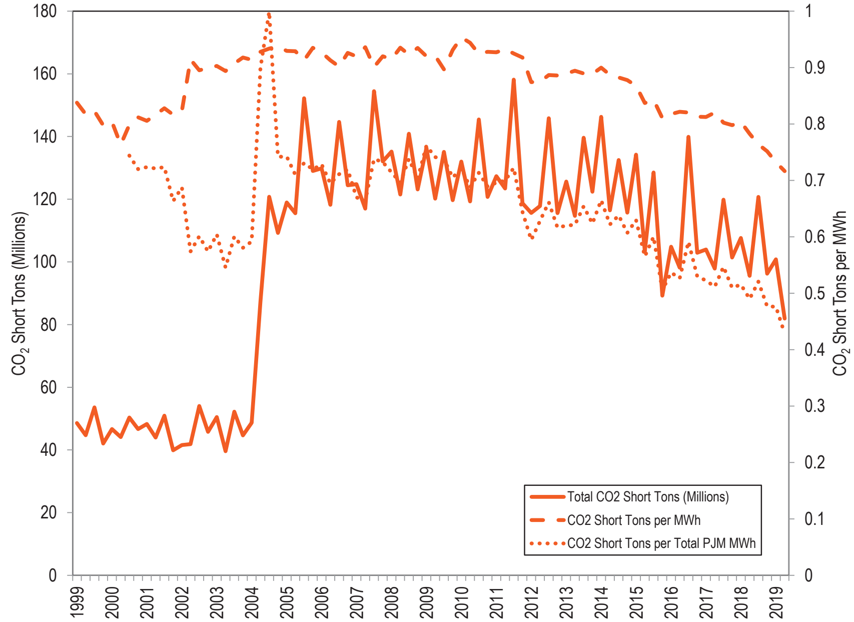


Figure 8-14 shows the total CO_2 emissions on peak and off peak and the CO_2 emissions per MWh for all CO_2 emitting units. Since 1999 the amount of CO_2 produced per MWh during off peak hours was at a minimum of 0.72 short tons per MWh in the second quarter of 2019, and a maximum of 0.97 short tons per MWh in the second quarter of 2010. Since 1999 the amount of CO_2 produced per MWh during on peak hours was at a minimum of 0.71 short tons per MWh in the second quarter of 2019, and a maximum of 0.94 short tons per MWh in the first quarter of 2010. In the second quarter of 2019, CO_2

159 Unless otherwise noted, emissions are measured in short tons. A short ton is 2,000 pounds.
160 Emissions data for the third quarter of 2019 was not yet available at the time of this report because generators have 60 days after the end of the quarter to submit their emissions data.
161 See the *2019 Quarterly State of the Market Report for PJM: January through June*. Section 3: Energy Market, Table 3-10.

162 The emissions are calculated from the continuous emission monitoring system (CEMS) data from generators located within the PJM footprint.
163 In 2004 and 2005, PJM integrated the American Electric Power (AEP), ComEd, Dayton Power & Light Company (DAY), Dominion, and Duquesne Light Company (DLCO) Control Zones. The large increase in total emissions from 2004 to 2005 was a result of these integrations. 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). In December 2018, PJM integrated the Ohio Valley Electric Corporation (OVEC).

emissions were 0.72 short tons per MWh for off peak hours and 0.71 for on peak hours.

Figure 8-14 Total CO_2 emissions during on and off peak hours by quarter (millions of short tons), by PJM units: 1999 through 2019[164]

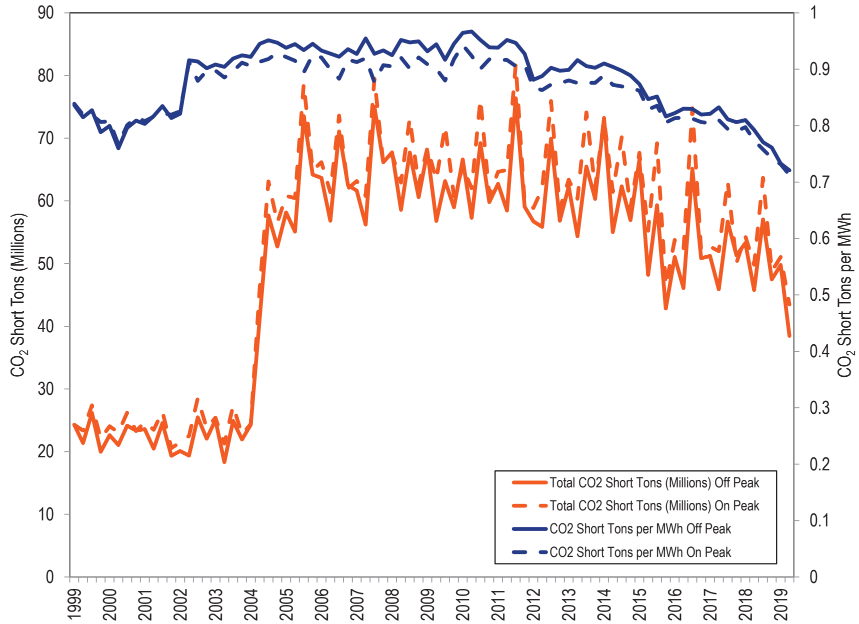


Figure 8-15 shows the total SO_2 and NO_X emissions and the short ton emissions per MWh for all SO_2 and NO_X emitting units, and the SO_2 and NO_X emissions per MWh of total PJM generation. For the period from 1999 through the second quarter of 2019, the minimum SO_2 produced per MWh was 0.000455 short tons per MWh in the second quarter of 2019, and the maximum was 0.008109 short tons per MWh in the fourth quarter of 2003. For the period from 1999 through the second quarter of 2019, the minimum NO_X produced per MWh was at a 0.000329 short tons per MWh in the second quarter of 2019, and the maximum was 0.002290 short tons per MWh in the first quarter of 1999. In the second quarter of 2019, SO_2 emissions were 0.000455 short tons per MWh and NO_X emissions were 0.000329 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, an increase in the use of natural gas, and the installation of environmental controls from 2006 to 2019.[165] [166]

Figure 8-15 SO_2 and NO_X emissions by quarter (thousands of short tons), by PJM units: 1999 through 2019[167]

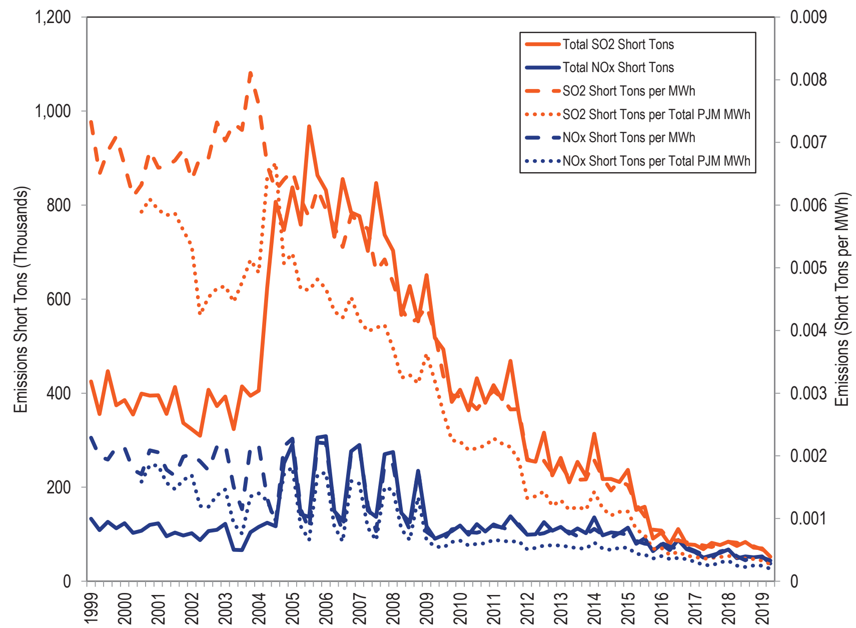


Figure 8-16 shows the total on peak hour and off peak hour SO_2 and NO_X emissions and the emissions per MWh from emitting resources for all SO_2 and NO_X emitting units. For the period from 1999 through the second quarter of 2019, the minimum SO_2 produced per MWh during off peak hours was 0.000427 short tons per MWh in the second quarter of 2019, and the

164 The emissions are calculated from the continuous emission monitoring system (CEMS) data from generators located within the PJM footprint.

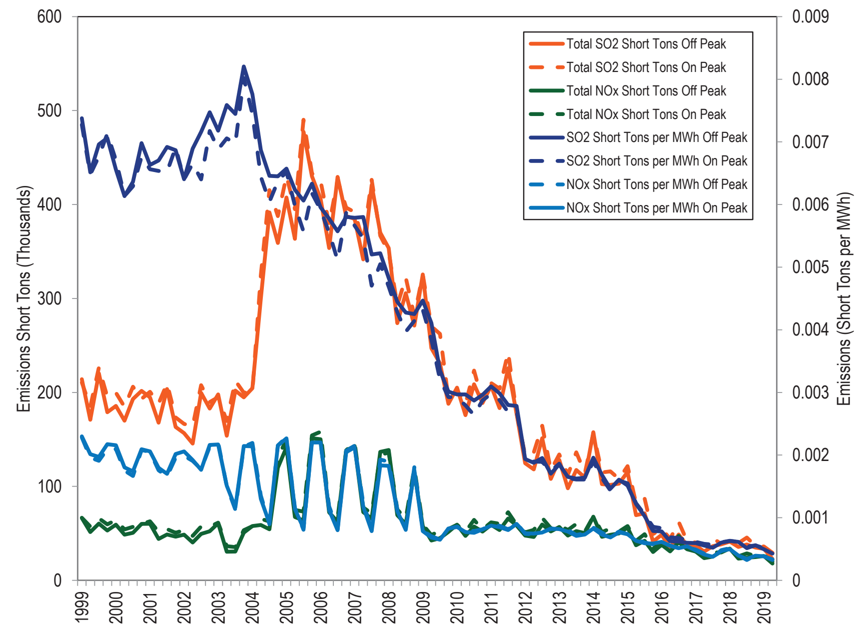
165 See EIA, "Changes in coal sector led to less SO_2 and NO_x emissions from electric power industry," <https://www.eia.gov/todayinenergy/detail.php?id=37752> (Accessed October 25, 2019).

166 See EIA, "Sulfur dioxide emissions from U.S. power plants have fallen faster than coal generation," <https://www.eia.gov/todayinenergy/detail.php?id=29812> (Accessed October 25, 2019).

167 The emissions are calculated from the continuous emission monitoring system (CEMS) data from generators located within the PJM footprint.

maximum was 0.008202 short tons per MWh in the fourth quarter of 2003. For the period from 1999 through the second quarter of 2019, the minimum SO_2 produced per MWh during on peak hours was 0.000481 short tons per MWh in the second quarter of 2019, and the maximum was 0.008020 short tons per MWh in the fourth quarter of 2003. For the period from 1999 through the second quarter of 2019, the minimum NO_X produced per MWh during off peak hours was 0.000326 short tons per MWh in the third quarter of 2018, and the maximum was 0.002284 short tons per MWh in the first quarter of 2005. For the period from 1999 through the second quarter of 2019, the minimum NO_X produced per MWh during on peak hours was 0.000325 short tons per MWh in the second quarter of 2019 and the maximum was 0.002298 short tons per MWh in the first quarter of 1999. In the second quarter of 2019, SO_2 emissions were 0.000427 short tons per MWh and 0.000481 short tons per MWh for off and on peak hours. In the second quarter of 2019, NO_X emissions were 0.000334 short tons per MWh and 0.000325 short tons per MWh for off and on peak hours.

Figure 8-16 SO_2 and NO_X emissions during on and off peak hours by quarter (thousands of short tons), by PJM units: 1999 through 2019[168]



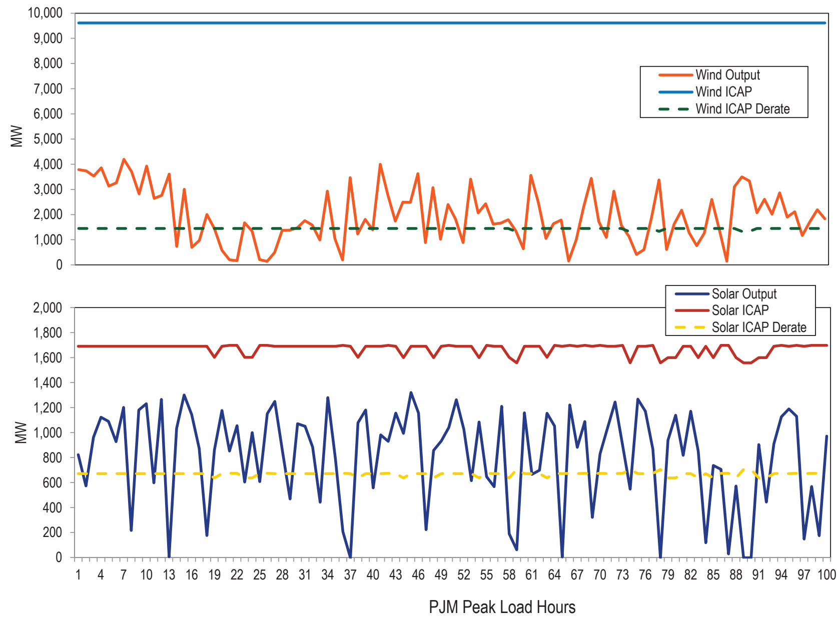
168 The emissions are calculated from the continuous emission monitoring system (CEMS) data from generators located within the PJM footprint.

Renewable Energy Output

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 8-17 shows the wind and solar output during the top 100 load hours in PJM for the first nine months of 2019. Of the top 100 load hours in PJM during the first nine months of 2019, 85 are PJM defined peak load hours. 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 capacity committed for each unit, or the ICAP of wind and solar PJM resources derated to 14.7 and 38.0 percent if the unit does not participate in the capacity market.[169] The actual output of the wind and solar resources during the top 100 load hours ranges above and below the derated capacity (ICAP) values. Wind output was above the derated ICAP for 64 hours and below the derated ICAP for 36 hours of the top 100 load hours of the first nine months of 2019. The wind capacity factor for the top 100 load hours of 2018 was 20.4 percent. Wind output was above the derated ICAP for 4,323 hours and below the derated ICAP for 2,228 hours in the first nine months of 2019. The wind capacity factor for the first nine months of 2019 was 30.8 percent. Solar output was above the derated ICAP for 68 hours and below the derated ICAP for 32 hours of the top 100 load hours of the first nine months of 2019. The solar capacity factor for the top 100 load hours of the first nine months of 2019 was 48.6 percent. Solar output was above the derated ICAP for 1,665 hours and below the derated ICAP for 4,886 hours for the first nine months of 2019. The solar capacity factor for the first nine months of 2019 was 25.1 percent.

Figure 8-17 Wind and solar output during the top 100 load hours in PJM: January through September, 2019



Wind Units

Table 8-26 shows the capacity factors of wind units in PJM. In the first nine months of 2019, the capacity factor of wind units in PJM was 31.5 percent. Wind units that were capacity resources had a capacity factor of 30.8 percent and an installed capacity of 8,075 MW. Wind units that were energy only had a capacity factor of 36.5 percent and an installed capacity of 1,547 MW. Wind capacity in RPM is derated to 14.7 or 17.6 percent of nameplate capacity for the capacity market, based on the wind farm terrain, and energy only resources are not included in the capacity market.[170]

169 PJM used derating factors of 13 and 38 percent until June 1, 2017. The current derating factors depend on installation type. PJM. Class Average Capacity Factors Wind and Solar Resources,, <https://www.pjm.com/-/media/planning/res-adeq/class-average-wind-capacity-factors.ashx?la=en> (Accessed October 17, 2019).

170 PJM. Class Average Capacity Factors, <https://www.pjm.com/-/media/planning/res-adeq/class-average-wind-capacity-factors.ashx?la=en> (Accessed October 17, 2019).

Table 8-26 Capacity factor of wind units in PJM: January through September, 2019[171]

Type of Resource	Capacity Factor	Installed Capacity (MW)
Energy-Only Resource	36.5%	1,547
Capacity Resource	30.8%	8,075
All Units	31.5%	9,622

Figure 8-18 shows the average hourly real-time generation of wind units in PJM, by month for January 1 through September 30, 2019. The hour with the highest average output, 4,021 MW, occurred in April, and the hour with the lowest average output, 789 MW, occurred in July. Wind output in PJM is generally higher during off peak hours and lower during on peak hours.

Figure 8-18 Average hourly real-time generation of wind units in PJM: January through September, 2019

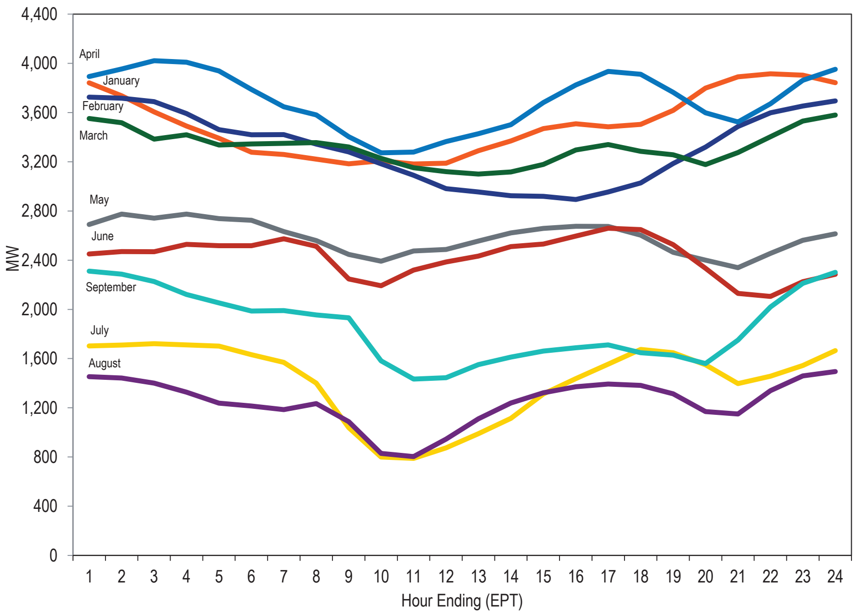


Table 8-27 shows the generation and capacity factor of wind units by month from January 1, 2018, through September 30, 2019.

Table 8-27 Capacity factor of wind units in PJM by month: January 2018 through September 2019

	2018		2019	
Month	Generation (MWh)	Capacity Factor	Generation (MWh)	Capacity Factor
January	2,599,270.5	48.0%	2,223,142.4	41.2%
February	1,948,008.3	40.1%	1,882,076.3	38.7%
March	2,146,698.1	41.1%	2,076,120.4	38.0%
April	1,840,728.2	37.2%	2,244,185.1	42.6%
May	1,370,215.9	27.3%	1,635,756.1	30.6%
June	1,010,945.4	21.0%	1,480,459.1	29.0%
July	790,461.6	16.6%	883,538.1	17.0%
August	884,856.3	19.0%	776,254.7	15.9%
September	1,047,738.1	22.0%	1,108,140.3	22.2%
October	1,870,676.4	35.6%		
November	1,835,280.5	36.3%		
December	2,003,254.1	37.0%		
Annual	19,348,133.6	32.2%	14,309,672.5	30.8%

Wind units that are capacity resources are required, like all capacity resources except demand resources, to offer the energy associated with their cleared capacity in the Day-Ahead Energy Market and in the Real-Time Energy Market. Figure 8-19 shows the average hourly day-ahead generation offers of wind units in PJM, by month.

171 Capacity factor is calculated based on online date of the resource.

Figure 8-19 Average hourly day-ahead generation of wind units in PJM: January through September, 2019

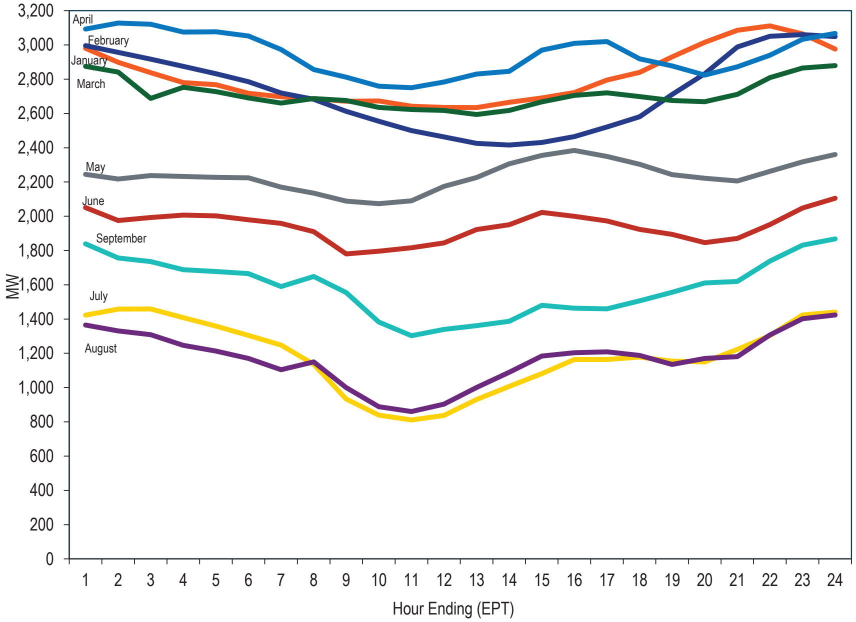
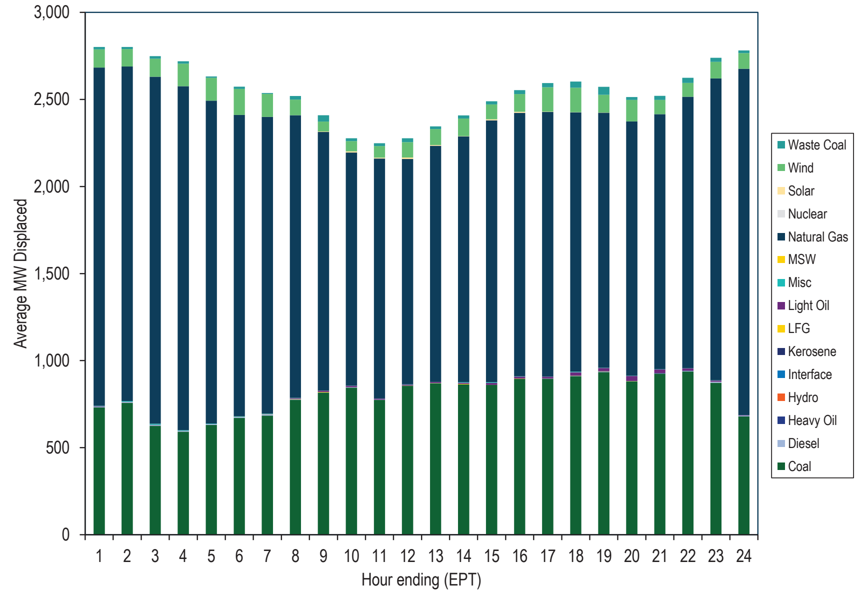


Figure 8-20 Marginal fuel at time of wind generation in PJM: January through September, 2019



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 8-20 and Table 8-28 show the hourly average proportion of marginal units by fuel type mapped to the hourly average MW of real-time wind generation in the first nine months of 2019. 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.

Table 8-28 Marginal fuel MW at time of wind generation in PJM: January through September, 2019

Hour	Coal	Diesel	Heavy Oil	Hydro	Interface	Kerosene	Landfill Gas	Light Oil	Miscellaneous	Solid Waste	Natural Gas	Nuclear	Solar	Wind	Waste Coal	Total
0	730.7	3.3	0.0	0.0	0.0	0.0	0.0	3.6	3.0	0.0	1,942.3	0.0	0.0	104.9	13.6	2,801.5
1	757.3	4.7	0.0	0.0	0.0	0.0	0.0	2.0	3.5	0.0	1,921.9	0.0	0.0	99.7	12.7	2,801.8
2	625.3	3.8	0.0	0.0	0.0	0.8	0.0	1.4	5.9	0.0	1,992.9	0.0	0.0	104.4	14.3	2,748.7
3	591.5	4.8	0.0	0.0	0.0	0.9	0.0	0.0	3.2	0.0	1,975.4	0.0	0.0	129.3	14.4	2,719.6
4	630.2	5.4	0.0	0.0	0.0	0.0	0.0	0.0	3.1	0.0	1,854.5	0.0	0.0	131.6	7.1	2,631.9
5	671.4	4.6	0.0	0.0	0.0	1.0	0.3	0.0	2.8	0.0	1,731.1	0.0	0.0	149.5	12.3	2,573.1
6	684.4	6.3	0.0	0.0	0.0	0.0	0.8	1.4	2.6	0.0	1,704.1	0.0	0.0	132.3	4.9	2,536.8
7	774.8	1.4	0.0	0.0	0.0	1.7	1.6	5.1	1.2	0.0	1,623.6	0.0	0.0	89.3	20.9	2,519.6
8	816.4	0.5	0.0	0.0	0.0	0.0	2.8	7.9	0.9	0.0	1,484.7	0.0	2.6	57.2	36.2	2,409.2
9	844.5	2.8	0.0	0.0	0.0	0.0	0.0	7.6	1.4	0.0	1,338.9	0.0	6.7	58.7	17.0	2,277.5
10	774.0	1.8	0.0	0.0	0.0	0.0	0.0	6.4	0.6	0.0	1,378.0	0.0	5.1	66.0	16.8	2,248.7
11	854.9	0.5	0.2	0.0	0.0	0.0	1.0	5.7	1.5	0.0	1,294.2	0.0	8.7	88.3	22.3	2,277.4
12	869.9	1.1	0.0	0.0	0.0	0.0	0.9	5.7	0.4	0.0	1,355.9	0.0	4.3	91.5	16.0	2,345.7
13	862.7	0.0	0.0	0.0	0.0	0.0	3.5	7.2	2.9	0.0	1,411.4	0.0	1.1	101.3	18.1	2,408.3
14	859.9	0.0	0.0	0.0	0.0	0.0	0.4	11.0	4.5	0.0	1,504.3	0.0	6.0	85.1	18.5	2,489.7
15	894.7	0.0	0.0	0.0	0.0	0.0	1.8	11.3	1.7	0.0	1,513.2	0.0	6.4	102.1	22.8	2,553.9
16	895.6	1.0	0.0	0.0	0.0	0.5	0.0	11.1	0.3	0.0	1,520.0	0.0	1.0	140.0	24.7	2,594.3
17	910.3	1.3	0.0	0.0	0.0	1.2	1.4	19.0	2.9	0.0	1,489.8	0.0	0.3	141.5	34.9	2,602.5
18	933.7	2.7	0.0	0.0	0.0	2.4	0.9	17.4	2.0	0.0	1,464.4	0.0	1.1	102.5	45.5	2,572.7
19	880.8	1.5	0.0	0.0	0.0	0.0	0.7	28.0	1.8	0.0	1,460.8	0.0	0.0	124.0	15.7	2,513.3
20	924.7	0.5	2.4	0.0	0.0	0.5	0.0	21.0	1.5	0.0	1,464.8	0.0	0.0	81.9	23.2	2,520.6
21	937.0	4.0	1.2	0.0	0.0	0.4	0.0	13.1	0.5	0.0	1,559.4	0.0	0.0	79.6	29.2	2,624.4
22	872.4	6.1	0.0	0.0	0.0	0.0	0.0	6.9	1.4	0.0	1,734.1	0.0	0.0	95.2	23.5	2,739.6
23	679.3	3.8	0.0	0.0	0.0	0.0	0.0	3.7	0.6	0.0	1,988.8	0.0	0.0	89.9	15.2	2,781.3
Average	803.2	2.6	0.2	0.0	0.0	0.4	0.7	8.2	2.1	0.0	1,612.8	0.0	1.8	101.9	20.0	2,553.8

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 8-15, there are 1,964.0 MW capacity of solar registered in GATS that are PJM units. As shown in Table 8-16, there are 5,862.0 MW capacity of solar registered in GATS that are not PJM units. 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. The MMU recommends that load and generation located at separate nodes be treated as separate resources.

Table 8-29 shows the capacity factor of solar units in PJM. In the first nine months of 2019, the capacity factor of solar units in PJM was 25.1 percent. Solar units that were capacity resources had a capacity factor of 25.1 percent and an installed capacity of 1,457 MW. Solar units that were energy only had a capacity factor of 25.6 percent and an installed capacity of 253 MW. Solar capacity in RPM is derated to 42.0, 60.0 or 38.0 percent of nameplate capacity for the capacity market, based on the installation type, and energy only resources are not included in the capacity market.[172]

Table 8-29 Capacity factor of solar units in PJM: January through September, 2019

Type of Resource	Capacity Factor	Installed Capacity (MW)
Energy-Only Resource	25.6%	253
Capacity Resource	25.1%	1,457
All Units	25.1%	1,711

Figure 8-21 shows the average hourly real-time generation of solar units in PJM, by month. The hour with the highest peak average output, 1,148 MW, occurred in July, and the hour with the lowest peak average output, 624 MW, occurred in January. Solar output in PJM is generally higher during peak hours and lower during off peak hours.

Figure 8-21 Average hourly real-time generation of solar units in PJM: January through September, 2019

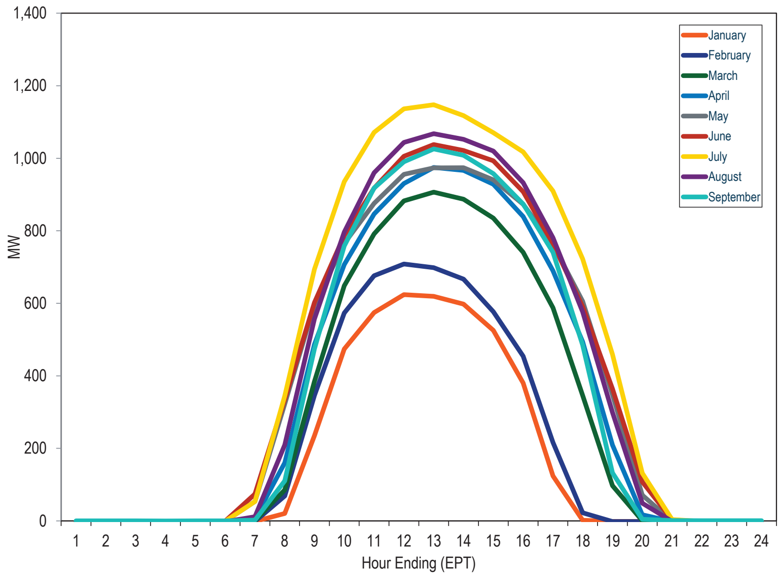


Table 8-30 shows the generation and capacity factor of solar units by month from January 1, 2018, through September 30, 2019.

Table 8-30 Capacity factor of solar units in PJM by month: January 2018 through September 2019

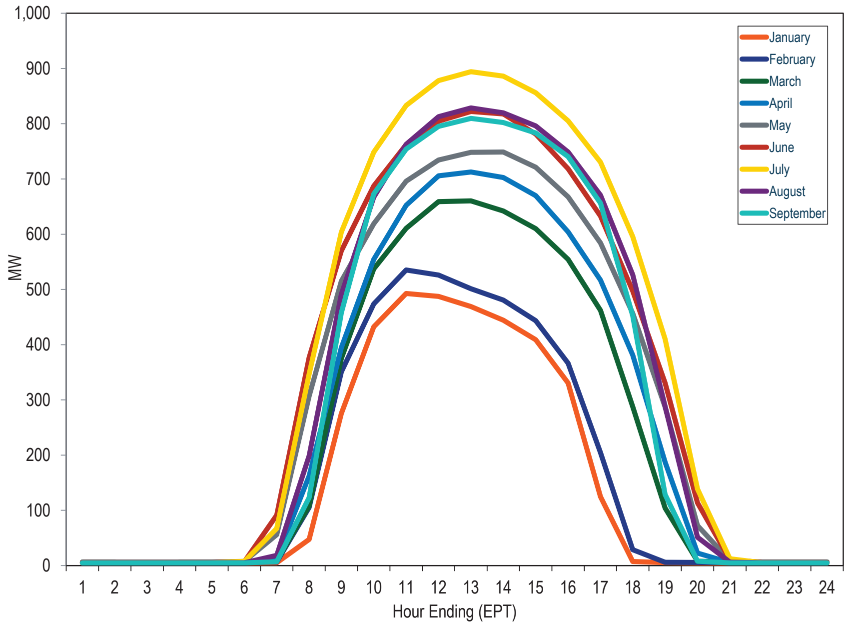
	2018		2019	
Month	Generation (MWh)	Capacity Factor	Generation (MWh)	Capacity Factor
January	102,186.2	15.4%	119,064.3	14.4%
February	90,326.9	14.2%	127,466.5	16.4%
March	159,409.4	22.4%	205,113.4	23.3%
April	201,417.3	28.2%	229,624.5	26.8%
May	203,063.6	27.3%	265,474.8	28.9%
June	222,228.7	30.6%	264,942.6	29.2%
July	220,650.2	29.4%	299,008.8	31.5%
August	217,755.2	28.9%	250,827.5	27.3%
September	142,705.9	21.0%	220,408.0	25.1%
October	156,045.7	21.4%		
November	113,801.1	15.3%		
December	96,445.7	12.6%		
Annual	1,926,036.0	22.3%	1,981,930.4	25.1%

Solar units that are capacity resources are required, like all capacity resources except demand resources, to offer the energy associated with their cleared capacity in the Day-Ahead Energy Market and in the Real-Time Energy Market. Figure 8-22 shows the average hourly day-ahead generation offers of solar units in PJM, by month.[173]

172 PJM. Class Average Capacity Factors, <https://www.pjm.com/-/media/planning/res-adeq/class-average-wind-capacity-factors.ashx?la=en> (Accessed October 17, 2019).

173 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 8-22 Average hourly day-ahead generation of solar units in PJM: January through September, 2019



Interchange Transactions

PJM market participants import energy from, and export energy to, external regions continuously. The transactions involved may fulfill long-term or short-term bilateral contracts or respond to price differentials. The external regions include both market and nonmarket balancing authorities.

Overview

Interchange Transaction Activity

- **Aggregate Imports and Exports in the Real-Time Energy Market.** In the first nine months of 2019, PJM was a monthly net exporter of energy in the Real-Time Energy Market in all months.[1] In the first nine months of 2019, the real-time net interchange was -25,916.9 GWh. The real-time net interchange in the first nine months of 2018 was -12,205.8 GWh.
- **Aggregate Imports and Exports in the Day-Ahead Energy Market.** In the first nine months of 2019, PJM was a monthly net exporter of energy in the Day-Ahead Energy Market in February, June, July, August and September, and a net importer of energy in the remaining months. In the first nine months of 2019, the total day-ahead net interchange was -4,540.7 GWh. The day-ahead net interchange in the first nine months of 2018 was 1,810.5.
- **Aggregate Imports and Exports in the Day-Ahead and the Real-Time Energy Market.** In the first nine months of 2019, gross imports in the Day-Ahead Energy Market were 527.0 percent of gross imports in the Real-Time Energy Market (260.8 percent in the first nine months of 2018). In the first nine months of 2019, gross exports in the Day-Ahead Energy Market were 130.5 percent of the gross exports in the Real-Time Energy Market (128.8 percent in the first nine months of 2018).
- **Interface Imports and Exports in the Real-Time Energy Market.** In the first nine months of 2019, there were net scheduled exports at 13 of PJM's 19 interfaces in the Real-Time Energy Market.
- **Interface Pricing Point Imports and Exports in the Real-Time Energy Market.** In the first nine months of 2019, there were net scheduled exports at 10 of PJM's 17 interface pricing points eligible for real-time transactions in the Real-Time Energy Market.[2]
- **Interface Imports and Exports in the Day-Ahead Energy Market.** In the first nine months of 2019, there were net scheduled exports at 11 of PJM's 19 interfaces in the Day-Ahead Energy Market.
- **Interface Pricing Point Imports and Exports in the Day-Ahead Energy Market.** In the first nine months of 2019, there were net scheduled exports at nine of PJM's 18 interface pricing points eligible for day-ahead transactions in the Day-Ahead Energy Market.
- **Up To Congestion Interface Pricing Point Imports and Exports in the Day-Ahead Energy Market.** In the first nine months of 2019, up to congestion transactions were net exports at three of PJM's 18 interface pricing points eligible for day-ahead transactions in the Day-Ahead Energy Market.
- **Inadvertent Interchange.** In the first nine months of 2019, net scheduled interchange was -25,917 GWh and net actual interchange was -25,870 GWh, a difference of 47 GWh. In the first nine months of 2018, the difference was 8 GWh. This difference is inadvertent interchange.
- **Loop Flows.** In the first nine months of 2019, the Northern Indiana Public Service (NIPS) Interface had the largest loop flows of any interface with -14 GWh of net scheduled interchange and -8,516 GWh of net actual interchange, a difference of 8,502 GWh. In the first nine months of 2019, the SouthIMP interface pricing point had the largest loop flows of any interface pricing point with 3,893 GWh of net scheduled interchange and 20,416 GWh of net actual interchange, a difference of 16,524 GWh.

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).

Interactions with Bordering Areas

PJM Interface Pricing with Organized Markets

- **PJM and MISO Interface Prices.** In the first nine months of 2019, 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 61.5 percent of the hours.
- **PJM and New York ISO Interface Prices.** In the first nine months of 2019, 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 57.9 percent of the hours.
- **Neptune Underwater Transmission Line to Long Island, New York.** In the first nine months of 2019, 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 73.1 percent of the hours.
- **Linden Variable Frequency Transformer (VFT) Facility.** In the first nine months of 2019, 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 68.3 percent of the hours.
- **Hudson DC Line.** In the first nine months of 2019, 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 66.3 percent of the hours.

Interchange Transaction Issues

- **PJM Transmission Loading Relief Procedures (TLRs).** PJM issued two TLRs of level 3a or higher in the first nine months of 2019, compared to four such TLR issued in the first nine months of 2018.
- **Up To Congestion.** The average number of up to congestion bids submitted in the Day-Ahead Energy Market decreased by 24.9 percent, from 68,693 bids per day in the first nine months of 2018 to 51,594 bids per day in the first nine months of 2019. The average cleared volume of up to congestion bids submitted in the Day-Ahead Energy Market increased by 15.9 percent, from 423,268 MWh per day in the first nine months of 2018, to 490,421 MWh per day in the first nine months of 2019.
- **45 Minute Schedule Duration Rule.** Effective May 19, 2014, PJM removed the 45 minute scheduling duration rule in response to FERC Order No. 764.[3] [4] 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.[5]

Recommendations

- The MMU recommends that PJM implement rules to prevent sham scheduling. The MMU recommends that PJM apply after the fact market settlement adjustments to identified sham scheduling segments to ensure that market participants cannot benefit from sham scheduling. (Priority: High. First reported 2012. Status: Not adopted. Stakeholder process.)
- The MMU recommends that PJM implement a validation method for submitted transactions that would prohibit market participants from breaking transactions into smaller segments to defeat the interface pricing rule by concealing the true source or sink of the transaction. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM implement a validation method for submitted transactions that would require market participants to submit transactions on paths that reflect the expected actual power flow in order to reduce unscheduled loop flows. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM end the practice of maintaining outdated definitions of interface pricing points, eliminate the NIPSCO, Southeast and Southwest interface pricing points from the Day-Ahead and Real-Time Energy Markets and, with VACAR, assign the transactions created under the reserve sharing agreement to the SouthIMP/EXP pricing point. (Priority: Medium. First reported 2013. Status: Not adopted.)

3 Order No. 764, 139 FERC ¶ 61,246 (2012), order on reh'g, Order No. 764-A, 141 FERC ¶ 61231 (2012).
4 See Letter Order, Docket No. ER14-381-000 (June 30, 2014).
5 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>.

- 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 PJM Settlement 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: Low. 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 the Commission require that the open FFE/FFL freeze date issues be addressed at a Commission technical conference, and that the Commission set a deadline to resolve the significant issues that result from the freeze date. (Priority: Medium. First reported Q2, 2019. Status: Not adopted.)

Conclusion

Transactions between PJM and multiple balancing authorities in the Eastern Interconnection are part of a single energy market. While some of these balancing authorities are termed market areas and some are termed 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. Pricing in the market areas is transparent and pricing in the nonmarket areas is 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 across the interfaces.

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.[6]

6 For an explanation and current rate for each billing line item, see "Quick Reference Guide to Market Settlements By Type of Business" (June 1, 2019) <https://www.pjm.com/-/media/training/core-curriculum/ip-ms-301/ms-301-quick-reference-guide-to-markets-settlements-by-type-of-business.ashx?la=en>.

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 December 2018, PJM integrated the Ohio Valley Electric Corporation (OVEC). This integration eliminated the OVEC Interface and the OVEC interface pricing point from the real-time and day-ahead markets. Eleven shareholders own portions of the Clifty Creek and Kyger Creek generation and share OVEC's generation output. The majority of generation output is owned by load serving entities or their affiliates located in the PJM footprint. Prior to integration, the Clifty Creek and Kyger Creek units were pseudo tied to PJM. The Inter-Company Power Agreement (ICPA), signed by OVEC's shareholders, requires the continued delivery of the remaining generation output that is not designated to serve PJM to points external to the PJM footprint.[7] Prior to integration, the contractual obligation to provide the portion of the generation output to points external to the PJM footprint were block scheduled exports at the OVEC interface. After the OVEC integration, with the elimination of the OVEC Interface, the continued contractual obligation to provide the portion of the generation output to points external to the PJM footprint will be to block schedule exports at the LGEE Interface.

7 See "Ohio Valley Electric Corporation: Company Background," <http://www.ovec.com/OVECHistory.pdf> (October 15, 2014).

Table 9-2 shows the real-time and day-ahead scheduled interchange totals for the first nine months of 2018 and 2019. In the first nine months of 2019, gross imports in the Day-Ahead Energy Market were 527.0 percent of gross imports in the Real-Time Energy Market (260.8 percent in the first nine months of 2018). In the first nine months of 2019, gross exports in the Day-Ahead Energy Market were 130.5 percent of gross exports in the Real-Time Energy Market (128.8 percent in the first nine months of 2018).

Table 9-2 Real-time and day-ahead scheduled interchange volumes (GWh): January through September, 2018 and 2019

Category	Jan-Sep 2018	Jan-Sep 2019	Percent Change
Real-Time Gross Imports	13,278.5	7,385.1	(44.4%)
Real-Time Gross Exports	25,484.3	33,302.0	30.7%
Real-Time Net Interchange	(12,205.8)	(25,916.9)	(112.3%)
Day-Ahead Gross Imports	34,630.1	38,921.1	12.4%
Day-Ahead Gross Exports	32,819.7	43,461.7	32.4%
Day-Ahead Net Interchange	1,810.5	(4,540.7)	350.8%
Monthly Average Real-Time Gross Exports	2,831.6	3,700.2	30.7%
Monthly Average Real-Time Gross Imports	1,475.4	820.6	(44.4%)
Monthly Average Day-Ahead Gross Exports	3,646.6	4,829.1	32.4%
Monthly Average Day-Ahead Gross Imports	3,847.8	4,324.6	12.4%

In the first nine months of 2019, PJM was a monthly net exporter of energy in the Real-Time Energy Market in all months. In the first nine months of 2019, PJM was a monthly net exporter of energy in the Day-Ahead Energy Market in February, June, July, August and September, and a net importer of energy in the remaining months (Figure 9-1).[8]

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.

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 the first nine months of 2019, the total day-ahead gross imports and exports were higher than the real-time gross imports and exports, the day-ahead imports net of up to congestion transactions were less than the real-time imports, and the day-ahead exports net of up to congestion transactions were less than real-time exports.

Figure 9-1 Scheduled imports and exports: January through September, 2019

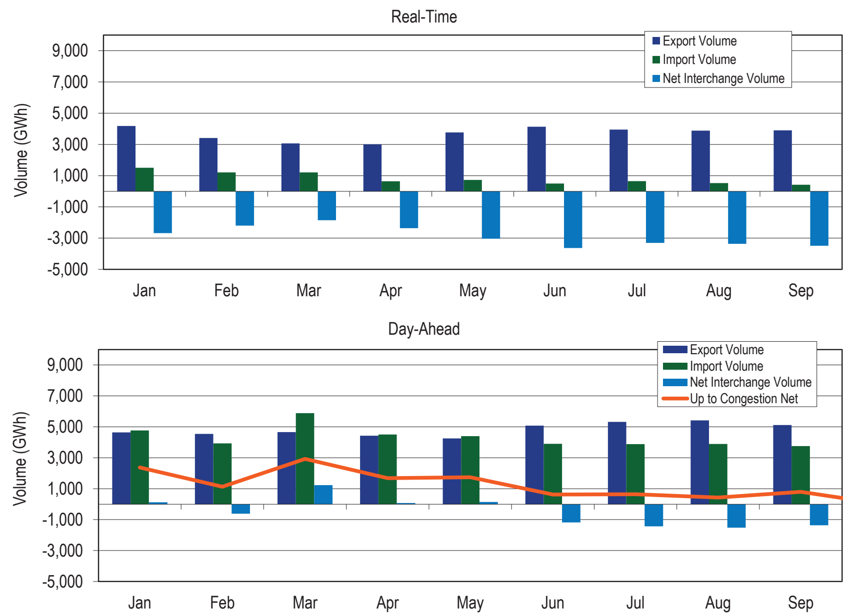


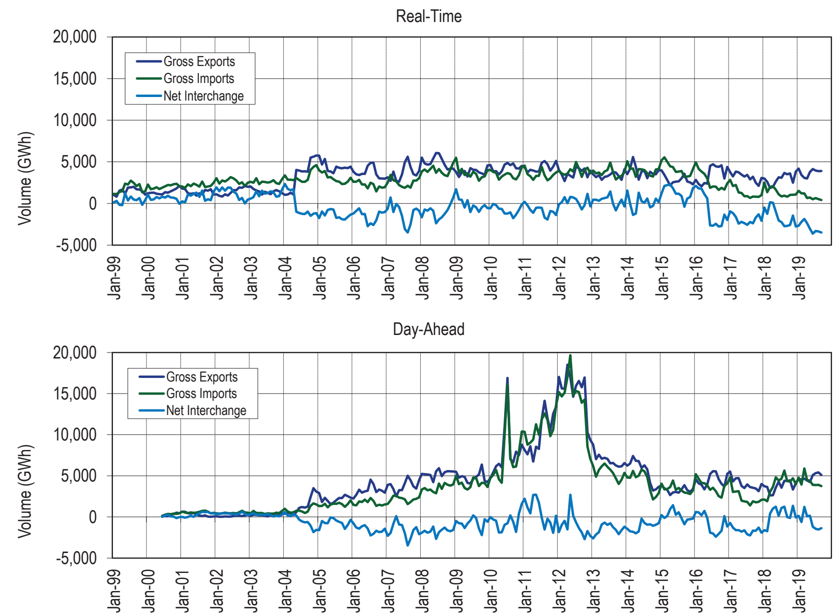
Figure 9-2 shows the real-time and day-ahead import and export volume for PJM from January 1999 through September 2019. PJM shifted from a consistent net importer of energy to relatively consistent net exporter of energy in 2004 in both the Real-Time and Day-Ahead Energy Markets, coincident with the expansion of the PJM footprint that included the integrations of Commonwealth Edison, American Electric Power and Dayton Power and

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

9 Up to congestion transactions create financial obligations to deliver in real time, but do not pay operating reserve charges.

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. The changes in up to congestion bidding behavior resulting from the February 20, 2018, FERC order limiting the eligible bidding points for up to congestion transactions to hubs, residual metered load and interfaces contributed to PJM becoming a net importer in the Day-Ahead Energy Market starting in March, 2018.

Figure 9-2 Scheduled import and export transaction volume history: January 1, 1999 through September 30, 2019



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 9-18 includes a list of active interfaces in the first nine months of 2019. Figure 9-3 shows the approximate geographic location of the interfaces. In the first nine months of 2019, PJM had 19 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 9-3 through Table 9-5 show the real-time energy market scheduled interchange totals at the individual NYISO interfaces, as well as with the NYISO as a whole. Similarly, the scheduled interchange totals at the individual interfaces between PJM and MISO are shown, as well as with MISO as a whole. Net scheduled interchange in the Real-Time Energy Market is shown by interface for the first nine months of 2019 in Table 9-3, while gross scheduled imports and exports are shown in Table 9-4 and Table 9-5.

In the Real-Time Energy Market, in the first nine months of 2019, there were net scheduled exports at 13 of PJM's 19 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 30.2 percent, PJM/ MidAmerican Energy Company (MEC) with 14.7 percent and PJM/Neptune (NEPT) with 14.3 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 34.0 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 eight of the 10 separate interfaces that connect PJM to MISO. Those eight exporting interfaces represented 65.3 percent of the total net PJM scheduled exports in the Real-Time Energy Market.

In the Real-Time Energy Market, in the first nine months of 2019, there were net scheduled imports at five of PJM's 19 interfaces. The top three importing interfaces in the Real-Time Energy Market accounted for 98.0 percent of the total net scheduled imports: PJM/Duke Energy Corp. (DUK) with 56.8 percent, PJM/Ameren-Illinois (AMIL) with 26.7 percent and PJM/Carolina Power and Light East (CPLE) with 14.5 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 one of the 10 separate interfaces that connect PJM to MISO (AMIL). That interface represented 26.7 percent of the total net PJM scheduled imports in the Real-Time Energy Market.

Table 9-3 Real-time scheduled net interchange volume by interface (GWh): January through September, 2019

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
CPLE	46.6	102.2	80.6	0.3	28.5	14.9	12.3	12.0	(39.8)	257.6
CPLW	(0.0)	0.0	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.2
DUK	(7.0)	265.4	243.5	81.0	54.8	29.2	167.2	141.9	30.2	1,006.2
LGEE	22.9	30.5	(4.9)	(11.9)	8.5	(62.2)	(60.2)	(70.6)	(42.5)	(190.4)
MISO	(1,235.4)	(1,568.2)	(756.4)	(1,764.8)	(2,635.6)	(2,723.9)	(2,051.0)	(2,278.9)	(2,592.4)	(17,606.5)
ALTE	(221.4)	(313.8)	(52.3)	(253.5)	(353.2)	(360.0)	(235.3)	(342.8)	(449.1)	(2,581.2)
ALTW	(5.3)	0.6	(4.6)	0.0	(57.6)	(21.0)	(0.2)	0.0	(19.1)	(107.3)
AMIL	316.0	106.1	157.8	8.3	4.6	(32.3)	(19.1)	(32.2)	(37.1)	472.1
CIN	(793.1)	(826.3)	(488.5)	(848.5)	(1,258.4)	(1,184.4)	(839.3)	(967.1)	(1,166.7)	(8,372.3)
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	(36.5)	(34.8)	(58.4)	(127.3)	(164.9)	(204.2)	(104.8)	(103.4)	(100.4)	(934.6)
MEC	(536.0)	(435.1)	(400.4)	(434.5)	(469.0)	(454.4)	(464.9)	(435.0)	(439.8)	(4,069.1)
MECS	129.6	(10.2)	113.2	(70.0)	(182.6)	(250.3)	(235.4)	(286.2)	(269.1)	(1,061.1)
NIPS	(4.3)	3.9	(0.3)	0.0	(13.8)	0.0	0.0	0.0	0.0	(14.4)
WEC	(84.4)	(58.5)	(22.8)	(39.3)	(140.7)	(217.3)	(152.0)	(112.3)	(111.2)	(938.6)
NYISO	(1,558.3)	(1,124.8)	(1,425.5)	(705.0)	(443.0)	(806.3)	(1,420.5)	(1,181.7)	(754.1)	(9,419.2)
HUDS	(204.6)	(91.7)	(164.3)	(97.9)	(11.2)	(103.1)	(117.6)	(124.0)	(54.1)	(968.5)
LIND	(227.9)	(199.4)	(226.6)	(137.2)	(142.6)	(141.5)	(166.1)	(175.2)	(132.6)	(1,549.1)
NEPT	(464.5)	(436.9)	(496.3)	(344.5)	(411.8)	(409.0)	(479.3)	(468.9)	(446.2)	(3,957.4)
NYIS	(661.2)	(396.8)	(538.3)	(125.4)	122.5	(152.6)	(657.5)	(413.6)	(121.3)	(2,944.2)
TVA	52.5	96.0	8.1	39.9	(51.0)	(88.9)	51.2	16.6	(89.4)	35.1
Total	(2,678.7)	(2,198.9)	(1,854.3)	(2,360.4)	(3,037.8)	(3,637.1)	(3,301.0)	(3,360.8)	(3,488.0)	(25,916.9)

10 In the Real-Time Energy Market, one PJM interface had a net interchange of zero (PJM/City Water Light & Power (CWLP)).

Table 9-4 Real-time scheduled gross import volume by interface (GWh): January through September, 2019

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
CPLE	161.9	144.3	165.6	55.3	83.1	71.0	54.8	38.9	8.7	783.5
CPLW	0.0	0.0	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.3
DUK	299.5	402.5	293.4	188.3	162.9	145.3	232.5	208.9	134.5	2,067.8
LGEE	113.4	101.6	93.3	48.5	114.3	21.0	35.9	17.9	34.4	580.3
MISO	665.3	290.4	468.2	113.6	93.0	51.1	72.0	58.1	85.9	1,897.7
ALTE	38.7	19.1	71.2	25.1	4.1	7.2	15.5	11.0	9.9	201.8
ALTW	0.1	0.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6
AMIL	334.0	139.1	172.3	19.9	54.9	4.0	1.3	1.5	3.9	730.9
CIN	31.0	24.9	43.3	9.8	9.4	15.1	16.1	15.9	16.7	182.0
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	4.1	3.0	3.7	0.2	1.5	2.3	3.9	2.7	4.9	26.2
MEC	19.2	17.1	24.1	21.7	19.7	16.4	15.1	17.3	21.2	172.1
MECS	231.4	77.7	152.0	23.9	3.2	4.9	19.7	9.4	18.0	540.2
NIPS	0.5	4.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.7
WEC	6.4	4.8	1.5	13.0	0.3	1.1	0.3	0.3	11.3	39.2
NYISO	163.0	125.9	125.3	141.0	237.1	168.9	126.2	126.1	132.0	1,345.6
HUDS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2
LIND	0.0	0.7	0.1	1.7	8.8	1.7	1.9	0.6	1.8	17.3
NEPT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.1
NYIS	163.0	125.2	125.2	139.3	228.3	167.1	124.3	125.5	130.1	1,327.9
TVA	104.3	144.6	62.4	96.9	37.7	40.6	128.0	73.7	21.7	709.9
Total	1,507.5	1,209.2	1,208.5	643.7	728.0	497.9	649.4	523.7	417.2	7,385.1

Table 9-5 Real-time scheduled gross export volume by interface (GWh): January through September, 2019

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
CPLE	115.3	42.0	84.9	55.0	54.7	56.1	42.4	26.9	48.4	525.9
CPLW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUK	306.5	137.0	49.9	107.3	108.1	116.1	65.3	67.1	104.3	1,061.6
LGEE	90.4	71.1	98.3	60.4	105.8	83.2	96.0	88.5	76.9	770.7
MISO	1,900.7	1,858.7	1,224.6	1,878.4	2,728.6	2,775.0	2,123.0	2,337.1	2,678.3	19,504.2
ALTE	260.1	332.9	123.6	278.6	357.3	367.2	250.8	353.8	458.9	2,783.0
ALTW	5.4	0.0	4.6	0.0	57.6	21.0	0.2	0.0	19.1	107.9
AMIL	17.9	33.0	14.6	11.6	50.3	36.3	20.5	33.7	41.0	258.8
CIN	824.0	851.1	531.7	858.3	1,267.8	1,199.5	855.5	983.0	1,183.4	8,554.3
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	40.6	37.8	62.1	127.5	166.4	206.5	108.7	106.1	105.2	960.8
MEC	555.3	452.3	424.5	456.2	488.7	470.9	480.0	452.3	461.0	4,241.2
MECS	101.9	87.9	38.8	93.9	185.8	255.2	255.1	295.6	287.1	1,601.3
NIPS	4.8	0.3	0.3	0.0	13.8	0.0	0.0	0.0	0.0	19.1
WEC	90.8	63.4	24.4	52.4	141.0	218.4	152.4	112.6	122.5	977.8
NYISO	1,721.3	1,250.6	1,550.8	846.0	680.1	975.2	1,546.7	1,307.8	886.1	10,764.8
HUDS	204.6	91.7	164.3	97.9	11.2	103.1	117.6	124.0	54.1	968.7
LIND	228.0	200.0	226.7	138.9	151.4	143.3	167.9	175.8	134.4	1,566.4
NEPT	464.5	436.9	496.3	344.5	411.8	409.0	479.3	468.9	446.2	3,957.5
NYIS	824.2	522.0	663.5	264.7	105.7	319.7	781.8	539.0	251.4	4,272.2
TVA	51.8	48.6	54.3	57.0	88.6	129.4	76.8	57.1	111.1	674.8
Total	4,186.1	3,408.1	3,062.8	3,004.1	3,765.8	4,135.0	3,950.4	3,884.5	3,905.2	33,302.0

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),

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.

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 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 9-19 presents the interface pricing points used in the first nine months of 2019. On September 16, 2014, PJM updated the mappings of external balancing authorities to individual pricing points. Figure 9-4 shows a map of the default interface pricing point assignments for all external balancing authorities. Figure 9-4 shows that all balancing authorities in the Western Interconnection are mapped to the Northwest interface pricing point. When power is scheduled across a DC tie line, its effects on the PJM system are as if a generator is located at the point in the Eastern Interconnection where the DC tie line connects. The electrical impact on PJM tie lines from sources in the Western Interconnection differ based on the relevant DC tie line and could vary from the Northwest interface pricing point to the SouthIMP interface pricing point. The MMU believes that transactions sourcing in the Western Interconnection should be priced depending on the DC tie line point of connection with the Eastern Interconnection. 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

12 See the 2007 State of the Market Report for PJM, Volume 2, Appendix D, "Interchange Transactions," for a more complete discussion of the development of pricing points.

13 See "Interface Pricing Point Assignment Methodology" (August 6, 2019) <http://www.pjm.com/~/media/etools/exschedule/interface-pricing-point-assignment-methodology.ashx>. PJM periodically updates these definitions on its website.

14 On June 1, 2015, PJM began using a dynamic weighting factor in the calculation for the Ontario interface pricing point.

PJM continued to use the Southwest pricing point for certain grandfathered transactions which have since expired.[15]

In the Real-Time Energy Market, in the first nine months of 2019, there were net scheduled exports at ten of PJM's 17 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 82.2 percent of the total net scheduled exports: PJM/MISO with 60.3 percent, PJM/NEPTUNE with 12.6 percent and PJM/NYIS with 9.4 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 29.9 percent of the total net PJM scheduled exports in the Real-Time Energy Market.

Table 9-6 Real-time scheduled net interchange volume by interface pricing point (GWh): January through September, 2019

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
IMO	193.2	86.2	82.4	7.8	8.5	4.6	28.1	15.0	17.0	442.6
MISO	(1,858.3)	(1,798.4)	(1,089.5)	(1,817.4)	(2,691.6)	(2,731.2)	(2,083.0)	(2,299.3)	(2,632.1)	(19,000.9)
NORTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NYISO	(1,559.3)	(1,124.8)	(1,425.5)	(707.3)	(444.3)	(806.3)	(1,420.5)	(1,181.7)	(754.3)	(9,424.0)
HUDSONTP	(204.6)	(91.7)	(164.3)	(97.9)	(11.2)	(103.1)	(117.6)	(124.0)	(54.1)	(968.5)
LINDENVFT	(227.9)	(199.4)	(226.6)	(137.2)	(142.6)	(141.5)	(166.1)	(175.2)	(132.6)	(1,549.1)
NEPTUNE	(464.5)	(436.9)	(496.3)	(344.5)	(411.8)	(409.0)	(479.3)	(468.9)	(446.2)	(3,957.4)
NYIS	(662.3)	(396.8)	(538.3)	(127.7)	121.2	(152.7)	(657.5)	(413.6)	(121.4)	(2,949.1)
Southern Imports	1,110.8	948.9	883.8	442.0	453.5	285.7	456.2	347.4	222.9	5,151.1
CPLEIMP	0.0	1.0	0.5	0.1	0.2	0.0	1.8	0.2	0.7	4.4
DUKIMP	40.2	42.7	69.0	38.0	37.5	12.0	46.6	55.4	14.2	355.6
NCMPAIMP	149.6	145.5	107.9	71.2	91.6	114.2	76.9	90.6	51.1	898.5
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHIMP	921.0	759.7	706.4	332.6	324.2	159.4	331.0	201.2	157.0	3,892.6
Southern Exports	(565.1)	(310.7)	(305.5)	(285.5)	(363.8)	(389.8)	(281.8)	(242.2)	(341.4)	(3,085.7)
CPLEEXP	(71.4)	(9.3)	(23.1)	(25.0)	(19.3)	(13.5)	(5.9)	(8.7)	(4.3)	(180.5)
DUKEXP	(137.8)	(86.6)	(10.1)	(37.9)	(1.9)	(0.3)	(0.2)	(3.9)	(8.0)	(286.7)
NCMPAEXP	0.0	0.0	0.0	0.0	0.0	0.0	(0.4)	0.0	0.0	(0.4)
SOUTHEAST	0.0	0.0	0.0	(0.1)	(1.3)	0.0	0.0	0.0	0.0	(1.4)
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEXP	(355.8)	(214.8)	(272.3)	(222.5)	(341.2)	(376.0)	(275.3)	(229.6)	(329.2)	(2,616.7)
Total	(2,678.7)	(2,198.9)	(1,854.3)	(2,360.4)	(3,037.8)	(3,637.1)	(3,301.0)	(3,360.8)	(3,488.0)	(25,916.9)

In the Real-Time Energy Market, in the first nine months of 2019, there were net scheduled imports at five of PJM's 17 interface pricing points eligible for real-time transactions. The top two net importing interface pricing points in the Real-Time Energy Market accounted for 85.7 percent of the total net scheduled imports: PJM/SouthIMP with 69.6 percent and PJM/NCMPAIMP with 16.1 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]

15 Use of the Southwest pricing point for grandfathered transactions is not appropriate, and the MMU 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 (Northwest and Southwest).

Table 9-7 Real-time scheduled gross import volume by interface pricing point (GWh): January through September, 2019

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
IMO	196.6	88.0	83.2	9.3	8.5	6.6	29.1	16.1	17.9	455.3
MISO	38.1	46.5	116.1	53.7	30.3	36.8	37.8	34.0	44.6	438.0
NORTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NYISO	162.0	125.9	125.3	138.8	235.7	168.9	126.2	126.1	131.8	1,340.7
HUDSONTP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2
LINDENVFT	0.0	0.7	0.1	1.7	8.8	1.7	1.9	0.6	1.8	17.3
NEPTUNE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.1
NYIS	161.9	125.2	125.2	137.1	226.9	167.1	124.3	125.5	130.0	1,323.1
Southern Imports	1,110.8	948.9	883.8	442.0	453.5	285.7	456.2	347.4	222.9	5,151.1
CPLEIMP	0.0	1.0	0.5	0.1	0.2	0.0	1.8	0.2	0.7	4.4
DUKIMP	40.2	42.7	69.0	38.0	37.5	12.0	46.6	55.4	14.2	355.6
NCMPAIMP	149.6	145.5	107.9	71.2	91.6	114.2	76.9	90.6	51.1	898.5
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHIMP	921.0	759.7	706.4	332.6	324.2	159.4	331.0	201.2	157.0	3,892.6
Southern Exports	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CPLEEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	1,507.5	1,209.2	1,208.5	643.7	728.0	497.9	649.4	523.7	417.2	7,385.1

Table 9-8 Real-time scheduled gross export volume by interface pricing point (GWh): January through September, 2019

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
IMO	3.4	1.8	0.9	1.5	0.0	2.0	1.1	1.2	0.9	12.7
MISO	1,896.4	1,844.9	1,205.6	1,871.1	2,722.0	2,768.0	2,120.8	2,333.3	2,676.7	19,438.8
NORTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NYISO	1,721.3	1,250.6	1,550.8	846.0	680.1	975.2	1,546.7	1,307.8	886.1	10,764.7
HUDSONTP	204.6	91.7	164.3	97.9	11.2	103.1	117.6	124.0	54.1	968.7
LINDENVFT	228.0	200.0	226.7	138.9	151.4	143.3	167.9	175.8	134.4	1,566.4
NEPTUNE	464.5	436.9	496.3	344.5	411.8	409.0	479.3	468.9	446.2	3,957.5
NYIS	824.2	522.0	663.5	264.7	105.7	319.7	781.8	539.0	251.4	4,272.1
Southern Imports	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CPLEIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Southern Exports	565.1	310.7	305.5	285.5	363.8	389.8	281.8	242.2	341.4	3,085.7
CPLEEXP	71.4	9.3	23.1	25.0	19.3	13.5	5.9	8.7	4.3	180.5
DUKEXP	137.8	86.6	10.1	37.9	1.9	0.3	0.2	3.9	8.0	286.7
NCMPAEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.4	0.0	0.0	0.4
SOUTHEAST	0.0	0.0	0.0	0.1	1.3	0.0	0.0	0.0	0.0	1.4
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEXP	355.8	214.8	272.3	222.5	341.2	376.0	275.3	229.6	329.2	2,616.7
Total	4,186.1	3,408.1	3,062.8	3,004.1	3,765.8	4,135.0	3,950.4	3,884.5	3,905.2	33,302.0

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

18 Effective September 17, 2010, up to congestion transactions no longer required a willing to pay congestion transmission reservation.

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 9-9, Table 9-10, and Table 9-11, the scheduled interface designation is determined by the transmission reservation that was acquired and associated with the day-ahead market transaction, and does not bear any necessary relationship to the pricing point designation selected at the time the transaction is submitted to PJM in real time. For example, if market participants want to import energy from the Southwest Power Pool (SPP) to PJM, they are likely to choose a scheduled path with the fewest transmission providers along the path and therefore the lowest transmission costs for the transaction, regardless of whether the resultant path is related to the physical flow of power. The lowest cost transmission path runs from SPP, through MISO, and into PJM, requiring only three transmission reservations, two of which are available at no cost (MISO transmission would be free based on the regional through and out rates, and the PJM transmission would be free, if using spot import transmission). Any other transmission path entering PJM, where the generating control area is to the south, would require the market participant to acquire transmission through nonmarket balancing authorities, and thus incur additional transmission costs. PJM's interface pricing method recognizes that transactions sourcing in SPP and sinking in PJM will create flows across the southern border and prices those transactions at the SouthIMP interface price. As a result, a market participant who plans to submit a transaction from SPP to PJM may have a transmission reservation with a point of receipt of MISO and a point of delivery of PJM but may select SouthIMP as the import pricing point when submitting the transaction in the Day-Ahead Energy Market. In the scheduled interface tables, the import transaction would appear as scheduled through the MISO Interface, and in 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 9-9 through Table 9-11 show the day-ahead scheduled interchange totals at the individual interfaces. Net scheduled interchange in the Day-Ahead Energy Market is shown by interface for the first nine months of 2019 in Table 9-9, while gross scheduled imports and exports are shown in Table 9-10 and Table 9-11.

In the Day-Ahead Energy Market, in the first nine months of 2019, there were net scheduled exports at 11 of PJM's 19 interfaces. The top three net exporting interfaces in the Day-Ahead Energy Market accounted for 64.9 percent of the total net scheduled exports: PJM/ MidAmerican Energy Company (MEC) with 22.9 percent, PJM/Neptune (NEPT) with 21.9 percent and PJM/Cinergy (CIN) with 20.1 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 41.9 percent of the total net PJM scheduled exports in the Day-Ahead Energy Market. In the first nine months of 2019, there were net exports in the Day-Ahead Energy Market at six of the 10 separate interfaces that connect PJM to MISO. Those six interfaces represented 56.3 percent of the total net PJM exports in the Day-Ahead Energy Market.

In the Day-Ahead Energy Market, in the first nine months of 2019, there were net scheduled imports at two of PJM's 19 interfaces. The top two net importing interfaces in the Day-Ahead Energy Market accounted for 100.0 percent of the total net scheduled imports: PJM/Duke Energy Corp. (DUK) with 54.5 percent and PJM/CPLE[20] with 45.5 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 Day-Ahead Energy Market. In the first nine months of 2019, there were net imports in the Day-Ahead Energy Market at none of the 10 separate interfaces that connect PJM to MISO.[21]

19 See the 2010 State of the Market Report for PJM, Volume 2, Section 4, "Interchange Transactions," for details.

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, six PJM interfaces had a net interchange of zero (PJM/Carolina Power and Light (West) (CPLW), PJM/Ameren Illinois (AMIL), PJM/City Water Light & Power (CWLP), PJM/Indianapolis Power and Light Company (IPL), PJM/Northern Indiana Public Service Company (NIPS) and PJM/Linden (LIND)).

Table 9-9 Day-ahead scheduled net interchange volume by interface (GWh): January through September, 2019

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
CPLE	159.7	130.7	88.9	20.6	83.2	55.5	41.4	54.2	14.2	648.3
CPLW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUK	104.1	161.7	92.0	93.4	17.9	47.7	98.7	119.8	42.8	778.1
LGEE	0.0	0.0	0.0	0.0	(48.4)	(0.0)	0.0	0.0	(1.2)	(49.6)
MISO	(1,270.9)	(1,187.1)	(757.2)	(1,156.1)	(1,187.0)	(1,207.4)	(975.3)	(1,097.6)	(1,466.0)	(10,304.6)
ALTE	(198.1)	(220.9)	(65.7)	(170.8)	(232.3)	(245.6)	(129.2)	(202.7)	(363.8)	(1,829.1)
ALTW	(3.9)	0.0	0.0	0.0	(46.6)	(23.5)	0.0	0.0	(18.8)	(92.8)
AMIL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CIN	(446.3)	(405.9)	(270.5)	(464.1)	(382.4)	(416.8)	(334.7)	(403.2)	(551.6)	(3,675.6)
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MEC	(525.0)	(443.0)	(398.5)	(468.2)	(487.9)	(469.9)	(476.7)	(456.2)	(460.9)	(4,186.3)
MECS	(34.7)	(54.1)	0.3	(15.4)	(20.3)	(26.3)	(7.6)	(17.7)	(36.3)	(212.0)
NIPS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
WEC	(62.9)	(63.2)	(22.8)	(37.6)	(17.5)	(25.2)	(27.2)	(17.7)	(34.6)	(308.8)
NYISO	(1,227.8)	(835.5)	(1,089.0)	(540.2)	(421.3)	(637.9)	(1,240.7)	(1,009.7)	(668.4)	(7,670.4)
HUDS	(106.9)	(38.3)	(49.1)	(37.3)	(4.9)	(35.2)	(59.2)	(70.9)	(27.2)	(429.0)
LIND	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NEPT	(457.1)	(441.3)	(499.0)	(352.4)	(417.0)	(409.3)	(485.8)	(495.2)	(461.0)	(4,018.1)
NYIS	(663.8)	(355.9)	(541.0)	(150.4)	0.7	(193.4)	(695.7)	(443.7)	(180.1)	(3,223.3)
TVA	(15.0)	(15.5)	(34.5)	(22.7)	(42.1)	(57.5)	(1.1)	(23.4)	(81.9)	(293.7)
Total without Up To Congestion	(2,249.9)	(1,745.7)	(1,699.8)	(1,605.0)	(1,597.8)	(1,799.6)	(2,077.0)	(1,956.6)	(2,160.5)	(16,892.0)
Up To Congestion	2,376.2	1,131.3	2,930.3	1,681.5	1,740.5	619.8	641.8	432.2	797.8	12,351.3
Total	126.3	(614.4)	1,230.4	76.4	142.7	(1,179.8)	(1,435.2)	(1,524.5)	(1,362.7)	(4,540.7)

Table 9-10 Day-ahead scheduled gross import volume by interface (GWh): January through September, 2019

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
CPLE	207.7	159.5	142.5	52.9	106.6	86.7	62.1	70.0	38.3	926.3
CPLW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUK	104.1	161.7	93.4	108.6	47.8	83.9	103.7	126.1	74.1	903.5
LGEE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MISO	56.9	38.4	51.3	8.1	3.0	5.9	14.2	5.6	2.7	186.0
ALTE	3.7	3.4	33.6	4.5	1.1	0.0	5.7	0.8	0.0	52.8
ALTW	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	0.0	0.0
CIN	4.4	3.5	10.7	1.1	1.6	3.6	4.6	2.4	2.1	34.0
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MEC	1.7	0.0	0.0	1.1	0.0	0.0	0.0	1.1	0.0	3.9
MECS	47.1	31.4	7.0	1.4	0.3	2.3	3.9	1.4	0.6	95.3
NIPS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
WEC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NYISO	37.2	19.4	0.2	8.8	49.6	24.7	2.1	0.0	0.8	142.8
HUDS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LIND	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NEPT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NYIS	37.2	19.4	0.2	8.8	49.6	24.7	2.1	0.0	0.8	142.8
TVA	0.0	0.0	0.0	4.6	0.5	8.0	28.6	4.2	0.7	46.6
Total without Up To Congestion	405.8	379.0	287.4	183.0	207.4	209.2	210.8	206.0	116.7	2,205.3
Up To Congestion	4,365.8	3,552.0	5,600.3	4,317.6	4,188.1	3,690.4	3,676.4	3,689.7	3,635.4	36,715.7
Total	4,771.6	3,931.0	5,887.7	4,500.6	4,395.5	3,899.6	3,887.2	3,895.7	3,752.1	38,921.1

Table 9-11 Day-ahead scheduled gross export volume by interface (GWh): January through September, 2019

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
CPLE	48.0	28.9	53.6	32.3	23.4	31.2	20.7	15.8	24.2	278.0
CPLW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUK	0.0	0.0	1.4	15.2	29.9	36.2	5.1	6.4	31.3	125.4
LGEE	0.0	0.0	0.0	0.0	48.4	0.0	0.0	0.0	1.2	49.6
MISO	1,327.8	1,225.5	808.5	1,164.2	1,190.0	1,213.3	989.5	1,103.2	1,468.7	10,490.7
ALTE	201.8	224.3	99.3	175.3	233.4	245.6	134.9	203.5	363.8	1,881.9
ALTW	3.9	0.0	0.0	0.0	46.6	23.5	0.0	0.0	18.8	92.8
AMIL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CIN	450.8	409.5	281.2	465.2	384.0	420.4	339.3	405.6	553.7	3,709.6
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MEC	526.7	443.0	398.5	469.3	487.9	469.9	476.7	457.3	460.9	4,190.2
MECS	81.8	85.5	6.7	16.7	20.6	28.7	11.4	19.1	36.9	307.4
NIPS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
WEC	62.9	63.2	22.8	37.6	17.5	25.2	27.2	17.7	34.6	308.8
NYISO	1,264.9	854.9	1,089.3	549.0	470.9	662.6	1,242.8	1,009.7	669.2	7,813.2
HUDS	106.9	38.3	49.1	37.3	4.9	35.2	59.2	70.9	27.2	429.0
LIND	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NEPT	457.1	441.3	499.0	352.4	417.0	409.3	485.8	495.2	461.0	4,018.1
NYIS	700.9	375.3	541.2	159.3	48.9	218.1	697.8	443.7	180.9	3,366.2
TVA	15.0	15.5	34.5	27.4	42.5	65.5	29.7	27.6	82.7	340.4
Total without Up To Congestion	2,655.7	2,124.7	1,987.3	1,788.1	1,805.2	2,008.7	2,287.8	2,162.6	2,277.2	19,097.3
Up To Congestion	1,989.6	2,420.7	2,670.0	2,636.1	2,447.6	3,070.7	3,034.6	3,257.6	2,837.6	24,364.4
Total	4,645.3	4,545.4	4,657.3	4,424.2	4,252.8	5,079.4	5,322.4	5,420.2	5,114.8	43,461.7

Day-Ahead Interface Pricing Point Imports and Exports

Table 9-12 through Table 9-17 show the day-ahead scheduled interchange totals at the interface pricing points. In the first nine months of 2019, up to congestion transactions accounted for 94.3 percent of all scheduled import MW transactions and 56.1 percent of all scheduled export MW transactions in the Day-Ahead Energy Market. The day-ahead net scheduled interchange in the first nine months of 2019, including up to congestion transactions, is shown by interface pricing point in Table 9-12. Scheduled up to congestion transactions by interface pricing point in the first nine months of 2019 are shown in Table 9-13. Day-ahead gross scheduled imports and exports, including up to congestion transactions, are shown in Table 9-14 and Table 9-16, while gross scheduled import and export up to congestion transactions are show in Table 9-15 and Table 9-17.

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 continued to also be used as an eligible source or sink for new FTRs through the 2016/2017 planning period, but was removed as an eligible bus for the 2017/2018 planning period.

In the first nine months of 2019, the day-ahead net scheduled interchange at the NIPSCO interface pricing point was -9,685.3 GWh (Table 9-12). Table 9-13 shows that all -9,685.3 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. PJM should immediately eliminate interface pricing points when changes to the market mean that the pricing points can no longer be used to price actual transactions and do not reflect actual price formation.

In the Day-Ahead Energy Market, in the first nine months of 2019, there were net scheduled exports at nine of PJM's 18 interface pricing points eligible for day-ahead transactions. The top three net exporting interface pricing points in the Day-Ahead Energy Market accounted for 78.4 percent of the total net scheduled exports: PJM/NIPSCO with 45.7 percent, PJM/SouthEXP with 22.8 percent and PJM/NEPTUNE with 9.8 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 23.2 percent of the total net PJM scheduled exports in the Day-Ahead Energy Market. However, the PJM/LINDENVFT interface pricing point had net scheduled imports in the Day-Ahead Energy Market.

In the Day-Ahead Energy Market, in the first nine months of 2019, there were net scheduled imports at seven of PJM's 18 interface pricing points eligible for day-ahead transactions. The top three net importing interface pricing points in the Day-Ahead Energy Market accounted for 88.1 percent of the total net scheduled imports: PJM/NORTHWEST with 51.5 percent, PJM/SouthImp with 29.4 percent and PJM/NCMPAIMP with 7.2 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 4.6 percent of the total net PJM scheduled imports in the Day-Ahead Energy Market. However, the PJM/NYIS, PJM/NEPTUNE and PJM/HUDSONTP interface pricing points had net scheduled exports in the Day-Ahead Energy Market.[22]

In the Day-Ahead Energy Market, in the first nine months of 2019, up to congestion transactions had net scheduled exports at three of PJM's 18 interface pricing points eligible for day-ahead transactions. The top two net exporting interface pricing points eligible for up to congestion transactions accounted for 97.0 percent of the total net up to congestion scheduled exports: PJM/NIPSCO with 67.0 percent and PJM/SouthEXP with 30.0 percent of the net up to congestion 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 3.0 percent of the total net scheduled up to congestion exports in the Day-Ahead Energy Market. However, the PJM/NYIS, PJM/NEPTUNE and PJM/LINDENVFT interface pricing points had net up to congestion scheduled imports in the Day-Ahead Energy Market.

In the Day-Ahead Energy Market, in the first nine months of 2019, up to congestion transactions had net scheduled imports at seven of PJM's 18 interface pricing points eligible for day-ahead transactions. The top three net importing interface pricing points eligible for up to congestion transactions accounted for 82.6 percent of the total net up to congestion scheduled imports:

22 In the Day-Ahead Energy Market, two PJM interface pricing points had a net interchange of zero (Southeast and Southwest).

PJM/NORTHWEST with 47.2 percent, PJM/MISO with 18.2 percent and PJM/SouthIMP with 17.2 percent of the net import up to congestion volume. The four separate interface pricing points that connect PJM to the NYISO (PJM/NYIS, PJM/NEPTUNE, PJM/HUDSONTP and PJM/LINDENVFT) together represented 14.7 percent of the total net scheduled up to congestion imports in the Day-Ahead Energy Market. However, the PJM/HUDSONTP interface pricing points had net up to congestion scheduled exports in the Day-Ahead Energy Market.[23]

Table 9-12 Day-ahead scheduled net interchange volume by interface pricing point (GWh): January through September, 2019

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
IMO	120.3	82.9	51.3	32.5	54.7	150.1	95.8	165.4	71.2	824.2
MISO	(405.0)	(801.4)	232.2	(428.0)	(136.2)	(195.8)	123.3	165.7	(11.1)	(1,456.3)
NIPSCO	(524.1)	(412.7)	(1,318.9)	(1,253.0)	(1,303.6)	(1,330.9)	(1,139.1)	(1,464.7)	(938.3)	(9,685.3)
NORTHWEST	1,323.3	(117.7)	1,739.0	1,137.7	977.9	1,158.8	992.5	811.7	536.9	8,560.0
NYISO	(1,126.4)	(632.1)	(641.4)	(13.6)	306.6	(221.2)	(960.0)	(628.1)	(231.5)	(4,147.6)
HUDSONTP	(218.7)	(288.3)	(75.0)	(92.3)	30.2	(49.0)	(27.3)	(93.8)	(27.8)	(841.9)
LINDENVFT	99.2	0.5	118.8	117.8	89.3	56.5	60.6	109.8	112.5	765.0
NEPTUNE	(308.0)	(184.3)	(224.1)	(150.8)	(91.2)	(191.3)	(312.9)	(333.0)	(281.8)	(2,077.5)
NYIS	(698.8)	(160.1)	(461.0)	111.7	278.3	(37.4)	(680.4)	(311.1)	(34.4)	(1,993.2)
Southern Imports	939.8	1,448.3	1,377.0	809.1	624.1	282.3	363.9	340.8	299.7	6,485.1
CPLEIMP	53.3	23.6	28.2	1.0	1.7	0.6	3.8	0.8	0.8	113.8
DUKIMP	26.8	51.6	29.3	35.8	9.3	13.8	36.5	57.4	23.4	283.9
NCMPAIMP	180.7	176.8	140.2	98.6	128.0	149.6	111.5	127.0	86.6	1,199.0
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHIMP	679.1	1,196.3	1,179.2	673.8	485.2	118.3	212.1	155.6	188.9	4,888.4
Southern Exports	(201.6)	(181.6)	(208.8)	(208.3)	(380.8)	(1,023.2)	(911.5)	(915.4)	(1,089.6)	(5,120.7)
CPLEEXP	(45.1)	(27.1)	(50.8)	(37.6)	(21.8)	(29.9)	(20.0)	(15.3)	(20.9)	(268.5)
DUKEXP	0.0	0.0	0.0	(8.4)	(5.1)	(1.0)	0.0	(1.5)	(5.0)	(21.1)
NCMPAEXP	0.0	0.0	0.0	0.0	(0.6)	0.0	0.0	0.0	0.0	(0.6)
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEXP	(156.4)	(154.6)	(158.0)	(162.3)	(353.3)	(992.2)	(891.6)	(898.5)	(1,063.7)	(4,830.6)
Total	126.3	(614.4)	1,230.4	76.4	142.7	(1,179.8)	(1,435.2)	(1,524.5)	(1,362.7)	(4,540.7)

23 In the Day-Ahead Energy Market, eight PJM interface pricing points had up to congestion net interchange of zero (PJM/CPLEIMP, PJM/DUKIMP, PJM/NCMPAIMP, PJM/CPLEEXP, PJM/DUKEXP, PJM/NCMPAEXP, PJM/Southeast and PJM/Southwest).

Table 9-13 Up to congestion scheduled net interchange volume by interface pricing point (GWh): January through September, 2019

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
IMO	74.4	49.9	43.3	31.1	54.4	147.8	87.2	163.4	70.6	721.9
MISO	431.1	(6.9)	610.7	268.1	566.2	552.4	635.8	813.7	998.9	4,869.9
NIPSCO	(524.1)	(412.7)	(1,318.9)	(1,253.0)	(1,303.6)	(1,330.9)	(1,139.1)	(1,464.7)	(938.3)	(9,685.3)
NORTHWEST	1,812.5	315.9	2,124.9	1,599.1	1,458.6	1,620.3	1,463.9	1,263.3	993.5	12,652.0
NYISO	92.9	195.4	447.7	526.6	732.2	416.8	280.7	381.6	436.9	3,510.8
HUDSONTP	(120.4)	(258.6)	(27.1)	(55.0)	35.2	(13.8)	29.8	(22.9)	(0.6)	(433.3)
LINDENVFT	99.2	0.5	118.8	117.8	89.3	56.5	60.6	109.8	112.5	765.0
NEPTUNE	149.1	257.1	274.8	201.5	325.8	218.0	172.9	162.1	179.3	1,940.6
NYIS	(35.0)	196.5	81.1	262.2	281.9	156.1	17.4	132.6	145.7	1,238.5
Southern Imports	628.0	1,127.0	1,141.1	643.0	469.1	103.7	169.4	140.5	186.5	4,608.5
CPLEIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHIMP	628.0	1,127.0	1,141.1	643.0	469.1	103.7	169.4	140.5	186.5	4,608.5
Southern Exports	(138.5)	(137.3)	(118.5)	(133.4)	(236.5)	(890.3)	(856.0)	(865.7)	(950.2)	(4,326.5)
CPLEEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEXP	(138.5)	(137.3)	(118.5)	(133.4)	(236.5)	(890.3)	(856.0)	(865.7)	(950.2)	(4,326.5)
Total Interfaces	2,376.2	1,131.3	2,930.3	1,681.5	1,740.5	619.8	641.8	432.2	797.8	12,351.3
INTERNAL	9,708.1	9,029.3	10,124.5	9,316.8	8,678.5	7,500.9	8,625.5	9,209.5	9,032.2	81,225.2
Total	12,084.3	10,160.6	13,054.8	10,998.2	10,419.0	8,120.6	9,267.3	9,641.6	9,830.0	93,576.5

Table 9-14 Day-ahead scheduled gross import volume by interface pricing point (GWh): January through September, 2019

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
IMO	152.0	135.3	80.3	95.8	80.5	188.1	141.9	200.6	109.6	1,184.1
MISO	863.4	515.5	1,137.6	840.0	949.5	894.5	957.2	1,104.4	1,260.7	8,522.7
NIPSCO	112.2	133.2	156.6	103.1	111.4	108.9	126.2	133.8	189.5	1,174.8
NORTHWEST	2,074.1	969.4	2,320.0	1,818.3	1,580.8	1,746.0	1,643.9	1,407.4	1,191.6	14,751.5
NYISO	630.1	729.4	816.3	834.3	1,049.2	679.8	654.2	708.5	701.1	6,802.9
HUDSONTP	43.1	43.7	80.1	43.7	118.4	40.5	82.9	43.2	106.8	602.5
LINDENVFT	154.0	103.2	173.2	170.5	186.0	108.0	123.2	189.8	160.3	1,368.1
NEPTUNE	207.3	293.3	309.0	257.1	365.2	264.2	244.0	247.2	214.8	2,402.1
NYIS	225.8	289.3	254.0	362.9	379.6	267.1	204.0	228.3	219.3	2,430.2
Southern Imports	939.8	1,448.3	1,377.0	809.1	624.1	282.3	363.9	340.8	299.7	6,485.1
CPLEIMP	53.3	23.6	28.2	1.0	1.7	0.6	3.8	0.8	0.8	113.8
DUKIMP	26.8	51.6	29.3	35.8	9.3	13.8	36.5	57.4	23.4	283.9
NCMPAIMP	180.7	176.8	140.2	98.6	128.0	149.6	111.5	127.0	86.6	1,199.0
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHIMP	679.1	1,196.3	1,179.2	673.8	485.2	118.3	212.1	155.6	188.9	4,888.4
Southern Exports	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CPLEEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	4,771.6	3,931.0	5,887.7	4,500.6	4,395.5	3,899.6	3,887.2	3,895.7	3,752.1	38,921.1

Table 9-15 Up to congestion scheduled gross import volume by interface pricing point (GWh): January through September, 2019

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
IMO	104.9	102.3	71.2	94.5	80.2	185.7	133.3	198.4	109.0	1,079.3
MISO	853.6	510.1	1,095.4	833.3	946.8	890.9	951.6	1,101.0	1,258.6	8,441.3
NIPSCO	112.2	133.2	156.6	103.1	111.4	108.9	126.2	133.8	189.5	1,174.8
NORTHWEST	2,074.1	969.4	2,320.0	1,818.3	1,580.8	1,746.0	1,643.9	1,407.4	1,191.6	14,751.5
NYISO	593.0	710.0	816.0	825.4	999.8	655.2	652.1	708.5	700.3	6,660.4
HUDSONTP	43.1	43.7	80.1	43.7	118.4	40.5	82.9	43.2	106.8	602.5
LINDENVFT	154.0	103.2	173.2	170.5	186.0	108.0	123.2	189.8	160.3	1,368.1
NEPTUNE	207.3	293.3	309.0	257.1	365.2	264.2	244.0	247.2	214.8	2,402.1
NYIS	188.7	269.9	253.7	354.0	330.2	242.5	201.9	228.3	218.5	2,287.7
Southern Imports	628.0	1,127.0	1,141.1	643.0	469.1	103.7	169.4	140.5	186.5	4,608.5
CPLEIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHIMP	628.0	1,127.0	1,141.1	643.0	469.1	103.7	169.4	140.5	186.5	4,608.5
Southern Exports	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CPLEEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Interfaces	4,365.8	3,552.0	5,600.3	4,317.6	4,188.1	3,690.4	3,676.4	3,689.7	3,635.4	36,715.7

Table 9-16 Day-ahead scheduled gross export volume by interface pricing point (GWh): January through September, 2019

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
IMO	31.7	52.4	29.0	63.4	25.8	37.9	46.1	35.2	38.4	359.9
MISO	1,268.4	1,316.9	905.4	1,268.0	1,085.7	1,090.3	833.9	938.7	1,271.8	9,979.0
NIPSCO	636.4	545.9	1,475.5	1,356.1	1,415.0	1,439.8	1,265.3	1,598.5	1,127.8	10,860.1
NORTHWEST	750.8	1,087.1	581.0	680.6	603.0	587.2	651.5	595.8	654.7	6,191.5
NYISO	1,756.6	1,361.5	1,457.6	847.9	742.6	901.0	1,614.2	1,336.6	932.5	10,950.5
HUDSONTP	261.9	332.0	155.0	136.0	88.2	89.5	110.2	137.0	134.6	1,444.3
LINDENVFT	54.8	102.7	54.4	52.7	96.7	51.5	62.6	80.0	47.8	603.2
NEPTUNE	515.3	477.5	533.2	408.0	456.4	455.5	556.9	580.2	496.6	4,479.6
NYIS	924.6	449.3	715.0	251.1	101.3	304.5	884.4	539.5	253.7	4,423.4
Southern Imports	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CPLEIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Southern Exports	201.6	181.6	208.8	208.3	380.8	1,023.2	911.5	915.4	1,089.6	5,120.7
CPLEEXP	45.1	27.1	50.8	37.6	21.8	29.9	20.0	15.3	20.9	268.5
DUKEXP	0.0	0.0	0.0	8.4	5.1	1.0	0.0	1.5	5.0	21.1
NCMPAEXP	0.0	0.0	0.0	0.0	0.6	0.0	0.0	0.0	0.0	0.6
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEXP	156.4	154.6	158.0	162.3	353.3	992.2	891.6	898.5	1,063.7	4,830.6
Total	4,645.3	4,545.4	4,657.3	4,424.2	4,252.8	5,079.4	5,322.4	5,420.2	5,114.8	43,461.7

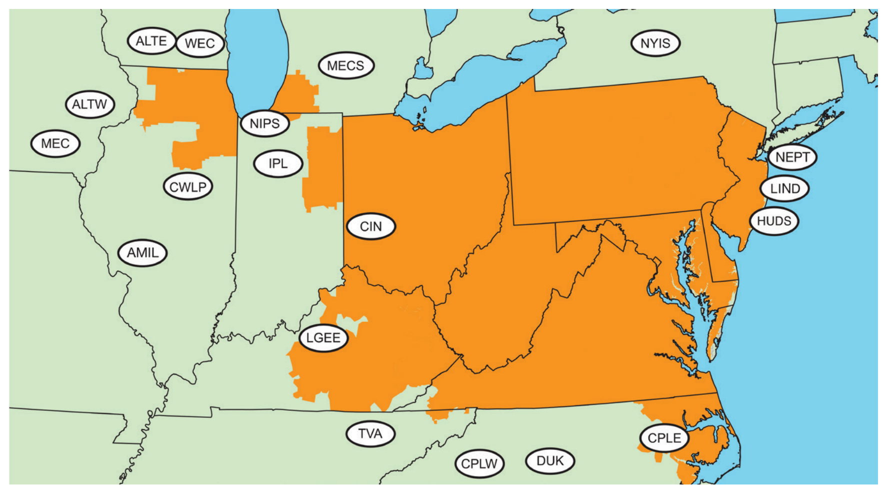
Table 9-17 Up to congestion scheduled gross export volume by interface pricing point (GWh): January through September, 2019

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
IMO	30.5	52.4	27.9	63.4	25.8	37.9	46.1	35.0	38.4	357.4
MISO	422.5	517.0	484.7	565.2	380.6	338.5	315.8	287.3	259.7	3,571.4
NIPSCO	636.4	545.9	1,475.5	1,356.1	1,415.0	1,439.8	1,265.3	1,598.5	1,127.8	10,860.1
NORTHWEST	261.6	653.5	195.1	219.2	122.2	125.7	180.1	144.2	198.1	2,099.5
NYISO	500.1	514.6	368.4	298.8	267.6	238.4	371.4	327.0	263.4	3,149.6
HUDSONTP	163.5	302.3	107.1	98.7	83.2	54.3	53.1	66.1	107.4	1,035.7
LINDENVFT	54.8	102.7	54.4	52.7	96.7	51.5	62.6	80.0	47.8	603.2
NEPTUNE	58.2	36.2	34.2	55.6	39.4	46.2	71.1	85.1	35.5	461.5
NYIS	223.7	73.4	172.6	91.8	48.3	86.3	184.5	95.8	72.8	1,049.2
Southern Imports	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CPLEIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Southern Exports	138.5	137.3	118.5	133.4	236.5	890.3	856.0	865.7	950.2	4,326.5
CPLEEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEXP	138.5	137.3	118.5	133.4	236.5	890.3	856.0	865.7	950.2	4,326.5
Total Interfaces	1,989.6	2,420.7	2,670.0	2,636.1	2,447.6	3,070.7	3,034.6	3,257.6	2,837.6	24,364.4

Table 9-18 Active scheduling interfaces: January through September, 2019[24]

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
ALTE	Active	Active	Active	Active	Active	Active	Active	Active	Active
ALTW	Active	Active	Active	Active	Active	Active	Active	Active	Active
AMIL	Active	Active	Active	Active	Active	Active	Active	Active	Active
CIN	Active	Active	Active	Active	Active	Active	Active	Active	Active
CPLE	Active	Active	Active	Active	Active	Active	Active	Active	Active
CPLW	Active	Active	Active	Active	Active	Active	Active	Active	Active
CWLP	Active	Active	Active	Active	Active	Active	Active	Active	Active
DUK	Active	Active	Active	Active	Active	Active	Active	Active	Active
HUDS	Active	Active	Active	Active	Active	Active	Active	Active	Active
IPL	Active	Active	Active	Active	Active	Active	Active	Active	Active
LGEE	Active	Active	Active	Active	Active	Active	Active	Active	Active
LIND	Active	Active	Active	Active	Active	Active	Active	Active	Active
MEC	Active	Active	Active	Active	Active	Active	Active	Active	Active
MECS	Active	Active	Active	Active	Active	Active	Active	Active	Active
NEPT	Active	Active	Active	Active	Active	Active	Active	Active	Active
NIPS	Active	Active	Active	Active	Active	Active	Active	Active	Active
NYIS	Active	Active	Active	Active	Active	Active	Active	Active	Active
TVA	Active	Active	Active	Active	Active	Active	Active	Active	Active
WEC	Active	Active	Active	Active	Active	Active	Active	Active	Active

Figure 9-3 PJM's footprint and its external scheduling interfaces

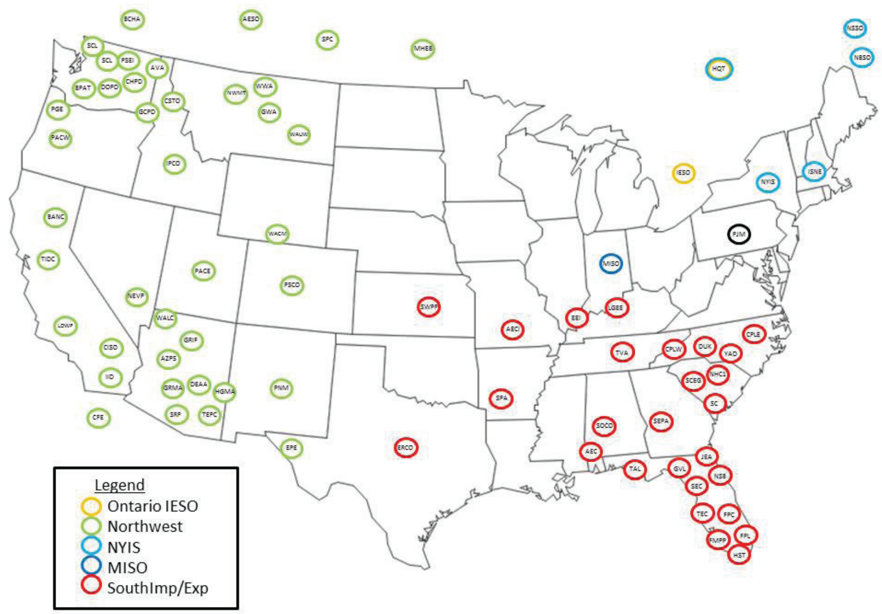


24 On July 2, 2012, Duke Energy Corp. (DUK) completed a merger with Progress Energy Inc. (CPLE and CPLW). As of September 30, 2019, DUK, CPLE and CPLW continued to operate as separate balancing authorities, and are still defined as distinct interfaces in the PJM energy market.

Table 9-19 Active scheduled interface pricing points: January through September, 2019[25]

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
CPLEEXP	Active	Active	Active	Active	Active	Active	Active	Active	Active
CPLEIMP	Active	Active	Active	Active	Active	Active	Active	Active	Active
DUKEXP	Active	Active	Active	Active	Active	Active	Active	Active	Active
DUKIMP	Active	Active	Active	Active	Active	Active	Active	Active	Active
HUDSONTP	Active	Active	Active	Active	Active	Active	Active	Active	Active
LINDENVFT	Active	Active	Active	Active	Active	Active	Active	Active	Active
MISO	Active	Active	Active	Active	Active	Active	Active	Active	Active
NCMPAEXP	Active	Active	Active	Active	Active	Active	Active	Active	Active
NCMPAIMP	Active	Active	Active	Active	Active	Active	Active	Active	Active
NEPTUNE	Active	Active	Active	Active	Active	Active	Active	Active	Active
NIPSCO	Active	Active	Active	Active	Active	Active	Active	Active	Active
Northwest	Active	Active	Active	Active	Active	Active	Active	Active	Active
NYIS	Active	Active	Active	Active	Active	Active	Active	Active	Active
Ontario IESO	Active	Active	Active	Active	Active	Active	Active	Active	Active
Southeast	Active	Active	Active	Active	Active	Active	Active	Active	Active
SOUTHEXP	Active	Active	Active	Active	Active	Active	Active	Active	Active
SOUTHIMP	Active	Active	Active	Active	Active	Active	Active	Active	Active
Southwest	Active	Active	Active	Active	Active	Active	Active	Active	Active

Figure 9-4 External balancing authority default interface pricing point assignments



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

25 The NIPSCO interface pricing point is valid only in the Day-Ahead Energy Market.

result is loop flow, despite the fact that system actual and scheduled power flow net to a zero difference.[26]

Loop flows result, in part, from a mismatch between incentives to use a particular scheduled transmission path and the market-based price differentials at interface pricing points that result from the actual physical flows on the transmission system.

PJM's approach to interface pricing attempts to match prices with physical power flows and their impacts on the transmission system. For example, if market participants want to import energy from the Southwest Power Pool (SPP) to PJM, they are likely to choose a scheduled path with the fewest transmission providers along the path and therefore the lowest transmission costs for the transaction, regardless of whether the resultant path is related to the physical flow of power. The lowest cost transmission path runs from SPP, through MISO, and into PJM, requiring only three transmission reservations, two of which are available at no cost (MISO transmission would be free based on the regional through and out rates, and the PJM transmission would be free, if using spot import transmission). Any other transmission path entering PJM, where the generating control area is to the south, would require the market participant to acquire transmission through 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 the first nine months of 2019, there were net scheduled flows of 957 GWh through MISO that received an interface pricing point associated with the southern interface but there were no net scheduled flows across the southern interface that received the MISO interface pricing point.

In the first nine months of 2019, net scheduled interchange was -25,917 GWh and net actual interchange was -25,870 GWh, a difference of 47 GWh. In the first nine months of 2018, net scheduled interchange was -12,206 GWh and net actual interchange was -12,197 GWh, a difference of 8 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. Inadvertent interchange accumulations that are paid back unilaterally are paid by controlling to a non-zero area control error (ACE). Unilateral paybacks are accounted for in the control performance standard calculations. Bilateral paybacks are scheduled with other balancing authority areas by scheduling a correction and incorporating that amount as a bias in the energy management system.[27]

Table 9-20 shows that in the first nine months of 2019, the Northern Indiana Public Service (NIPS) Interface had the largest loop flows of any interface with -14 GWh of net scheduled interchange and -8,516 GWh of net actual interchange, a difference of 8,502 GWh.

26 See the 2012 State of the Market Report for PJM, Volume 2, Section 8, "Interchange Transactions," for a more detailed discussion.

27 See PJM. "Manual 12: Balancing Operations," Rev. 39 (February 21, 2019).

Table 9-20 Net scheduled and actual PJM flows by interface (GWh): January through September, 2019

	Actual	Net Scheduled	Difference (GWh)
CPLE	257	258	(1)
CPLW	(592)	0	(592)
DUK	1,537	1,006	531
LGEE	2,186	(190)	2,377
MISO	(24,307)	(17,606)	(6,701)
ALTE	(2,250)	(2,581)	331
ALTW	(1,652)	(107)	(1,545)
AMIL	(2,434)	472	(2,906)
CIN	(5,649)	(8,372)	2,723
CWLP	(127)	0	(127)
IPL	(1,412)	(935)	(478)
MEC	(4,850)	(4,069)	(781)
MECS	(1,012)	(1,061)	49
NIPS	(8,516)	(14)	(8,502)
WEC	3,595	(939)	4,533
NYISO	(9,316)	(9,419)	104
HUDS	(968)	(968)	0
LIND	(1,549)	(1,549)	0
NEPT	(3,957)	(3,957)	0
NYIS	(2,841)	(2,944)	104
TVA	4,364	35	4,329
Total	(25,870)	(25,917)	47

Every external balancing authority is mapped to an import and export interface pricing point. The mapping is designed to reflect the physical flow of energy between PJM and each balancing authority. The net scheduled values for interface pricing points are defined as the MWh of scheduled transactions that will receive the interface pricing point based on the external balancing authority mapping.[28] For example, the MWh for a transaction whose transmission path is SPP through MISO and into PJM would be reflected in the SouthIMP interface pricing point net schedule totals because SPP is mapped to the SouthIMP interface pricing point. The actual flow on an interface pricing point is defined as the metered flow across the transmission lines that are included in the interface pricing point.

28 The terms balancing authority and control area are used interchangeably in this section. The NERC Tag applications maintained the terminology of generation control area (GCA) and load control area (LCA) after the implementation of the NERC functional model. The NERC functional model classifies the balancing authority as a reliability service function, with, among other things, the responsibility for balancing generation, demand and interchange balance.

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 9-21 shows the net scheduled and actual PJM flows by interface pricing point. The CPLEEXP, CPLEIMP, DUKEXP, DUKIMP, NCMPAEXP, and NCMPAIMP interface pricing points were created as part of operating agreements with external balancing authorities, and reflect the same physical ties as the SouthIMP and SouthEXP interface pricing points.

Because the SouthIMP and SouthEXP interface pricing points are the same physical point, if there are net actual exports from the PJM footprint to the southern region, by definition, there cannot be net actual imports into the PJM footprint from the southern region and therefore there will not be actual flows at the SouthIMP interface pricing point. In the case of PJM's southern border, loop flows can be analyzed by comparing the net scheduled and net actual flows as a sum of the pricing points, rather than the individual pricing points. To accurately calculate the loop flows from the southern region, the net actual flows from the southern region are compared to the net scheduled flows from the southern region. The net actual flows from the southern region are determined by summing the total southern import actual flows (20,416 GWh) and the total southern export actual flows (-12,664 GWh) for 7,753 GWh of net imports. The net scheduled flows from the southern region are determined by summing the total southern import scheduled flows (5,151 GWh) and the total southern export scheduled flows (-3,086 GWh) for 2,065 GWh of net imports. In the first nine months of 2019, the loop flows at the southern region were the difference between the southern region net scheduled flows

(2,065 GW) and the southern region net actual flows (7,753 GWh) for a total of 5,688 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 9-21 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 9-21 PJM flows by interface pricing point (GWh): January through September, 2019

	Actual	Net Scheduled	Difference (GWh)
IMO	0	443	(443)
MISO	(24,307)	(19,001)	(5,306)
NORTHWEST	0	0	0
NYISO	(9,316)	(9,424)	108
HUDSONTP	(968)	(968)	(0)
LINDENVFT	(1,549)	(1,549)	0
NEPTUNE	(3,957)	(3,957)	0
NYIS	(2,841)	(2,949)	108
Southern Imports	20,416	5,151	15,265
CPLEIMP	0	4	(4)
DUKIMP	0	356	(356)
NCMPAIMP	0	899	(899)
SOUTHEAST	0	0	0
SOUTHWEST	0	0	0
SOUTHIMP	20,416	3,893	16,524
Southern Exports	(12,664)	(3,086)	(9,578)
CPLEEXP	0	(180)	180
DUKEXP	0	(287)	287
NCMPAEXP	0	(0)	0
SOUTHEAST	0	(1)	1
SOUTHWEST	0	0	0
SOUTHEXP	(12,664)	(2,617)	(10,047)
Total	(25,870)	(25,917)	47

Table 9-22 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 9-24 shows that 438 of the 443 GWh (98.9 percent) of gross scheduled transactions that were mapped to the IMO interface pricing point were scheduled as imports through MISO, and 5 of the 443 GWh (1.1 percent) were scheduled as imports through the NYISO.

Table 9-22 shows that in the first nine months of 2019, the SouthIMP interface pricing point had the largest loop flows of any interface pricing point with 3,893 GWh of net scheduled interchange and 20,416 GWh of net actual interchange, a difference of 16,524 GWh.

Table 9-22 PJM flows by interface pricing point (GWh) (Adjusted for IMO Scheduled Interfaces): January through September, 2019

	Actual	Net Scheduled	Difference (GWh)
MISO	(24,307)	(18,563)	(5,744)
NORTHWEST	0	0	0
NYISO	(9,316)	(9,419)	104
HUDSONTP	(968)	(968)	(0)
LINDENVFT	(1,549)	(1,549)	0
NEPTUNE	(3,957)	(3,957)	0
NYIS	(2,841)	(2,944)	104
Southern Imports	20,416	5,151	15,265
CPLEIMP	0	4	(4)
DUKIMP	0	356	(356)
NCMPAIMP	0	899	(899)
SOUTHEAST	0	0	0
SOUTHWEST	0	0	0
SOUTHIMP	20,416	3,893	16,524
Southern Exports	(12,664)	(3,086)	(9,578)
CPLEEXP	0	(180)	180
DUKEXP	0	(287)	287
NCMPAEXP	0	(0)	0
SOUTHEAST	0	(1)	1
SOUTHWEST	0	0	0
SOUTHEXP	(12,664)	(2,617)	(10,047)
Total	(25,870)	(25,917)	47

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 9-23 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 9-23 shows that in the first nine months of 2019, 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 SOUTHIMP Interface, and thus actual flows were assigned the SOUTHIMP interface pricing point (42 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 (-8,388 GWh).

Table 9-23 Net scheduled and actual flows by interface and interface pricing point (GWh): January through September, 2019

Interface	Interface Pricing Point	Actual	Net Scheduled	Difference (GWh)	Interface	Interface Pricing Point	Actual	Net Scheduled	Difference (GWh)
ALTE		(2,250)	(2,581)	331	HUDS		(968)	(968)	0
	IMO	0	89	(89)		HUDSONTP	(968)	(968)	0
	MISO	(2,250)	(2,672)	422	IPL		(1,412)	(935)	(478)
	SOUTHEXP	0	(3)	3		IMO	0	4	(4)
	SOUTHIMP	0	4	(4)		MISO	(1,412)	(935)	(477)
ALTW		(1,652)	(107)	(1,545)		SOUTHEXP	0	(4)	4
	MISO	(1,652)	(103)	(1,549)		SOUTHIMP	0	0	(0)
	SOUTHEXP	0	(5)	5	LGEE		2,186	(190)	2,377
AMIL		(2,434)	472	(2,906)		SOUTHEXP	(5,699)	(771)	(4,928)
	MISO	(2,434)	(251)	(2,182)		SOUTHIMP	7,885	580	7,305
	SOUTHEXP	0	(1)	1	LIND		(1,549)	(1,549)	0
	SOUTHIMP	0	725	(725)		LINDENVFT	(1,549)	(1,549)	0
CIN		(5,649)	(8,372)	2,723	MEC		(4,850)	(4,069)	(781)
	IMO	0	3	(3)		MISO	(4,850)	(4,072)	(778)
	MISO	(5,649)	(8,388)	2,739		SOUTHEXP	0	(1)	1
	SOUTHEXP	0	(29)	29		SOUTHIMP	0	3	(3)
	SOUTHIMP	0	42	(42)	MECS		(1,012)	(1,061)	49
CPLE		257	258	(1)		IMO	0	341	(341)
	CPLEEXP	0	(178)	178		MISO	(1,012)	(1,584)	572
	CPLEIMP	0	4	(4)		SOUTHEXP	0	(10)	10
	DUKEXP	0	(7)	7		SOUTHIMP	0	191	(191)
	DUKIMP	0	39	(39)	NEPT		(3,957)	(3,957)	0
	NCMPAIMP	0	430	(430)		NEPTUNE	(3,957)	(3,957)	0
	SOUTHEXP	(2,736)	(339)	(2,396)	NIPS		(8,516)	(14)	(8,502)
	SOUTHIMP	2,992	310	2,682		MISO	(8,516)	(19)	(8,497)
	SOUTHEAST	0	(1)	1		SOUTHIMP	0	5	(5)
CPLW		(592)	0	(592)	NYIS		(2,841)	(2,944)	104
	SOUTHEXP	(668)	(0)	(668)		IMO	0	5	(5)
	SOUTHIMP	76	0	76		NYIS	(2,841)	(2,949)	108
CWLP		(127)	0	(127)	TVA		4,364	35	4,329
	MISO	(127)	0	(127)		SOUTHEXP	(2,746)	(675)	(2,071)
DUK		1,537	1,006	531		SOUTHIMP	7,110	710	6,401
	CPLEEXP	0	(3)	3	WEC		3,595	(939)	4,533
	DUKEXP	0	(279)	279		MISO	3,595	(977)	4,571
	DUKIMP	0	317	(317)		SOUTHEXP	0	(1)	1
	NCMPAEXP	0	(0)	0		SOUTHIMP	0	39	(39)
	NCMPAIMP	0	468	(468)	Grand Total		(25,870)	(25,917)	47
	SOUTHEXP	(815)	(779)	(36)					
	SOUTHIMP	2,352	1,283	1,070					

Table 9-24 shows the net scheduled and actual PJM flows by interface pricing point and interface. The grouping is reversed from Table 9-23. Table 9-24 shows the interfaces where transactions were scheduled which received the individual interface pricing points. For example, Table 9-24 shows that in the first nine months of 2019, the majority of imports to the PJM energy market for which a market participant specified a generation control area for which it was assigned the IMO interface pricing point, had a path that entered the PJM energy market at the MECS Interface (341 GWh). In the first nine months of 2019, there were no net exports from the PJM energy market for which a market participant specified a load control area for which it was assigned the IMO interface pricing point.

Table 9-24 Net scheduled and actual flows by interface pricing point and interface (GWh): January through September, 2019

Interface Pricing Point	Interface	Actual	Net Scheduled	Difference (GWh)
CPLEEXP		0	(180)	180
	CPLE	0	(178)	178
	DUK	0	(3)	3
CPLEIMP		0	4	(4)
	CPLE	0	4	(4)
DUKEXP		0	(287)	287
	CPLE	0	(7)	7
	DUK	0	(279)	279
DUKIMP		0	356	(356)
	CPLE	0	39	(39)
	DUK	0	317	(317)
HUDSONTP		(968)	(968)	0
	HUDS	(968)	(968)	0
IMO		0	443	(443)
	ALTE	0	89	(89)
	CIN	0	3	(3)
	IPL	0	4	(4)
	MECS	0	341	(341)
	NYIS	0	5	(5)
LINDENVFT		(1,549)	(1,549)	0
	LIND	(1,549)	(1,549)	0
MISO		(24,307)	(19,001)	(5,306)
	ALTE	(2,250)	(2,672)	422
	ALTW	(1,652)	(103)	(1,549)
	AMIL	(2,434)	(251)	(2,182)
	CIN	(5,649)	(8,388)	2,739
	CWLP	(127)	0	(127)
	IPL	(1,412)	(935)	(477)
	MEC	(4,850)	(4,072)	(778)
	MECS	(1,012)	(1,584)	572
	NIPS	(8,516)	(19)	(8,497)
	WEC	3,595	(977)	4,571
NCMPAEXP		0	(0)	0
	DUK	0	(0)	0
NCMPAIMP		0	899	(899)
	CPLE	0	430	(430)
	DUK	0	468	(468)
NEPTUNE		(3,957)	(3,957)	0
	NEPT	(3,957)	(3,957)	0
NYIS		(2,841)	(2,949)	108
	NYIS	(2,841)	(2,949)	108
SOUTHEAST		0	(1)	1
	CPLE	0	(1)	1
SOUTHEXP		(12,664)	(2,617)	(10,047)
	ALTE	0	(3)	3
	ALTW	0	(5)	5
	AMIL	0	(1)	1
	CIN	0	(29)	29
	CPLE	(2,736)	(339)	(2,396)
	CPLW	(668)	(0)	(668)
	DUK	(815)	(779)	(36)
	IPL	0	(4)	4
	LGEE	(5,699)	(771)	(4,928)
	MEC	0	(1)	1
	MECS	0	(10)	10
	TVA	(2,746)	(675)	(2,071)
	WEC	0	(1)	1
SOUTHIMP		20,416	3,893	16,524
	ALTE	0	4	(4)
	AMIL	0	725	(725)
	CIN	0	42	(42)
	CPLE	2,992	310	2,682
	CPLW	76	0	76
	DUK	2,352	1,283	1,070
	IPL	0	0	(0)
	LGEE	7,885	580	7,305
	MEC	0	3	(3)
	MECS	0	191	(191)
	NIPS	0	5	(5)
	TVA	7,110	710	6,401
	WEC	0	39	(39)
Grand Total		(25,870)	(25,917)	47

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 required access to NERC Tag data. In addition to the Tag data, actual tie line data, dynamic schedule and pseudo-tie data are required in order to analyze the differences between actual and scheduled transactions. ACE data, market flow impact data and generation and load data are required in order to understand the sources, within each balancing authority, of loop flows that do not result from differences between actual and scheduled transactions.[29]

NERC Tag Data

An analysis of loop flow requires knowledge of the scheduled path of energy transactions. NERC Tag data include 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. Complete tag data include the identity of the specific market participants. FERC Order No. 771 required access to NERC Tag data for the Commission, regional transmission organizations, independent system operators and market monitoring units.[30]

Actual Tie Line Flow Data

An analysis of loop flow requires knowledge of the actual path of energy transactions. Currently, a very limited set of tie line data is made available via the NERC IDC and the Central Repository for Curtailments (CRC) website. 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 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.

29 It is requested that all data be made available in downloadable format in order to make analysis possible. A data viewing tool alone is not adequate.
30 141 FERC ¶ 61,235 (2012).

NERC makes real-time ACE graphs available on their Reliability Coordinator Information System (RCIS) website. This information is presented only in graphical form, and the underlying data is not available for analysis.

Market Flow Impact Data

In addition to interchange transactions, internal dispatch can also affect flows on balancing authorities' tie lines. The impact of internal dispatch on tie lines is called market flow. Market flow data are imported in the IDC, but there is only limited historical data, as only market flow data related to TLR levels 3 or higher are required to be made available via a Congestion Management Report (CMR). The remaining data are deleted.

There is currently a project in development through the NERC Operating Reliability Subcommittee (ORS) called the Market Flow Impact Tool. The purpose of this tool is to make visible the impacts of dispatch on loop flows. The MMU supports the development of this tool, but, equally important, 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

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 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 interface definitions led to questions about the level of congestion included in interchange pricing.[31]

PJM modified the definition of the PJM/MISO interface price effective June 1, 2014. PJM's new MISO interface pricing point includes 10 equally weighted buses that are close to the PJM/MISO border. The 10 buses were selected based on PJM's analysis that showed that over 80 percent of the hourly tie

31 See "LMP Aggregate Definitions" (September 25, 2019) <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>.

line flows between PJM and MISO occurred on 10 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.

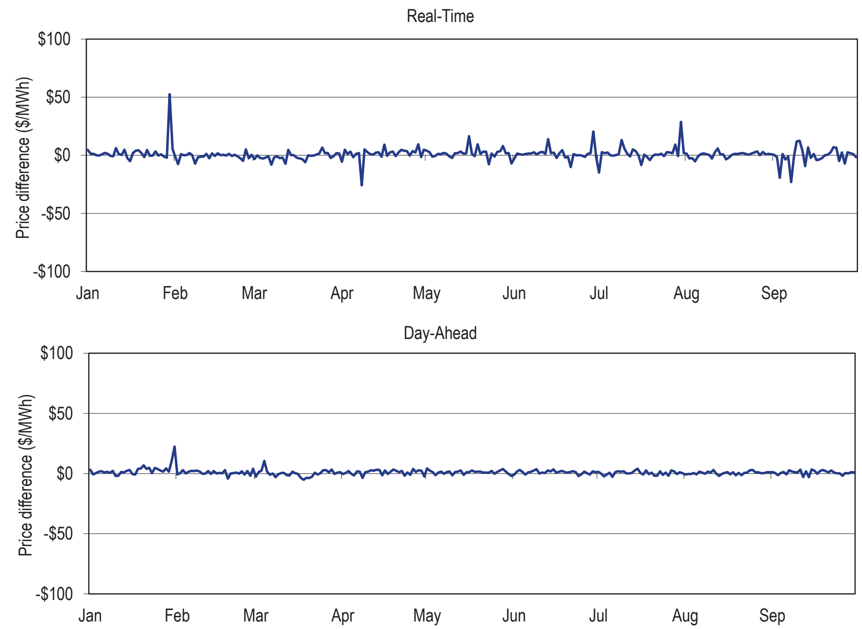
Real-Time and Day-Ahead PJM/MISO Interface Prices

In the first nine months of 2019, the direction of flow was consistent with price differentials in 61.5 percent of the hours. Table 9-25 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 9-5 shows the underlying variability in prices calculated on a daily hourly average basis. 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 9-29).

Table 9-25 PJM and MISO flow based hours and price differences: January through September, 2019

LMP Difference	Flow Direction	Number of Hours	Average Hourly Price Difference
MISO/PJM LMP > PJM/MISO LMP	Total Hours	4,033	$5.28
	Consistent Flow (PJM to MISO)	4,031	$5.27
	Inconsistent Flow (MISO to PJM)	2	$7.38
	No Flow	0	$0.00
PJM/MISO LMP > MISO/PJM LMP	Total Hours	2,518	$6.39
	Consistent Flow (MISO to PJM)	1	$18.83
	Inconsistent Flow (PJM to MISO)	2,517	$6.39
	No Flow	0	$0.00

Figure 9-5 Price differences (MISO/PJM Interface minus PJM/MISO Interface): January through September, 2019



Distribution and Prices of Hourly Flows at the PJM/MISO Interface

In the first nine months of 2019, the direction of hourly energy flows was consistent with PJM and MISO interface price differentials in 4,032 hours (61.5 percent of all hours), and was inconsistent with price differentials in 2,519 hours (38.5 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. Of the 2,519 hours where flows were in a direction inconsistent with price differences, 1,842 of those hours (73.1 percent) had a price difference greater than or equal to $1.00 and 619 of those hours (24.6 percent) had a price difference greater than or equal to $5.00. The largest price difference with such flows was $589.40. Of the 4,032 hours where flows were consistent with price differences, 3,154 of those hours

(78.2 percent) had a price difference greater than or equal to $1.00 and 776 of all such hours (19.2 percent) had a price difference greater than or equal to $5.00. The largest price difference with such flows was $575.74.

Table 9-26 Distribution of hourly flows that are consistent and inconsistent with price differences between PJM and MISO: January through September, 2019

Price Difference Range (Greater Than or Equal To)	Inconsistent Hours	Percent of Inconsistent Hours	Consistent Hours	Percent of Consistent Hours
$0.00	2,519	100.0%	4,032	100.0%
$1.00	1,842	73.1%	3,154	78.2%
$5.00	619	24.6%	776	19.2%
$10.00	335	13.3%	378	9.4%
$15.00	200	7.9%	226	5.6%
$20.00	138	5.5%	156	3.9%
$25.00	91	3.6%	113	2.8%
$50.00	40	1.6%	46	1.1%
$75.00	25	1.0%	25	0.6%
$100.00	17	0.7%	18	0.4%
$200.00	6	0.2%	6	0.1%
$300.00	2	0.1%	4	0.1%
$400.00	2	0.1%	3	0.1%
$500.00	2	0.1%	2	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.[32]

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 the first nine months of 2019, 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 57.9 percent of the hours in the first nine months of 2019. 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 9-6 shows the underlying variability in prices calculated

32 See the 2012 State of the Market Report for PJM, Volume2, Section 8, "Interchange Transactions," for a more detailed discussion.

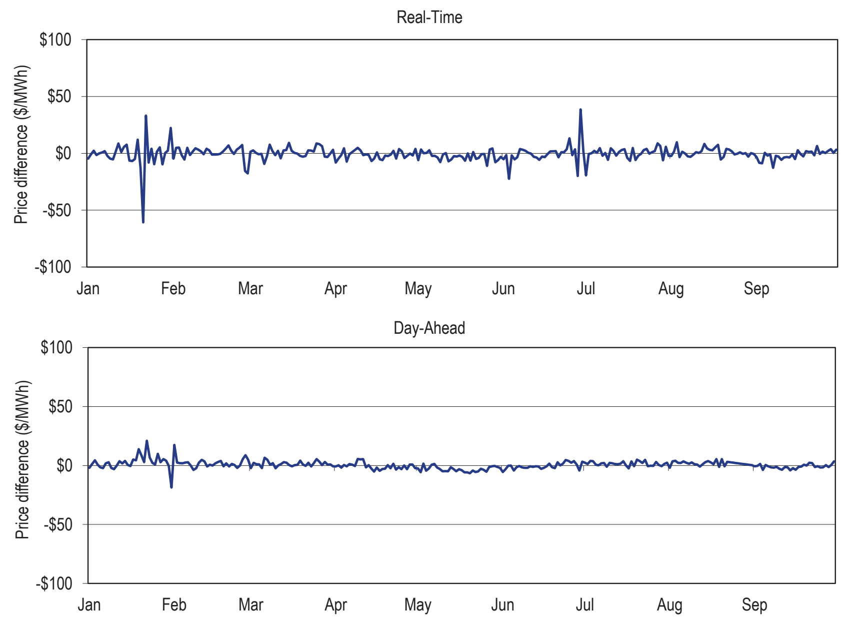
on a daily hourly average basis. There are a number of relevant measures of variability, including the number of times the price differential fluctuates between positive and negative, the standard deviation of individual prices and of price differences and the absolute value of the price differences (Table 9-29).

Table 9-27 PJM and NYISO flow based hours and price differences: January through September, 2019[33]

LMP Difference	Flow Direction	Number of Hours	Average Hourly Price Difference
NYIS/PJM proxy bus LBMP > PJM/NYIS LMP	Total Hours	3,361	$7.48
	Consistent Flow (PJM to NYIS)	2,774	$7.59
	Inconsistent Flow (NYIS to PJM)	587	$6.92
	No Flow	0	$0.00
PJM/NYIS LMP > NYIS/PJM proxy bus LBMP	Total Hours	3,190	$8.75
	Consistent Flow (NYIS to PJM)	1,020	$6.85
	Inconsistent Flow (PJM to NYIS)	2,170	$9.64
	No Flow	0	$0.00

33 The NYISO Locational Based Marginal Price (LBMP) is the equivalent term to PJM's Locational Marginal Price (LMP).

Figure 9-6 Price differences (NY/PJM proxy - PJM/NYIS Interface): January through September, 2019



Distribution and Prices of Hourly Flows at the PJM/NYISO Interface

In the first nine months of 2019, the direction of hourly energy flows was consistent with PJM/NYISO and NYISO/PJM price differences in 3,794 hours (57.9 percent of all hours), and was inconsistent with price differences in 2,757 hours (42.1 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 2,757 hours where flows were in a direction inconsistent with price differences, 2,339 of those hours (84.8 percent) had a price difference greater than or equal to $1.00 and 1,117 of all those hours (40.5 percent) had a price difference greater than or equal to $5.00. The largest price difference with such flows was $461.20. Of the 3,794 hours where flows were consistent with price differences, 3,304 of those hours (87.1 percent) had a price difference greater than or equal to $1.00 and 1,551 of all such hours (40.9 percent) had a price difference greater than or equal to $5.00. The largest price difference with such flows was $332.39.

Table 9-28 Distribution of hourly flows that are consistent and inconsistent with price differences between PJM and NYISO: January through September, 2019

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%	3,794	100.0%
$1.00	2,339	84.8%	3,304	87.1%
$5.00	1,117	40.5%	1,551	40.9%
$10.00	564	20.5%	665	17.5%
$15.00	341	12.4%	352	9.3%
$20.00	242	8.8%	218	5.7%
$25.00	189	6.9%	159	4.2%
$50.00	81	2.9%	54	1.4%
$75.00	46	1.7%	28	0.7%
$100.00	23	0.8%	16	0.4%
$200.00	5	0.2%	7	0.2%
$300.00	3	0.1%	2	0.1%
$400.00	2	0.1%	0	0.0%
$500.00	0	0.0%	0	0.0%

Summary of Interface Prices between PJM and Organized Markets

Some measures of the real-time and day-ahead PJM interface pricing with MISO and with the NYISO are summarized and compared in Table 9-29, including average prices and measures of variability.

Table 9-29 PJM, NYISO and MISO border price averages: January through September, 2019[34]

		Real-Time		Day-Ahead	
	Description	NYISO	MISO	NYISO	MISO
Average Interval Price	PJM Price at ISO Border	$24.99	$24.69	$25.24	$25.00
	ISO Price at PJM Border	$24.56	$25.48	$25.71	$26.00
	Difference at Border (PJM-ISO)	$0.43	($0.79)	($0.47)	($1.00)
	Average Absolute Value of Interval Difference at Border	$38.58	$43.06	$3.38	$2.53
	Sign Changes per Day	43.9	44.4	2.9	3.6
Standard Deviation	PJM Price at ISO Border	$32.85	$34.29	$11.22	$7.86
	ISO Price at PJM Border	$26.67	$28.99	$12.03	$8.21
	Difference at Border (PJM-ISO)	$39.90	$43.62	$4.64	$3.30

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 73.1 percent of the hours in the first nine months of 2019. Table 9-30 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 9-30 PJM and NYISO flow based hours and price differences (Neptune): January through September, 2019

LMP Difference	Flow Direction	Number of Hours	Average Hourly Price Difference
NYIS/Neptune Bus LBMP > PJM/NEPT LMP	Total Hours	4,792	$11.97
	Consistent Flow (PJM to NYIS)	4,787	$11.97
	Inconsistent Flow (NYIS to PJM)	0	$0.00
	No Flow	5	$11.20
PJM/NEPT LMP > NYIS/Neptune Bus LBMP	Total Hours	1,759	$8.48
	Consistent Flow (NYIS to PJM)	0	$0.00
	Inconsistent Flow (PJM to NYIS)	1,759	$8.48
	No Flow	0	$0.00

34 Effective April 1, 2018, PJM implemented 5 minute LMP settlements in the Real-Time Energy Market. The sign changes per day represented in this table reflect the number of intervals where the sign changed per day. For the Real-Time Energy Market, there are 288 five minute intervals. For the Day Ahead Market there are 24 hourly intervals.

To move power from PJM to NYISO using the Neptune Line, two PJM transmission service reservations are required. A transmission service reservation is required from the PJM Transmission System to the Neptune HVDC Line ("Out Service") and another transmission service reservation is required on the Neptune HVDC Line ("Neptune Service").[35] The PJM Out Service is covered by normal PJM OASIS business operations.[36] The Neptune Service falls under the provisions for controllable merchant facilities, Schedule 14 of the PJM Tariff. The Neptune Service is also acquired on the PJM OASIS.

Neptune Service is owned by a primary rights holder, and any 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 September 30, 2019, the rate for the nonfirm service released by default was $10.00 per MWh. The primary rights holder remains obligated to pay for the released service unless a second transmission customer acquires the released service.

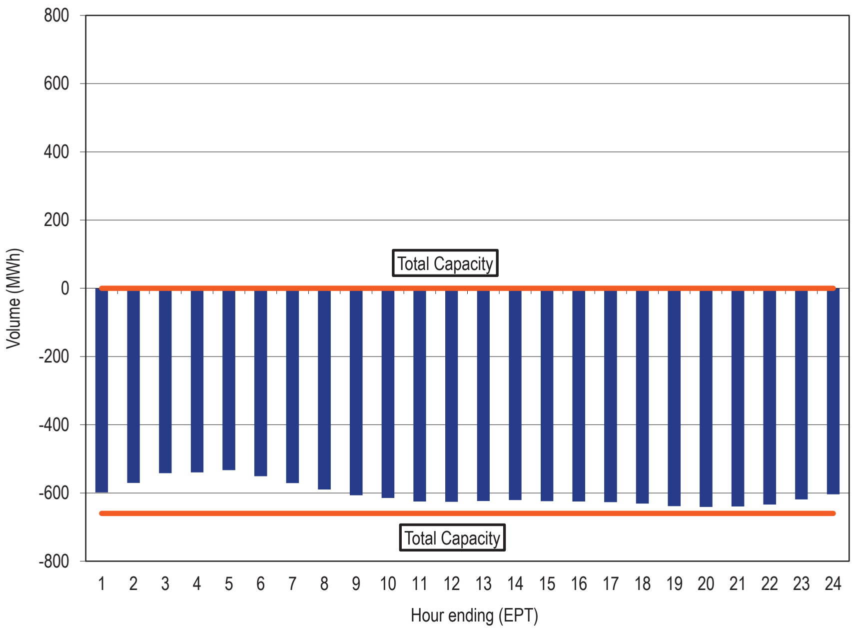
Table 9-31 shows the percent of scheduled interchange across the Neptune Line by the primary rights holder since commercial operations began in July, 2007. Table 9-31 shows that in the first nine months of 2019, the primary rights holder was responsible for 100 percent of the scheduled interchange across the Neptune Line in all months. Figure 9-7 shows the hourly average flow across the Neptune Line for the first nine months of 2019.

Table 9-31 Percent of scheduled interchange across the Neptune Line by primary rights holder: July 2007 through September 2019

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
January	NA	100.00%	100.00%	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%	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%	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%	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%	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%	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%	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%	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%	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%	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%	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%	100.00%	

35 See OASIS "PJM Business Practices for Neptune Transmission Service," <http://www.pjm.com/~/media/etools/oasis/merch-trans-facilities/neptune-oasis-Business-practices-doc-clean.ashx>.
36 See OASIS "Regional Transmission and Energy Scheduling Practices," Rev. 8 (June 23, 2019) <http://www.pjm.com/~/media/etools/oasis/regional-practices-clean-pdf.ashx>.

Figure 9-7 Neptune hourly average flow: January through September, 2019



Linden Variable Frequency Transformer (VFT) facility

The Linden VFT facility is a controllable AC merchant transmission facility, with a capacity of 315 MW, providing a direct connection between PJM (Linden, New Jersey) and NYISO (Staten Island, New York). The flows were consistent with price differentials in 68.3 percent of the hours in the first nine months of 2019. Table 9-32 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 9-32 PJM and NYISO flow based hours and price differences (Linden): January through September, 2019

LMP Difference	Flow Direction	Number of Hours	Average Hourly Price Difference
NYIS/Linden Bus LBMP > PJM/LIND LMP	Total Hours	4,560	$8.20
	Consistent Flow (PJM to NYIS)	4,473	$8.11
	Inconsistent Flow (NYIS to PJM)	0	$0.00
	No Flow	87	$12.68
PJM/LIND LMP > NYIS/Linden Bus LBMP	Total Hours	1,991	$13.15
	Consistent Flow (NYIS to PJM)	0	$0.00
	Inconsistent Flow (PJM to NYIS)	1,963	$13.07
	No Flow	28	$18.91

To move power from PJM to NYISO on the Linden VFT Line, two PJM transmission service reservations are required. A transmission service reservation is required from the PJM Transmission System to the Linden VFT ("Out Service") and another transmission service reservation is required on the Linden VFT ("Linden VFT Service").[37] The PJM Out Service is covered by normal PJM OASIS business operations.[38] The Linden VFT Service falls under the provisions for controllable merchant facilities, Schedule 16 and Schedule 16-A of the PJM Tariff. The Linden VFT Service is also acquired on the PJM OASIS.

Linden VFT Service is owned by a primary rights holder, and any nonfirm service that is not used (as defined by a schedule on a NERC Tag) may be released either voluntarily by the primary rights holder or by default by PJM. The primary rights holder may elect to voluntarily release monthly, weekly, daily or hourly firm or nonfirm service. Voluntarily releasing the service allows for the primary rights holder to specify a rate to be charged for the released service. If the primary rights holder elects to not voluntarily release nonfirm service, and does not use the service, the available transmission will be released by default at 12:00, one business day before the start of service. On September 30, 2019, 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.

37 See OASIS "PJM Business Practices for Linden VFT Transmission Service," <http://www.pjm.com/~/media/etools/oasis/merch-trans-facilities/linden-vft-oasis-Business-practices-doc-clean.ashx>.

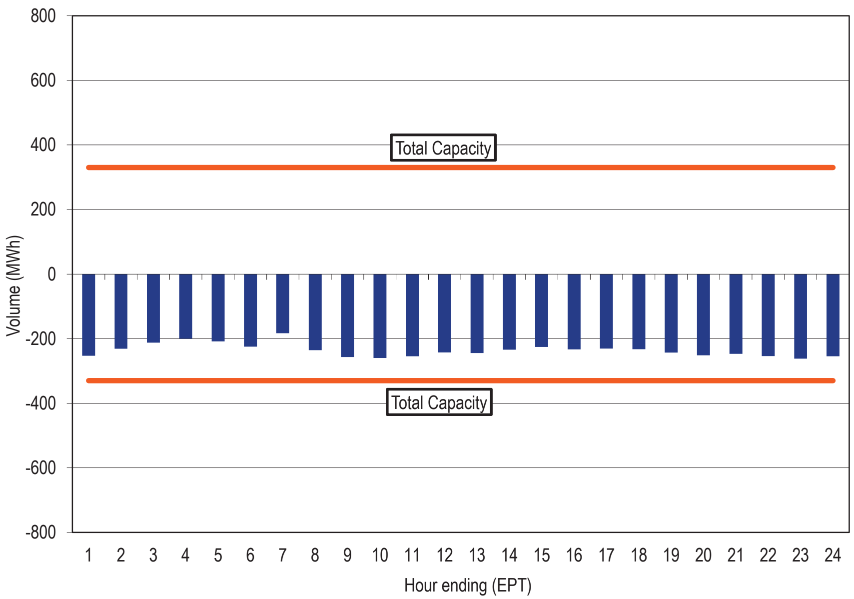
38 See OASIS "Regional Transmission and Energy Scheduling Practices," Rev. 8 (June 23, 2019) <http://www.pjm.com/~/media/etools/oasis/regional-practices-clean-doc.ashx>.

Table 9-33 shows the percent of scheduled interchange across the Linden VFT Line by the primary rights holder since commercial operations began in November, 2009. Table 9-33 shows that in the first nine months of 2019, the primary rights holder was responsible for 100 percent of the scheduled interchange across the Linden VFT Line in all months. Figure 9-8 shows the hourly average flow across the Linden VFT Line for the first nine months of 2019.

Table 9-33 Percent of scheduled interchange across the Linden VFT Line by primary rights holder: November 2009 through September 2019

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
January	NA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	70.53%	100.00%	100.00%	100.00%
February	NA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	94.95%	100.00%	100.00%	100.00%
March	NA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	96.46%	100.00%	100.00%	100.00%
April	NA	99.97%	100.00%	100.00%	100.00%	99.98%	100.00%	49.32%	100.00%	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%	27.27%	100.00%	100.00%	100.00%	100.00%	100.00%
July	NA	100.00%	100.00%	100.00%	100.00%	29.56%	100.00%	100.00%	100.00%	100.00%	100.00%
August	NA	100.00%	100.00%	100.00%	100.00%	82.46%	100.00%	100.00%	100.00%	100.00%	100.00%
September	NA	100.00%	100.00%	100.00%	100.00%	81.68%	100.00%	100.00%	100.00%	100.00%	100.00%
October	NA	100.00%	100.00%	100.00%	100.00%	100.00%	35.05%	100.00%	100.00%	100.00%	
November	100.00%	100.00%	100.00%	100.00%	99.86%	100.00%	61.45%	100.00%	100.00%	100.00%	
December	100.00%	100.00%	100.00%	98.22%	100.00%	100.00%	84.57%	100.00%	100.00%	100.00%	

Figure 9-8 Linden hourly average flow: January through September, 2019[39]



39 The Linden VFT Line is a bidirectional facility. The "Total Capacity" lines represent the maximum amount of interchange possible in either direction. These lines were included to maintain a consistent scale, for comparison purposes, with the Neptune DC Tie Line.

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 had 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 66.3 percent of the hours in the first nine months of 2019. Table 9-34 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 9-34 PJM and NYISO flow based hours and price differences (Hudson): January through September, 2019

LMP Difference	Flow Direction	Number of Hours	Average Hourly Price Difference
NYIS/Hudson Bus LBMP > PJM/HUDS LMP	Total Hours	4,462	$8.29
	Consistent Flow (PJM to NYIS)	4,345	$8.34
	Inconsistent Flow (NYIS to PJM)	0	$0.00
	No Flow	117	$6.56
PJM/HUDS LMP > NYIS/Hudson Bus LBMP	Total Hours	2,089	$9.64
	Consistent Flow (NYIS to PJM)	0	$0.00
	Inconsistent Flow (PJM to NYIS)	2,035	$9.80
	No Flow	54	$3.88

To move power from PJM to NYISO on the Hudson Line, two PJM transmission service reservations are required. A transmission service reservation is required from the PJM Transmission System to the Hudson Line ("Out Service") and another transmission service reservation is required on the Hudson Line ("Hudson Service").[40] The PJM Out Service is covered by normal PJM OASIS business operations.[41] The Hudson Service falls under the provisions for controllable merchant facilities, Schedule 17 of the PJM Tariff. The Hudson Service is also acquired on the PJM OASIS.

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 September 30, 2019, the rate for the nonfirm service released by default was $10.00 per MWh. The primary rights holder remains obligated to pay for the released service unless a second transmission customer acquires the released service.

Table 9-35 shows the percent of scheduled interchange across the Hudson Line by the primary rights holder since commercial operations began in May, 2013. Table 9-35 shows that in the first nine months of 2019, the primary rights holder was responsible for 100 percent of the scheduled interchange across the Hudson Line in April and May, and the primary rights holder was responsible for less than 100 percent of the scheduled interchange in the remaining months. Figure 9-9 shows the hourly average flow across the Hudson Line for the first nine months of 2019.

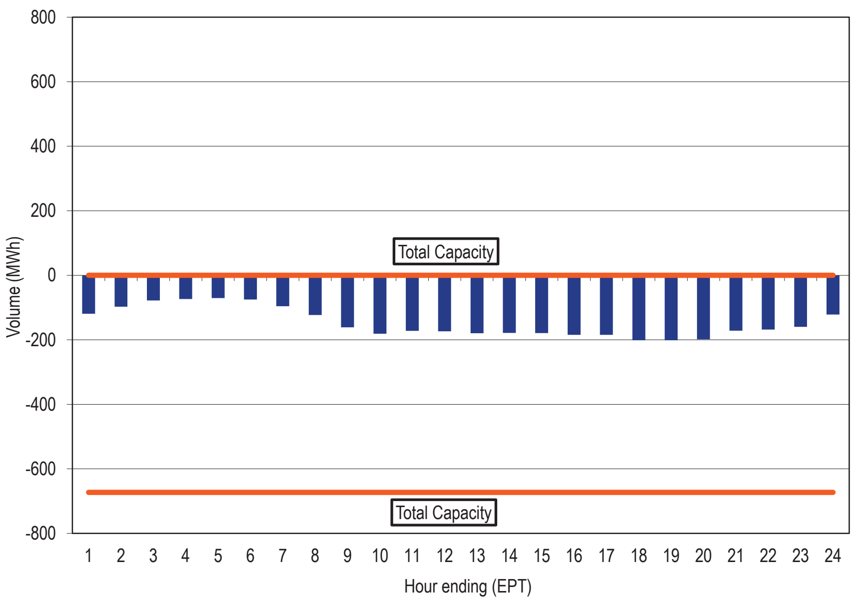
40 See OASIS "PJM Business Practices for Hudson Transmission Service,"<http://www.pjm.com/~/media/etools/oasis/merch-trans-facilities/htp-Business-practices.ashx>.

41 See OASIS "Regional Transmission and Energy Scheduling Practices," Rev. 8 (June 23, 2019) <http://www.pjm.com/~/media/etools/oasis/regional-practices-clean-doc.ashx>.

Table 9-35 Percent of scheduled interchange across the Hudson Line by primary rights holder: May 2013 through September 2019

	2013	2014	2015	2016	2017	2018	2019
January	NA	51.22%	16.27%	100.00%	NA	24.44%	52.21%
February	NA	49.00%	14.67%	NA	NA	23.25%	77.12%
March	NA	40.40%	71.88%	NA	NA	9.55%	72.40%
April	NA	100.00%	100.00%	NA	NA	15.13%	100.00%
May	100.00%	26.87%	100.00%	100.00%	NA	92.18%	100.00%
June	100.00%	5.89%	59.72%	100.00%	NA	44.89%	34.29%
July	100.00%	18.51%	84.34%	NA	NA	16.26%	0.00%
August	100.00%	75.17%	65.48%	NA	NA	19.24%	0.00%
September	100.00%	75.31%	78.73%	NA	NA	22.90%	0.00%
October	100.00%	99.71%	18.65%	100.00%	NA	22.67%	
November	85.57%	99.60%	24.67%	100.00%	80.12%	50.44%	
December	28.32%	1.68%	100.00%	NA	21.93%	29.38%	

Figure 9-9 Hudson hourly average flow: January through September, 2019



Interchange Activity During High Load Hours

The PJM metered system peak load during the first nine months of 2019 was 148,228 MW in the HE 1800 on July 19, 2019. PJM was under a hot weather alert in that hour. PJM did not make any emergency energy purchases or sales in that hour. PJM was a net scheduled exporter of energy in all hours on July 19, 2019, with average hourly scheduled exports of 3,880 MW. During HE 1800 on July 19, 2019, PJM had net scheduled exports of 2,967 MW and net metered actual exports of 3,005 MW. Net transaction exports during this time were inconsistent with the price differences between PJM and MISO. Net transaction exports were also inconsistent with price differences between PJM and the NYISO interfaces (NYIS, Neptune, Linden and Hudson). During the month of July 2019, PJM was a net scheduled exporter of energy in all 744 hours. During July 2019, the average hourly scheduled interchange was -4,437 MW (representing 4.2 percent of the average hourly load of 105,197 MW in January 2019).

Operating Agreements with Bordering Areas

To improve reliability and reduce potential seams issues, PJM and its neighbors have developed operating agreements, including: 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 9-36 shows a summary of the elements included in each of the operating agreements PJM has with its bordering areas.

Table 9-36 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[42]

The Joint Operating Agreement between MISO and PJM Interconnection, L.L.C. was executed on December 31, 2003. The PJM/MISO JOA includes provisions for market based congestion management that, for designated flowgates within MISO and PJM, allow for redispatch of units within the PJM and MISO regions to jointly manage congestion on these flowgates and to assign the costs of congestion management appropriately. In 2012, MISO and PJM initiated a joint stakeholder process to address issues associated with the operation of the markets at the seam.[43]

Under the market to market rules, the organizations coordinate pricing at their borders. PJM and MISO each calculate an interface LMP using network models including distribution factor impacts. PJM uses 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.[44] On June 1, 2017, MISO modified their MISO/PJM interface definition to match PJM's PJM/MISO interface definition.[45]

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.[46] Coordinated flowgates are identified to determine which flowgates an operating entity affects 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 affected by the flows of the operating 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

42 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C." (December 11, 2008) <http://www.pjm.com/directory/merged-tariffs/miso-joa.pdf>.

43 See "PJM/MISO Joint and Common Market Initiative," <http://www.pjm.com/committees-and-groups/stakeholder-meetings/pjm-miso-joint-common.aspx>.

44 See the 2012 State of the Market Report for PJM, Volume II, Section 8, "Interchange Transactions," for a more detailed discussion.

45 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>.

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/directory/merged-tariffs/miso-joa.pdf>.

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.[47] 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.

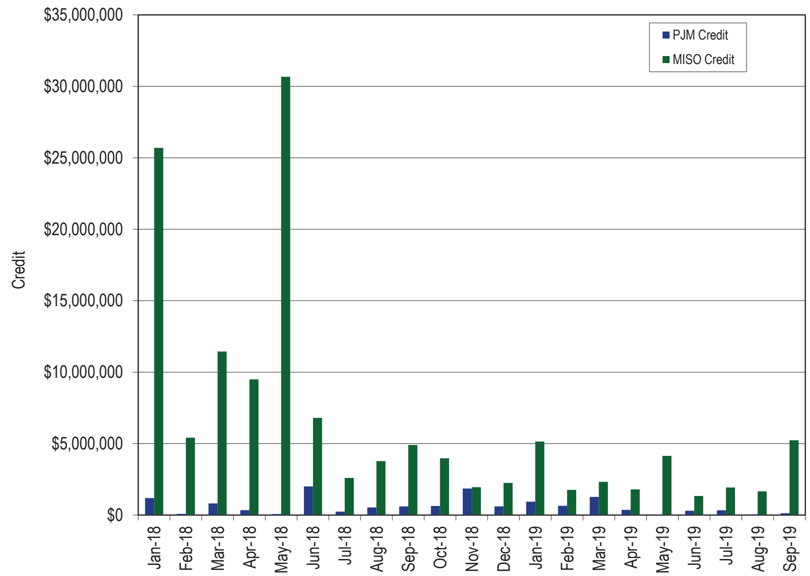
As of January 1, 2019, PJM had 137 flowgates eligible for M2M (Market to Market) coordination. In the first nine months of 2019, PJM added 18 flowgates and deleted 16 flowgates, leaving 139 flowgates eligible for M2M coordination as of September 30, 2019. As of January 1, 2019, MISO had 239 flowgates eligible for M2M coordination. In the first nine months of 2019, MISO added 59 flowgates and deleted 113 flowgates, leaving 185 flowgates eligible for M2M coordination as of September 30, 2019.

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 nonmonitoring RTO's real-time market flow is less than their FFE plus the approved MW adjustment from day-ahead coordination, then the monitoring RTO will pay the nonmonitoring RTO for congestion relief provided by the nonmonitoring RTO based on the difference between the nonmonitoring RTO's market flow and their FFE.

April 1, 2004, known as the Freeze Date, is used to determine the firm rights on flowgates based on historic premarket firm flows as of that date. In the past 15 years, topology and market changes have occurred, making the 2004 flows irrelevant in 2019. The RTOs and stakeholders recognize that a modification to the Freeze Date is necessary. The RTOs have stated that the issues with the Freeze Date have become prominent.[48] PJM and MISO stakeholders have spent several years on the Freeze Date issues. Discussions regarding the Firm Flow Limit (FFL) solutions between market and nonmarket areas are also ongoing. No resolution to these issues appears imminent. The MMU recommends that the Commission require that the open FFE/FFL freeze date issues be addressed at a Commission technical conference, and that the Commission set a deadline to resolve the significant issues that result from the freeze date.

In the first nine months of 2019, market to market operations resulted in MISO and PJM redispatching units to control congestion on M2M flowgates and the exchange of payments for this redispatch. Figure 9-10 shows credits for coordinated congestion management between PJM and MISO.

Figure 9-10 PJM/MISO credits for coordinated congestion management: January 2018 through September 2019[49]



47 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/directory/merged-tariffs/miso-joa.pdf>.

48 See "Freeze Date Alternatives." (May 21, 2019) <https://www.pjm.com/-/media/committees-groups/stakeholder-meetings/pjm-miso-joint-common/20190521/20190521-item-01-freeze-date-update.ashx>.

49 The totals represented in this figure represent the settlements as of the time of this report and may not include adjustments or resettlements.

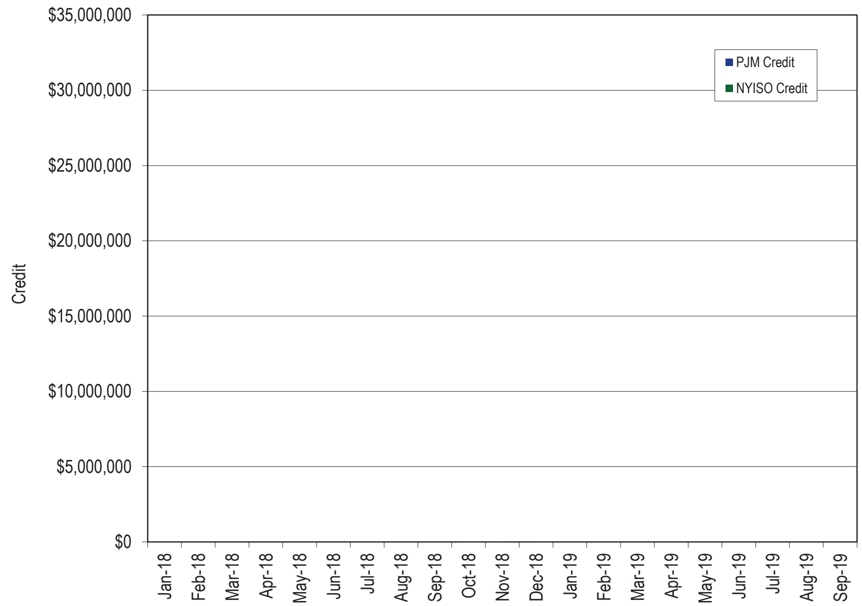
PJM and New York Independent System Operator Joint Operating Agreement (JOA)[50]

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.

On June 28, 2019, NYISO and PJM submitted revisions to the NYISO-PJM Joint Operating Agreement (JOA). The revisions would address RTO concerns identified in their joint request for limited waiver of the JOA to authorize redispatch of generation in PJM. The intent of the redispatch would be to mitigate post-contingency overloads of transmission equipment on the New York side of the East Towanda-Hillside 230 kV transmission line. The agreement allows for the RTOs to control for this contingency without the exchange of payments for redispatch.[51]

In the first nine months of 2019, market to market operations did not result in NYISO and PJM redispatching units to control congestion on M2M flowgates. Therefore, there was no exchange of payments for redispatch in the first nine months of 2019. Figure 9-11 shows credits for coordinated congestion management between PJM and NYISO.

Figure 9-11 PJM/NYISO credits for coordinated congestion management (flowgates): January 2018 through September 2019[52]

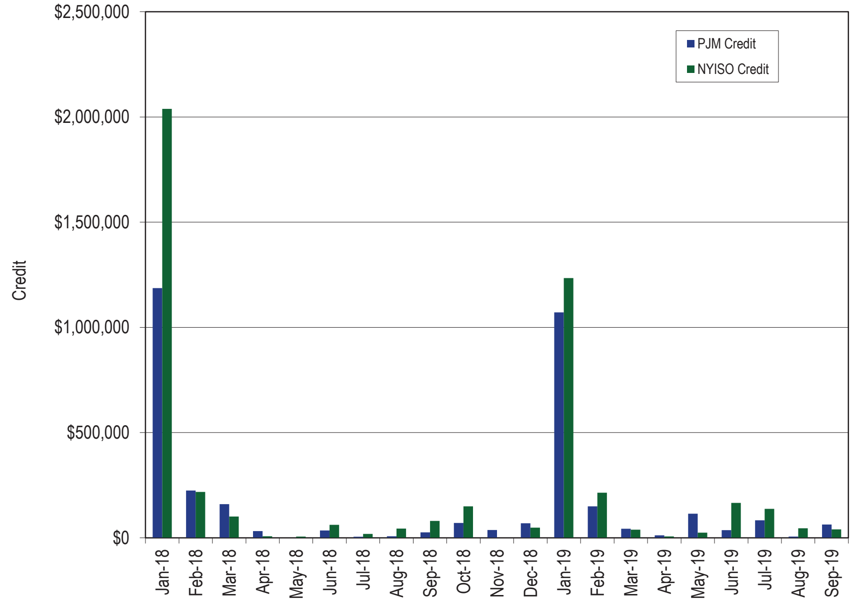


The M2M coordination process focuses on real-time market coordination to manage transmission limitations that occur on M2M flowgates in a cost effective manner. Coordination between NYISO and PJM includes not only joint redispatch, but also incorporates coordinated operation of the PARs that are located 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.[53] 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

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 FERC Docket No. ER19-2282-000
52 The totals represented in this figure represent the settlements as of the time of this report and may not include adjustments or resettlements.
53 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>.

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 the first nine months of 2019, market to market operations resulted in NYISO and PJM adjusting PARs to control congestion and the exchange of payments for this coordination. Figure 9-12 shows the PAR credits for coordinated congestion management between PJM and NYISO. The large increase in PAR credits in January 2018 and January 2019 was due to system operations coordination during the extreme temperatures in the first week of January 2018 and in January 2019.

Figure 9-12 PJM/NYISO credits for coordinated congestion management (PARs): January 2018 through September 2019[54]



PJM and TVA Joint Reliability Coordination Agreement (JRCA)[55]

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. 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

54 The totals represented in this figure represent the settlements as of the time of this report and may not include adjustments or resettlements.

55 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>.

constraint. Unlike the M2M procedure between MISO and PJM, this redispatch does not result in M2M payments. However, electing to redispatch generation within PJM can avoid potential market disruption by curtailing transactions under the Transmission Line Loading Relief (TLR) procedure to achieve the same relief. The agreement remained in effect in the first nine months of 2019.

PJM and Duke Energy Progress, Inc. Joint Operating Agreement[56]

On September 9, 2005, 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 include a CMP under Article 14 of the JOA.[57] 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).

On May 20, 2019, PJM and DEP submitted revisions to the JOA to delete Article 14.[58] These revisions eliminate the congestion management agreement and also modify the interface price calculation from the marginal cost proxy method to the high low interface pricing method. PJM and DEP requested an effective date of July 22, 2019, for the filed revisions. On July 2, 2019, the Commission accepted for filing the revisions to the JOA to delete the congestion management agreement effective July 22, 2019.[59]

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 the first nine months of 2019.

Balancing Authority Operations Coordination Agreement between Wisconsin Electric Power Company (WEC) and PJM Interconnection, LLC[61]

The Balancing Authority Operations Coordination Agreement executed on July 20, 2013, provides for the exchange of information between WEC and PJM. The purpose of the data exchange is to allow for the coordination of balancing authority actions to ensure the reliable operation of the systems. The agreement remained in effect in the first nine months of 2019.

Northeastern ISO-Regional Transmission Organization Planning Coordination Protocol[62]

The Northeastern ISO-RTO Planning Coordination Protocol executed on December 8, 2004, provides for the exchange of information among PJM, NYISO and ISO New England. The purpose of the data exchange is to allow for the long-term planning coordination among and between the ISOs and RTOs in the Northeast. The agreement remained in effect in the first nine months of 2019.

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.

56 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/directory/merged-tariffs/progress-joa.pdf>.
57 See PJM Interconnection, L.L.C and Progress Energy Carolinas, Inc. Docket No. ER10-713-000 (February 2, 2010).
58 See PJM Interconnection, L.L.C, Docket No. ER19-1905-000 (May 20, 2019).
59 FERC Docket No. ER19-905-000 (July 2, 2019).
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, L.L.C.," (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>.

The PJM/DEP JOA allows for the CPLEIMP and CPLEEXP interface pricing points to be calculated using the Marginal Cost Proxy Pricing method.[63] [64] 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 9-37 shows the real-time LMP calculated per the PJM/DEP JOA and the high/low pricing method used by Duke and NCMPA for the first nine months of 2019.[65] The values shown in Table 9-37 are the average LMP over only the hours in the first nine months of 2019 where interchange transactions settled at those pricing points. The difference between the LMP under these agreements and PJM's SouthIMP LMP ranged from -$0.47 with PEC to $0.07 with NCMPA. This means that under the specific interface pricing agreements, transactions settling at the PEC interface price would receive, on average, $0.47 less for importing energy into PJM than if they were to receive the SouthIMP pricing point. In the first nine months of 2019, market participants received $4,674 less for importing energy using this pricing point 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 $0.40 with Duke to $1.45 with PEC.[66] This means that under the specific interface pricing agreements, transactions settling at the PEC interface price would pay, on average, $1.45 more for exporting energy from PJM than they would have if they were to pay the SouthEXP pricing point. In the first nine months of 2019, market participants paid $338,252 more for exporting energy using this pricing point than they would have if they were to have paid the SouthEXP pricing point.

Table 9-37 Real-time LMP comparison for Duke, PEC and NCMPA: January through September, 2019

	Import LMP	Export LMP	SOUTHIMP	SOUTHEXP	Difference IMP LMP - SOUTHIMP	Difference EXP LMP - SOUTHEXP
Duke	$26.99	$28.88	$27.10	$28.47	($0.11)	$0.40
PEC	$27.24	$31.58	$27.71	$30.13	($0.47)	$1.45
NCMPA	$24.66	$49.72	$24.59	$48.56	$0.07	$1.15

Table 9-38 shows the day-ahead LMP calculated per the PJM/DEP JOA and the high/low pricing method used by Duke and NCMPA for the first nine months of 2019.[67] The values shown in Table 9-38 are the average LMP over only the hours in the first nine months of 2019 where interchange transactions settled at those pricing points. The difference between the LMP under these agreements and PJM's SouthIMP LMP ranged from $0.31 with Duke to $0.44 with PEC. This means that under the specific interface pricing agreements, transactions settling at the PEC interface price would receive, on average, $0.44 more for importing energy into PJM than if they were to receive the SouthIMP pricing point. In the first nine months of 2019, market participants received $59,019 more for importing energy using this pricing point 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 $0.00 with Duke to $0.81 with PEC. This means that under the specific interface pricing agreements, transactions settling at the PEC interface price would pay, on average, $0.81 more for exporting energy from PJM than if they were to pay the SouthEXP pricing point. In the first nine months of 2019, market participants paid $251,747 more for exporting energy using this pricing point than they would have if they were to have paid the SouthEXP pricing point.

63 See PJM Interconnection, L.L.C, Docket No. ER10-2710-000 (September 17, 2010).
64 Effective July 22, 2019, the PJM/DEP JOA was modified to remove Article 14. Article 14 of the JOA included the Congestion Management Agreement provisions that defined the Marginal Cost Proxy Pricing method. Upon termination of Article 14, the CPLEIMP and CPLEEXP interface pricing points reverted to using the high-low pricing method as defined in Section 2.6A (1) of the PJM Tariff.
65 The totals reflect the change in the PEC price calculation method from the Marginal Cost Proxy method to the high-low pricing method coincident with the termination of the PJM/DEP congestion management agreement on July 22, 2019.
66 The Progress Energy Carolinas (PEC) LMP is defined as the Carolina Power and Light (East) (CPLE) pricing point.

67 The totals reflect the change in the PEC price calculation method from the Marginal Cost Proxy method to the high-low pricing method coincident with the termination of the PJM/DEP congestion management agreement on July 22, 2019.

Table 9-38 Day-ahead LMP comparison for Duke, PEC and NCMPA: January through September, 2019

	Import LMP	Export LMP	SOUTHIMP	SOUTHEXP	Difference IMP LMP - SOUTHIMP	Difference EXP LMP - SOUTHEXP
Duke	$30.04	$27.02	$29.73	$27.02	$0.31	$0.00
PEC	$28.43	$30.36	$27.99	$29.56	$0.44	$0.81
NCMPA	$25.70	$23.30	$25.35	$22.99	$0.35	$0.30

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.

Interchange Transaction Issues

Requests to Convert Firm to NonFirm Transmission Withdrawal Rights

In 2014, cost allocations for RTEP projects included the Bergen-Linden Corridor (BLC) project. 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 May 1, 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.[68]

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 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.[69] On September 8, 2017, the Commission rejected the amended ISAs 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 ISAs to reflect the conversion of FTWRs to NFTWRs.[70] [71] 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.[72]

Linden requested, and obtained, 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 requested that PJM provide an initial study with the assumption that FERC approves the termination of their FTWRs. Linden VFT expects to maintain the ability to export capacity to NYISO from PJM with the same level of transmission service they currently have under the FTWR construct while avoiding an RTEP cost allocation. Linden VFT has obtained assurance from NYISO that NFTWRs in conjunction with firm point to point transmission

68 155 FERC ¶ 61,089 (2016), *reh'g pending*. With rehearing pending, in light of subsequent developments, including service cancellations intended to avoid RTEP cost allocations, the Commission established settlement proceedings to consider settlement of this proceeding and related cost allocation proceedings. 164 FERC ¶ 61,034 (2018). Settlement proceedings resulted in an impasse, the proceedings are terminated, and the matter has been returned to the Commission for disposition. Order of Chief Judge Terminating Settlement Judge Procedures, Docket No. EL17-67-003 (July 22, 2019).

69 See *PJM Interconnection, L.L.C*, Docket No. ER17-2267-000 (August 9, 2017).

70 161 FERC ¶ 62,242 (2017).

71 161 FERC ¶ 62,264 (2017).

72 See *PJM Interconnection, L.L.C.*, Docket No. ER18-680-000 (January 19, 2018).

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.[73]

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 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 its 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.

73 See Discussion of UDR Deliverability Requirements (September 18, 2017) at: <https://www.nyiso.com/documents/20142/1406254/UDR%20Deliverability%20Requirements.pdf/09988c85-84d5-f911-42ba-8c578695128d>.

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.[74] 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 four in the first nine months of 2018 to two in the first nine months of 2019.[75] The number of different flowgates for which PJM declared a TLR 3a or higher was three in the first nine months of 2018 and one in the first nine months of 2019. The total MWh of transactions curtailed decreased by 74.3 percent from 5,832 MWh in the first nine months of 2018 to 1,499 MWh in the first nine months of 2019.

The number of MISO issued TLRs of level 3a or higher decreased from 47 in the first nine months of 2018 to 35 in the first nine months of 2019. The number of different flowgates for which MISO declared a TLR 3a decreased from 19 in the first nine months of 2018 to 15 in the first nine months of 2019. The total MWh of transaction curtailments decreased by 5.2 percent

74 PJM files cost responsibility assignments for transmission projects that are selected in the PJM Regional Transmission Expansion Plan (RTEP) for purposes of cost allocations in accordance with Schedule 12 of the OATT.

75 TLR Level 3a is the first level of TLR that results in the curtailment of transactions. See the 2018 State of the Market Report for PJM, Volume 2, Appendix E, "Interchange Transactions," for a more complete discussion of TLR levels.

from 35,768 MWh in the first nine months of 2018 to 33,893 MWh in the first nine months of 2019.

The number of NYISO issued TLRs of level 3a or higher increased from two in the first nine months of 2018 to eight in the first nine months of 2019. The number of different flowgates for which NYISO declared a TLR 3a or higher increased from two in the first nine months of 2018 to four in the first nine months of 2019. The total MWh of transaction curtailments increased by 143.7 percent from 6,194 MWh in the first nine months of 2018 to 15,092 MWh in the first nine months of 2019.

Table 9-39 PJM, MISO, and NYISO TLR procedures: January 2016 through September 2019

	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-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
Jan-18	1	7	1	1	4	1	3,283	9,198	1,428
Feb-18	0	0	0	0	0	0	0	0	0
Mar-18	0	2	0	0	2	0	0	1,185	0
Apr-18	2	3	0	1	3	0	656	1,180	0
May-18	1	11	0	1	7	0	1,893	3,373	0
Jun-18	0	12	0	0	5	0	0	9,643	0
Jul-18	0	1	0	0	1	0	0	134	0
Aug-18	0	6	0	0	3	0	0	7,852	0
Sep-18	0	5	1	0	3	1	0	3,203	4,766
Oct-18	0	5	0	0	4	0	0	6,474	0
Nov-18	0	1	0	0	1	0	0	440	0
Dec-18	1	3	0	1	3	0	234	13,258	0
Jan-19	2	0	5	1	0	1	1,499	0	14,742
Feb-19	0	2	0	0	2	0	0	927	0
Mar-19	0	6	0	0	6	0	0	2,431	0
Apr-19	0	3	1	0	1	1	0	1,604	350
May-19	0	4	0	0	3	0	0	1,143	0
Jun-19	0	5	2	0	4	2	0	8,804	0
Jul-19	0	1	0	0	1	0	0	991	0
Aug-19	0	9	0	0	3	0	0	13,899	0
Sep-19	0	5	0	0	5	0	0	4,094	0

Table 9-40 Number of TLRs by TLR level by reliability coordinator: January through September, 2019[76]

Year	Reliability Coordinator	3a	3b	4	5a	5b	6	Total
2019	MISO	10	10	0	6	9	0	35
	NYIS	8	0	0	0	0	0	8
	ONT	7	2	0	0	0	0	9
	PJM	1	1	0	0	0	0	2
	SOCO	0	0	0	0	0	0	0
	SWPP	10	4	0	16	7	0	37
	TVA	7	14	0	4	7	0	32
	VACS	2	3	0	0	0	0	5
Total		45	34	0	26	23	0	128

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.[77]

Up to congestion transactions affect 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.[78]

Following the elimination of the requirement to procure and pay for transmission service for up to congestion transactions effective September 17, 2010, the volume of transactions increased dramatically.

On August 29, 2014, FERC issued an order which created an obligation for UTCs to pay any uplift determined to be appropriate based on Commission review, effective September 8, 2014.[79] As a result of the potential 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..."[80]

On February 20, 2018, FERC issued an order limiting the eligible bidding points for up to congestion transactions to hubs, residual metered load and interfaces.[81] As a result, market participants reduced up to congestion trading effective February 22, 2018. In the months following this change, the volume of submitted and cleared volumes of up to congestion transactions has remained below the historic highs observed between 2010 and 2014. However, the volumes of submitted and cleared bids have once again been increasing.

The average number of up to congestion bids submitted in the Day-Ahead Energy Market decreased by 24.9 percent, from 68,693 bids per day in the first nine months of 2018 to 51,594 bids per day in the first nine months of 2019. The average cleared volume of up to congestion bids submitted in the Day-Ahead Energy Market increased by 15.9 percent, from 423,268 MWh per day in the first nine months of 2018, to 490,421 MWh per day in the first nine months of 2019.

76 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.

77 See the 2012 State of the Market Report for PJM, Volume 2, Section 8, "Interchange Transactions," for a more detailed discussion.

78 See the 2019 Quarterly State of the Market Report for PJM: January through September, Section 13: FTRs and ARRs, "FTR Forfeitures" for more information on up to congestion transaction impacts on FTRs.

79 148 FERC ¶ 61,144 (2014).

80 16 U.S.C. § 824e.

81 162 FERC ¶ 61,139 (2018).

Figure 9-13 Monthly up to congestion cleared bids in MWh: January 2005 through September 2019

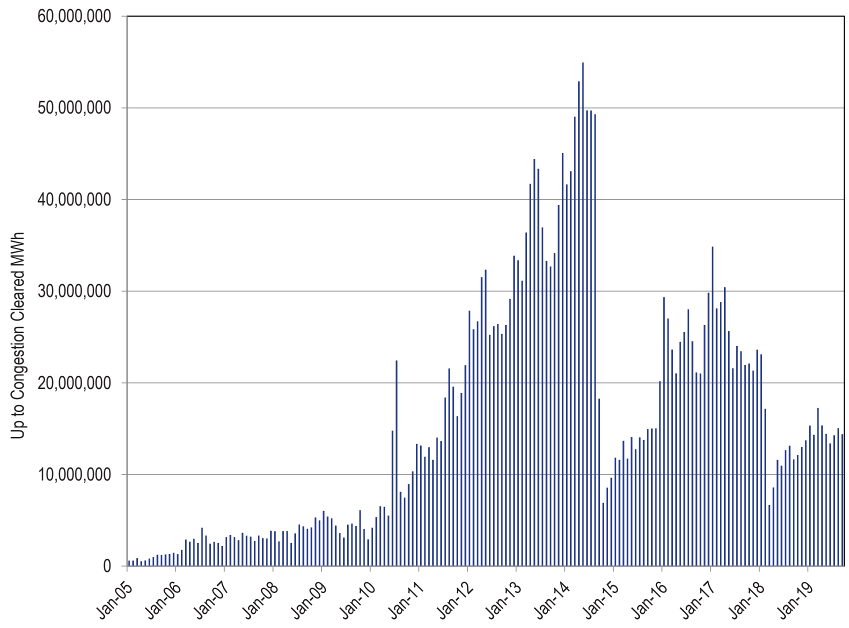


Table 9-41 Monthly volume of cleared and submitted up to congestion bids: January 2018 through September 2019

	Bid MWh					Bid Volume (Number of bids)				
Month	Import	Export	Wheel	Internal	Total	Import	Export	Wheel	Internal	Total
Jan-18	6,693,483	7,662,968	964,569	77,009,951	92,330,971	248,760	203,232	17,467	4,374,531	4,843,990
Feb-18	5,221,484	6,409,422	819,944	51,178,869	63,629,719	178,507	175,403	18,605	2,787,881	3,160,396
Mar-18	7,198,570	2,684,392	1,641,523	9,285,316	20,809,801	405,718	170,727	76,172	810,443	1,463,060
Apr-18	10,593,924	3,145,340	2,567,203	15,365,820	31,672,285	479,450	120,650	68,477	771,799	1,440,376
May-18	11,309,503	3,914,473	2,621,845	19,453,217	37,299,037	517,327	119,707	53,586	886,577	1,577,197
Jun-18	10,165,362	3,767,069	2,613,562	16,723,385	33,269,378	399,986	87,810	40,434	763,388	1,291,618
Jul-18	9,895,083	2,011,081	2,397,682	22,207,892	36,511,737	488,146	129,135	48,678	1,183,510	1,849,469
Aug-18	13,524,492	1,838,512	3,071,033	21,055,373	39,489,410	561,803	100,964	46,574	1,014,352	1,723,693
Sep-18	10,503,480	4,148,333	3,322,123	20,309,280	38,283,216	445,037	94,821	51,019	812,439	1,403,316
Oct-18	10,977,336	4,063,127	2,832,812	19,223,993	37,097,269	435,432	133,048	50,325	954,489	1,573,294
Nov-18	11,903,568	4,093,631	2,752,372	23,118,009	41,867,580	474,565	96,770	44,125	950,934	1,566,394
Dec-18	8,557,434	3,709,128	2,408,350	26,836,764	41,511,676	276,497	103,963	47,479	1,248,751	1,676,690
Jan-19	9,353,494	3,989,206	2,204,341	33,209,495	48,756,536	317,900	137,306	61,239	1,335,488	1,851,933
Feb-19	7,584,708	5,424,852	1,991,198	29,512,609	44,513,366	242,071	142,957	50,914	916,766	1,352,708
Mar-19	11,841,555	4,801,188	3,292,862	36,636,988	56,572,593	320,490	105,336	58,064	1,115,308	1,599,198
Apr-19	7,500,490	5,206,737	2,465,809	30,466,646	45,639,682	210,977	99,870	51,861	839,285	1,201,993
May-19	7,645,790	5,234,141	3,161,264	28,363,918	44,405,113	257,707	114,116	60,815	841,562	1,274,200
Jun-19	6,110,456	5,605,115	2,611,193	22,881,326	37,208,089	265,643	160,729	65,564	914,109	1,406,045
Jul-19	7,056,992	4,330,830	3,316,928	27,078,704	41,783,454	299,274	158,591	62,817	1,164,220	1,684,902
Aug-19	6,498,469	6,138,104	4,180,281	26,961,166	43,778,021	300,981	231,654	84,937	1,279,890	1,897,462
Sep-19	8,573,470	7,472,142	7,582,592	30,007,306	53,635,511	330,868	198,568	110,558	1,176,657	1,816,651
TOTAL	188,709,142	95,649,789	58,819,485	586,886,028	930,064,445	7,457,139	2,885,357	1,169,710	26,142,379	37,654,585

	Cleared MWh					Cleared Volume (Number of bids)				
Month	Import	Export	Wheel	Internal	Total	Import	Export	Wheel	Internal	Total
Jan-18	1,467,644	1,595,640	259,173	19,790,703	23,113,162	72,327	67,941	6,648	1,470,535	1,617,451
Feb-18	1,312,958	1,559,790	223,702	14,068,590	17,165,039	65,952	70,121	8,429	1,103,722	1,248,224
Mar-18	2,228,586	819,477	399,161	3,232,145	6,679,368	145,743	55,930	24,612	318,655	544,940
Apr-18	2,951,060	728,157	352,423	4,557,862	8,589,502	191,558	40,919	19,629	379,069	631,175
May-18	3,891,624	1,073,540	638,477	5,996,981	11,600,622	215,222	48,034	21,288	381,157	665,701
Jun-18	3,473,835	1,218,987	769,637	5,500,944	10,963,403	172,868	43,078	17,529	361,764	595,239
Jul-18	3,756,816	616,857	691,554	7,588,929	12,654,157	234,818	51,413	21,034	512,342	819,607
Aug-18	4,449,172	759,823	929,122	6,999,351	13,137,468	248,048	43,884	20,619	429,365	741,916
Sep-18	3,382,522	1,130,568	813,755	6,322,535	11,649,379	189,297	37,680	17,342	372,208	616,527
Oct-18	3,372,457	1,254,074	665,212	6,823,263	12,115,006	182,064	56,691	18,422	441,069	698,246
Nov-18	3,614,335	1,206,420	657,895	7,518,666	12,997,315	210,762	54,479	21,050	460,142	746,433
Dec-18	2,988,179	1,139,101	674,573	8,921,740	13,723,593	126,333	60,064	20,146	650,430	856,973
Jan-19	3,646,671	1,270,480	719,143	9,708,127	15,344,421	163,962	69,096	25,497	648,338	906,893
Feb-19	2,891,175	1,759,853	660,811	9,029,295	14,341,133	113,778	70,552	21,952	469,157	675,439
Mar-19	4,473,700	1,543,428	1,126,598	10,124,498	17,268,224	153,456	50,367	23,840	550,873	778,536
Apr-19	3,399,991	1,718,522	917,569	9,316,753	15,352,837	114,678	51,233	25,154	436,881	627,946
May-19	3,312,686	1,572,184	875,397	8,678,534	14,438,801	131,807	51,047	23,406	434,766	641,026
Jun-19	2,818,707	2,198,956	871,722	7,500,886	13,390,271	138,482	86,395	32,233	478,224	735,334
Jul-19	2,622,343	1,980,537	1,054,098	8,625,452	14,282,430	130,706	101,912	30,468	576,429	839,515
Aug-19	2,596,501	2,164,346	1,093,209	9,209,462	15,063,518	136,493	114,788	33,781	647,784	932,846
Sep-19	2,533,520	1,735,695	1,101,876	9,032,182	14,403,273	129,191	83,956	33,247	571,636	818,030
TOTAL	65,184,481	29,046,434	15,495,108	178,546,898	288,272,922	3,267,545	1,309,580	466,326	11,694,546	16,737,997

In the first nine months of 2019, the cleared MW volume of up to congestion transactions was comprised of 21.1 percent imports, 11.9 percent exports, 6.3 percent wheeling transactions and 60.7 percent internal transactions. Less than 0.1 percent of the up to congestion transactions had matching real-time energy market transactions.

Sham Scheduling

Sham scheduling refers to a scheduling method under which a market participant breaks a single transaction, from generation balancing authority (source) to load balancing authority (sink), into multiple segments. Sham scheduling hides the actual source of generation from the load balancing authority. When unable to identify the source of the energy, the load balancing authority 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 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.[82]

82 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>.

The MMU believes that the new PJM/IMO interface price method is a step in the right direction towards pricing energy that sources or sinks in Ontario based on the path of the actual, physical transfer of energy. The MMU remains concerned about the assumption of PAR operations, and will continue to evaluate the impact of PARs on the scheduled and actual flows and the impacts on the PJM/IMO interface price. The MMU remains concerned about the potential for market participants to continue to engage in sham scheduling activities after the new method is implemented.

The MMU recommends that if the PJM/IMO interface price remains and with PJM's new method in place, that PJM implement additional business rules to remove the incentive to engage in sham scheduling activities using the PJM/IMO interface price. Such rules would prohibit the same market participant from scheduling an export transaction from PJM to any balancing authority while at the same time an import transaction is scheduled to PJM that receives the PJM/IMO interface price. PJM should also prohibit the same market participant from scheduling an import transaction to PJM from any balancing authority while at the same time an export transaction is scheduled from PJM that receives the PJM/IMO interface price.

In the first nine months of 2019, of the 443 GWh of the gross scheduled transactions between PJM and IESO, 438 GWh (98.9 percent) wheeled through MISO (Table 9-24). 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.[83]

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.[84] 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

83 On October 1, 2013, a sub-group of PJM's Market Implementation Committee started stakeholder discussions to address this inconsistency in market pricing.

84 PJM and the NYISO implemented CTS on November 4, 2014. 146 FERC ¶ 61,096 (2014).

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 the first nine months of 2019. Table 9-42 shows that over all 12 forecast ranges, ITSCED predicted the real-time PJM/NYIS interface LMP within the range of $0.00 to $5.00 in 45.4 percent of the intervals. In those intervals, the average price difference between the ITSCED forecasted LMP and the actual real-time LMP was $1.52 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 $65.07 when the price difference was greater than $20.00, and $307.28 when the price difference was greater than -$20.00.

Table 9-42 Differences between forecast and actual PJM/NYIS interface prices: January through September, 2019

Range of Price Differences	Percent of All Intervals	Average Price Difference
> $20	3.4%	$65.07
$10 to $20	4.3%	$13.81
$5 to $10	6.7%	$7.08
$0 to $5	45.4%	$1.52
$0 to -$5	32.1%	$1.37
-$5 to -$10	3.0%	$6.93
-$10 to -$20	2.0%	$14.27
< -$20	3.1%	$307.28

Table 9-43 shows how the accuracy of the ITSCED forecasted LMPs changes as the cases approach real-time. In the final ITSCED results prior to real time, in 78.4 percent of all intervals, the average price difference between the ITSCED forecasted LMP and the actual real-time interface LMP fell within +/- $5.00 of the actual PJM/NYIS interface real-time LMP, compared to 78.2 percent in the 135 minute ahead ITSCED results.

Table 9-43 Differences between forecast and actual PJM/NYIS interface prices: January through September, 2019

	~ 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	1.6%	$53.68	1.8%	$53.55	2.9%	$54.94	3.1%	$55.28
$10 to $20	3.5%	$13.72	3.7%	$13.65	3.8%	$13.79	4.1%	$13.68
$5 to $10	5.1%	$7.14	5.6%	$7.14	6.5%	$7.03	7.1%	$7.04
$0 to $5	31.9%	$1.59	32.8%	$1.60	47.1%	$1.54	48.1%	$1.54
$0 to -$5	46.3%	$1.58	46.1%	$1.54	31.0%	$1.37	30.3%	$1.34
-$5 to -$10	4.6%	$6.90	4.2%	$6.86	3.2%	$6.94	2.9%	$7.00
-$10 to -$20	3.1%	$14.34	2.7%	$14.19	2.1%	$14.25	1.8%	$14.41
< -$20	3.9%	$337.49	3.2%	$196.68	3.4%	$383.55	2.7%	$222.68

In 5.8 percent of the intervals in the 30 minute ahead forecast, the absolute value of the average price difference between the ITSCED forecasted LMP and the actual real-time interface LMP was greater than $20.00. The average price difference was $55.28 when the price difference was greater than $20.00, and $222.68 when the price difference was greater than -$20.00.

Table 9-44 and Table 9-45 show the monthly differences between forecasted and actual PJM/NYIS interface prices. Analysis of the data on a monthly basis shows that there is a decline in the accuracy of the ITSCED forecast ability during periods of cold and hot weather.

Table 9-44 Monthly Differences between forecast and actual PJM/NYIS interface prices (percent of intervals): January through September, 2019

Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	YTD Avg
~ 30 Minutes Prior to Real-Time	> $20	5.7%	2.7%	1.4%	2.3%	1.3%	1.4%	7.2%	2.6%	2.6%	3.1%
	$10 to $20	2.7%	2.1%	2.8%	5.6%	3.9%	3.3%	8.4%	4.4%	3.9%	4.1%
	$5 to $10	4.5%	3.6%	6.5%	10.4%	7.2%	5.6%	10.1%	8.2%	7.5%	7.1%
	$0 to $5	37.7%	45.1%	46.1%	46.9%	54.2%	56.3%	45.7%	53.0%	48.1%	48.1%
	$0 to -$5	35.7%	36.9%	33.8%	27.0%	28.6%	30.1%	22.7%	27.5%	30.6%	30.3%
	-$5 to -$10	4.4%	3.2%	3.8%	3.1%	2.0%	1.9%	2.1%	2.0%	3.5%	2.9%
	-$10 to -$20	3.0%	2.2%	1.8%	2.1%	1.3%	0.7%	1.8%	1.1%	1.9%	1.8%
	< -$20	6.4%	4.2%	3.8%	2.6%	1.5%	0.7%	1.8%	1.2%	2.0%	2.7%
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	YTD Avg
~ 45 Minutes Prior to Real-Time	> $20	5.1%	2.4%	1.0%	1.6%	1.4%	1.5%	7.2%	2.8%	2.6%	2.9%
	$10 to $20	3.3%	1.6%	2.1%	4.4%	3.4%	2.9%	8.5%	4.1%	3.5%	3.8%
	$5 to $10	3.4%	3.5%	5.4%	9.1%	6.5%	5.4%	9.7%	8.6%	7.2%	6.5%
	$0 to $5	37.5%	44.1%	43.5%	45.4%	53.0%	55.8%	45.5%	52.3%	47.0%	47.1%
	$0 to -$5	36.3%	37.0%	34.1%	28.5%	30.2%	30.5%	23.3%	27.9%	32.2%	31.0%
	-$5 to -$10	4.4%	3.3%	5.0%	3.9%	2.4%	2.3%	2.0%	2.2%	3.4%	3.2%
	-$10 to -$20	3.5%	2.9%	2.1%	2.8%	1.6%	1.0%	2.0%	1.0%	2.0%	2.1%
	< -$20	6.6%	5.2%	6.9%	4.2%	1.4%	0.7%	1.8%	1.3%	2.0%	3.4%
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	YTD Avg
~ 90 Minutes Prior to Real-Time	> $20	4.6%	1.3%	2.0%	1.7%	0.5%	0.9%	2.7%	0.6%	1.5%	1.8%
	$10 to $20	2.9%	1.5%	3.2%	4.2%	2.2%	2.6%	9.0%	4.9%	2.7%	3.7%
	$5 to $10	3.9%	2.3%	5.9%	6.5%	4.0%	4.0%	10.1%	8.2%	5.1%	5.6%
	$0 to $5	25.8%	29.3%	35.9%	32.8%	34.1%	34.1%	31.9%	38.9%	31.8%	32.8%
	$0 to -$5	44.6%	53.2%	42.4%	45.8%	50.5%	51.4%	39.0%	41.5%	47.5%	46.1%
	-$5 to -$10	6.3%	4.2%	4.9%	3.9%	4.0%	3.4%	2.4%	2.7%	5.7%	4.2%
	-$10 to -$20	4.5%	3.3%	1.9%	2.2%	2.8%	2.6%	2.7%	1.8%	2.7%	2.7%
	< -$20	7.5%	4.9%	3.9%	3.0%	2.0%	1.0%	2.3%	1.4%	3.0%	3.2%
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	YTD Avg
~ 135 Minutes Prior to Real-Time	> $20	4.4%	1.0%	1.4%	1.3%	0.6%	0.8%	2.8%	0.5%	1.5%	1.6%
	$10 to $20	2.8%	1.2%	2.0%	3.4%	1.9%	2.4%	9.1%	5.4%	3.0%	3.5%
	$5 to $10	3.7%	2.3%	4.8%	5.1%	3.8%	4.0%	9.6%	7.9%	4.6%	5.1%
	$0 to $5	24.6%	27.5%	34.6%	30.7%	33.4%	34.1%	31.1%	38.7%	31.9%	31.9%
	$0 to -$5	45.8%	54.0%	42.3%	46.1%	50.2%	51.0%	39.6%	41.5%	47.4%	46.3%
	-$5 to -$10	6.2%	4.1%	5.8%	5.4%	5.0%	3.8%	2.7%	2.8%	5.9%	4.6%
	-$10 to -$20	4.7%	3.6%	2.2%	3.4%	3.4%	2.9%	2.8%	1.9%	2.7%	3.1%
	< -$20	7.8%	6.3%	6.9%	4.6%	1.9%	1.1%	2.3%	1.3%	3.0%	3.9%

Table 9-45 Monthly differences between forecast and actual PJM/NYIS interface prices (average price difference): January through September, 2019

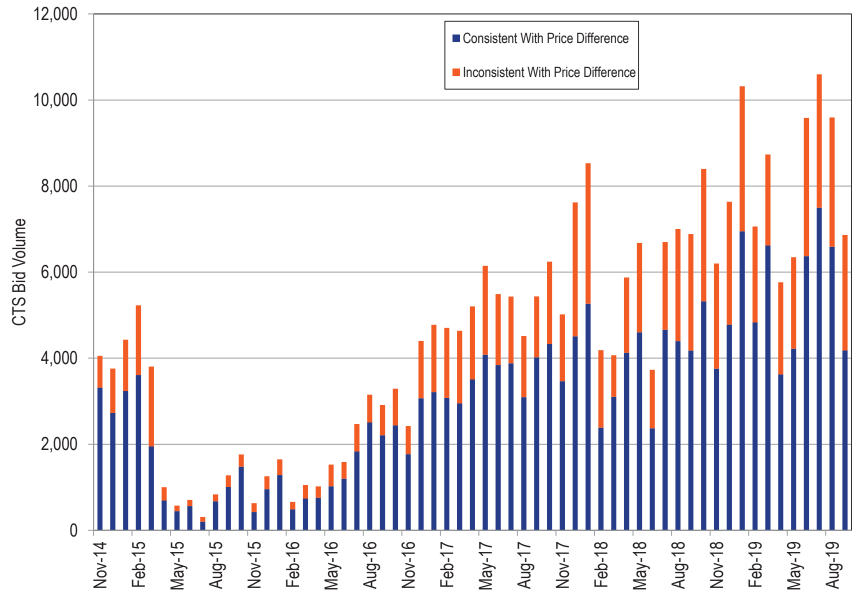
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	YTD Avg
~ 30 Minutes Prior to Real-Time	> $20	$79.73	$90.51	$45.45	$39.96	$34.12	$37.01	$47.34	$32.43	$52.23	$55.28
	$10 to $20	$13.95	$13.81	$13.64	$13.53	$13.52	$13.53	$13.62	$13.65	$14.17	$13.68
	$5 to $10	$7.12	$6.73	$7.02	$6.78	$6.92	$7.00	$7.32	$7.19	$7.13	$7.04
	$0 to $5	$1.44	$1.41	$1.54	$1.80	$1.54	$1.48	$1.52	$1.58	$1.51	$1.54
	$0 to -$5	$1.40	$1.32	$1.45	$1.44	$1.30	$1.24	$1.23	$1.24	$1.38	$1.34
	-$5 to -$10	$6.93	$7.15	$6.99	$7.01	$6.82	$6.78	$7.21	$7.05	$7.00	$7.00
	-$10 to -$20	$14.75	$14.47	$14.03	$14.31	$14.65	$14.95	$14.37	$14.07	$14.19	$14.41
	< -$20	$109.20	$169.71	$436.84	$676.44	$43.90	$64.36	$111.90	$49.30	$89.78	$222.68
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	YTD Avg
~ 45 Minutes Prior to Real-Time	> $20	$78.44	$85.72	$37.73	$40.42	$36.28	$37.89	$49.61	$33.65	$56.09	$54.94
	$10 to $20	$14.51	$15.06	$13.50	$13.61	$13.80	$13.54	$13.62	$13.73	$13.67	$13.79
	$5 to $10	$7.16	$6.86	$6.91	$6.81	$6.81	$7.01	$7.23	$7.13	$7.22	$7.03
	$0 to $5	$1.43	$1.38	$1.47	$1.75	$1.59	$1.52	$1.55	$1.57	$1.53	$1.54
	$0 to -$5	$1.41	$1.37	$1.47	$1.55	$1.33	$1.25	$1.28	$1.25	$1.40	$1.37
	-$5 to -$10	$6.93	$6.99	$6.96	$7.00	$6.77	$6.73	$7.19	$7.11	$6.80	$6.94
	-$10 to -$20	$14.46	$13.97	$14.09	$14.43	$14.56	$15.31	$13.65	$14.22	$14.00	$14.25
	< -$20	$104.35	$272.98	$701.93	$961.94	$44.48	$57.99	$113.59	$47.95	$88.53	$383.55
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	YTD Avg
~ 90 Minutes Prior to Real-Time	> $20	$86.98	$63.07	$44.96	$43.09	$39.41	$30.17	$29.01	$24.18	$39.61	$53.55
	$10 to $20	$13.73	$12.83	$13.44	$13.64	$14.22	$13.68	$13.99	$13.25	$13.33	$13.65
	$5 to $10	$7.15	$7.24	$7.13	$7.10	$7.04	$6.94	$7.27	$7.17	$7.05	$7.14
	$0 to $5	$1.52	$1.43	$1.52	$1.84	$1.67	$1.37	$1.61	$1.69	$1.67	$1.60
	$0 to -$5	$1.54	$1.53	$1.55	$1.71	$1.64	$1.53	$1.38	$1.41	$1.57	$1.54
	-$5 to -$10	$6.82	$6.84	$6.97	$7.07	$6.93	$6.67	$7.06	$6.80	$6.71	$6.86
	-$10 to -$20	$15.06	$14.30	$13.86	$13.31	$14.59	$13.48	$14.09	$13.67	$14.23	$14.19
	< -$20	$102.51	$154.46	$440.43	$593.65	$42.14	$53.40	$104.43	$48.56	$73.93	$196.68
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	YTD Avg
~ 135 Minutes Prior to Real-Time	> $20	$87.42	$64.44	$43.97	$43.47	$38.50	$31.51	$29.22	$24.29	$40.21	$53.68
	$10 to $20	$13.68	$12.62	$13.88	$13.70	$14.16	$14.23	$14.02	$13.20	$13.42	$13.72
	$5 to $10	$7.24	$7.05	$7.03	$6.96	$7.02	$7.05	$7.33	$7.24	$7.00	$7.14
	$0 to $5	$1.43	$1.41	$1.59	$1.82	$1.61	$1.36	$1.67	$1.68	$1.70	$1.59
	$0 to -$5	$1.61	$1.58	$1.59	$1.72	$1.69	$1.57	$1.39	$1.44	$1.61	$1.58
	-$5 to -$10	$6.89	$6.99	$7.12	$6.71	$6.83	$6.72	$7.06	$6.89	$6.91	$6.90
	-$10 to -$20	$15.07	$14.32	$14.31	$14.03	$14.67	$13.74	$14.22	$13.84	$14.16	$14.34
	< -$20	$99.93	$241.48	$695.65	$895.06	$42.47	$47.23	$105.25	$49.02	$74.41	$337.49

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 September 30, 2019, 271,771 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 87,419 (32.2 percent) of the intervals was inconsistent with the differences in real-time PJM/NYISO and NYISO/PJM prices. For example, if a market participant submits a CTS transaction from NYISO to PJM with a spread bid of $5.00, and NYISO's forecasted PJM interface price was at least $5.00 lower than PJM's forecasted NYISO interface price, the transaction would be approved. For 32.2 percent of the approved transactions, the actual, real-time price differentials were in the opposite direction of the forecast differential. The actual, real-time price differentials meant that the transactions would have been economic in the opposite direction. For 67.8 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 4, 2014 through September 30, 2019



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 proposed the implementation of coordinated interchange transactions, similar to the PJM/NYISO approach, through the Joint and Common Market Initiative. The PJM/MISO coordinated transaction scheduling (CTS) process provides 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 is 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 uses a joint clearing process in which both RTOs share forward looking prices. 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 the first nine months of 2019. Table 9-46 shows that over all 12 forecast ranges, ITSCED predicted the real-time PJM/MISO interface LMP within the range of $0.00 to $5.00 in 44.1 percent of all intervals. In those intervals, the average price difference between the ITSCED forecasted LMP and the actual real-time LMP was $1.63. In 6.1 percent of all intervals, the absolute value of the average price difference between the ITSCED forecasted LMP and the actual real-time interface LMP was greater than $20.00. The average price differences were $58.47 when the price difference was greater than $20.00, and $302.69 when the price difference was greater than -$20.00.

Table 9-46 Differences between forecast and actual PJM/MISO interface prices: January through September, 2019

Range of Price Differences	Percent of All Intervals	Average Price Difference
> $20	3.2%	$58.47
$10 to $20	4.6%	$13.80
$5 to $10	8.0%	$7.05
$0 to $5	44.1%	$1.63
$0 to -$5	31.9%	$1.43
-$5 to -$10	3.3%	$6.96
-$10 to -$20	2.0%	$14.09
< -$20	2.9%	$302.69

Table 9-47 shows how the accuracy of the ITSCED forecasted LMPs change as the cases approach real-time. In the final ITSCED results prior to real-time, in 77.2 percent of all intervals, the average price difference between the ITSCED forecasted LMP and the actual real-time interface LMP fell within +/- $5.00 of the actual PJM/MISO interface real-time LMP, compared to 77.9 percent in the 135 minute ahead ITSCED results.

Table 9-47 Differences between forecast and actual PJM/MISO interface prices: January through September, 2019

	~ 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	1.2%	$41.37	1.2%	$40.72	2.6%	$47.48	2.6%	$45.02
$10 to $20	3.0%	$13.72	3.0%	$13.56	4.4%	$13.62	4.5%	$13.58
$5 to $10	5.2%	$7.09	5.2%	$7.03	8.8%	$7.01	8.8%	$7.03
$0 to $5	28.6%	$1.59	29.4%	$1.57	48.0%	$1.67	49.0%	$1.66
$0 to -$5	49.2%	$1.69	48.7%	$1.67	29.0%	$1.34	28.2%	$1.34
-$5 to -$10	5.7%	$6.88	5.6%	$6.89	2.7%	$7.01	2.5%	$7.06
-$10 to -$20	3.3%	$13.88	3.3%	$13.96	1.7%	$14.25	1.7%	$14.29
< -$20	3.7%	$287.01	3.5%	$254.30	2.8%	$319.72	2.7%	$292.30

In 5.3 percent of the intervals in the 30 minute ahead forecast, the absolute value of the average price difference between the ITSCED forecasted LMP and the actual real-time interface LMP was greater than $20.00, the average price differences were $45.02 when the price difference was greater than $20.00, and $292.30 when the price difference was greater than -$20.00.

Table 9-48 and Table 9-49 show the monthly differences between forecasted and actual PJM/MISO interface prices. Analysis of the data on a monthly basis shows that there is a decline in the accuracy of the ITSCED forecast ability during periods of cold and hot weather.

Table 9-48 Monthly Differences between forecast and actual PJM/MISO interface prices (percent of intervals): January through September, 2019

Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	YTD Avg
	> $20	2.7%	1.6%	0.9%	1.8%	0.9%	1.7%	6.6%	2.8%	4.0%	2.6%
	$10 to $20	2.2%	2.3%	2.3%	6.4%	5.1%	2.9%	8.3%	4.5%	6.6%	4.5%
	$5 to $10	3.5%	5.6%	7.2%	8.8%	11.4%	6.2%	10.4%	10.9%	15.2%	8.8%
~ 30 Minutes Prior to	$0 to $5	45.3%	45.9%	48.3%	48.1%	52.2%	56.9%	47.2%	53.0%	43.8%	49.0%
Real-Time	$0 to -$5	39.8%	34.5%	31.9%	26.1%	25.0%	28.5%	21.5%	23.8%	22.9%	28.2%
	-$5 to -$10	3.1%	2.9%	3.3%	2.5%	2.4%	1.6%	2.4%	2.1%	2.7%	2.5%
	-$10 to -$20	1.8%	2.4%	1.8%	2.4%	1.4%	0.9%	1.5%	1.4%	1.9%	1.7%
	< -$20	1.8%	4.8%	4.4%	4.1%	1.6%	1.4%	2.1%	1.5%	2.9%	2.7%

Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	YTD Avg
	> $20	2.4%	1.7%	0.9%	2.0%	1.1%	1.6%	6.8%	2.8%	4.0%	2.6%
	$10 to $20	2.4%	2.4%	2.1%	5.5%	5.3%	3.2%	8.0%	4.4%	6.0%	4.4%
	$5 to $10	3.3%	5.5%	6.7%	9.1%	10.5%	6.6%	10.7%	11.6%	15.0%	8.8%
~ 45 Minutes Prior to	$0 to $5	45.0%	44.8%	47.1%	46.8%	52.2%	55.3%	46.4%	51.1%	43.3%	48.0%
Real-Time	$0 to -$5	40.2%	35.5%	32.9%	27.5%	25.4%	29.3%	21.9%	25.1%	23.9%	29.0%
	-$5 to -$10	3.4%	3.1%	3.1%	2.9%	2.1%	1.7%	2.5%	2.3%	3.0%	2.7%
	-$10 to -$20	1.6%	2.5%	2.3%	2.2%	1.8%	0.8%	1.6%	1.2%	1.7%	1.7%
	< -$20	1.8%	4.4%	4.9%	4.0%	1.6%	1.5%	2.1%	1.5%	3.1%	2.8%

Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	YTD Avg
	> $20	1.8%	0.6%	1.5%	1.1%	0.3%	1.0%	1.7%	0.5%	1.9%	1.2%
	$10 to $20	1.9%	1.7%	1.9%	3.5%	1.0%	1.7%	8.3%	4.5%	2.6%	3.0%
	$5 to $10	2.9%	3.1%	5.1%	4.6%	4.0%	3.8%	8.8%	7.7%	6.4%	5.2%
~ 90 Minutes Prior to	$0 to $5	27.5%	26.6%	36.4%	31.1%	27.5%	28.8%	29.1%	33.3%	24.4%	29.4%
Real-Time	$0 to -$5	55.1%	54.4%	43.3%	46.4%	51.9%	55.5%	42.6%	46.4%	43.4%	48.7%
	-$5 to -$10	5.2%	5.1%	4.4%	5.5%	7.2%	4.4%	3.6%	3.6%	11.5%	5.6%
	-$10 to -$20	3.2%	3.2%	2.3%	3.1%	5.3%	2.9%	2.8%	2.2%	4.7%	3.3%
	< -$20	2.4%	5.2%	5.0%	4.8%	2.9%	1.8%	3.2%	1.8%	5.0%	3.5%

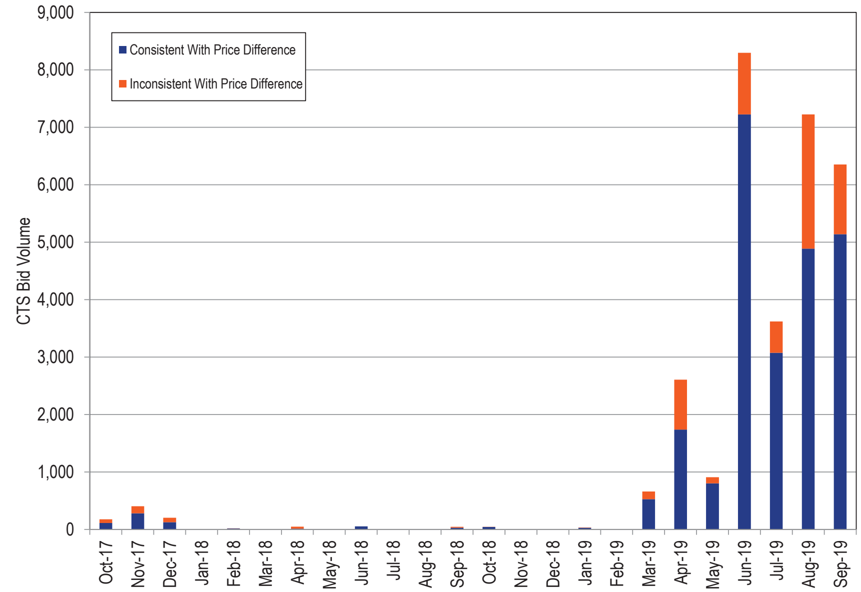
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	YTD Avg
	> $20	1.9%	0.7%	1.2%	1.1%	0.3%	1.0%	1.9%	0.5%	1.9%	1.2%
	$10 to $20	1.8%	1.4%	1.9%	3.3%	1.0%	1.7%	8.7%	4.5%	2.6%	3.0%
	$5 to $10	2.8%	2.9%	5.2%	4.4%	4.1%	4.4%	8.6%	7.7%	6.5%	5.2%
~ 135 Minutes Prior to	$0 to $5	26.6%	25.6%	35.2%	30.3%	27.0%	27.5%	28.6%	32.7%	23.8%	28.6%
Real-Time	$0 to -$5	55.8%	55.5%	43.7%	46.9%	52.0%	56.6%	42.9%	46.7%	43.5%	49.2%
	-$5 to -$10	5.0%	5.5%	4.9%	6.0%	7.3%	4.0%	3.2%	3.9%	11.9%	5.7%
	-$10 to -$20	3.4%	3.1%	2.5%	3.3%	5.2%	3.0%	2.8%	2.2%	4.5%	3.3%
	< -$20	2.6%	5.3%	5.4%	4.6%	3.1%	1.8%	3.2%	1.8%	5.3%	3.7%

Table 9-49 Monthly differences between forecast and actual PJM/MISO interface prices (average price difference): January through September, 2019

Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	YTD Avg
~ 30 Minutes Prior to Real-Time	> $20	$44.69	$44.07	$47.98	$41.73	$29.97	$37.87	$46.74	$34.04	$57.85	$45.02
	$10 to $20	$14.36	$13.27	$13.39	$13.90	$13.48	$13.14	$13.65	$13.39	$13.47	$13.58
	$5 to $10	$7.17	$6.92	$7.02	$6.81	$7.07	$7.07	$7.26	$7.00	$6.97	$7.03
	$0 to $5	$1.34	$1.55	$1.62	$1.79	$1.85	$1.56	$1.62	$1.73	$1.90	$1.66
	$0 to -$5	$1.21	$1.36	$1.42	$1.42	$1.45	$1.21	$1.22	$1.25	$1.59	$1.34
	-$5 to -$10	$7.24	$6.97	$6.85	$7.11	$6.95	$7.18	$7.23	$7.16	$6.94	$7.06
	-$10 to -$20	$14.22	$14.22	$14.16	$14.28	$14.68	$14.54	$13.86	$13.77	$14.89	$14.29
	< -$20	$77.60	$179.96	$604.25	$648.50	$66.87	$68.61	$110.84	$71.68	$106.38	$292.30
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	YTD Avg
~ 45 Minutes Prior to Real-Time	> $20	$50.71	$43.83	$43.20	$44.99	$32.36	$41.70	$48.08	$35.87	$63.05	$47.48
	$10 to $20	$15.00	$13.44	$13.46	$13.66	$13.31	$13.42	$13.76	$13.35	$13.53	$13.62
	$5 to $10	$7.12	$6.95	$6.88	$6.86	$7.01	$6.93	$7.23	$6.98	$7.08	$7.01
	$0 to $5	$1.32	$1.56	$1.66	$1.80	$1.86	$1.55	$1.61	$1.69	$1.93	$1.67
	$0 to -$5	$1.23	$1.36	$1.42	$1.51	$1.39	$1.22	$1.18	$1.27	$1.58	$1.34
	-$5 to -$10	$7.08	$7.00	$6.79	$7.10	$6.91	$7.12	$7.14	$7.09	$6.88	$7.01
	-$10 to -$20	$14.69	$14.48	$13.83	$14.05	$14.28	$14.28	$13.24	$14.60	$15.06	$14.25
	< -$20	$64.73	$181.49	$677.95	$700.70	$72.16	$76.31	$109.51	$72.50	$101.41	$319.72
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	YTD Avg
~ 90 Minutes Prior to Real-Time	> $20	$48.58	$42.18	$41.28	$43.68	$37.74	$28.77	$33.52	$29.25	$46.95	$40.72
	$10 to $20	$14.66	$13.20	$13.75	$13.79	$13.32	$13.49	$13.80	$12.91	$13.00	$13.56
	$5 to $10	$7.08	$6.79	$6.98	$6.91	$6.87	$7.26	$7.22	$7.08	$6.90	$7.03
	$0 to $5	$1.29	$1.48	$1.61	$1.80	$1.62	$1.35	$1.53	$1.59	$1.92	$1.57
	$0 to -$5	$1.47	$1.64	$1.60	$1.77	$1.80	$1.70	$1.38	$1.64	$2.02	$1.67
	-$5 to -$10	$7.06	$6.71	$6.87	$6.97	$7.03	$6.69	$7.05	$6.53	$6.90	$6.89
	-$10 to -$20	$15.20	$14.00	$13.97	$13.59	$13.89	$13.89	$13.71	$14.11	$13.52	$13.96
	< -$20	$73.77	$209.99	$476.22	$722.26	$61.64	$63.52	$87.49	$67.41	$81.50	$254.30
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	YTD Avg
~ 135 Minutes Prior to Real-Time	> $20	$50.44	$43.01	$41.85	$40.18	$38.26	$29.77	$34.40	$29.08	$48.72	$41.37
	$10 to $20	$13.48	$12.92	$14.08	$14.33	$13.58	$13.60	$13.88	$13.11	$13.91	$13.72
	$5 to $10	$7.27	$7.11	$6.94	$6.99	$6.86	$7.21	$7.18	$7.23	$6.95	$7.09
	$0 to $5	$1.29	$1.59	$1.60	$1.83	$1.60	$1.36	$1.50	$1.62	$1.95	$1.59
	$0 to -$5	$1.51	$1.62	$1.64	$1.80	$1.81	$1.71	$1.45	$1.64	$2.03	$1.69
	-$5 to -$10	$7.06	$6.62	$6.79	$6.92	$7.12	$6.66	$7.19	$6.63	$6.85	$6.88
	-$10 to -$20	$14.89	$13.95	$13.92	$13.69	$13.65	$13.82	$13.62	$13.94	$13.63	$13.88
	< -$20	$61.97	$236.83	$723.62	$671.91	$59.92	$64.08	$86.74	$67.05	$78.28	$287.01

CTS transactions were evaluated for each interval. From October 3, 2017, through September 30, 2019, 30,698 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 6,614 (21.5 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 21.5 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 78.5 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 September 30, 2019



The data reviewed show that ITSCED is not a highly accurate predictor of the real-time PJM/MISO interface prices. If this remains true, it will limit the effectiveness of CTS in improving interface pricing between PJM and MISO.

Willing to Pay Congestion and Not Willing to Pay Congestion

When reserving nonfirm transmission, market participants have the option to choose whether or not they are willing to pay congestion. When the market participant elects to pay congestion, PJM operators redispatch the system if necessary to allow the energy transaction to continue to flow. The system redispatch often creates price separation across buses on the PJM system. The difference in LMPs between two buses in PJM is the congestion cost (and losses) that the market participant pays in order for their transaction to continue to flow.

The MMU recommended that PJM modify the not willing to pay congestion product to address the issues of uncollected congestion charges. The MMU recommended charging market participants for any congestion incurred while the transaction is loaded, regardless of their election of transmission service, and restricting the use of not willing to pay congestion transactions (as well as all other real-time external energy transactions) to transactions at interfaces.

On April 12, 2011, the PJM Market Implementation Committee (MIC) endorsed the changes recommended by the MMU. The elimination of internal sources and sinks on transmission reservations addressed most of the MMU concerns, as there can no longer be uncollected congestion charges for imports to PJM or exports from PJM. There is still potential exposure to uncollected congestion charges in wheel through transactions, and the MMU will continue to evaluate if additional mitigation measures would be appropriate to address this exposure.

Table 9-50 shows that since the inception of the business rule change on April 12, 2013, there was uncollected congestion in only two months (January 2016 and February 2019). In both months, there was negative uncollected congestion. 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 both January 2016 and February 2019.

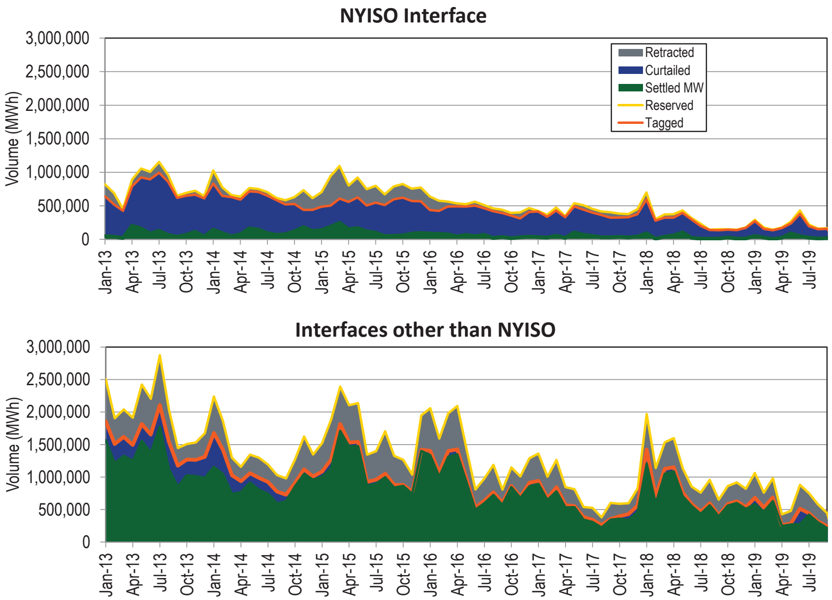
Table 9-50 Monthly uncollected congestion charges: January 2010 through September 2019

Month	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Jan	$148,764	$3,102	$0	$5	$0	$0	($44)	$0	$0	$0
Feb	$542,575	$1,567	($15)	$249	$0	$0	$0	$0	$0	($69,992)
Mar	$287,417	$0	$0	$0	$0	$0	$0	$0	$0	$0
Apr	$31,255	$4,767	($68)	($3,114)	$0	$0	$0	$0	$0	$0
May	$41,025	$0	($27)	$0	$0	$0	$0	$0	$0	$0
Jun	$169,197	$1,354	$78	$0	$0	$0	$0	$0	$0	$0
Jul	$827,617	$1,115	$0	$0	$0	$0	$0	$0	$0	$0
Aug	$731,539	$37	$0	$0	$0	$0	$0	$0	$0	$0
Sep	$119,162	$0	$0	$0	$0	$0	$0	$0	$0	$0
Oct	$257,448	($31,443)	($6,870)	$0	$0	$0	$0	$0	$0	
Nov	$30,843	($795)	($4,678)	$0	$0	$0	$0	$0	$0	
Dec	$127,176	($659)	($209)	$0	$0	$0	$0	$0	$0	
Total	$3,314,018	($20,955)	($11,789)	($2,860)	$0	$0	($44)	$0	$0	($69,992)

Spot Imports

Figure 9-16 shows the spot import service use for the NYISO Interface, and for all other interfaces, from January 1, 2013 through September 30, 2019. 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.[85]

Figure 9-16 Spot import service use: January 2013 through September 2019



The MMU continues to recommend that PJM permit unlimited spot market imports (as well as all nonfirm point-to-point willing to pay congestion imports and exports) at all PJM interfaces.

Interchange Optimization

When PJM prices are higher than prices in surrounding balancing authorities, imports will flow into PJM until the prices are approximately equal. This is an appropriate market response to price differentials. Given the nature of interface pricing and the treatment of interface transactions, it is not possible for PJM system operators to reliably predict the quantity or sustainability of such imports. The inability to predict interchange volumes creates additional challenges for PJM dispatch in trying to meet loads, especially on high-load days. If all external transactions were submitted as real-time dispatchable transactions during emergency conditions, PJM would be able to include interchange transactions in its supply stack, and dispatch only enough interchange to meet the demand.

The MMU recommends that the submission deadline for real-time dispatchable transactions be modified from 1800 on the prior day to three hours prior to the requested start time, and that the minimum duration be modified from one hour to 15 minutes.[86] These changes would give PJM a more flexible product that could be used to meet load based on economic dispatch rather than guessing the sensitivity of the transactions to price changes.

In addition to changing prices, transmission line loading relief procedures (TLRs), market participants' curtailments for economic reasons, and external balancing authority curtailments affect the duration of interchange transactions.

The MMU recommends that PJM explore an interchange optimization solution with its neighboring balancing authorities that would remove the need for market participants to schedule physical transactions across seams. Such a solution would include an optimized, but limited, joint dispatch approach that uses supply curves and treats seams between balancing authorities as constraints, similar to other constraints within an LMP market.

Interchange Cap During Emergency Conditions

An interchange cap is a limit on the level of interchange permitted for nondispatchable energy using spot import or hourly point-to-point transmission. An interchange cap is a nonmarket intervention which should be a temporary solution and should be replaced with a market-based solution

85 See the 2018 State of the Market Report for PJM, Volume 2, Section 9, "Interchange Transactions," for a more complete discussion of the history of spot import transmission service.

86 The minimum duration for a real-time dispatchable transaction was modified to 15 minutes as per FERC Order No. 764.

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 although that has not been shown to be correct. 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.[87] [88] On April 17, 2014, FERC issued its order which found that PJM's 45 minute duration rule was inconsistent with Order No. 764.[89]

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.[90]

MISO Multi-Value Project Usage Rate (MUR)

A multi-value project (MVP) is a project, as defined by MISO, which 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.[91] On July 15, 2010, MISO submitted revisions to the MISO Tariff to implement criteria for identifying and allocating the costs of MVPs.[92] On December 16, 2010, the Commission accepted the proposed MVP charge for export and wheel-through transactions, except for transactions that sink in PJM.[93] 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.[94] The Court ordered the Commission to consider on remand whether, in light of current conditions, what if any limitations on export pricing to PJM by MISO are justified.[95] 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.[96]

On July 13, 2016, FERC issued an order permitting MISO to collect charges associated with MVPs for all transactions sinking in PJM, effective immediately.[97] 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."[98]

Table 9-51 shows the projected usage rate to be collected for all wheels through and exports from MISO, including those that sink in PJM, for 2019 through 2038.[99] It is not clear whether the MUR charge has affected interchange volumes from MISO into PJM.

87 Order No. 764, 139 FERC ¶ 61,246 (2012), *order on reh'g*, Order No. 764-A, 141 FERC ¶ 61231 (2012).
88 Order No. 764 at P 51.
89 *See Id.* at P 12.
90 *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>.
91 See MISO. MTEP "Multi Value Project Portfolio Analysis," <https://cdn.misoenergy.org/2011%20MVP%20Portfolio%20Analysis%20Full%20Report117059.pdf>.
92 See Midwest Independent Transmission Operator Inc. filing, Docket No. ER10-1791-000 (July 15, 2010).
93 133 FERC ¶ 61,221 (2010); *order on reh'g*, 137 FERC ¶ 61,074 (2011).
94 Illinois Commerce Commission, et al. v. FERC, 721 F.3d 764, 778–780 (7th Cir. 2013).
95 *Id.* at 780.
96 *Id.* at 779.
97 156 FERC ¶ 61,034 (2016).
98 *Id.* at P 55.
99 See MISO, "Schedule 26A Indicative Annual Charges" (August 29, 2016) <https://cdn.misoenergy.org/Schedule%2026A%20Indicative%20Annual%20Charges106365.xlsx>.

Table 9-51 MISO projected multi value project usage rate: 2019 through 2038

Year	Total Indicative MVP Usage Rate ($/MWh)
2019	$1.76
2020	$1.77
2021	$1.76
2022	$1.76
2023	$1.76
2024	$1.83
2025	$1.77
2026	$1.75
2027	$1.74
2028	$1.72
2029	$1.70
2030	$1.68
2031	$1.66
2032	$1.65
2033	$1.63
2034	$1.61
2035	$1.60
2036	$1.58
2037	$1.56
2038	$1.55

Ancillary Service Markets

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 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 the first nine months of 2019.

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.

1 75 FERC ¶ 61,080 (1996).
2 Energy imbalance service refers to the Real-Time Energy Market.

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 DASR market would have failed a three pivotal supplier test in less than one percent of cleared hours in the first nine months of 2019. The day-ahead scheduling reserve market structure remains evaluated as not competitive based on persistent structural issues.
- 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 were part of the clearing price in all but three of the 803 hours when the clearing price was above $0.00.
- Market design was evaluated as mixed because the DASR product does not include performance obligations. Offers should be based on opportunity cost only, to ensure competitive outcomes and that market power cannot be exercised.

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 because the PJM Regulation Market failed the three pivotal supplier (TPS) test in 93.3 percent of the hours in the first nine months of 2019.
- Participant behavior in the PJM Regulation Market was evaluated as competitive for the first nine months of 2019 because market power

mitigation requires competitive offers when the three pivotal supplier test is failed and there was no evidence of generation owners engaging in noncompetitive behavior.

- Market performance was evaluated as competitive, despite significant issues with the market design.
- Market design was evaluated as flawed. The market design has failed to correctly incorporate a consistent implementation of the marginal benefit factor in optimization, pricing and settlement. The market results continue to include the incorrect definition of opportunity cost. The result is significantly flawed market signals to existing and prospective suppliers of regulation.

Overview

Primary Reserve

PJM's primary reserves are made up of resources, both synchronized and nonsynchronized, that can provide energy within 10 minutes. Primary reserve is PJM's implementation of the NERC 15-minute contingency reserve requirement.[3]

On April 1, 2018, PJM implemented five minute settlements. PJM determines the primary reserve requirement based on the most severe single contingency every five minutes. The market solution calculates the available tier 1 synchronized reserve every five minutes. In every five minute interval, the required synchronized reserve and nonsynchronized reserve are calculated and dispatched, and there are associated clearing prices (SRMCP and NSRMCP). Scheduled resources are credited based on their five minute assignment and clearing price.

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 most severe single contingency. In the first nine months of 2019, the average primary reserve requirement was 2,474.8 MW in the RTO Zone and 2,530.9 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 in response to a PJM declared synchronized reserve event. Synchronized reserve consists of tier 1 and tier 2 synchronized reserves.

Tier 1 synchronized reserve 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 reserves. The market solution estimates tier 1 synchronized reserve as available 10 minute ramp from the energy dispatch. In the first nine months of 2019, there was an average hourly supply of 2,185.1 MW of tier 1 available in the RTO Zone. In the first nine months of 2019, there was an average hourly supply of 1,574.7 MW of tier 1 synchronized reserve available within the MAD Subzone.
- **Demand.** The synchronized reserve requirement is calculated for each five minute interval as the most severe single 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 for increasing its output (or reducing load for demand response) at the rate

3 See PJM. "Manual 10: Pre-Scheduling Operations," § 3.1.1 Day-ahead Scheduling (Operating Reserve, Rev. 38 (Aug. 22, 2019).

of $50 per MWh in addition to LMP.[4] This is the Synchronized Energy Premium Price.

- **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 synchronized energy premium price of $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 is 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, $2,197,514 in 2017, $4,732,025 in 2018, and $2,295,217 in the first nine months of 2019.

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 may incur costs to be synchronized, and that have an obligation to respond to PJM declared synchronized reserve events. Tier 2 synchronized reserve is penalized for failure to respond to a PJM declared synchronized reserve event. PJM has established a required amount of synchronized reserve as no less than the largest single contingency, and a 10 minute primary reserve at no less than 150 percent of the largest single contingency. This is stricter than the NERC standard of the greater of 80 percent of the largest single contingency or 900 MW.[5]

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).

4 See PJM. "Manual 11: Energy & Ancillary Services Market Operations,"§ 4.2.10 Settlements, Rev. 107 (Sep. 26, 2019).
5 NERC (August 12, 2019) <NERC Reliability Standard BAL 002-2 Glossary_of_Terms.pdf>.

Market Structure

- **Supply.** In the first nine months 2019, the supply of offered and eligible tier 2 synchronized reserve was 28,609.4 MW in the RTO Zone of which 5,484.6 MW was located in the MAD Subzone.
- **Demand.** The average hourly synchronized reserve requirement was 1,713.8 MW in the RTO Reserve Zone and 1,697.8 MW for the Mid-Atlantic Dominion Reserve Subzone. The hourly average cleared tier 2 synchronized reserve was 280.6 MW in the MAD Subzone and 536.9 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 the first nine months 2019.

  The average HHI for tier 2 synchronized reserve in the RTO Zone was 5505 which is classified as highly concentrated.

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. PJM automatically enters an offer of $0 for tier 2 synchronized reserve when an offer is not entered by the owner.

Market Performance

- **Price.** The weighted average price for tier 2 synchronized reserve for all cleared hours/intervals in the Mid-Atlantic Dominion (MAD) Subzone in the first nine months of 2019 was $3.07 per MW, a decrease of $1.85 from the same period in 2018.

  The weighted average price for tier 2 synchronized reserve for all cleared hours/intervals in the RTO Synchronized Reserve Zone was $3.19 per

MW in the first nine months of 2019, a decrease of $2.59 from the same period in 2018.

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 for nonsynchronized reserve. 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 the first nine months of 2019, the average hourly supply of eligible nonsynchronized reserve was 3,953.1 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.[6] The actual amount of nonsynchronized reserve scheduled often exceeds the demand and the corresponding price is $0.00. In the RTO Zone, the market scheduled an hourly average of 1,461.9 MW of nonsynchronized reserve in the first nine months of 2019.
- **Market Concentration.** The MMU calculates that the three pivotal supplier test would have been failed in 61.3 percent of hours in the first nine months of 2019.

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 was $0.20 per MW in the first nine months of 2019. The price cleared above $0.00 in 0.9 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.[7] 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

6 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," § $b.2.2 Non-Synchronized Reserve Zones and Levels, Rev. 107 (Sep. 26, 2019). "Because Synchronized Reserve may be utilized to meet the Primary Reserve requirement, there is no explicit requirement for non-synchronized reserves."

7 See PJM, "Manual 11: Energy & Ancillary Services Market Operations," § 11.2.7 Day-Ahead Scheduling Reserve Performance, Rev. 107(Sep. 26, 2019).

point for all online units. In the first nine months of 2019, the average available hourly DASR was 44,547.9 MW.

- **Demand.** The DASR requirement for 2019 is 5.29 percent of peak load forecast, which is up 0.01 percent from in 2018. The average hourly DASR MW purchased in the first nine months of 2019 was 5,511.0 MW. This is a reduction from the 5,625.4 hourly MW in 2018.
- **Concentration.** In the first nine months of 2019, the DASR Market failed the three pivotal supplier test in less than one percent of hours.

Market Conduct

- **Withholding.** Economic withholding remains an issue in the DASR Market. The direct marginal cost of providing DASR is zero. PJM calculates the opportunity cost for each resource. All offers by resource owners greater than zero constitute economic withholding. In the first nine months of 2019, a daily average of 39.6 percent of units offered above $0.00. A daily average of 16.6 percent of units offered above $5.
- **DR.** Demand resources are eligible to participate in the DASR Market. Some demand resources have entered offers for DASR. No demand resources cleared the DASR market in the first nine months of 2019.

Market Performance

- **Price.** In the first nine months of 2019, the weighted average DASR price for all hours when the DASRMCP was above $0.00 was $1.24.

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 rates. 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 technical substitution (MRTS), called a marginal benefit factor (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 the first nine months of 2019, the average hourly eligible supply of regulation for nonramp hours was 1,062.1 performance adjusted MW (801.2 effective MW). This was a decrease of 37.2 performance adjusted MW (a decrease of 56.5 effective MW) from the first nine months of 2018, when the average hourly eligible supply of regulation was 1,099.3 performance adjusted MW (857.7 effective MW). In the first nine months of 2019, the average hourly eligible supply of regulation for ramp hours was 1,357.8 performance adjusted MW (1,127.6 effective MW). This was a decrease of 53.3 performance adjusted MW (a decrease of 64.1 effective MW) from the first nine months of 2018, when the average hourly eligible supply of regulation was 1,411.1 performance adjusted MW (1,191.8 effective MW).
- **Demand.** The hourly regulation demand is 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 470.7 hourly average performance adjusted actual MW in the first nine months of 2019. This is a decrease of 16.1 performance adjusted actual MW from the first nine months of 2018, when the average hourly total regulation cleared performance adjusted actual MW for nonramp hours were 486.8 performance adjusted actual MW. The ramp regulation requirement of 800.0 effective MW was provided by a combination of

RegA and RegD resources equal to 722.8 hourly average performance adjusted actual MW in the first nine months of 2019. This is a decrease of 27.1 performance adjusted actual MW from the first nine months of 2018, where the average hourly regulation cleared MW for ramp hours were 750.0 performance adjusted actual MW.

The ratio of the average hourly eligible supply of regulation to average hourly regulation demand (performance adjusted cleared MW) for ramp hours was 1.88 in the first nine months of 2019 (unchanged from the first nine months of 2018). The ratio of the average hourly eligible supply of regulation to average hourly regulation demand (performance adjusted cleared MW) for nonramp hours was 2.25 in the first nine months of 2019 (2.26 in the first nine months of 2018).

- **Market Concentration.** In the first nine months of 2019, the three pivotal supplier test was failed in 93.3 percent of hours. In the first nine months of 2019, the effective MW weighted average HHI of RegA resources was 2362 which is highly concentrated and the weighted average HHI of RegD resources was 1307 which is moderately concentrated.[8] The weighted average HHI of all resources was 1366, 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.[9] In the first nine months of 2019, there were 213 resources following the RegA signal and 59 resources following the RegD signal.

Market Performance

- **Price and Cost.** The weighted average clearing price for regulation was $14.97 per MW of regulation in the first nine months of 2019. This is a decrease of $13.25 per MW, or 47.0 percent, from the weighted average clearing price of $28.21 per MW in the first nine months of 2018. The weighted average cost of regulation in the first nine months of 2019 was $19.14 per MW of regulation. This is a decrease of $15.91 per MW, or 45.4 percent, from the weighted average cost of $35.05 per MW in the first nine months of 2018.

- **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.

- **Marginal Benefit Factor.** The marginal benefit factor (MBF) is intended to measure the operational substitutability of RegD resources for RegA resources. The marginal benefit factor is incorrectly defined and applied in the PJM market clearing. Correctly defined, the MBF 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 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 of RegD can also degrade the ability of PJM to control ACE.

- **Changes to the Regulation Market.** The MMU and PJM developed a joint proposal to address the significant flaws in the regulation market design which was approved by the PJM Members Committee on July 27, 2017, and filed with FERC on October 17, 2017. The proposal addresses issues with the inconsistent application of the marginal benefit factor throughout

8 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.

9 See the 2018 State of the Market Report for PJM, Vol. 2, Appendix F "Ancillary Services Markets."

the optimization and settlement process in the PJM Regulation Market. On March 30, 2018, this joint proposal was rejected by FERC.[10] The MMU and PJM filed requests for rehearing.[11]

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).[12]

In the first nine months of 2019, total black start charges were $48.37 million, including $48.21 million in revenue requirement charges and $0.160 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 in the first nine months of 2019 ranged from $0.04 per MW-day in the DLCO Zone (total charges were $33,657) to $4.03 per MW-day in the PENELEC Zone (total charges were $3,299,265).

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 voltage levels on the transmission system and is essential to the flow of real power (measured in MW).

Reactive capability charges are based on FERC approved filings that permit recovery based on a cost of service approach.[13] Reactive service charges are paid to units that operate in real time outside of their normal range at the direction of PJM for the purpose of providing reactive service. Reactive service charges are paid for scheduling in the Day-Ahead Energy Market and committing units in real time that provide reactive service. In the first nine months of 2019, total reactive charges were $258.68 million, a 3.2 percent increase from $250.76 million in the first nine months of 2018. Reactive capability charges increased from $238.35 million in the first nine months of 2018 to $258.23 million in the first nine months of 2019 and reactive service charges decreased from $12.41 million in the first nine months of 2018 to $0.45 million in 2019. Total reactive service charges in the first nine months of 2019 ranged from $0 in the RECO and OVEC Zones, to $36.00 million in the AEP Zone.

Frequency Response

On February 15, 2018, the Commission issued Order No. 842, which modified the pro forma large and small generator interconnection agreements and procedures to require newly interconnecting generating facilities, both synchronous and non-synchronous, to include equipment for primary frequency response capability as a condition to receive interconnection service.[14] PJM filed revisions in compliance with Order No. 842 that substantively incorporated the pro forma agreements into its market rules.[15]

The PJM Tariff requires that all new generator interconnection customers (NRC regulated facilities are exempt from this provision) have hardware and/or software that provides frequency responsive real power control with the ability to sense changes in system frequency and autonomously adjust real power output in a direction to correct for frequency deviations. This includes a governor or equivalent controls capable of operating with a maximum five percent droop and a +/- 0.036 deadband.[16] PJM is currently studying individual unit response to NERC identified frequency events and evaluating compliance.

10 162 FERC ¶ 61,295.
11 FERC Docket No. ER18-87-002.
12 OATT Schedule 1 § 1.3BB.
13 OATT Schedule 2.
14 See 157 FERC ¶ 61,122 (2016).
15 See 164 FERC ¶ 61,224 (2018).
16 PJM OATT (ER18-1629-000) October 1, 2018, 4.7.2 Primary Frequency Response, p. 3.

Ancillary Services Costs per MWh of Load: January through September, 1999 through 2019

Table 10-4 shows PJM ancillary services costs for the first nine months of 1999 through 2019, per MWh of load. The rates are calculated as the total charges for the specified ancillary service divided by the total PJM real-time load in MWh. The scheduling, system control, and dispatch category of costs is comprised of PJM scheduling, PJM system control and PJM dispatch; owner scheduling, owner system control and owner dispatch; other supporting facilities; black start services; direct assignment facilities; and Reliability*First* Corporation charges. The cost per MWh of load in Table 10-4 is a different metric than the cost of each ancillary service per MW of that service. The cost per MWh of load includes the effects both of price changes per MW of the ancillary service and changes in total load.

Table 10-4 History of ancillary services costs per MWh of load: January through September, 1999 through 2019[17] [18]

Year (Jan-Sep)	Regulation	Scheduling, Dispatch and System Control	Reactive	Synchronized Reserve	Total
1999	$0.16	$0.22	$0.25	$0.00	$0.63
2000	$0.33	$0.29	$0.31	$0.00	$0.93
2001	$0.55	$0.70	$0.22	$0.00	$1.47
2002	$0.42	$0.82	$0.19	$0.00	$1.43
2003	$0.53	$1.01	$0.23	$0.13	$1.90
2004	$0.50	$0.99	$0.25	$0.14	$1.88
2005	$0.78	$0.73	$0.26	$0.11	$1.88
2006	$0.55	$0.74	$0.28	$0.07	$1.64
2007	$0.65	$0.72	$0.27	$0.06	$1.70
2008	$0.78	$0.44	$0.33	$0.07	$1.62
2009	$0.36	$0.34	$0.36	$0.04	$1.10
2010	$0.38	$0.36	$0.36	$0.06	$1.16
2011	$0.36	$0.37	$0.38	$0.09	$1.20
2012	$0.23	$0.42	$0.44	$0.03	$1.12
2013	$0.27	$0.42	$0.67	$0.03	$1.39
2014	$0.36	$0.43	$0.40	$0.14	$1.33
2015	$0.25	$0.42	$0.36	$0.12	$1.15
2016	$0.11	$0.43	$0.37	$0.05	$0.96
2017	$0.13	$0.48	$0.42	$0.06	$1.09
2018	$0.20	$0.47	$0.42	$0.06	$1.15
2019	$0.11	$0.47	$0.44	$0.04	$1.06

17 Note: The totals in Table 10-4 account for after the fact billing adjustments made by PJM and may not match totals presented in past reports.
18 Reactive totals include FERC approved rates for reactive capability.

Recommendations

- 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 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. FERC rejected, pending rehearing request before FERC.[19])
- 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.[20] FERC rejected, pending rehearing request before FERC.[21])
- The MMU recommends that the lost opportunity cost 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: Not adopted. FERC rejected, pending rehearing request before FERC.[22])
- 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. FERC rejected, pending rehearing request before FERC.[23])
- The MMU recommends enhanced documentation of the implementation of the Regulation Market design. (Priority: Medium. First reported 2010.

19 FERC Docket No. ER18-87.
20 This recommendation was adopted by PJM for the Energy Market. Lost opportunity costs in the Energy Market are calculated using the schedule on which the unit was scheduled to run. In the Regulation Market, this recommendation has not been adopted, as the LOC continues to be calculated based on the lower of price or cost in the energy market offer.
21 FERC Docket No. ER18-87.
22 Id.
23 Id.

Status: Not adopted. FERC rejected, pending rehearing request before FERC.[24])

- 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: Adopted, 2018.)
- 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 that the $7.50 margin be eliminated from the definition of the cost of tier 2 synchronized reserve because it is a markup and not a cost. (Priority: Medium. First reported 2018. Status: Not adopted.)
- 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 on a daily and hourly basis. 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, for calculating the penalty for a tier 2 resource failing to meet its scheduled obligation during a spinning event, the definition of the IPI be changed from the average number of days between events to the actual number of days since the last event greater than 10 minutes. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that aggregation not be permitted to offset unit specific penalties for failure to respond to a synchronized reserve event. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM eliminate the use of Degree of Generator Performance (DGP) in the synchronized reserve market solution and improve the actual tier 1 estimate. If PJM continues to use DGP, DGP should be documented in PJM's manuals. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that a reason code be attached to every hour in which PJM market operations adds additional DASR MW. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that 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 offers in the DASR Market be based on opportunity cost only in order to eliminate market power. (Priority: Low. First reported 2009. Modified, 2018. Status: Not adopted.)
- The MMU recommends that separate cost of service 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 payments for reactive capability, if continued, be based on the 0.90 power factor that PJM has determined is necessary. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that all resources, new and existing, have a requirement to include and maintain equipment for primary frequency

24 Id.

response capability as a condition of interconnection service and that compensation is provided through the capacity and energy markets. (Priority: Medium. First reported 2018. Status: Not adopted.)

- The MMU recommends for oil tanks shared with other resources that 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 2017. Status: Not adopted.)
- The MMU recommends that the same capability be required of both new and existing resources. The MMU agrees with Order No. 842 that RTOs not be required to provide additional compensation specifically for frequency response. The current PJM market design provides compensation for all capacity costs, including these, in the capacity market. The current market design provides compensation, through heat rate adjusted energy offers, for any costs associated with providing frequency response. Because the PJM market design already compensates resources for frequency response capability and any costs associated with providing frequency response, any separate filings submitted on behalf of resources for compensation under section 205 of the Federal Power Act should be rejected as double recovery. (Priority: Low. First reported 2017. Status: Not adopted.)
- The MMU recommends that fleet wide cost of service rates used to compensate resources for reactive capability be eliminated and replaced with compensation based on unit specific costs. (Priority: Low. New recommendation.[25] Status: Not adopted.)

Conclusion

The current PJM regulation market design that incorporates two signals using two resource types was a result of FERC Order No. 755 and subsequent orders.[26]

The design of the PJM Regulation Market is significantly flawed. The market design does not 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 are the basis for 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.[27] 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. FERC rejected the joint proposal on March 30, 2018, as being noncompliant with Order No. 755.[28] The MMU and PJM separately filed requests for rehearing.[29]

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, the $7.50 margin is not a cost. The margin is effectively a rule-based form of market power and is therefore not consistent with a competitive outcome. The $7.50 margin should be eliminated. Participant performance has not been adequate. Compliance with calls to respond to actual synchronized reserve events remains less than 100 percent. For the 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. For the seven spinning events longer

25 The MMU has discussed this recommendation in state of the market reports since 2016 but this is the first time it has been reported as a formal MMU recommendation.
26 Order No. 755, 137 FERC ¶ 61,064 at PP 197–200 (2011).
27 18 CFR § 385,211 (2017)
28 162 FERC ¶ 61,295 (2018).
29 The MMU filed its request for rehearing on April 27, 2018, and PJM filed its request for rehearing on April 30, 2018.

than 10 minutes in 2018, the response was 74.2 percent of scheduled tier 2 MW. There was only one spinning event that lasted longer than 10 minutes in the first nine months of 2019. This one spinning event in the first nine months of 2019 occurred on September 23. In the September 23 event, tier 2 response was 87.4 percent of the amount scheduled and tier 1 response was 71.8 percent of DGP estimated amount. Actual participant performance means that the penalty structure is not adequate to incent performance.

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, $2.2 million in 2017, $4.7 million in 2018, and $2.3 million in the first nine months of 2019.

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 significantly flawed. The MMU concludes that the synchronized reserve market results were competitive, although the $7.50 margin should be removed. 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-002-3, Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event, requires PJM to carry sufficient contingency reserve to recover from a sudden balancing contingency (usually a loss of generation). The Contingency Event Recovery Period is the time required to return the ACE to zero if it was zero or positive before the event or to its pre-event level if it was negative at the start of the event. NERC standards set the Contingency Event Recovery Period as 15 minutes and Contingency Reserve Restoration Period as 90 minutes.[30] The NERC requirement is 100 percent compliance and status must be reported quarterly. PJM implements this contingency reserve requirement using primary reserves.[31] 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. PJM does not currently have a Contingency Reserve Restoration Period standard.

Market Structure

Demand

PJM requires that 150 percent of the largest single 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.

The Primary Reserve Market requirement is set equal to 150 percent of the largest single contingency for each market solution, ASO, IT SCED, and RT SCED. This is usually the output of the largest generating unit. In cases where temporary switching conditions create the risk that a single fault could remove

30 See PJM "Manual 12: Balancing Operations," Rev. 39 (Feb. 21, 2019) Attachment D, "the Disturbance Recovery Period is 15 minutes after the start of a Reportable Disturbance. Subsequently, PJM must fully restore the Synchronized Reserve within 90 minutes."

31 See PJM "Manual 10: Pre-Scheduling Operations," § 3.1.1 Day-ahead Scheduling (Operating) Reserve, Rev. 38 (Aug. 22, 2019).

several generators, PJM will define the largest single contingency as the sum of the output of those generators.[32]

PJM can also increase the primary and synchronized reserve requirement in cases of hot weather or cold weather alerts or escalating emergency procedures.[33] Such additional reserves are committed as part of the hourly (ASO) and five minute (RT SCED) processes. In the first nine months of 2019, the average five minute interval primary reserve requirement for the RTO Zone was 2,477.6 MW. The average five minute interval primary reserve requirement in the MAD Subzone was 2,453.6 MW. These averages include the hours when PJM raised the requirements.

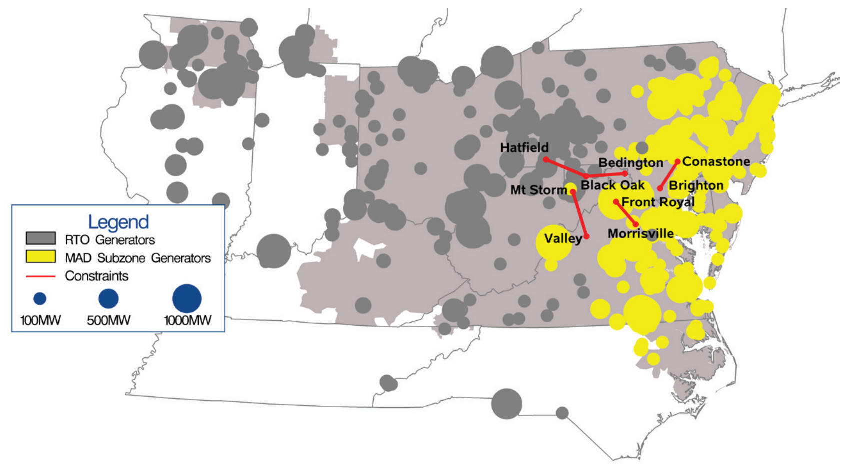
The MMU identified instances when PJM increased the primary and synchronized reserve requirements (Table 10-5). The amounts of the increases are estimated against average requirement levels before and after the periods of increase.

Table 10-5 Temporary adjustments to primary and synchronized reserve in 2019

From	To	Number of Hours	Amount of Adjustment
12-Feb-19	12-Feb-19	10	Primary Reserve (1,350 MW), Synchronized Reserve (1,000 MW)
4-Mar-19	5-Mar-19	24	Primary Reserve (220 MW), Synchronized Reserve (150 MW)
29-Apr-19	3-May-19	61	Primary Reserve (65 MW), Synchronized Reserve (50 MW)
7-May-19	7-May-19	6	Primary Reserve (280 MW), Synchronrized Reserve (230 MW)
6-Jun-19	6-Jun-19	5	Primary Reserve (600 MW), Synchronized Reserve (400 MW)
11-Jun-19	11-Jun-19	5	Primary Reserve (600 MW), Synchronized Reserve (300 MW)
17-Jun-19	19-Jun-19	24	Primary Reserve (220 MW), Synchronized Reserve (150 MW)
10-Sep-19	13-Sep-19	52	Primary Reserve (625 MW), Synchronized Reserve (425 MW)

Transmission constraints limit the deliverability of reserves within the RTO, requiring the definition of the Mid-Atlantic Dominion (MAD) Subzone (Figure 10-1).[34] Figure 10-1 is a map of constraints and major generation sources. The constraints separating the RTO Zone and MAD Subzone are defined by underlying grid topology. The RTO Zone into MAD Subzone constraints reflect limits on the transmission line capacity that separate the RTO Zone and MAD Subzone. If, in the case of a spinning event, the current economic dispatch plus the current synchronized market dispatch would overload the constraint, then all additional synchronized reserve MW must be cleared from the unconstrained side of the constraints. When this occurs, the synchronized reserve prices between the RTO Zone and the MAD Subzone will diverge.

Figure 10-1 PJM RTO Zone and MAD Subzone map of constraints and generation sources



The most limiting transmission constraint for power flow from the RTO Zone into the MAD Subzone since August, 2017, has been the AP South Interface, which includes Brighton-Conastone, Belmont-Stonewall, Bedington-Black Oak, Cloverdale-Lexington, and Mt. Storm-Valley constraints.

The NERC standard requires a control area to carry primary reserve MW equal to or greater than the most severe single contingency (MSSC).[35] PJM requires primary reserves in the amount of 150 percent of the largest single contingency with at least 100 percent of the requirement made up of

32 PJM Manual 11: Energy & Ancillary Services Market Operations, Rev. 107 (Sep 26, 2019), p. 84
33 PJM Manual 11: Energy & Ancillary Services Market Operations, Rev. 107(Sep. 26, 2019), p. 84
34 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," § 4.2.2 Synchronized Reserve Requirement Determination, Rev. 107 (Sep. 26, 2019).
35 NERC BAL-002-3. "Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event," September 25, 2018. <https://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-002-3.pdf>.

synchronized reserves.[36] In the first nine months of 2019, the five minute average synchronized reserve requirement in the RTO Zone was 1,713.8 MW. The five minute average synchronized reserve requirement in the MAD Subzone was 1,697.8 MW. The synchronized reserve requirement is calculated every five minutes.

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 is 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 1,576.0 MW of tier 1 was identified by the RT SCED market solution as available in the first nine months of 2019 (Table 10-6).[37] Tier 1 synchronized reserve fully satisfied the MAD Subzone synchronized reserve requirement or reduced the need for tier 2 synchronized reserve to self scheduled reserves in 12.9 percent of intervals in the first nine months of 2019. In the RTO Zone, an average of 2,179.5 MW of tier 1 was available (Table 10-7) fully satisfying the synchronized reserve requirement in 59.4 percent of intervals.

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. 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.[38]

After tier 1 is estimated, the remainder of the synchronized reserve requirement is met by tier 2. In the RTO Zone, there were 29,209.1 MW of tier 2 synchronized reserve offered daily. Of this, 5,463.9 MW were located in the MAD Subzone and available to meet the average MAD tier 2 hourly demand of 280.0 MW (Table 10-6).

In the MAD Subzone, there was an average of 3,054.2 MW of eligible nonsynchronized reserve supply available to meet the average interval demand for primary reserve. (Table 10-7) In the RTO Zone, an average of 3,953.1 MW supply was available to meet the average interval demand of 1,774.5 MW (Table 10-7).

Table 10-6 provides the average interval reserves, by type of reserve, used by the RT SCED market solution to satisfy the primary reserve requirement in the MAD Subzone from January 2018 through September 2019.

36 "PJM Manual 13: Emergency Operations," Rev 72 (Sep. 26, 2019), p. 18.

37 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.

38 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 4.2 PJM Synchronized Reserve Market Business Rules, Rev. 107 (Sep. 26, 2019).

Table 10-6 Average hourly reserves used to satisfy the primary reserve requirement, MAD Subzone: January 2018 through September 2019

Year	Month	Tier 1 Total MW	Tier 2 Synchronized Reserve MW	Nonsynchronized Reserve MW	Total Primary Reserve MW
2018	Jan	1,371.1	290.4	1,454.0	3,382.4
2018	Feb	1,408.1	264.3	1,461.1	3,504.1
2018	Mar	1,313.3	350.3	1,642.3	3,529.1
2018	Apr	1,192.8	453.7	1,226.4	3,175.5
2018	May	1,191.3	462.4	1,063.7	2,913.2
2018	Jun	1,445.7	185.6	1,195.9	3,239.7
2018	Jul	1,380.1	367.8	1,312.2	3,212.9
2018	Aug	1,334.4	460.1	1,228.5	3,052.2
2018	Sep	1,377.5	383.5	1,007.8	2,916.0
2018	Oct	1,356.5	356.0	602.4	2,705.8
2018	Nov	1,442.4	259.5	798.0	2,813.3
2018	Dec	1,542.6	363.8	1,103.4	3,081.2
2018	Average	1,363.0	349.8	1,174.6	3,127.1
2019	Jan	1,653.3	220.6	1,407.0	3,060.4
2019	Feb	1,630.0	304.7	1,554.3	3,184.4
2019	Mar	1,537.9	277.7	1,601.1	3,139.1
2019	Apr	1,368.4	303.4	1,590.7	2,959.2
2019	May	1,451.2	194.0	1,432.1	2,883.7
2019	Jun	1,676.6	295.6	1,440.5	3,117.2
2019	Jul	1,674.9	267.3	1,336.9	3,012.4
2019	Aug	1,684.2	284.5	1,465.8	3,150.1
2019	Sep	1,507.6	382.1	1,538.5	3,046.2
2019	Average	1,576.0	281.1	1,485.2	3,061.4

Table 10-7 shows the average hourly reserves, by type of reserve, used by the RT SCED market solution to satisfy the primary reserve requirement in the RTO Zone for January 2018 through September 2019.

Table 10-7 Average monthly reserves used to satisfy the primary reserve requirement, RTO Zone: January 2018 through September 2019

Year	Month	Tier 1 Total MW	Tier 2 Synchronized Reserve MW	Nonsynchronized Reserve MW	Total Primary Reserve MW
2018	Jan	1,792.5	466.6	2,189.8	3,982.2
2018	Feb	1,899.6	379.0	2,207.8	4,107.5
2018	Mar	1,552.4	541.8	2,394.6	3,947.0
2018	Apr	1,034.6	895.0	2,374.9	3,409.5
2018	May	1,318.7	786.6	1,984.7	3,303.3
2018	Jun	2,150.5	344.3	1,927.9	4,078.3
2018	Jul	2,036.8	532.1	1,972.3	4,009.2
2018	Aug	1,948.1	625.8	1,862.3	3,810.3
2018	Sep	1,825.1	602.6	1,717.4	3,542.5
2018	Oct	1,383.0	778.3	1,682.7	3,065.7
2018	Nov	1,596.0	639.6	1,649.7	3,245.6
2018	Dec	1,523.2	382.5	1,578.3	3,101.4
2018	Average	1,671.7	581.2	1,961.9	3,633.5
2019	Jan	2,540.4	375.6	1,542.2	4,458.2
2019	Feb	2,060.9	629.8	1,818.6	4,509.3
2019	Mar	1,965.2	593.7	1,848.0	4,407.0
2019	Apr	1,593.8	666.6	1,878.5	4,139.0
2019	May	2,022.4	483.7	1,657.0	4,163.0
2019	Jun	2,520.3	424.1	1,862.6	4,807.1
2019	Jul	2,601.7	425.6	1,652.5	4,679.8
2019	Aug	2,472.6	498.9	1,871.8	4,843.3
2019	Sep	1,837.9	753.1	1,905.1	4,496.1
2019	Average	2,179.5	539.0	1,781.8	4,500.3

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).

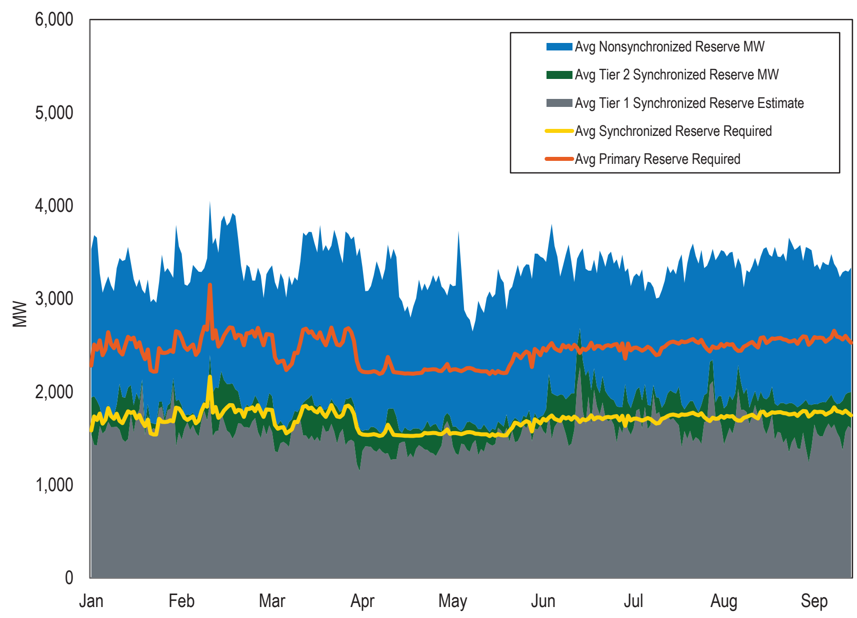
All market solutions determine the actual primary reserves required each hour as 150 percent of the largest contingency plus 190 MW. Of this, synchronized reserves must be 100 percent of the largest contingency plus 190 MW.

PJM's Ancillary Services Optimizer (ASO) optimizes the three components of primary reserve an hour ahead of the first interval of each operating hour. Using forecast LMPs, ASO calculates the tier 1 synchronized reserve available for the operating hour based on economic dispatch. The ASO compares the amount of estimated tier 1 synchronized reserve to the required synchronized reserve less self-scheduled synchronized reserve. If the synchronized reserve requirement is not met, the ASO clears, in economic order, inflexible tier 2 synchronized reserve and identifies flexible synchronized reserve sufficient to meet the remaining synchronized reserve requirement. ASO commits the economic inflexible resources from this solution to provide synchronized reserve for all intervals during the hour. This is inflexible Tier 2 Synchronized Reserve. All resources committed for inflexible tier 2 synchronized reserve are notified of their commitment via Markets Gateway thirty minutes before the operating hour. The economic flexible resources identified in the ASO solution are not committed as synchronized reserves prior to the hour.

Ten to 14 minutes before each interval of the operating hour RT SCED runs. If the tier 1 synchronized reserve plus ASO committed inflexible tier 2 synchronized reserve does not meet the requirement, RT SCED will commit available flexible tier 2 synchronized reserve. If there is an excess of synchronized reserve in an interval, the RT SCED may decommit previously committed flexible synchronized reserve.

Figure 10-2 illustrates how the ASO satisfied the primary reserve requirement (orange line) for the Mid-Atlantic Dominion Subzone. For the Mid-Atlantic Dominion Reserve Subzone the market solutions must first satisfy the synchronized reserve requirement (yellow line) which is calculated hourly in the MAD Subzone. The market solutions first estimate 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 they jointly optimize the 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 is filled with tier 2 synchronized reserve (green 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): January through September, 2019



The solution method is the same for the RTO Reserve Zone.[39] Figure 10-3 shows how the market solutions satisfy the primary reserve requirement for the RTO Zone.

Figure 10-3 RTO reserve zone primary reserve MW by source (Daily Averages): January through September, 2019

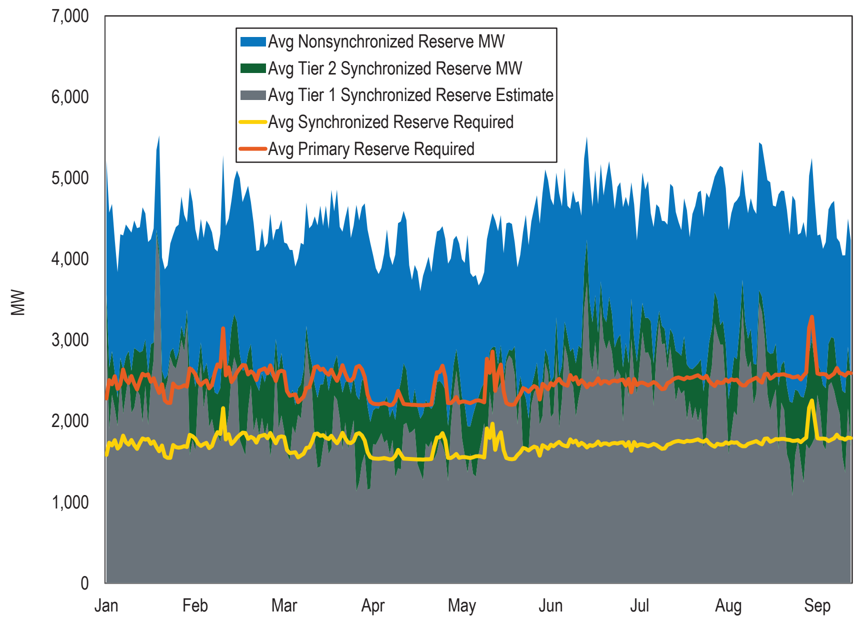


Figure 10-2 shows that within the MAD Subzone, Tier 1, Tier 2 from MAD, and Tier 2 from the RTO are all essential to satisfying the synchronized reserve requirement. Figure 10-3 shows that tier 1 synchronized reserve remains the major contributor to satisfying the synchronized reserve requirement in the RTO Zone.

39 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.

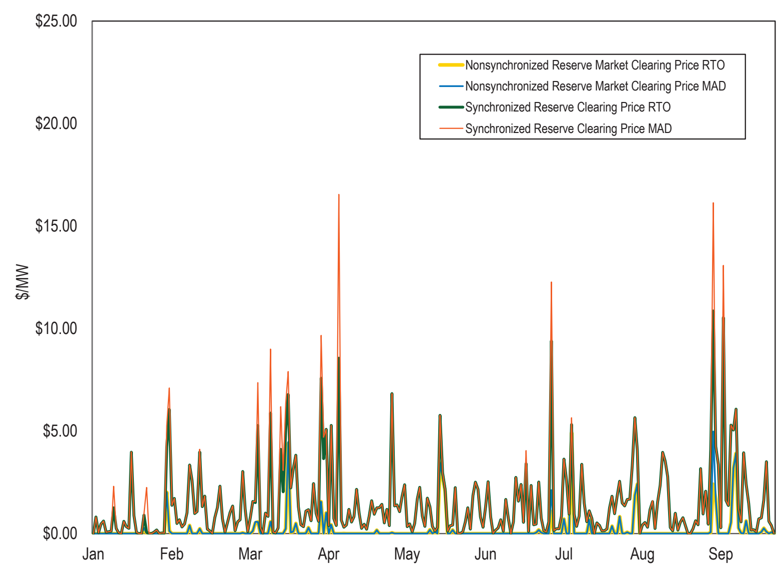
Price and Cost

The price of primary reserves results from the demand curve for primary reserves and the supply of primary reserves. The demand curve is modeled in each of the primary reserve clearing engines (ASO, IT SCED, RT SCED). The demand curve for primary reserves has two steps, with an $850 penalty factor for primary reserve levels ranging from 0 MW to a MW amount equal to 150 percent of the MSSC and a constraint with a $300 penalty factor for primary reserves ranging from 150 percent of MSSC to 150 percent of MSSC plus 190 MW.

The supply of primary reserves is made up of available tier 1 and tier 2 synchronized reserves and nonsynchronized reserves. Offer prices for synchronized reserve are capped at $7.50 plus costs plus opportunity costs.

Figure 10-4 shows daily weighted average synchronized and nonsynchronized market clearing prices in the first nine months of 2019.

Figure 10-4 Daily average market clearing prices ($/MW) for synchronized reserve and nonsynchronized reserve: January through September, 2019



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-002-3 primary reserve requirement is calculated by combining the three components. Each of these three components is shown in Table 10-8. The "Cost per MW" column is the total credits divided by the total MW of reserves.

On a combined basis, the ratio of price to cost for all primary reserve during the first nine months 2019 was 43.0 percent. 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 10-8 shows that the cost of tier 1 reserves is $23.30 per MW when the price of nonsynchronized reserve is greater than zero, or more than four times the cost of tier 2 reserves which is $4.79 per MW.

Table 10-8 Primary reserve requirement components, RTO Reserve Zone: January through September, 2019

Product	MW Share of Primary Reserve Requirement	MW	Credits Paid	Price Per MW Reserve	Cost Per MW Reserve
Tier 1 Synchronized Reserve Response	NA	2,985	$149,282	NA	$50.00
Tier 1 Synchronized Reserve in Market Solution	1.0%	98,503	$2,295,217	$0.00	$23.30
Tier 2 Synchronized Reserve Scheduled	28.5%	2,834,264	$13,576,310	$3.19	$4.79
Non Synchronized Reserve Scheduled	70.5%	7,002,727	$8,233,987	$0.20	$1.18
Primary Reserve (total of above)	100.0%	9,938,480	$24,254,796	$1.05	$2.44

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 estimated as the lesser of the available 10 minute ramp or the difference between the economic dispatch point and the synchronized reserve maximum output. By default the synchronized reserve maximum for a resource is equal to its economic maximum. Resource owners may request a lower synchronized reserve maximum if a physical limitation exists.[40] Tier 1 resources are identified by the market solution. Tier 1 synchronized reserve has an incremental cost of zero. Tier 1 synchronized reserve is paid under two circumstances. Tier 1 reserves are paid when they respond to a synchronized reserve event. Tier 1 reserves are paid the synchronized reserve market clearing price when the nonsynchronized reserve market clearing price is above $0.

While PJM relies on tier 1 resources to respond to a synchronized reserve event, tier 1 resources are not obligated to respond during an event. Tier 1 resources are credited if they do respond but are not penalized if they do not.

Market Structure

Supply

All generating resources operating on the PJM system with the exception of those assigned to tier 2 synchronized reserve are available for tier 1 synchronized reserve and any response to a spinning event will be credited at the Synchronized Energy Premium Price.

Beginning in 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. 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.[41] DGP should be documented in PJM's Market Rules. DGP violates the basic PJM principle that generation owners are solely responsible for their own offers. In addition,

40 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 4.2.1 Synchronized Reserve Market Eligibility, Rev. 107 (Sep. 26, 2019).

41 PJM. Ancillary Services, "Communication of Synchronized Reserve Quantities to Resource Owners," (May 6, 2015). <http://www.pjm.com/~/media/markets-ops/ancillary/communication-of-synchronized-reserve-quantities-to-resource-owners.ashx>

DGP is a crude estimate of ramp rates and does not account for the actual discontinuities along unit offer curves.

The supply of tier 1 synchronized reserve available to the market solution is adjusted by eliminating from the DGP estimate tier 1 MW from unit types that cannot reliably provide synchronized reserve. These unit types are nuclear, wind, solar, landfill gas, energy storage, and hydro units (Table 10-10).[42] 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. There is a review process for resources excluded from the tier 1 estimate that wish to be included.[43] This limitation by unit type necessarily restricts the fuel type supplying tier 1 synchronized reserve (Table 10-9).

Table 10-9 Supply of Tier 1 Synchronized Reserve by Fuel Type: January through September, 2019

Fuel	Percentage of Tier 1 MW	Percentage of Tier 1 Credits
Natural Gas	57.3%	57.9%
Coal	30.2%	28.6%
Hydro	8.0%	7.5%
LFG	1.7%	2.2%
Solar	0.9%	1.2%
Wind	0.8%	1.3%
MSW	0.5%	0.7%
Waste Coal	0.3%	0.2%
Biomass	0.1%	0.1%
Nuclear	0.1%	0.1%

Table 10-10 Supply of Tier 1 Synchronized Reserve by Unit Type: January through September, 2019

Unit Type	Percentage of Tier 1 MW	Percentage of Tier 1 Credits
CC	45.7%	44.1%
Steam	33.8%	32.3%
CT	8.6%	10.8%
Hydro	8.0%	7.5%
Diesel	2.0%	2.7%
Solar	0.9%	1.2%
Wind	0.8%	1.3%
Nuclear	0.1%	0.1%
DSR	0.1%	0.1%

In the first nine months of 2019, the market solutions estimated tier 1 MW from an average of 142 units that could contribute ramp in a spinning event. In the RTO Reserve Zone, the average interval estimated tier 1 synchronized reserve was 2,170.5 MW (Table 10-11). In 59.4 percent of intervals, 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 plus self scheduled tier 2.

In the first nine months of 2019, the average estimated tier 1 synchronized reserve available was 1,571.7 MW in the MAD Subzone of which 578.5 MW was available from the RTO (Table 10-12). In 13.1 percent of RT SCED intervals, the estimated tier 1 synchronized reserve available within the MAD Subzone plus self scheduled tier 2 in MAD was greater than the synchronized reserve requirement and no tier 2 market needed to be cleared.

42 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," § 4.2.1 Synchronized Reserve Market Eligibility, Rev. 107 (Sep. 26, 2019)
43 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," § 4.2.1 Synchronized Reserve Market Eligibility, Rev. 107 (Sep. 26, 2019)

Table 10-11 Monthly average interval market solutions for tier 1 synchronized reserve (MW): January 2018 through September 2019

Year	Month	Average Interval Tier 1 Local To MAD	Tier 1 Synchronized Reserve From RTO Zone	Average Interval Tier 1 Used in MAD	Average Interval Tier 1 Used in RTO Zone
2018	Jan	814.2	554.9	1,369.1	1,796.0
2018	Feb	765.6	640.3	1,406.0	1,886.0
2018	Mar	746.1	571.6	1,317.7	1,559.7
2018	Apr	434.1	756.2	1,190.3	1,028.6
2018	May	540.6	654.5	1,195.1	1,340.3
2018	Jun	825.7	613.4	1,439.1	2,113.7
2018	Jul	865.6	509.0	1,374.5	2,058.2
2018	Aug	835.4	493.2	1,328.6	1,923.0
2018	Sep	836.7	540.7	1,377.4	1,805.3
2018	Oct	617.9	737.1	1,355.0	1,393.8
2018	Nov	880.2	566.4	1,446.6	1,611.5
2018	Dec	1,101.1	421.2	1,522.2	2,025.8
2018	Average	771.9	588.2	1,360.1	1,711.9
2019	Jan	1,265.1	383.4	1,648.5	2,518.6
2019	Feb	999.1	630.9	1,629.9	2,052.6
2019	Mar	928.9	607.0	1,535.9	1,937.1
2019	Apr	665.7	703.5	1,369.2	1,593.3
2019	May	869.5	578.0	1,447.5	1,987.7
2019	Jun	1,154.9	509.5	1,664.5	2,523.7
2019	Jul	1,139.0	521.2	1,660.2	2,579.8
2019	Aug	1,178.8	504.2	1,683.0	2,477.1
2019	Sep	737.6	769.3	1,506.9	1,864.4
2019	Average	993.2	578.5	1,571.7	2,170.5

Demand

There is no required amount of tier 1 synchronized reserve. The estimated tier 1 MW are used to satisfy the total required amount of primary 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 and does not minimize the total cost of primary reserves. The MMU recommends that tier 1 synchronized reserve not be paid when the nonsynchronized reserve market clearing price is above $0.

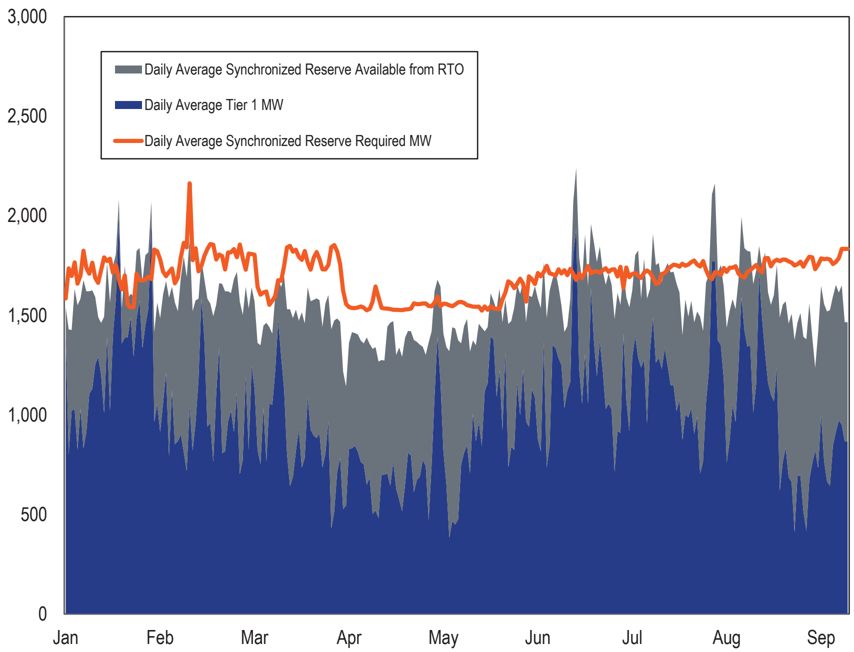
Supply and Demand

The price of synchronized reserves results from the demand curve for synchronized reserves and the supply of synchronized reserves. The demand curve is modeled in each of the synchronized reserve clearing engines (ASO, IT SCED, RT SCED). The demand curve for synchronized reserves has two steps, with an $850 penalty factor for synchronized reserve levels ranging from 0 MW to a MW amount equal to 100 percent of the MSSC and a constraint with a $300 penalty factor for synchronized reserves ranging from 100 percent of MSSC to 100 percent of MSSC plus 190 MW.

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 (blue area of Figure 10-5) as well as the synchronized reserve MW estimated to be available within the MAD Subzone from the RTO Zone (gray area of Figure 10-5) up to the synchronized reserve requirement. If the total tier 1 synchronized reserve is less than the synchronized reserve requirement, the remainder of the synchronized reserve requirement is filled with tier 2 synchronized reserve (white area below the synchronized reserve required line in Figure 10-5).

Figure 10-5 Daily average tier 1 synchronized reserve supply (MW) in the MAD Subzone: January through September, 2019



Tier 1 Synchronized Reserve Event Response

Tier 1 synchronized reserve is awarded credits when a synchronized reserve event occurs and it responds. Tier 1 synchronized reserve resources are paid for increasing output (or reducing load for demand response) at the rate of $50 per MWh in addition to LMP.[44] This is the Synchronized Energy Premium Price. 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. Spinning event response is calculated as the highest output between 9 minutes and 11 minutes after the event is declared minus the lowest output between one minute before and one minute after the event is declared. Total response credited to a resource is capped at 110 percent of estimated capability.

In the first nine months of 2019, tier 1 synchronized reserve spinning event response credits of $149,282 were paid for 10 spinning events covering 20 intervals. The average tier 1 response over the six spinning events was 285.5 MWh (Table 10-12).

Table 10-12 Tier 1 synchronized reserve event response costs: January 2018 through September 2019

		Synchronized Reserve Events			Hours When NSRMCP>$0		
Year	Month	Total MWh	Total Credits	Average MWh Per Event	Total MWh	Total Credits	Average MW Per Hour
2018	Jan	6,081.6	$1,146,858	676.3	39,047.0	$2,394,953	1,259.6
2018	Feb	0.0	$0	NA	0.0	NA	NA
2018	Mar	0.0	$0	NA	9,906.4	$176,651	990.6
2018	Apr	287.4	$14,969	534.0	2,584.1	$48,880	143.6
2018	May	0.0	$0	NA	5,564.8	$191,459	347.8
2018	Jun	1,422.0	$71,416	1,422.0	3,545.3	$20,354	590.9
2018	Jul	1,511.8	$76,588	518.6	1,762.9	$4,888	440.7
2018	Aug	534.2	$26,716	534.2	1,380.3	$15,568	460.1
2018	Sep	1,026.8	$53,492	513.4	18,255.9	$478,289	553.2
2018	Oct	144.1	$7,205	144.0	60,896.0	$1,212,173	609.0
2018	Nov	0.0	$0	NA	12,278.0	$184,777	341.1
2018	Dec	0.0	$0	NA	770.0	$4,034	192.5
2018		11,007.8	$1,397,244	620.4	155,990.7	$4,732,025	539.0
2019	Jan	784.8	$39,244	261.6	2,671.7	$96,303	445.3
2019	Feb	228.4	$11,422	228.4	2,733.0	$35,529	390.4
2019	Mar	633.7	$31,688	316.9	12,050.0	$436,108	446.3
2019	Apr	0.0	$0	NA	3,065.4	$115,550	383.2
2019	May	0.0	$0	NA	38,102.7	$398,500	952.6
2019	Jun	0.0	$0	NA	2,089.8	$12,776	522.4
2019	Jul	79.4	$3,971	79.4	7,574.0	$419,285	504.9
2019	Aug	394.9	$19,743	394.9	1,899.8	$126,928	474.9
2019	Sep	864.3	$43,214	432.1	28,317.0	$654,238	629.3
2019		2,985.4	$149,282	285.5	98,503.4	$2,295,217	527.7

44 See PJM. "Manual 11: Energy & Ancillary Services Market Operations,"§ 4.2.10 Settlements, Rev. 107 (Sep. 26, 2019).

Paying Tier 1 the Tier 2 Price

Tier 1 synchronized reserve has zero marginal cost and the corresponding competitive 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. 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 10-14). 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 (Table 10-13). The nonsynchronized reserve market clearing price was above $0.00 in 156 hours in the first nine months of 2019. For those 156 hours, tier 1 synchronized reserve resources were paid a weighted average synchronized reserve market clearing price of $31.64 per MW and earned $2,295,217 in credits.

Table 10-13 Price of tier 1 synchronized reserve attributable to a nonsynchronized reserve price above zero: January 2018 through September 2019

Year	Month	Total Hours When NSRMCP>$0	Weighted Average SRMCP for Hours When NSRMCP>$0	Total Tier 1 MWh Credited for Hours When NSRMCP>$0	Total Tier 1 Credits Paid When NSRMCP>$0	Average Tier 1 MWh Paid
2018	Jan	31	$61.34	39,047.0	$2,394,953	1,259.6
2018	Feb	0	NA	NA	NA	NA
2018	Mar	10	$17.83	9,906.4	$176,651	990.6
2018	Apr	18	$18.91	2,584.0	$48,880	143.6
2018	May	16	$34.41	5,564.8	$191,459	347.8
2018	Jun	6	$5.74	3,545.3	$20,354	590.9
2018	Jul	4	$2.77	1,762.9	$4,888	440.7
2018	Aug	3	$11.27	1,380.3	$15,568	460.1
2018	Sep	33	$26.20	18,256.0	$478,289	553.2
2018	Oct	100	$19.91	60,896.0	$1,212,173	609.0
2018	Nov	36	$15.05	12,278.0	$184,777	341.1
2018	Dec	4	$5.24	770.0	$4,034	192.5
2018		261	$19.88	155,990.7	$4,732,026	539.0
2019	Jan	6	$36.05	2,671.7	$96,303	445.3
2019	Feb	7	$13.00	2,733.0	$35,529	390.4
2019	Mar	27	$36.19	12,049.7	$436,108	446.3
2019	Apr	8	$37.69	3,065.4	$115,550	383.2
2019	May	40	$10.46	38,102.7	$398,500	952.6
2019	Jun	4	$6.11	2,089.8	$12,776	522.4
2019	Jul	15	$55.36	7,574.0	$419,285	504.9
2019	Aug	4	$66.81	1,899.8	$126,928	474.9
2019	Sep	45	$23.10	28,317.0	$654,238	629.3
2019		156	$31.64	98,502.9	$2,295,217	527.7

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 the first nine months of 2019, there has only been one spinning event of 10 minutes or longer. In that event of September 23, 71.8 percent of the 924.7 MW of DGP estimated Tier 1 responded and 87.4 percent of the 723.2 MW of tier 2 responded. A total of 1,998.0 MW of tier 1 did respond. 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 the first nine months of 2019, tier 1 synchronized reserve was paid $149,282 for responding to synchronized reserve events. During the same time period, tier 1 synchronized reserve was paid a windfall of $2,295,217 simply because the NSRMCP was greater than $0.00 in 40 hours. Table 10-12 provides a comparison of the cost of tier 1 as used for spinning events and the cost when compensated because the NSRMCP was greater than $0.

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.[45] 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 synchronized energy premium price.

PJM's current tier 1 compensation rules are presented in Table 10-14.

45 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 10-14 Tier 1 compensation as currently implemented by PJM

Tier 1 Compensation by Type of Interval as Currently Implemented by PJM		
Interval Parameters	No Synchronized Reserve Event	Synchronized Reserve Event
NSRMCP=$0	T1 credits = $0	T1 credits = Synchronized Energy Premium Price * actual response MWi
NSRMCP>$0	T1 credits = T2 SRMCP * estimated tier 1 MW	T1 credits = T2 SRMCP * min(estimated tier 1 MW, actual response MWi)

The MMU's recommended compensation rules for tier 1 MW are in Table 10-15.

Table 10-15 Tier 1 compensation as recommended by MMU

Tier 1 Compensation by Type of Hour as Recommended by MMU		
Interval Parameters	No Synchronized Reserve Event	Synchronized Reserve Event
NSRMCP=$0	T1 credits = $0	T1 credits = Synchronized Energy Premium Price * actual response MWi
NSRMCP>$0	T1 credits = $0	T1 credits = Synchronized Energy Premium Price * actual response MWi

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).

Synchronized reserve resources can be flexible or inflexible. Inflexible resources are defined as those resources that require an hourly commitment due to minimum run times or staffing constraints. Examples of inflexible reserves are synchronous condensers operating in condensing mode and demand resources. Tier 2 synchronized reserve inflexible resources are committed for a full hour by the hour ahead market solution. Inflexible resources cannot be released for energy during the operating hour. The inflexible commitments made by the hour ahead ASO solution may satisfy only part of the tier 2 requirement. The actual requirement is determined every five minutes by the RT SCED solution and the requirement not satisfied by inflexible units is satisfied by flexible units for the interval.

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 online 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.[46]

In the first nine months of 2019, the Mid Atlantic Dominion (MAD) Reserve Subzone averaged 5,473.4 MW of tier 2 synchronized reserve offers, and the RTO Reserve Zone averaged 29,238.5 MW of tier 2 synchronized reserve offers (Figure 10-9).

The supply of tier 2 synchronized reserve offered in the first nine months of 2019 was sufficient to cover the ASO hourly requirement net of tier 1 in both the RTO Reserve Zone and the MAD Reserve Subzone.

The largest portion of cleared tier 2 synchronized reserve from generation in the first nine months of 2019 was from CTs (Table 10-17). Although demand resources are limited to providing no more than 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 some hours demand resources make up considerably more than 33 percent of the cleared Tier 2 MW. DR MW were 2.9 percent of cleared plus self-scheduled tier 2 synchronized reserve in the first nine months of 2019.

Table 10-16 Supply of Generation Tier 2 Synchronized Reserve by Fuel Type: January through September, 2019

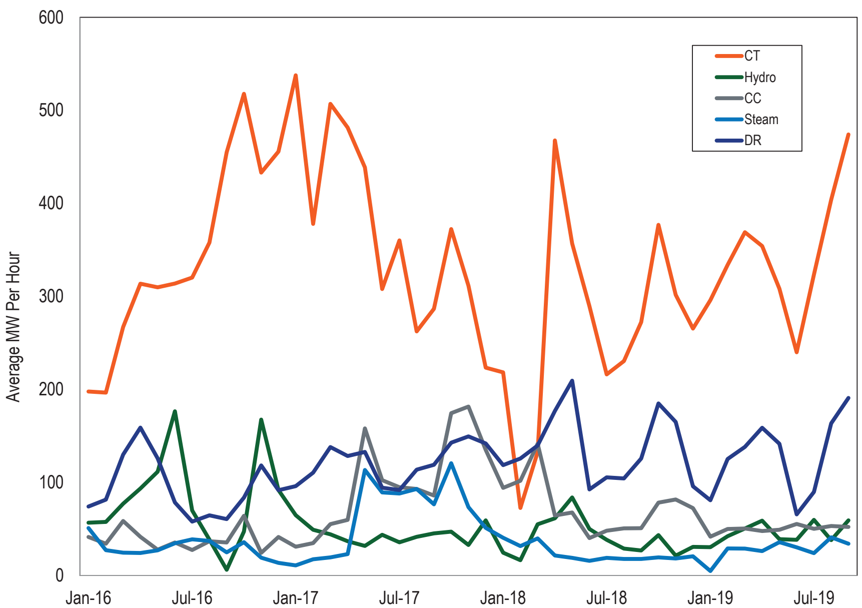
Fuel	Percentage of Tier 2 MW	Percentage of Tier 2 Credits
Natural Gas	64.1%	74.6%
Light Oil	22.9%	18.2%
Hydro	9.8%	3.0%
Coal	2.9%	3.9%
Waste Oil	0.2%	0.2%
Diesel	0.0%	0.0%
Biomass	0.0%	0.0%
LFG	0.0%	0.0%

46 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 4.2.1 Synchronized Reserve Market Eligibility, Rev. 107 (Sep.26, 2019).

Table 10-17 Supply of Tier 2 Synchronized Reserve by Unit Type: January through September, 2019

Unit Type	Percentage of Tier 2 MW	Percentage of Tier 2 Credits
CT	69.5%	68.2%
CC	14.8%	15.7%
Hydro	9.5%	2.7%
Steam	3.1%	3.9%
DSR	2.9%	9.2%
Diesel	0.2%	0.3%

Figure 10-6 Cleared tier 2 synchronized reserve average MW per hour by unit type, RTO Zone: January 2016 through September 2019



Demand

On July 12, 2017, PJM adopted a dynamic synchronized reserve requirement set equal to 100 percent of the most severe single contingency (MSSC), determined in each five minute interval by RT SCED. There are two circumstances in which PJM may alter the synchronized reserve requirement from its 100 percent of the largest contingency value. Reserve requirements may be increased during a temporary switching condition when transmission outages or configuration problems cause several generation resources to be subject to a single contingency. When PJM operators anticipate periods of high 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 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.[47]

In the first nine months of 2019, the average synchronized reserve requirement per interval in the RTO Zone was 1,713.8 MW and the average synchronized reserve requirement in the MAD Subzone was 1,697.8 MW. These averages include temporary increases to the synchronized reserve requirement.

The RTO Reserve Zone purchased an interval average of 536.2 MW of tier 2 synchronized reserves in the first nine months of 2019. Of this, an average of 280.2 MW cleared within the MAD Subzone.

Figure 10-7 and Figure 10-8 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 September 2019, for the RTO Reserve Zone and MAD Reserve Subzone. There were 21 intervals of shortage in the first nine months of 2019. There were ten spinning events in the first nine months of 2019 but only one lasted longer than 10 minutes (September 23, 2019).

47 PJM "Manual 11: Energy & Ancillary Services Market Operations," § 4.2.2 Synchronized Reserve Requirement Determination, Rev. 107 (Sep 26, 2019).

Figure 10-7 MAD hourly average tier 2 synchronized reserve scheduled MW: January 2016 through September 2019

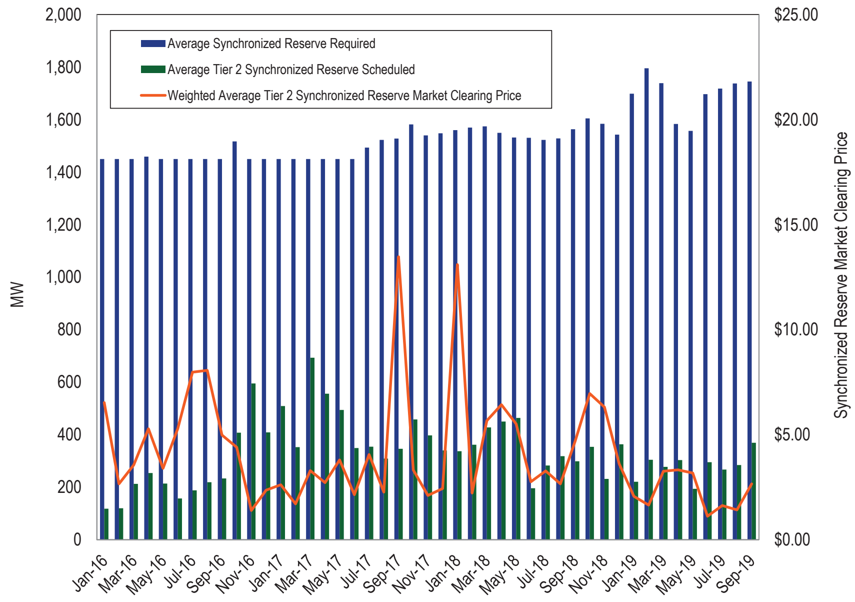
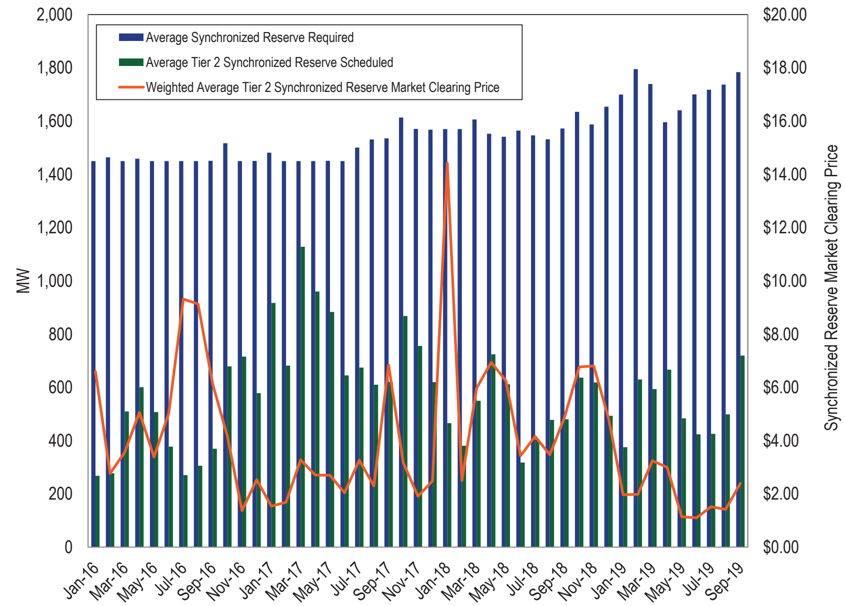


Figure 10-8 RTO hourly average tier 2 synchronized reserve scheduled MW: January 2016 through September 2019



Market Concentration

The average HHI for tier 2 synchronized reserve cleared intervals in the Mid-Atlantic Dominion Subzone Tier 2 Synchronized Reserve Market in the first nine months of 2019 was 4319, which is defined as highly concentrated. In 62.6 percent of all cleared intervals the maximum market share greater than or equal to 40 percent.

The average HHI for tier 2 synchronized reserve for cleared intervals of the RTO Zone Tier 2 Synchronized Reserve Market in the first nine months of 2019 was 5505, which is defined as highly concentrated. In 94.3 percent of cleared intervals there was a maximum market share greater than or equal to 40 percent.

In the MAD Subzone, flexible synchronized reserve was 9.5 percent of all tier 2 synchronized reserve in the first nine months of 2019. In the RTO Zone, flexible synchronized reserve assigned was 24.0 percent of all tier 2 synchronized reserve during the same period.

In the first nine months of 2019 9.7 percent of hours would have failed the three pivotal supplier test in the RTO Zone and MAD Subzone for all cleared hours of the inflexible Synchronized Reserve Market in the hour ahead market (Table 10-18).

Table 10-18 Three pivotal supplier test results for the RTO Zone and MAD Subzone: January 2018 through September 2019

Year	Month	MAD Reserve Subzone Pivotal Supplier Hours	RTO Reserve Zone Pivotal Supplier Hours
2018	Jan	65.5%	19.5%
2018	Feb	31.4%	0.0%
2018	Mar	41.2%	13.6%
2018	Apr	17.4%	9.2%
2018	May	15.2%	6.6%
2018	Jun	16.0%	9.3%
2018	Jul	15.4%	11.2%
2018	Aug	13.6%	7.0%
2018	Sep	17.3%	8.3%
2018	Oct	10.6%	11.2%
2018	Nov	16.0%	15.1%
2018	Dec	8.5%	11.6%
2018	Average	22.3%	10.2%
2019	Jan	3.8%	3.4%
2019	Feb	6.6%	6.8%
2019	Mar	2.6%	2.6%
2019	Apr	2.7%	2.7%
2019	May	1.8%	1.8%
2019	Jun	13.0%	11.2%
2019	Jul	20.7%	16.9%
2019	Aug	21.1%	18.5%
2019	Sep	25.8%	20.2%
2019	Average	10.9%	9.3%

The market structure results indicate that the RTO Zone and Mid-Atlantic Dominion Subzone Tier 2 Synchronized Reserve Markets are not structurally competitive.

Market Behavior

Offers

Daily cost-based offers are submitted for each unit by the unit owner. For generators the offer must include when relevant a tier 1 synchronized reserve ramp rate, a tier 1 synchronized reserve maximum, self scheduled status, synchronized reserve availability, synchronized reserve offer quantity (MW), tier 2 synchronized reserve offer price, energy use for tier 2 condensing resources (MW), condense to gen cost, shutdown costs, condense startup cost, condense hourly cost, condense notification time, and spin as a condenser status. The synchronized reserve offer price made by the unit owner is subject to an offer cap of marginal cost plus a markup of $7.50 per MW. The tier 1 synchronized reserve ramp rate must be greater than or equal to the real-time economic ramp rate. If the synchronized reserve ramp rate is greater than the economic ramp rate it must be justified by the submission of actual data from previous synchronized reserve events.[48] 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.[49]

Figure 10-9 shows the daily average of hourly offered tier 2 synchronized reserve MW for both the RTO Synchronized Reserve Zone and the Mid-Atlantic Dominion Synchronized Reserve Subzone. In the first nine months of 2019, the ratio of eligible tier 2 synchronized reserve to synchronized reserve required across the RTO was 14.7.

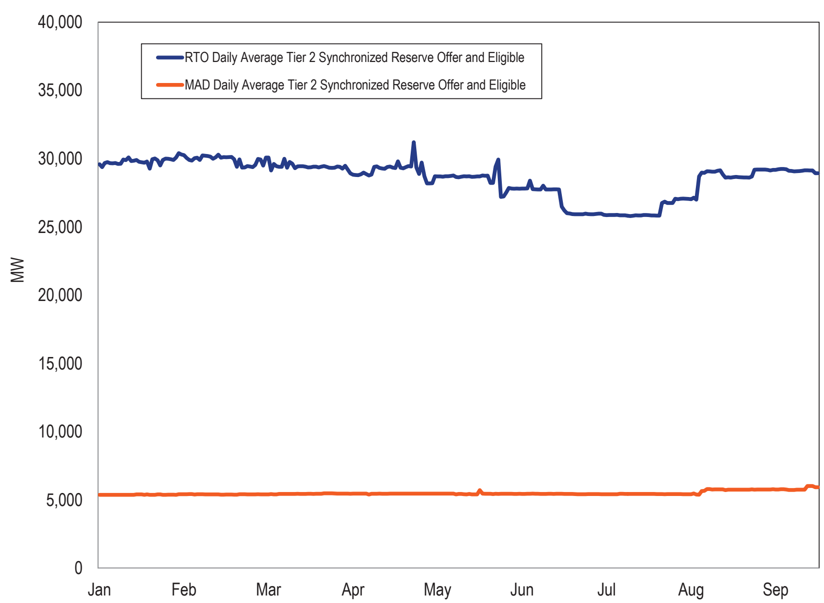
PJM has a tier 2 synchronized reserve must offer requirement for all generation that is online, nonemergency, and physically able to operate with an output

48 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 4.2.1 Synchronized Reserve Market Eligibility Rev. 107 (Sep. 26, 2019).

49 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 4.2.1 Synchronized Reserve Market Eligibility Rev. 107 (Sep. 26, 2019).

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.[50] The Tier 2 Synchronized Reserve Market is not 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 10-9). 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 10-9 Tier 2 synchronized reserve hourly offer and eligible volume (MW): January through September, 2019



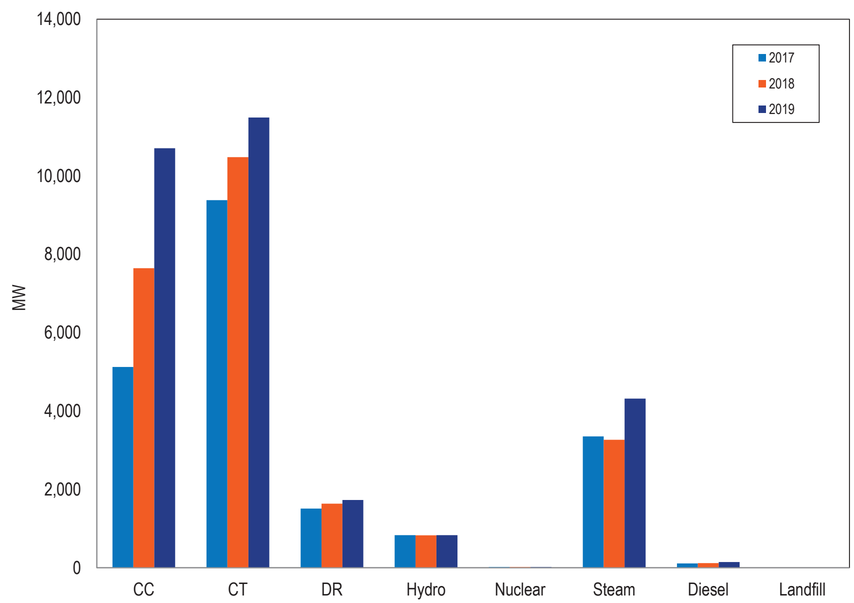
50 See id. ("Regardless of online/offline state, all non-emergency generation capacity resources must submit a daily offer for Tier 2 Synchronized Reserve in eMKT…").

While over 97 percent of resources have tier 2 synchronized reserve offers, there remain a large number of hours when many units make themselves unavailable for tier 2 synchronized reserve.

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.[51]

Figure 10-10 shows average full RTO daily offer MW volume by unit type in the first nine months of 2017 through 2019.

Figure 10-10 RTO daily tier 2 synchronized reserve offers by unit type (MW): January through September, 2017 through 2019



51 PJM 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.

Market Performance

Price

The price of tier 2 synchronized reserve is calculated in real time every five minutes for the RTO Reserve Zone and the MAD Subzone.

In the first nine months of 2019 there was enough tier 1 synchronized reserve plus self-scheduled tier 2 reserve to cover the full requirement in 13.1 percent of cleared intervals. For the first nine months of 2019 the MAD tier 2 market cleared an average of 280.6 MW at a weighted average clearing price of $3.07 compared to an average of 348.7 MW $4.92 in the same period of 2018 (Table 10-19).

In the first nine months of 2019, the RTO tier 2 market cleared an average of 536.9 MW at a weighted average price of $3.19 compared to an average of 490.3 MW at $5.78 in the same period of 2018 (Table 10-20).

In 99.87 percent of cleared intervals, the synchronized reserve market clearing price was the same for both the MAD Subzone and the RTO Zone. The 0.13 percent of intervals when the price diverged only occurred during periods of high prices where the average MAD SRMCP was $275.11 and average RTO SRMCP was $164.48.

Supply, performance, and demand are reflected in the price of synchronized reserve. (Figure 10-7 and Figure 10-8).

Table 10-19 MAD Subzone, average SRMCP and average scheduled, tier 1 estimated and demand response MW: January 2018 through September 2019

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)
2018	Jan	$13.10	211.7	1,371.1	125.6
2018	Feb	$2.22	181.4	1,408.1	180.6
2018	Mar	$5.67	271.5	1,313.3	156.0
2018	Apr	$6.58	359.6	1,192.8	90.4
2018	May	$5.62	349.3	1,191.3	114.5
2018	Jun	$2.93	146.3	1,445.7	49.7
2018	Jul	$3.29	223.7	1,380.1	59.1
2018	Aug	$2.83	269.5	1,334.4	48.6
2018	Sep	$4.94	238.0	1,377.5	60.8
2018	Oct	$7.28	277.2	1,356.5	76.6
2018	Nov	$6.91	192.6	1,442.4	39.1
2018	Dec	$3.29	222.9	1,524.4	33.7
2018	Average	$5.39	245.3	1,361.5	86.2
2019	Jan	$2.05	221.9	1,650.6	26.5
2019	Feb	$1.73	307.3	1,629.9	32.4
2019	Mar	$3.14	279.4	1,536.7	44.9
2019	Apr	$2.82	305.2	1,368.8	59.5
2019	May	$2.76	196.5	1,449.2	48.4
2019	Jun	$2.27	294.9	1,669.8	23.9
2019	Jul	$4.05	267.5	1,667.0	24.6
2019	Aug	$3.07	285.1	1,683.3	26.0
2019	Sep	$5.72	367.8	1,505.8	42.3
2019	Average	$3.07	280.6	1,573.5	36.5

Table 10-20 RTO zone average SRMCP and average scheduled, tier 1 estimated and demand response MW: January 2018 through September 2019

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)
2018	Jan	$14.42	348.3	1,792.5	117.4
2018	Feb	$2.50	257.6	1,899.6	123.6
2018	Mar	$5.97	412.0	1,552.5	137.6
2018	Apr	$7.06	633.8	1,034.6	90.4
2018	May	$6.19	498.1	1,318.7	114.0
2018	Jun	$3.38	211.6	2,150.5	106.0
2018	Jul	$4.32	291.6	2,036.8	113.1
2018	Aug	$3.74	355.9	1,948.1	122.1
2018	Sep	$5.63	356.1	1,825.1	124.2
2018	Oct	$7.42	512.7	1,383.0	123.9
2018	Nov	$7.32	451.5	1,596.0	167.0
2018	Dec	$4.38	377.3	2,021.6	116.2
2018	Average	$6.15	392.2	1,728.7	121.3
2019	Jan	$2.26	378.7	2,528.7	72.9
2019	Feb	$1.96	634.4	2,056.8	118.2
2019	Mar	$3.48	598.6	1,948.4	136.5
2019	Apr	$3.10	667.6	1,593.4	157.8
2019	May	$2.61	494.0	2,003.4	134.1
2019	Jun	$2.55	420.5	2,522.5	53.9
2019	Jul	$4.30	423.6	2,590.4	68.7
2019	Aug	$3.34	498.8	2,474.0	82.5
2019	Sep	$5.07	715.7	1,887.7	133.3
2019	Average	$3.19	536.9	2,178.4	106.4

Cost

As a result of changing grid conditions, load forecasts, and unexpected generator performance, prices do not always cover the full cost including the final LOC for each resource. Because price formation occurs within the hour (on a five minute basis integrated over the hour) but inflexible 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 100 percent, the more the market price reflects the full cost of tier 2 synchronized reserve. A price to cost ratio close to 100 percent is an indicator of an efficient synchronized reserve market design.

In the first nine months of 2019, the price to cost (including self scheduled) ratio of the RTO Zone Tier 2 Synchronized Reserve Market averaged 39.9 percent (Table 10-21); the price to cost ratio of the MAD Subzone (Table 10-22) averaged 43.3 percent.

Table 10-21 RTO Zone tier 2 synchronized reserve MW, credits, price, and cost: January 2018 through September 2019

Zone	Year	Month	Tier 2 Credited MW	Tier 2 Credits	LOC Credits	Weighted Average Synchronized Reserve Market Clearing Price	Tier 2 Synchronized Reserve Cost	Price/Cost Ratio
RTO Zone	2018	Jan	251,473	$3,736,516	$3,597,281	$14.86	$29.16	50.9%
RTO Zone	2018	Feb	167,661	$432,250	$475,401	$2.58	$5.41	47.6%
RTO Zone	2018	Mar	305,748	$1,829,286	$955,726	$5.98	$9.11	65.7%
RTO Zone	2018	Apr	513,898	$3,676,407	$2,979,772	$7.15	$12.95	55.2%
RTO Zone	2018	May	424,953	$2,693,398	$3,328,585	$6.34	$14.17	44.7%
RTO Zone	2018	Jun	178,862	$617,449	$1,027,023	$3.45	$9.19	37.5%
RTO Zone	2018	Jul	242,712	$1,063,555	$794,436	$4.38	$7.66	57.2%
RTO Zone	2018	Aug	284,146	$1,071,340	$1,407,424	$3.77	$8.72	43.2%
RTO Zone	2018	Sep	280,391	$1,597,878	$1,418,818	$5.70	$10.76	53.0%
RTO Zone	2018	Oct	437,122	$3,294,095	$1,904,130	$7.54	$11.89	63.4%
RTO Zone	2018	Nov	324,837	$2,417,158	$1,454,718	$7.44	$11.92	62.4%
RTO Zone	2018	Dec	287,288	$1,259,020	$962,818	$4.38	$7.73	56.7%
RTO Zone	2018		3,699,091	$23,688,351	$20,306,132	$6.13	$11.56	53.1%
RTO Zone	2019	Jan	198,030	$447,932	$1,021,911	$2.26	$7.42	30.5%
RTO Zone	2019	Feb	329,482	$644,828	$1,464,022	$1.96	$6.40	30.6%
RTO Zone	2019	Mar	384,207	$1,338,602	$2,131,555	$3.48	$9.03	38.6%
RTO Zone	2019	Apr	382,642	$1,187,948	$1,662,252	$3.10	$7.45	41.7%
RTO Zone	2019	May	294,931	$768,953	$902,854	$2.61	$5.67	46.0%
RTO Zone	2019	Jun	238,489	$609,117	$598,266	$2.55	$5.06	50.4%
RTO Zone	2019	Jul	255,474	$1,098,202	$2,419,557	$4.30	$13.77	31.2%
RTO Zone	2019	Aug	320,989	$1,071,987	$1,063,553	$3.34	$6.65	50.2%
RTO Zone	2019	Sep	430,020	$2,191,848	$2,312,339	$5.07	$10.47	48.4%
RTO Zone	2019		2,834,264	$9,359,417	$13,576,310	$3.19	$7.99	39.9%

Table 10-22 MAD Subzone tier 2 synchronized reserve MW, credits, price, and cost: January 2018 through September 2019

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	2018	Jan	246,978	$3,908,791	$13.10	$24.89	52.6%
MAD Subzone	2018	Feb	121,873	$537,031	$2.22	$4.41	50.4%
MAD Subzone	2018	Mar	201,995	$1,548,772	$5.67	$7.67	74.0%
MAD Subzone	2018	Apr	258,116	$3,020,632	$6.58	$11.70	56.2%
MAD Subzone	2018	May	259,906	$3,164,879	$5.62	$12.18	46.1%
MAD Subzone	2018	Jun	100,506	$593,608	$2.93	$5.91	49.5%
MAD Subzone	2018	Jul	158,652	$832,799	$3.29	$5.25	62.7%
MAD Subzone	2018	Aug	195,521	$1,354,403	$2.83	$6.93	40.8%
MAD Subzone	2018	Sep	166,472	$1,204,564	$4.94	$7.24	68.3%
MAD Subzone	2018	Oct	206,868	$2,222,948	$7.28	$10.75	67.8%
MAD Subzone	2018	Nov	136,323	$1,642,482	$6.91	$12.05	57.4%
MAD Subzone	2018	Dec	166,883	$856,328	$3.29	$5.13	64.2%
MAD Subzone	2018		2,220,094	$20,887,236	$5.39	$9.51	56.7%
MAD Subzone	2019	Jan	112,251	$655,861	$2.05	$5.84	35.1%
MAD Subzone	2019	Feb	141,165	$604,896	$1.73	$4.29	40.5%
MAD Subzone	2019	Mar	177,502	$1,096,369	$3.14	$6.18	50.9%
MAD Subzone	2019	Apr	163,121	$882,886	$2.82	$5.41	52.0%
MAD Subzone	2019	May	109,987	$519,107	$2.76	$4.72	58.5%
MAD Subzone	2019	Jun	132,344	$490,618	$2.27	$3.71	61.4%
MAD Subzone	2019	Jul	142,123	$574,936	$4.05	$16.72	24.2%
MAD Subzone	2019	Aug	159,378	$488,997	$3.07	$6.60	46.5%
MAD Subzone	2019	Sep	205,095	$1,175,659	$5.72	$10.26	55.7%
MAD Subzone	2019		1,342,966	$6,489,329	$3.07	$7.08	43.3%

Performance

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.[52] 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.[53] Tier 2 resources are obligated to sustain their final output for the shorter of the length of the event or 30 minutes. Penalties are assessed for failure of a scheduled tier 2 resource to perform during any synchronized reserve event lasting 10 minutes or longer.

In the first nine months of 2019, there were 10 spinning events and only one lasted more than 10 minutes. The MMU has reported synchronized reserve event response levels and recommended that PJM take action to increase compliance rates. Most resources respond at 100 percent but some resources consistently fail to fully respond.

A tier 2 resource is penalized for all hours in the Immediate Past Interval (IPI) in the amount of MW it falls short of its scheduled MW during an event and for any hour in that day for which it cleared. The penalty period is calculated as the lesser of the average number of days between spinning events over the past two years (ISI) or the number of days since the resource last failed to respond fully. For 2018, PJM uses the average number of days between spinning events from November 2016 through October 2018 which is 19 days. 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.

The penalty for a tier 2 resource failing to meet its scheduled obligation during a spinning event involves two components. First, the resource foregoes payment for the MW of under-response for all cleared hours of the day of the event. Second, the resource is charged a penalty in the amount of its MW under-response against all of its cleared hours of synchronized reserve during the Immediate Past Interval (IPI) or since the resource last failed to respond to a spinning event, whichever is less. IPI is calculated yearly on December 1 as the average number of days between spinning events over the past two years. Participants with more than one resource can aggregate their response from over responders to offset under responders during an event.[54]

52 See 2011 State of the Market Report for PJM, Vol. 2, Section 9, "Ancillary Services," at 250.

53 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 4.2.10 Settlements Rev. 107 (Sep. 26, 2019).

54 See PJM "Manual 28: Operating Agreement Accounting,"§ 6.3 Charges for Synchronized Reserve, Rev. 82 (July25, 2019.)

The penalty structure for tier 2 synchronized reserve nonperformance is flawed. The current penalty rule structure has a number of design issues which limit its effectiveness in providing an incentive for tier 2 MW to respond to spin events.

Under the current penalty structure it is possible for a resource to not respond to any spin events and yet be paid for providing tier 2. The current penalty structure for tier 2 synchronized reserve nonperformance is not adequate to provide appropriate performance incentives.

Under the current penalty structure nonperformance is only defined for spinning events of 10 minutes or longer. For events of less than 10 minutes, all resources, regardless of actual performance, are considered to have performed perfectly. But the IPI is defined as the number of days between spinning events, regardless of duration. This definition artificially shortens the period since the last requirement to perform. The IPI should be defined as the number of days between spinning events 10 minutes or longer. If only events 10 minutes or longer were considered, the IPI would increase to almost double its current 20 days. Regardless, use of an average IPI is not appropriate. The penalty should be based on the actual time since the last spinning event of 10 minutes or longer during which the resource performed. That is the only way to capture the actual failure to perform of the resource and the only way to provide an appropriate performance incentive.

In addition, allowing an organization to aggregate responses from all online resources is a mistake because it weakens the incentive to perform and creates an incentive to withhold reserves from other resources. The obligation to respond is unit specific. Any potentially offsetting response from an affiliated tier 1 resource should have been included as part of the reserves in the tier 1 estimate. Any potentially offsetting response from a tier 2 resource should have been included in that tier 2 offer.

The MMU recommends that aggregation not be permitted to offset unit specific penalties for failure to respond to a synchronized reserve event.

Based on an analysis of the most heavily scheduled resources in the tier 2 synchronized reserve market, the MMU concludes that under the current penalty structure, completely unresponsive resources would be paid for providing reserves (Table 10-23). The analysis covered the period from the April 1, 2018, which was the date that five minute pricing was introduced, through December 31, 2018. For resources that completely fail to respond for all spinning events, resource owners would earn 58.2 percent of what they would earn from a perfect response.

Table 10-23 Tier 2 synchronized reserve market penalties, actual vs. hypothetical under proposed IPI change: April 1, 2018, through December 31, 2018

Total Scheduled MWh	Actual Spinning Event Shortfall MWh	Credits for Hypothetical T2 Response of 100%	Credits for Hypothetical T2 Response of 0%	Actual T2 Credits	Actual Credits Under IMM Proposed IPI Change
24,926	609	$1,350,022	$786,492	$1,345,571	$1,343,272

The MMU recommends that the definition of the IPI be changed from the average number of days between events to the actual number of days since the last spinning event that lasted more than 10 minutes.

Tier 1 resource owners are paid for the actual amount of synchronized reserve they provide in response to a synchronized reserve event.[55] Tier 2 resource owners are paid for being available 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.

The data in Table 10-24 comes from several different sources. Tier 1 Estimate is the estimate done by the most recent five minute market solution. The Tier 1 Estimate takes only those units which are DGP eligible and estimates their available ramp. It is an accurate, conservative estimate of available tier 1 synchronized reserve. Actual tier 1 response is taken from real-time SCADA data. Actual tier 1 data is used to calculate settlement credits for tier 1 response from all units including those which are not part of the DGP estimate

55 See *id.* at 98.

used by the five minute market solution. Because the market solution estimate is very conservative the actual response is usually higher than the estimate at market solution time.

Table 10-24 Synchronized reserve events 10 minutes or longer, tier 2 response compliance, RTO Reserve Zone: January 2018 through September 2019

Spin Event (Day, EPT 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
Jan 3, 2018 03:00	13	1,896.7	509.9	112.6	57.6	55.0	26.9%	51.2%
Apr 12, 2018 17:28	10	1,063.3	1,635.4	464.6	372.5	92.1	153.8%	80.2%
Jun 30, 2018 09:46	11	2,710.1	3,993.8	71.6	56.8	14.8	147.4%	79.3%
Jul 10, 2018 15:45	12	784.3	2,219.5	494.6	308.8	185.8	283.0%	62.4%
Aug 12, 2018 11:06	11	1,824.5	2,915.0	274.5	229.8	44.7	159.8%	83.7%
Sep 30, 2018 11:29	11	1,430.9	2,355.8	231.2	216.9	14.3	164.6%	93.8%
Oct 30, 2018 06:40	11	239.7	816.0	607.7	431.5	176.2	340.4%	71.0%
2018 Average	11	1,421.4	2,063.6	322.4	239.1	83.3	145.2%	74.2%
Sep 23, 2019 12:07	11	924.7	664.1	723.2	632.1	91.1	71.8%	87.4%
2019 Average	11	924.7	664.1	723.2	632.1	91.1	71.8%	87.4%

History of Synchronized Reserve Events

Synchronized reserve is designed to provide relief for disturbances.[56] [57] 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 operators have used synchronized reserve as a source of energy to provide relief from low ACE.

The risk of using synchronized reserves for energy or any other nondisturbance 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.

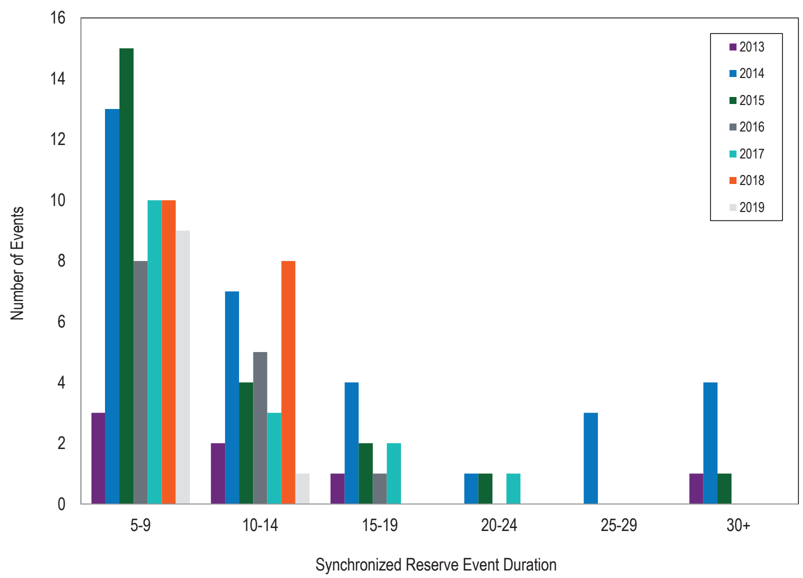
From January 1, 2010, through September 30, 2019, PJM experienced 230 synchronized reserve events (Table 10-25), approximately 2.2 events per month. During this period, synchronized reserve events had an average duration of 11.7 minutes.

56 2013 State of the Market Report for PJM, Appendix F – PJM's DCS Performance, at 451–452.
57 See PJM "Manual 12: Balancing Operations," Rev. 39 (Feb. 21, 2019) § 4.1.2 Loading Reserves.

Table 10-25 Synchronized reserve events: January 2017 through September 2019[58]

Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)
JAN-08-2017 03:21	RTO	7	JAN-01-2018 02:41	RTO	7	JAN-22-2019 22:30	RTO	8
JAN-09-2017 19:24	RTO	9	JAN-03-2018 03:00	RTO	13	JAN-31-2019 01:26	RTO	5
JAN-10-2017 13:05	MAD	9	JAN-07-2018 14:15	RTO	9	JAN-31-2019 09:26	RTO	9
JAN-15-2017 20:13	RTO	8	APR-12-2018 13:28	RTO	10	FEB-25-2019 00:25	RTO	9
JAN-23-2017 09:08	RTO	7	JUN-04-2018 10:22	RTO	6	MAR-03-2019 12:31	RTO	9
FEB-13-2017 18:30	RTO	7	JUN-29-2018 15:21	RTO	9	MAR-06-2019 22:06	RTO	9
FEB-14-2017 00:11	RTO	6	JUN-30-2018 09:46	RTO	11	JUL-27-2019 23:31	RTO	7
FEB-15-2017 06:37	RTO	6	JUL-04-2018 10:56	RTO	7	AUG-11-2019 12:14	RTO	8
MAR-23-2017 06:48	RTO	24	JUL-10-2018 15:45	RTO	13	SEP-03-2019 13:39	RTO	9
APR-08-2017 11:53	RTO	10	JUL-23-2018 09:02	RTO	8	SEP-23-2019 16:06	RTO	11
MAY-08-2017 04:18	RTO	10	JUL-23-2018 15:43	RTO	6			
JUN-08-2017 03:39	RTO	10	JUL-24-2018 16:17	RTO	7			
JUN-20-2017 05:38	RTO	9	AUG-12-2018 11:06	RTO	11			
SEP-04-2017 20:18	MAD	15	SEP-13-2018 09:47	RTO	7			
SEP-07-2017 09:16	RTO	9	SEP-14-2018 13:24	RTO	7			
SEP-21-2017 14:15	RTO	16	SEP-26-2018 19:08	RTO	8			
			SEP-30-2018 11:29	RTO	11			
			OCT-30-2018 10:40	RTO	11			

Figure 10-11 Synchronized reserve events duration distribution curve: January 2013 through September 2019



58 For full history of spinning events, see the 2018 State of the Market Report for PJM, Appendix F - Ancillary Service Markets.

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 less than or equal to the synchronized reserve market clearing price. In most hours, the nonsynchronized reserve clearing price is zero.

Market Structure

Demand

Demand for primary reserve is established by PJM as one and a half times the largest contingency. Demand for primary reserve is calculated dynamically in every synchronized and nonsynchronized reserve market solution. After filling the synchronized reserve requirement the balance of primary reserve can be made up by the most economic combination of synchronized and nonsynchronized reserve. In practice this means that the primary reserve requirement minus the scheduled synchronized reserve is the nonsynchronized requirement for the interval. PJM may increase the primary reserve requirement to cover times when a single contingency could cause an outage of several generating units or in times of high load conditions causing operational uncertainty.[59]

The average scheduled nonsynchronized reserve in the RTO Zone in the first nine months 2019 was 1,461.9 MW. The average scheduled nonsynchronized reserve in the MAD Subzone for primary reserve in the first nine months 2019 was 1,274.9 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 market solution considers the available 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 market supply curve is constructed from the nonsynchronized units' 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 and combined cycles that

59 See PJM "Manual 11: Energy and Ancillary Services Market Operations," § 4.2.2 Synchronized Reserve Requirement Determination, Rev. 107 (Sep. 26, 2019).

can start in 10 minutes or less, and diesels.[60] In the first nine months of 2019, an average of 1,461.9 MW of nonsynchronized reserve was scheduled hourly out of 3,953.1 eligible MW as part of the primary reserve requirement in the RTO Zone.

In the first nine months of 2019, CTs provided 85.5 percent of scheduled nonsynchronized reserve (Table 10-27). Natural gas was the primary fuel for nonsynchronized reserve in the first nine months of 2019 (Table 10-26).

Table 10-26 Supply of Nonsynchronized Reserve by Fuel Type: January through September, 2019

Fuel	Percentage of NSR MW	Percentage of NSR Credits
Natural Gas	53.2%	63.2%
Light Oil	30.0%	26.8%
Hydro	14.5%	7.7%
Diesel	2.3%	1.9%
LFG	0.1%	0.1%

Table 10-27 Supply of Nonsynchronized Reserve by Unit Type: January through September, 2019

Unit Type	Percentage of NSR MW	Percentage of NSR Credits
CT	85.5%	92.3%
Hydro	14.5%	7.7%

Market Concentration

The supply of nonsynchronized reserves in the Mid-Atlantic Dominion Subzone and the RTO Zone was highly concentrated in the first nine months of 2019.

Table 10-28 Nonsynchronized reserve market pivotal supplier test: January 2018 through September 2019

Year	Month	Non Synchronized Reserve Three Pivotal Supplier Hours
2018	Jan	87.2%
2018	Feb	88.0%
2018	Mar	93.5%
2018	Apr	16.0%
2018	May	6.9%
2018	Jun	58.0%
2018	Jul	76.8%
2018	Aug	55.9%
2018	Sep	16.7%
2018	Oct	12.1%
2018	Nov	5.2%
2018	Dec	21.5%
2018	Average	44.8%
2019	Jan	71.4%
2019	Feb	81.0%
2019	Mar	53.2%
2019	Apr	62.9%
2019	May	54.2%
2019	Jun	44.4%
2019	Jul	73.0%
2019	Aug	64.0%
2019	Sep	47.9%
2019	Average	61.3%

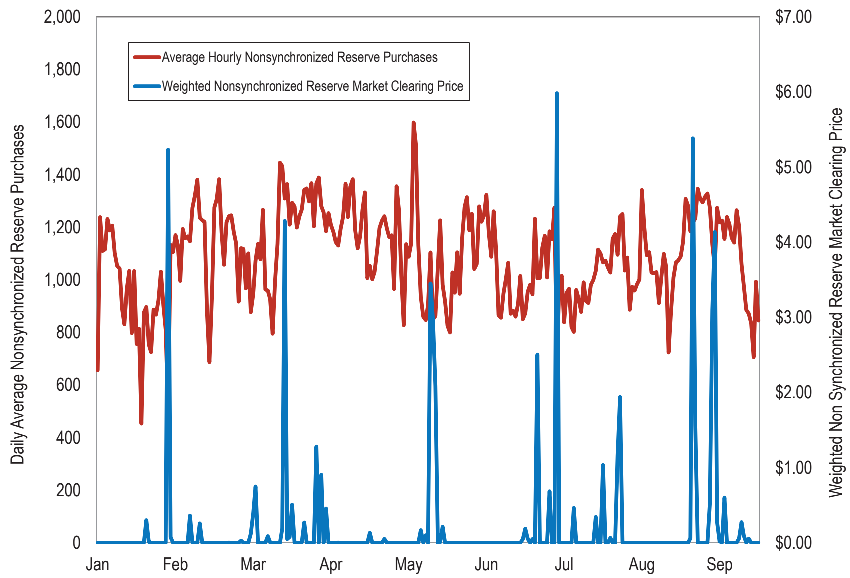
Price

The price of nonsynchronized reserve is calculated in real time every five minutes for the RTO Reserve Zone and the Mid-Atlantic Dominion Reserve Subzone.

Figure 10-12 shows the daily average nonsynchronized reserve market clearing price (NSRMCP) and average scheduled MW for the RTO Zone. In the first nine months of 2019, the average nonsynchronized market clearing price was $0.20 per MW. The hourly average nonsynchronized reserve scheduled was 1,086.1 MW. The market cleared at a price greater than $0 in 0.9 percent of all intervals. The maximum interval clearing price was $600.00 per MW on July 1, 2019, which was the result of a shortage of reserves.

60 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 4b.2 Non-Synchronized Reserve Market Business Rules, Rev. 107 (Sep. 26, 2019)

Figure 10-12 Daily average RTO Zone nonsynchronized reserve market clearing price and MW purchased: January through September, 2019



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 is greater than the generator's offer at economic minimum, then an LOC is paid.[61]

The full cost of nonsynchronized reserve including payments for the clearing price and uplift costs is calculated and compared to the price (Table 10-29). The closer the price to cost ratio comes to one, the more the market price reflects the full cost of nonsynchronized reserve.

61 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 2.16 Minimum Capacity Emergency in Day-ahead Market, Rev. 107 (Sep. 26, 2019).

In the first nine months 2019, the price to cost ratio for the RTO Zone was 16.1 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 0.9 percent of hours.

Table 10-29 RTO zone nonsynchronized reserve MW, charges, price, and cost: 2018 through September 2019

Market	Year	Month	Total Nonsynchronized Reserve MW	Total Nonsynchronized Reserve Charges	Weighted Nonsynchronized Reserve Market Price	Nonsynchronized Reserve Cost	Price/Cost Ratio
RTO Zone	2018	Jan	873,930	$4,616,906	$0.94	$5.28	17.7%
RTO Zone	2018	Feb	886,683	$249,232	$0.00	$0.28	0.0%
RTO Zone	2018	Mar	954,515	$1,693,691	$0.05	$1.77	3.0%
RTO Zone	2018	Apr	968,046	$1,385,351	$0.12	$1.52	7.9%
RTO Zone	2018	May	898,840	$1,894,687	$0.31	$2.66	11.8%
RTO Zone	2018	Jun	870,244	$1,026,193	$0.01	$1.22	1.2%
RTO Zone	2018	Jul	823,952	$639,914	$0.00	$0.74	0.7%
RTO Zone	2018	Aug	769,348	$858,148	$0.01	$1.05	1.4%
RTO Zone	2018	Sep	727,163	$986,756	$0.55	$1.52	36.1%
RTO Zone	2018	Oct	757,591	$1,590,789	$1.37	$2.60	52.8%
RTO Zone	2018	Nov	728,020	$566,419	$0.14	$0.74	19.5%
RTO Zone	2018	Dec	733,417	$348,069	$0.00	$0.44	0.8%
RTO Zone	2018	Total	9,991,749	$15,856,155	$0.29	$1.65	17.8%
RTO Zone	2019	Jan	691,682	$808,141	$0.16	$1.29	12.0%
RTO Zone	2019	Feb	777,009	$549,304	$0.02	$0.67	3.3%
RTO Zone	2019	Mar	865,531	$1,209,490	$0.22	$1.35	16.2%
RTO Zone	2019	Apr	870,167	$1,441,716	$0.09	$1.70	5.6%
RTO Zone	2019	May	779,072	$624,877	$0.29	$0.94	31.0%
RTO Zone	2019	Jun	727,972	$458,230	$0.01	$0.61	1.7%
RTO Zone	2019	Jul	707,373	$870,865	$0.34	$1.52	22.2%
RTO Zone	2019	Aug	764,814	$429,814	$0.10	$0.57	18.2%
RTO Zone	2019	Sep	819,107	$1,841,551	$0.54	$2.39	22.6%
RTO Zone	2019	Total	7,002,727	$8,233,987	$0.20	$1.23	16.1%

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.[62]

Market Structure

Supply

Both generation and demand resources are eligible to offer DASR. DASR offers consist of price only. Available 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 the first nine months of 2019, the average available hourly DASR was 44,547.9 MW, a 13.8 percent increase from the same time period in 2018. The DASR hourly MW purchased averaged 5,511.0 MW.

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.[63] 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 noneligibility.

62 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 10.5 Aggregation for Economic and Emergency Demand Resources, Rev. 107 (Sep. 26, 2019).

63 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 11.2.2 Day-Ahead Scheduling Reserve Market Eligibility, Rev. 107 (Sep. 26, 2019).

Of the 5,511.0 MW average hourly DASR cleared in the first nine months 2019, 80.7 percent was from CTs (Table 10-31). Demand response resources did not provide any DASR MW in the first nine months of 2019. Most DASR MW was provided by natural gas fueled resources (Table 10-30).

Table 10-30 Scheduled DASR by Fuel Type: January through September, 2019

Fuel	Percentage of DASR MW	Percentage of DASR Credits
Natural Gas	65.7%	69.8%
Coal	5.9%	7.3%
Diesel	9.6%	5.3%
Hydro	9.4%	4.3%
Light Oil	9.1%	12.6%
LFG	0.1%	0.4%
Waste Coal	0.1%	0.1%

Table 10-31 Scheduled DASR by Unit Type: January through September, 2019

Unit Type	Percentage of DASR MW	Percentage of DASR Credits
CT	80.7%	77.2%
Hydro	9.4%	4.3%
Steam	6.3%	8.6%
CC	3.2%	8.8%
Diesel	0.4%	1.2%

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.[64] 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. Effective January 1, 2019, the day-ahead scheduling reserve requirement is 5.29 percent of the peak load forecast. This is based on a 2.18 percent load forecast error component and a 3.11 percent forced outage rate component. The DASR requirement is applicable for all hours of the operating day.

64 See PJM "Manual 13: Emergency Operations," § 2.2 Reserve Requirements, Rev. 73 (October 31, 2019).

The DASR requirement can be increased by PJM operators under conditions of "hot weather or cold weather alert or max emergency generation alert or other escalating emergency."[65] The amount of additional DASR MW that may be required is the Adjusted Fixed Demand (AFD) determined by a Seasonal Conditional Demand (SCD) factor.[66] 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 2018 through October 2019, the SCD values are 3.75 percent for winter and 2.45 percent for summer. For November 2019 through October 2020, the SCD values will be 2.80 percent for winter and 2.42 percent for summer. PJM Dispatch may also schedule additional Day-Ahead Scheduling Reserves as deemed necessary for conservative operations.[67] 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.[68] The result is substantial discretion for PJM to increase the demand for DASR under a variety of circumstances. PJM invoked adjusted fixed demand on 18 days during the first nine months 2019. The 39 hours with the highest DASR market clearing price during the first nine months of 2019 were all on these days.

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 10-32

Table 10-32 DASR market three pivotal supplier test results and number of hours with DASRMCP above $0: January 2018 through September 2019

Year	Month	Number of Hours When DASRMCP > $0	Percent of Hours Pivotal
2018	Jan	197	7.6%
2018	Feb	14	40.9%
2018	Mar	66	0.0%
2018	Apr	189	0.5%
2018	May	339	5.6%
2018	Jun	101	11.8%
2018	Jul	190	11.5%
2018	Aug	161	16.8%
2018	Sep	146	22.6%
2018	Oct	117	0.0%
2018	Nov	20	0.0%
2018	Dec	10	0.0%
2018	Average	151	9.8%
2019	Jan	32	1.5%
2019	Feb	22	1.4%
2019	Mar	24	0.0%
2019	Apr	15	0.0%
2019	May	43	0.0%
2019	Jun	72	0.0%
2019	Jul	237	0.0%
2019	Aug	173	0.0%
2019	Sep	182	0.0%
2019	Average	89	0.3%

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.[69] 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 the first nine months of 2019, 39.6 percent of generation units offered DASR at a daily price above $0.00, compared to 38.8 percent in 2018.

65 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>.

66 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 11.2.1 Day-Ahead Scheduling Reserve Market Requirement. Rev. 107 (Sep. 26, 2019)

67 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 11.2.1 Day-Ahead Scheduling Reserve Market Reserve Requirement, Rev. 107 (Sep. 26, 2019).

68 See PJM "Manual 13: Emergency Operations," § 3.2 Conservative Operations, Rev. 73, (October 31, 2019).

69 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 11.2.2 Day-Ahead Scheduling Reserve Market Eligibility, Rev. 107 (Sep. 26, 2019).

In the first nine months of 2019, 16.6 percent of daily offers were above $5.00 per MW.

The MMU recommends that offers in the DASR Market be based on opportunity cost only in order to eliminate market power.

Market Performance

In the first nine months of 2019, the DASR Market cleared at a price above $0.00 in 12.3 percent of hours. The weighted average DASR price for all hours was $0.35. The average cleared MW in all hours was 5,511.0 MW. The average cleared MW in all hours when the DASRMCP was above $0.00 was 7,498.0 MW. The highest DASR price was $20.00 during 13 hours in Q3 of 2019.

The introduction of Adjusted Fixed Demand (AFD) on March 1, 2015, created a bifurcated market (Table 10-33 and Table 10-34)). 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. In 2018, PJM added AFD to the normal 5.28 percent in 598 hours. In the first nine months of 2019, PJM added AFD to the normal 5.29 percent in 423 hours. The difference in market clearing price, MW cleared, obligation incurred, and charges to PJM load are substantial. Table 10-33 shows the differences in price and MW between AFD hours and non-AFD hours.

Table 10-33 Impact of Adjusted Fixed Demand on DASR prices and demand: January through September, 2019

Metric	Year	Number Hours	Weighted Day-Ahead Scheduling Reserve Market Clearing Price (DASRMCP)	Average Hourly Total DASR MW
All Hours	Jan-Sep 2019	6,552	$0.35	5,511.0
All Hours when DASRMCP > $0	Jan-Sep 2020	803	$2.10	7,498.0
All Hours when AFD is used	Jan-Sep 2021	423	$2.41	10,428.0

While the new rules allow PJM operators' 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 operators 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.

Comparing the Normal Hour column against the AFD Hour column for five metrics (Table 10-34) shows that the use of AFD for 598 hours in 2018, and 248 hours in the first nine months of 2019 significantly increased the cost of DASR. Table 10-34 shows that the cost increase was a result of a substantial increase in DASR MW cleared.

Table 10-34 DASR Market, regular hours vs. adjusted fixed demand hours: January 2018 through September 2019

		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
2018	Jan	197	120	$0.94	$3.56	97,785	119,404	5,220	9,164	$5,479	$32,627
2018	Feb	14	0	$0.00	NA	89,397	NA	5,066	NA	$16	NA
2018	Mar	66	0	$0.03	NA	87,295	NA	4,906	NA	$147	NA
2018	Apr	190	0	$0.10	NA	79,086	NA	4,508	NA	$444	NA
2018	May	339	72	$1.96	$8.99	82,800	91,483	4,758	10,886	$10,491	$97,845
2018	Jun	101	94	$0.75	$3.70	89,867	108,143	5,366	8,839	$4,369	$32,747
2018	Jul	190	168	$2.00	$5.97	97,978	109,671	5,899	9,949	$13,650	$59,428
2018	Aug	161	72	$0.71	$4.47	100,580	116,844	6,050	9,438	$4,540	$42,177
2018	Sep	146	72	$1.69	$7.70	87,995	115,611	5,117	12,483	$9,859	$96,066
2018	Oct	117	0	$0.20	NA	81,077	NA	4,665	NA	$948	NA
2018	Nov	20	0	$0.00	NA	85,755	NA	4,774	NA	$4	NA
2018	Dec	12	0	$0.00	NA	89,847	NA	5,121	NA	$2	NA
2018		1553	598	$0.39	$4.88	89,122	110,193	5,121	10,126	$4,162	$60,148
2019	Jan	8	24	$0.00	$0.28	95,058	117,071	5,359	8,907	$20	$2,521
2019	Feb	6	16	$0.00	$0.20	91,649	116,426	5,201	10,812	$6	$2,175
2019	Mar	24	NA	$0.01	NA	86,172	NA	4,915	NA	$42	NA
2019	Apr	15	NA	$0.01	NA	75,107	NA	4,406	NA	$37	NA
2019	May	43	NA	$0.02	NA	79,257	NA	4,544	NA	$77	NA
2019	Jun	31	42	$0.03	$1.72	85,713	105,502	5,138	11,076	$139	$19,030
2019	Jul	137	101	$0.16	$2.74	102,486	115,059	6,179	10,207	$984	$27,931
2019	Aug	127	46	$0.11	$4.52	95,624	110,089	5,846	11,056	$631	$49,980
2019	Sep	163	19	$0.20	$3.52	87,318	105,508	5,234	11,840	$1,055	$41,682
2019		554	248	$0.06	$2.10	88,709	111,609	5,202	10,650	$332	$23,886

Table 10-35 shows total number of hours when a DASR market cleared at a price above $0 along with average load, cleared MW, additional MW under AFD, and total charges for the DASR Market in 2018 and the first nine months of 2019.

Table 10-35 DASR Market all hours of DASR market clearing price greater than $0: January 2018 through September 2019

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 Credits
2018	Jan	197	$2.66	101,276	3,869,914	481,887	$2,327,273
2018	Feb	14	$0.13	89,397	3,404,236	0	$10,436
2018	Mar	66	$0.32	87,295	3,650,839	0	$109,491
2018	Apr	190	$0.37	79,086	3,247,134	0	$319,905
2018	May	339	$3.73	83,640	3,586,629	395,742	$3,734,941
2018	Jun	101	$4.08	92,253	3,953,938	235,382	$2,315,966
2018	Jul	190	$6.09	100,619	4,506,459	562,931	$5,980,639
2018	Aug	161	$2.86	102,154	4,543,607	201,820	$2,228,076
2018	Sep	146	$5.55	90,756	3,779,739	434,532	$3,270,385
2018	Oct	117	$1.25	95,642	3,470,604	0	$705,607
2018	Nov	20	$0.03	100,565	3,447,112	0	$2,753
2018	Dec	10	$0.03	105,913	3,810,223	0	$1,310
2018	Average	129	$2.26	94,050	3,772,536	192,691	$1,750,565
2018	Total	1,551	$2.26	94,050	45,270,434	2,312,294	$21,006,782
2019	Jan	32	$0.61	123,223	297,046	97,612	$182,645
2019	Feb	22	$0.31	111,730	220,097	85,339	$67,211
2019	Mar	24	$0.26	105,987	123,430	0	$31,569
2019	Apr	15	$0.39	90,323	67,501	0	$26,475
2019	May	43	$0.28	98,135	204,957	0	$57,122
2019	Jun	72	$2.12	117,694	689,662	251,804	$1,460,362
2019	Jul	237	$2.55	125,398	1,965,812	439,584	$5,016,482
2019	Aug	173	$3.03	120,698	1,327,657	251,704	$4,022,640
2019	Sep	182	$1.57	106,434	1,101,852	122,368	$1,734,343
2019	Total	802	$1.24	111,069	5,998,014	1,248,410	$12,598,850

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. Adjusted Fixed Demand related increases in the DASR requirement (Table 10-35) in the first nine months of 2019 caused prices to increase.

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.[70] 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 for resources with limited ability to sustain energy output and with faster ramp rates. Resources must qualify to follow one or both of the RegA and RegD signals, but will be assigned by the market clearing engine to follow only one signal in a given market hour.

The PJM regulation market design includes three clearing price components: capability ($/MW, based on the MW being offered); performance ($/mile, based on the total MW movement requested by the control signal, known as mileage); and lost opportunity cost ($/MW of lost revenue from the energy market as a result of providing regulation). The marginal benefit factor (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 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 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 marginal rate of technical substitution (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. 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

70 Order No. 755, 137 FERC ¶ 61,064 at P 2 (2011).

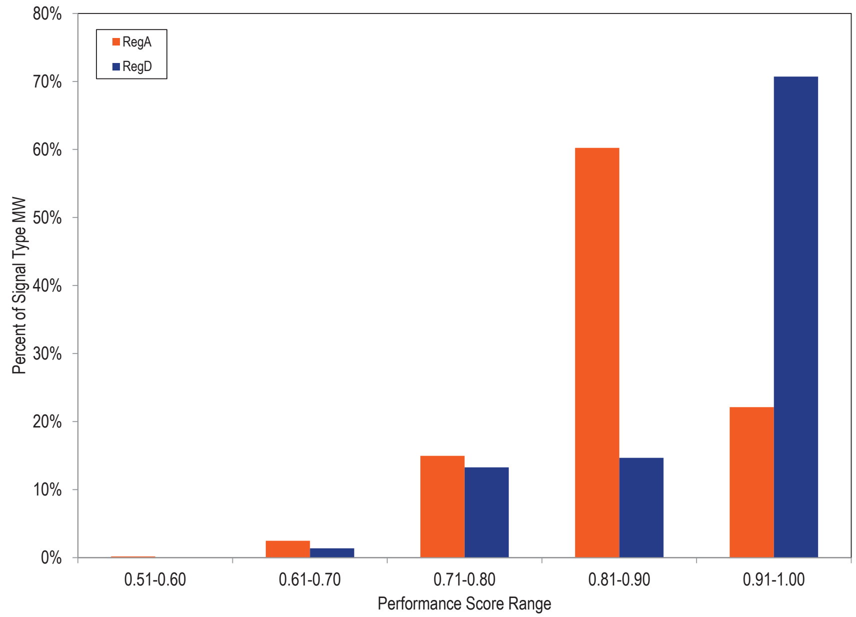
output and the regulation signal; and precision, the difference between the regulation response and the regulation requested.[71] Performance scores are reported on an hourly basis for each resource.

Table 10-36 and Figure 10-13 show the average performance score by resource type and the signal followed in the first nine months of 2019. In these figures, the MW used are actual MW and the performance score is the hourly performance score of the regulation resource.[72] Each category is based on the percentage of the full performance score distribution for each resource (or signal) type. As Figure 10-13 shows, 70.7 percent of RegD resources had average performance scores within the 0.91-1.00 range, and 22.1 percent of RegA resources had average performance scores within that range, in the first nine months of 2019. These scores are higher than the scores for both product types in the first nine months of 2018, where 43.5 percent of RegD resources had average performance scores within the 0.91-1.00 range, and 18.1 percent of RegA resources had average performance scores within that range.

Table 10-36 Hourly average performance score by unit type: January through September, 2019

		Performance Score Range				
		51-60	61-70	71-80	81-90	91-100
RegA	Battery	-	-	-	-	-
	CT	-	0.1%	15.7%	53.5%	30.7%
	Diesel	-	-	-	-	100.0%
	DSR	-	12.2%	22.8%	61.8%	3.2%
	Hydro	-	-	0.9%	35.2%	63.9%
	Steam	0.2%	3.3%	19.4%	68.4%	8.7%
RegD	Battery	-	0.5%	12.5%	10.6%	76.4%
	CT	-	0.4%	43.9%	52.7%	3.0%
	Diesel	-	-	2.2%	97.8%	-
	DSR	0.0%	0.1%	26.7%	26.9%	46.2%
	Hydro	-	21.2%	-	38.2%	40.5%
	Steam	-	-	-	-	-

Figure 10-13 Hourly average performance score by regulation signal type: January through September, 2019



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

71 PJM "Manual 12: Balancing Operations," § 4.5.6 Performance Score Calculation, Rev. 39 (Feb. 21, 2019).
72 Except where explicitly referred to as effective MW or effective regulation MW, MW means actual MW unadjusted for either MBF or performance factor.

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.

In a well functioning market, every resource should be paid the same clearing price per unit produced. That is not true in the PJM Regulation Market. RegA and RegD resources are not paid the same clearing price in dollars per effective MW. RegD resources are being paid more than the market clearing price.

This flaw in the market design has caused operational issues, has caused over investment in RegD resources, and has caused significant price spikes in PJM's Regulation Market that continued in the first nine months of 2019.

If all MW of regulation were treated the same in both the clearing of the market and in settlements, many of the issues in the PJM Regulation Market would be resolved. However, the current PJM rules result in the payment to RegD resources being up to 1,000 times the correct price.

RegA and RegD have different physical capabilities. In order to permit RegA and RegD to compete in the single PJM Regulation Market, RegD must be translated into the same units as RegA. One MW of RegA is one effective MW. The translation is done using the marginal benefit factor (MBF). As more RegD is added to the market, the relative value of RegD declines, based on its actual performance attributes. For example, if the MBF is 0.001, a MW of RegD is worth 0.001 MW of RegA (or 1/1,000 MW of a MW of RegA). This is the same thing as saying that 1.0 MW of RegD is equal to 0.001 effective MW when the MBF is 0.001.

Almost all of the issues in PJM's Regulation Market are caused by the inconsistent application of the MBF. Because the MBF is not included in settlements, when the MBF is less than 1.0, RegD resources are paid too much. When the MBF is less than 1.0, each MW of RegD is worth less than 1.0 MW of RegA. The market design buys the correct amount of RegD, but pays RegD as if the MBF were 1.0. In an extreme case, when the MBF is 0.001, RegD MW are paid 1,000 times too much. If the market clearing price is $1.00 per MW of RegA, RegD is paid $1,000 per effective MW. Resolution of this problem requires that PJM pay RegD for the same effective MW it provides in regulation, 0.001 MW.

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. 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. On March 30, 2018, FERC rejected the proposal finding it inconsistent with Order No. 755.[73] Both PJM and the MMU have filed requests for rehearing.[74]

73 162 FERC ¶ 61,295 (2018).
74 See FERC Docket No. ER18-87-002.

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 9, 2017, 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 10-37). 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 10-37 Seasonal regulation requirement definitions[75]

Season	Dates	Nonramp Hours	Ramp Hours
		00:00 - 03:59	04:00 - 08:59
Winter	Dec 1 - Feb 28(29)	09:00 - 15:59	16:00 - 23:59
		00:00 - 04:59	05:00 - 07:59
Spring	Mar 1 - May 31	08:00 - 16:59	17:00 - 23:59
		00:00 - 04:59	05:00 - 13:59
Summer	Jun 1 - Aug 31	14:00 - 17:59	18:00 - 23:59
		00:00 - 04:59	05:00 - 07:59
Fall	Sep 1 - Nov 30	08:00 - 16:59	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 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

75 See PJM. "Regulation Requirement Definition," <http://www.pjm.com/~/media/markets-ops/ancillary/regulation-requirement-definition.ashx>.

performance scores under the signal design prior to January 9, 2017, was not an indication of good ACE control.

The January 9, 2017, 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.[76]

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, addresses issues with the inconsistent application of the marginal benefit factor throughout the optimization and settlement process in the PJM Regulation Market.[77]

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 the relative costs of RegA and RegD MW, the least cost feasible combination of RegA and RegD MW. If the MBF function

76 The MBF, as used in this report, refers to PJM's incorrectly calculated MBF and not the MBF equivalent to the MRTS.
77 18 CFR § 385.211 (2017)

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.[78] 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.

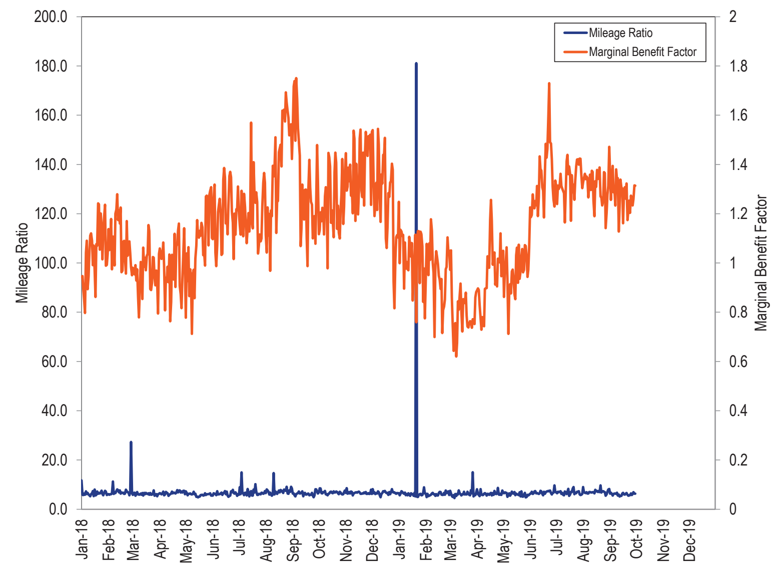
The change in design decreased RegA mileage (the change in MW output in response to regulation signal per MW of capability), increased the proportion of cleared RegD resources' capability that was called by the RegD signal (increased REG for a given MW) to better match offered capability, increased the 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.

78 145 FERC ¶ 61,011 (2013).

Figure 10-14 shows the daily average MBF and the mileage ratio. The weighted average mileage ratio increased from 6.65 in the first nine months of 2018, to 7.09 in the first nine months of 2019 (an increase of 6.7 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.

Figure 10-14 Daily average MBF and mileage ratio: January 2018 through September 2019



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.

Table 10-38 shows RegD resource payments on a performance adjusted actual MW basis and RegA resource payments on a performance adjusted MW basis by month, from January 1, 2018, through September 30, 2019. In 2018, RegD resources earned 32.8 percent more per performance adjusted actual MW than RegA resources. In the first nine months of 2019, RegD resources earned 39.7 percent more per performance adjusted actual MW than RegA resources due to the inclusion of the mileage ratio in RegD MW settlement.

Table 10-38 Average monthly price paid per performance adjusted actual MW of RegD and RegA: January 2018 through September 2019

		Settlement Payments		
Year	Month	RegD ($/Performance Adjusted MW)	RegA ($/Performance Adjusted MW)	Percent Performance Adjusted RegD/RegA Overpayment
2018	Jan	$86.14	$78.36	9.9%
	Feb	$21.92	$12.22	79.3%
	Mar	$27.46	$21.76	26.2%
	Apr	$33.75	$26.41	27.8%
	May	$36.74	$29.36	25.1%
	Jun	$24.05	$18.06	33.2%
	Jul	$25.40	$18.79	35.2%
	Aug	$24.70	$15.92	55.2%
	Sep	$29.33	$20.09	46.0%
	Oct	$30.20	$19.45	55.3%
	Nov	$22.17	$14.39	54.0%
	Dec	$20.15	$12.44	61.9%
Average		$31.96	$24.07	32.8%
2019	Jan	$19.00	$13.89	36.8%
	Feb	$16.64	$11.68	42.4%
	Mar	$18.29	$13.79	32.6%
	Apr	$20.44	$15.85	28.9%
	May	$16.36	$12.04	36.0%
	Jun	$17.62	$10.66	65.3%
	Jul	$22.81	$15.78	44.6%
	Aug	$21.22	$13.99	51.7%
	Sep	$26.45	$20.35	29.9%
Average		$19.89	$14.24	39.7%

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. Instead of being paid based on the MBF (RMCCP + RMPCP)*MBF, RegD resources are currently paid based on the mileage ratio (RMCCP + (RMPCP*mileage ratio)). Because the RMCCP component makes up the majority of the overall clearing price, when the MBF is above one, RegD resources can be underpaid on a per effective MW basis by the current payment method, unless 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 greater than 1.0 in the first nine months of 2018 (1.14), however, RegD resources were still overpaid on average compared to payment on a per effective MW basis. In the first nine months of 2019, the average MBF was equal to 1.11.

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 10-39. Table 10-39 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 more than 1.0 in the first nine months of 2018 (1.14), while the average daily mileage ratio was 6.65, resulting in RegD resources being paid $18.7 million more than they would have been if the MBF were correctly implemented. In the first nine months of 2019, the MBF averaged 1.11, while the average daily mileage ratio was 7.09, resulting in RegD resources being paid $3.23 million more than they would have been if the MBF were correctly implemented.

Table 10-39 Average monthly price paid per effective MW of RegD and RegA under mileage and MBF based settlement: January 2018 through September 2019

		RegD Settlement Payments				
Year	Month	Mileage Based RegD ($/Effective MW)	Marginal Rate of Technical Substitution Based RegD ($/Effective MW)	RegA ($/Effective MW)	Percent RegD Overpayment	Total RegD Overpayment ($)
2018	Jan	$70.22	$78.36	$78.36	(10.4%)	($1,127,265)
	Feb	$16.69	$12.22	$12.22	36.5%	$560,643
	Mar	$21.85	$21.76	$21.76	0.4%	$11,868
	Apr	$28.52	$28.08	$28.08	1.6%	$56,125
	May	$32.51	$31.22	$31.22	4.1%	$166,582
	Jun	$21.11	$15.48	$15.48	36.3%	$736,671
	Jul	$138.39	$17.84	$17.84	675.7%	$15,177,248
	Aug	$36.26	$13.14	$13.14	175.9%	$3,086,258
	Sep	$20.86	$20.42	$20.42	2.2%	$56,086
	Oct	$22.31	$18.49	$18.49	20.7%	$503,136
	Nov	$13.19	$12.64	$12.64	4.4%	$70,761
	Dec	$14.55	$12.46	$12.46	16.8%	$287,209
Yearly		$36.70	$23.64	$23.64	55.2%	$20,404,205
2019	Jan	$17.55	$14.65	$14.65	19.8%	$387,830
	Feb	$14.94	$10.85	$10.85	37.7%	$482,828
	Mar	$20.72	$12.64	$12.64	64.0%	$905,586
	Apr	$27.93	$21.67	$21.67	28.9%	$724,705
	May	$12.93	$10.30	$10.30	25.5%	$327,045
	Jun	$13.12	$11.26	$11.26	16.6%	$260,619
	Jul	$18.76	$18.18	$18.18	3.2%	$84,937
	Aug	$14.22	$13.56	$13.56	4.9%	$96,762
	Sep	$18.74	$20.82	$20.82	(10.0%)	($267,920)
Yearly		$17.66	$14.89	$14.89	18.6%	$3,226,104

Figure 10-15 shows, for January 2018 through September 2019, the maximum, minimum and average MBF, by month. The average MBF in the first nine months of 2018 was 1.14. The average MBF in the first nine months of 2019 was 1.11.

Figure 10-15 Maximum, minimum, and average PJM calculated MBF by month: January 2018 through September 2019

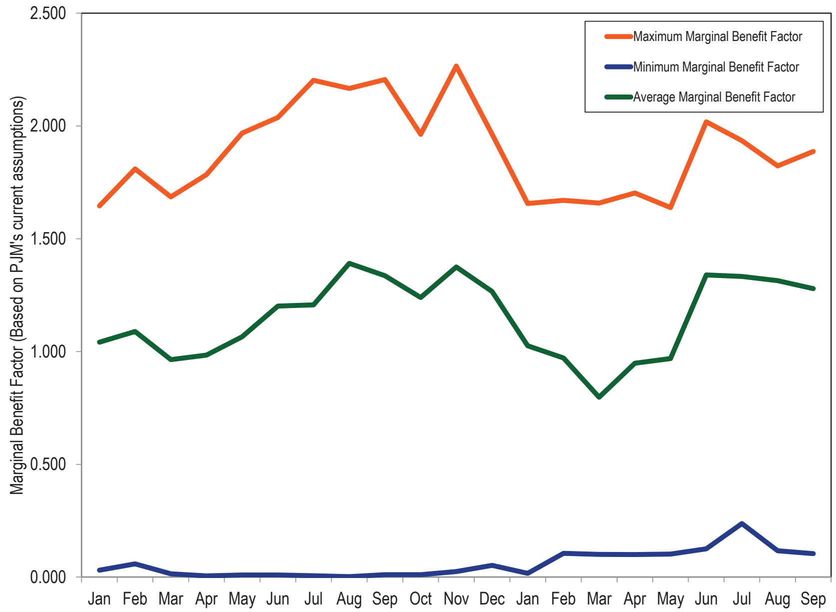


Table 10-40 shows actual and effective MW that were eligible and cleared during the first nine months of 2018 and 2019.

Table 10-40 Actual and effective RegD MW eligible and cleared: January through September, 2018 and 2019

	RegD MW		
	2018 (Jan-Sep)	2019 (Jan-Sep)	Change
Actual Eligible	271.6	325.5	19.9%
Effective Eligible	288.6	310.6	7.6%
Actual Cleared	162.3	166.5	2.6%
Effective Cleared	276.5	296.7	7.3%

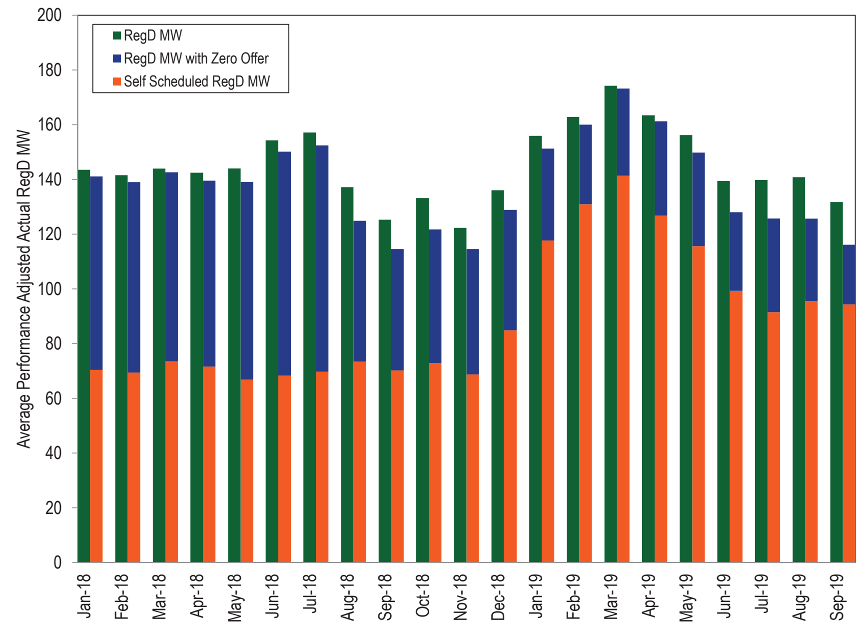
The MMU recommends that the Regulation Market be modified to incorporate a consistent and correct application of the MBF throughout the optimization, assignment and settlement process.[79]

The overpayment of RegD has resulted in offers from RegD resources that are almost all at an effective cost of $0.00 ($0.00 offers plus self scheduled offers). RegD MW providers are ensured that $0.00 and self scheduled offers will be cleared and will be paid a price determined by the offers of RegA resources. This is evidence of the impact of the flaws in the clearing engine and the over payment of RegD resources on the offer behavior of RegD resources.

Figure 10-16 shows, by month, the proportion of cleared RegD MW with an effective price of $0.00 from January 1, 2018, through September 30, 2019. In the first nine months of 2019, 94.3 percent of all RegD MW clearing the market had an effective offer of $0.00. In the first nine months of 2018, 96.3 percent of all cleared RegD MW had an effective cost of $0.00. In the first nine months of 2019, 73.9 percent of all RegD offers were self scheduled, compared to 49.3 percent of all RegD offers in the first nine months of 2018.

The increase in self scheduled offers is a result of the incentives created by the flaws in the regulation market. Because self scheduled offers are price takers, they are cleared prior to any zero cost offers in the market clearing engine. Given the increasing saturation of the regulation market with RegD MW, market participants that offer at zero instead of self scheduling run the risk of not clearing the market. The average monthly RegD cleared in the market increased 5.8 percent in the first nine months of 2019 compared to the first nine months of 2018.

Figure 10-16 Average cleared RegD MW and average cleared RegD with an effective price of $0.00 by month: January 2018 through September 2019



Price Spikes

Beginning in 2018, extreme price spikes were identified in the regulation market. The price spikes were caused by a combination of the inconsistent application of the MBF in the market design and the discrepancy between the hour ahead estimated LOC and the actual realized within hour LOC.

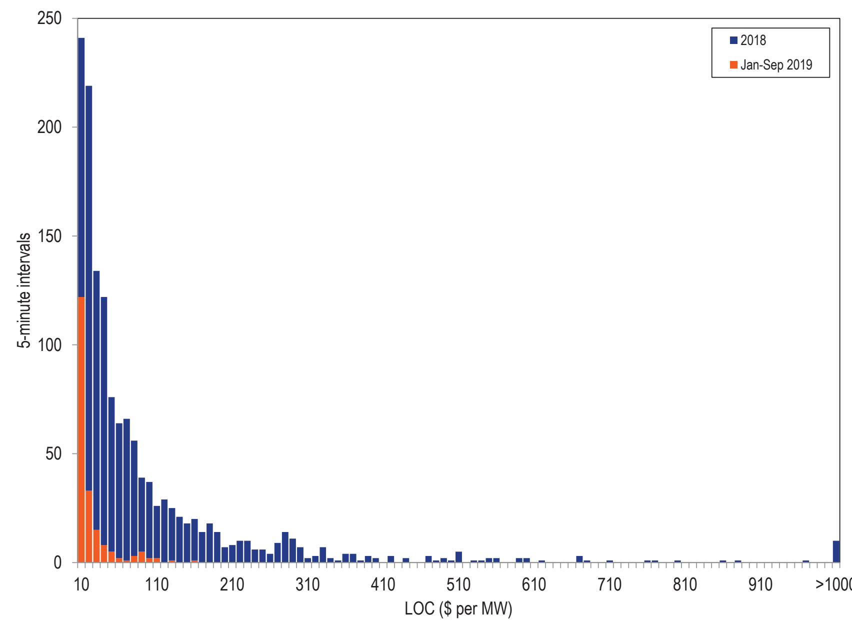
79 See "Regulation Market Review," Operating Committee (May 5, 2015) <http://www.pjm.com/~/media/committees-groups/committees/oc/20150505/20150505-item-17-regulation-market-review.ashx>.

The regulation market is cleared on an hour ahead basis, using offers that are adjusted by dividing each component of an offer (capability, performance, and lost opportunity cost) by the product of the unit specific benefit factor and unit specific performance score. To calculate the hour ahead estimate of the adjusted LOC offer component, hour ahead projections of LMPs are used. Units are then cleared based on the sum of each of their hour ahead adjusted offer components. The actual LOC is used to determine the final, actual interval specific all-in offer of RegD resources.

In some cases the estimated LOC is very low or zero but the actual within hour LOC is a positive number. In instances where the MBF of the within hour marginal unit was very low (less than one), this discrepancy in the estimated and realized LOC will cause a large discrepancy between the expected offer price (as low as $0/MW) of that resource in the clearing of the market engine, and the realized offer price of the resource, after it is cleared, in the actual market result. This will cause a significant and unexpected price spike in the regulation market. In cases where the MBF of the marginal resource is very low, such as 0.001, the price spikes can be very significant for a small change between expected and actual LOC. In January, FERC approved PJM's proposal to create a 0.1 floor for the MBF to reduce the occurrence of these price spikes.[80] This change reduced the amount and frequency of the price spikes, but it was not designed to eliminate them and it did not eliminate them. PJM's new MBF floor of 0.1 did not and will not eliminate unjust and unreasonable outcomes for market participants. PJM's market change does not correct the underlying problem with the current market design because it does not address the overpayment of RegD MW when the MBF is less than 1.0. Correspondingly, RegD is still underpaid when the MBF is greater than 1.0. Figure 10-17 shows the LOC in each five-minute interval in which a RegD unit was the marginal unit and the LOC was greater than zero in 2018 versus the first nine months of 2019.

80 See 166 FERC ¶ 61,040 (2019).

Figure 10-17 LOC distribution in each five-minute interval with a RegD marginal unit and an LOC greater than zero: 2018 and January through September, 2019



For a RegD resource to clear the regulation market with an MBF of 0.001, the resource's offer, in dollars per marginal effective MW, must be less than or equal to competing offers from RegA MW. A RegD offer of 1 MW with an MBF of 0.001 and a price of $1/MW, would provide 0.001 effective MW at a price of $1,000 per effective MW. So long as RegA MW are available for less than $1,000 per effective MW, this resource will not clear. The only way for RegD MW to clear to the point where the MBF of the last MW is 0.001, is if the offer price of the relevant resources that clear, including estimated LOC, is $0.00. But, if the same resource(s) has a positive LOC within the hour, based on real time changes in LMP, the zero priced offer is adjusted to reflect the positive LOC, resulting in an extremely high offer and clearing price for regulation.

While an incorrect estimate of a potential LOC can result in an extremely high price, the resulting regulation market prices are mathematically correct for the price of each effective MW. The prices in every interval reflect the marginal costs of regulation given the resources dispatched and accurately reflect the marginal offer of minimally effective resources which had unexpectedly high LOC components of their within hour offers. But, due to the current market design's failure to make use of the MBF in settlement, RegD is not paid on a dollar per effective MW basis. This disconnect between the process of setting price and the process of paying resources is the primary source of the market failure in PJM's Regulation Market and the cause of the observed price spikes in the regulation market. In the example, the 0.001 MW from the RegD resource should be paid $1,000 times 0.001 MW or $1.00. But the current rules would pay the RegD resource $1,000 times 1.0 MW or $1,000. If the market clearing and the settlements rules were consistent, the incentive for this behavior would be eliminated. The current rules provide a strong incentive for this behavior.

The prices spikes observed in PJM's regulation market are a symptom of a market failure in PJM's Regulation Market. The market failure in PJM's Regulation Market is caused by an inconsistent application of the MBF between market clearing and market settlement. Due to the inconsistent application of the MBF, the current market results are not consistent with a competitive market outcome. In any market, resources should be paid the marginal clearing price for their marginal contribution. In the regulation market, all resources should be paid the marginal clearing price per effective MW and all resources in the regulation market should be paid for each of their effective MW. PJM's Regulation Market does not do this. PJM's market applies the MBF in determining the relative and total value of RegD MW in the market solution for purposes of market clearing and price, but does not apply the same logic in determining the payment of RegD for purposes of settlement. As a result, market prices do not align with payment for contributions to regulation service in market settlements.

The inconsistent application of the MBF in PJM's regulation market design is generating perverse incentives and perverse market results. The price spikes are a symptom of the problem, not the problem itself.

Market Structure

Supply

Table 10-41 shows actual capability MW, actual average daily offer MW, average hourly eligible MW (actual and effective), and average hourly cleared MW (actual and effective) for all hours in the first nine months of 2019.[81] Actual MW are adjusted by the historic 100-hour moving average performance score to get performance adjusted MW, and 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.

In the first nine months of 2019, the average hourly eligible supply of regulation for nonramp hours was 1,062.1 actual MW (801.2 effective MW). This was a decrease of 37.2 actual MW (a decrease of 56.5 effective MW) from the first nine months of 2018, when the average hourly eligible supply of regulation was 1,099.3 actual MW (857.7 effective MW). In the first nine months of 2019, the average hourly eligible supply of regulation for ramp hours was 1,357.8 actual MW (1,127.6 effective MW). This was a decrease of 53.3 actual MW (a decrease of 64.1 effective MW) from the first nine months of 2018, when the average hourly eligible supply of regulation was 1,411.1 actual MW (1,191.8 effective MW).

81 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.

The ratio of the average hourly eligible supply of regulation to average hourly regulation demand (actual cleared MW) for ramp hours was 1.88 in the first nine months of 2019 (unchanged from the first nine months of 2018). The ratio of the average hourly eligible supply of regulation to average hourly regulation demand (actual cleared MW) for nonramp hours was 2.25 in the first nine months of 2019 (2.26 in the first nine months of 2018).

Table 10-41 PJM regulation capability, daily offer and hourly eligible: January through September, 2019[82 83]

			By Resource Type		By Signal Type	
		All Regulation	Generating Resources	Demand Resources	RegA Following Resources	RegD Following Resources
Capability MW	Daily	11,285.1	11,251.9	33.2	10,899.8	662.1
Offered MW	Daily	5,994.2	5,968.3	26.0	5,597.1	397.1
Actual Eligible MW	Ramp	1,357.8	1,332.4	25.4	1,021.0	336.8
	Nonramp	1,062.1	1,039.4	22.7	748.5	313.6
Effective Eligible MW	Ramp	1,127.6	1,097.2	30.4	775.1	352.5
	Nonramp	801.2	780.2	20.9	534.8	266.3
Actual Cleared MW	Ramp	723.9	706.9	17.0	550.3	173.6
	Nonramp	471.0	456.7	14.3	311.9	159.1
Effective Cleared MW	Ramp	800.0	770.2	29.8	470.4	329.6
	Nonramp	528.6	508.2	20.4	266.7	261.8

Table 10-42 PJM regulation by source: January through September, 2018 and 2019[84]

	2018 (Jan-Sep)				2019 (Jan-Sep)			
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	23	758,087	21.7%	$27,143,323	24	830,956	24.5%	$16,472,536
Coal	37	337,934	9.7%	$16,572,934	19	262,284	7.7%	$6,947,315
Hydro	28	682,585	19.5%	$24,040,207	25	623,305	18.4%	$12,779,787
Natural Gas	168	1,649,390	47.2%	$50,442,658	165	1,588,027	46.8%	$25,775,991
DR	30	68,494	2.0%	$2,306,400	26	88,680	2.6%	$1,824,937
Total	286	3,496,490.7	100.0%	$120,505,522	259	3,393,252.5	100.0%	$63,800,565

Table 10-42 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 10-42 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 settled MW decreased 3.0 percent from 3,496,490.7 MW in the first nine months of 2018 to 3,393,252.5 MW in the first nine months of 2019. The average proportion of regulation provided by battery units had the largest increase (2.8 percent), providing 21.7 percent of regulation in the first nine months of 2018 and 24.5 percent of regulation in the first nine months of 2019. Coal units had the largest decrease in average proportion of regulation provided (1.9 percent), decreasing from 9.7 percent in the first nine months of 2018, to 7.7 percent in the first nine months of 2019. The total regulation credits in the first nine months of 2019 were $63,800,565, down 47.1 percent from $120,505,522 in the first nine months of 2018. The reduction in regulation credits is due, in part, to a lower LOC component of regulation prices as a result of lower energy prices in 2019 compared to 2018.

Significant flaws in the regulation market design have led to an 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 10-43).

82 Average Daily Offer MW excludes units that have offers but are unavailable for the day.
83 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.
84 Biomass data have been added to the natural gas category for confidentiality purposes.

Table 10-43 Active battery storage projects in the PJM queue system by submitted year: 2012 to 2019

Year	Number of Storage Projects	Total Capacity (MW)
2012	1	4.5
2013	0	0.0
2014	1	10.0
2015	7	66.0
2016	2	39.7
2017	3	2.5
2018	29	962.0
2019	48	2,570.7
Total	91	3,655.3

The supply of regulation can be affected by regulating units retiring from service. If all units that are requesting retirement through the end of the first nine months of 2019 retire, the supply of regulation in PJM will be reduced by less than one percent.

Demand

The demand for regulation does not change with price. The regulation requirement is set by PJM to meet NERC control standards, based on reliability objectives, which means that a significant amount of judgment is exercised by PJM in determining the actual demand. Prior to October 1, 2012, the regulation requirement was 1.0 percent of the forecast peak load for on peak hours and 1.0 percent of the forecast valley load for off peak hours. Between October 1, 2012, and December 31, 2012, PJM changed the regulation requirement several times. It had been scheduled to be reduced from 1.0 percent of peak load forecast to 0.9 percent on October 1, 2012, but instead it was changed from 1.0 percent of peak load forecast to 0.78 percent of peak load forecast. It was further reduced to 0.74 percent of peak load forecast on November 22, 2012 and reduced again to 0.70 percent of peak load forecast on December 18, 2012. On December 14, 2013, it was reduced to 700 effective MW during peak hours and 525 effective MW during off peak hours. The regulation requirement remained 700 effective MW during peak hours and 525 effective MW during off peak hours 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 10-37).

Table 10-44 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 470.7 hourly average performance adjusted actual MW in the first nine months of 2019. This is a decrease of 16.1 performance adjusted actual MW from the first nine months of 2018, when the average hourly total regulation cleared performance adjusted actual MW for nonramp hours were 486.8 performance adjusted actual MW. The ramp regulation requirement of 800.0 effective MW was provided by a combination of RegA and RegD resources equal to 722.8 hourly average performance adjusted actual MW in the first nine months of 2019. This is a decrease of 27.1 performance adjusted actual MW from the first nine months of 2018, where the average hourly regulation cleared MW for ramp hours were 750.0 performance adjusted actual MW.

Table 10-44 Required regulation and ratio of supply to requirement: January through September, 2018 and 2019

		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	2018	2019	2018	2019	2018	2019	2018	2019
Ramp	Jan	756.8	719.3	800.0	799.9	1.88	2.10	1.49	1.51
	Feb	738.7	710.3	799.9	799.9	1.90	2.10	1.48	1.53
	Mar	742.9	707.6	800.0	799.9	1.86	1.92	1.43	1.39
	Apr	747.4	718.8	799.9	799.9	1.76	1.81	1.39	1.36
	May	747.2	717.5	800.1	800.0	1.76	1.81	1.42	1.35
	Jun	746.4	728.5	800.0	800.0	1.88	1.81	1.51	1.37
	Jul	756.2	737.2	800.0	800.0	1.91	1.78	1.54	1.39
	Aug	760.4	733.3	800.1	799.9	1.94	1.79	1.53	1.39
	Sep	754.0	733.1	797.3	800.0	1.98	1.78	1.57	1.39
	Oct	752.0	-	800.0	-	1.92	-	1.49	-
	Nov	747.3	-	800.1	-	2.13	-	1.63	-
	Dec	742.3	-	800.1	-	2.08	-	1.55	-
Nonramp	Jan	497.6	465.5	525.1	525.5	2.27	2.57	1.71	1.72
	Feb	482.0	466.6	525.2	525.1	2.37	2.67	1.70	1.83
	Mar	486.6	484.6	525.2	538.0	2.35	2.30	1.67	1.55
	Apr	488.1	472.4	525.0	525.1	2.03	2.18	1.47	1.48
	May	481.5	465.9	524.9	525.6	2.13	2.15	1.55	1.41
	Jun	482.7	466.9	524.9	526.8	2.36	2.18	1.68	1.42
	Jul	488.8	482.1	525.0	541.5	2.24	2.06	1.63	1.41
	Aug	483.5	463.7	525.1	525.3	2.32	2.14	1.65	1.43
	Sep	490.5	469.0	535.1	525.3	2.33	2.08	1.66	1.43
	Oct	477.2	-	525.1	-	2.30	-	1.60	-
	Nov	471.1	-	525.1	-	2.61	-	1.83	-
	Dec	466.5	-	525.1	-	2.74	-	1.89	-

Market Concentration

In the first nine months of 2019, the effective MW weighted average HHI of RegA resources was 2362 which is highly concentrated and the weighted average HHI of RegD resources was 1307 which is moderately concentrated.[85] The weighted average HHI of all resources was 1366, which is moderately concentrated. The HHI of RegA resources and the HHI of RegD resources reflect the fact that different owners have large market shares in the RegA and RegD markets.

Table 10-45 includes a monthly summary of three pivotal supplier (TPS) results. In the first nine months of 2019, 93.3 percent of hours had three or fewer pivotal suppliers. The MMU concludes that the PJM Regulation Market in the first nine months of 2019 was characterized by structural market power.

Table 10-45 Regulation market monthly three pivotal supplier results: January 2017 through September 2019

	Percent of Hours Pivotal		
Month	2017	2018	2019
Jan	90.6%	88.7%	77.8%
Feb	93.1%	77.5%	76.0%
Mar	92.7%	83.9%	93.3%
Apr	92.9%	90.3%	93.1%
May	88.7%	87.8%	94.0%
Jun	89.2%	79.9%	91.0%
Jul	91.0%	79.4%	92.7%
Aug	88.0%	79.6%	93.1%
Sep	82.6%	78.6%	93.3%
Oct	68.1%	82.1%	
Nov	72.5%	78.2%	
Dec	79.3%	74.2%	
Average	85.7%	81.7%	89.4%

85 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.[86] When offering into the regulation market, regulating resources must submit a cost-based offer and may submit a price-based offer (capped at $100/MW) by 2:15 pm the day before the operating day.[87]

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-based 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 margin. The $12.00 margin embeds market power in the regulation offers and is not part of the cost of regulation. The performance component for cost-based offers is not to exceed the increased costs (increased short run marginal costs including 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.[88]

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.[89]

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 10-47).[90] Figure 10-18 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.[91] Self scheduled regulation comprised an average of 43.0 percent during ramp hours and 58.8 percent during nonramp hours in the first nine months of 2019.

86 See "PJM Manual 11: Energy & Ancillary Services Market Operations," § 3.2.1 Regulation Market Eligibility, Rev. 107 (Sep. 26, 2019).
87 Id. at 3.2.2, at p 62.
88 See "PJM Manual 15: Cost Development Guidelines," § 7.8 Regulation Cost, Rev. 32 (May 13, 2019).
89 See "PJM Manual 11: Energy & Ancillary Services Market Operations," § 3.2.1 Regulation Market Eligibility, Rev. 107 (Sep. 26, 2019).
90 See "PJM Manual 28: Operating Agreement Accounting," § 4.1Regulation Accounting Overview, Rev. 82 (July 25, 2019).
91 See "PJM Manual 11: Energy & Ancillary Services Market Operations," § 3.2.1 Regulation Market Eligibility, Rev. 107 (Sep. 26, 2019).

Figure 10-18 Nonramp and ramp regulation levels: January 2018 through September 2019[92]

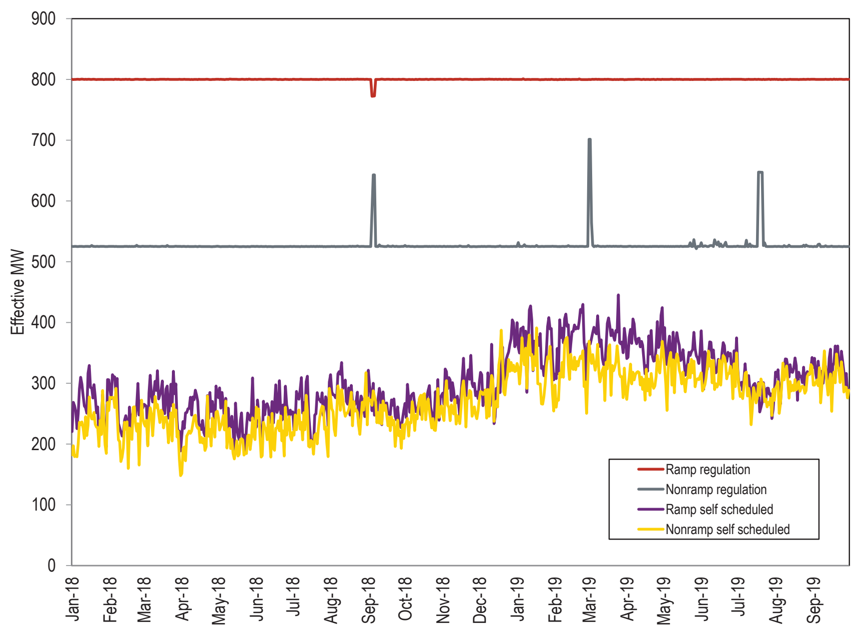


Table 10-46 shows the role of RegD resources in the regulation market. RegD resources are both a growing proportion of the market (10.9 percent of the total effective MW at the start of the performance based regulation market design in October 2012 and 42.1 percent of the total effective MW in September 2019) and a growing proportion of resources that self schedule (25.0 percent of all self scheduled MW in October 2012 and 63.7 percent of all self scheduled MW in September 2019). In the first nine months of 2019, the average RegD percentage of total self scheduled MW was 65.9 percent, an increase of 10.7 percent from the first nine months of 2018, when the average was 55.2 percent. The increase in the effective MW 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.

92 The effective MW increases during the nonramp hours of September 2018, March 2019, and July 2019 were a result of PJM operations treating those hours as ramp hours, with a regulation requirement of 800 MW rather than 525 MW.

Table 10-46 RegD self scheduled regulation by month: October 2012 through September 2019

Year	Month	RegD Self Scheduled Effective MW	RegD Effective MW	Total Self Scheduled Effective MW	Total Effective MW	RegD Percent of Total Self Scheduled Effective MW	RegD Percent of Total Effective MW
2012	Oct	66.3	71.8	264.7	658.1	25.0%	10.9%
2012	Nov	74.4	88.3	196.5	716.5	37.9%	12.3%
2012	Dec	82.5	88.8	188.8	701.1	43.7%	12.7%
2013	Jan	35.7	82.5	133.6	720.0	26.7%	11.5%
2013	Feb	84.8	90.2	212.2	724.3	39.9%	12.5%
2013	Mar	80.1	119.3	279.8	680.7	28.6%	17.5%
2013	Apr	82.3	106.9	266.0	594.1	30.9%	18.0%
2013	May	74.0	109.0	268.2	616.2	27.6%	17.7%
2013	Jun	79.6	122.7	334.9	730.6	23.8%	16.8%
2013	Jul	77.6	120.4	303.6	822.9	25.6%	14.6%
2013	Aug	83.6	127.6	366.0	756.8	22.8%	16.9%
2013	Sep	112.2	152.1	381.6	669.9	29.4%	22.7%
2013	Oct	120.2	163.7	349.6	613.3	34.4%	26.7%
2013	Nov	133.9	175.7	396.5	663.3	33.8%	26.5%
2013	Dec	136.5	180.7	313.6	663.5	43.5%	27.2%
2013 Average		91.7	129.2	300.5	688.0	30.6%	19.0%
2014	Jan	132.9	193.5	261.1	663.6	50.9%	29.2%
2014	Feb	134.3	193.4	289.0	663.6	46.5%	29.1%
2014	Mar	131.8	193.8	287.2	663.8	45.9%	29.2%
2014	Apr	126.8	212.4	270.8	663.7	46.8%	32.0%
2014	May	121.7	248.5	265.6	663.6	45.8%	37.4%
2014	Jun	123.3	231.0	365.5	663.9	33.7%	34.8%
2014	Jul	126.4	235.5	352.7	663.5	35.8%	35.5%
2014	Aug	117.6	229.8	368.2	663.6	31.9%	34.6%
2014	Sep	121.0	242.6	393.8	663.6	30.7%	36.6%
2014	Oct	116.1	255.4	352.7	663.6	32.9%	38.5%
2014	Nov	113.5	235.1	347.5	664.2	32.7%	35.4%
2014	Dec	116.7	254.3	353.0	663.6	33.1%	38.3%
2014 Average		123.5	227.1	325.6	663.7	38.9%	34.2%
2015	Jan	116.4	250.1	304.8	663.7	38.2%	37.7%
2015	Feb	111.3	245.8	242.6	663.5	45.9%	37.0%
2015	Mar	113.8	255.2	229.9	663.8	49.5%	38.5%
2015	Apr	110.1	248.2	283.7	663.7	38.8%	37.4%
2015	May	121.8	265.1	266.7	663.6	45.7%	39.9%
2015	Jun	158.9	283.1	321.2	663.7	49.5%	42.6%
2015	Jul	161.4	278.3	314.0	663.8	51.4%	41.9%
2015	Aug	159.5	276.0	300.7	663.6	53.0%	41.6%
2015	Sep	155.4	289.2	286.0	663.5	54.3%	43.6%
2015	Oct	147.1	299.0	292.8	663.4	50.2%	45.1%
2015	Nov	164.9	302.1	298.1	664.2	55.3%	45.5%
2015	Dec	144.6	317.2	260.7	663.9	55.5%	47.8%
2015 Average		138.8	275.8	283.4	663.7	48.9%	41.6%
2016	Jan	187.7	335.9	295.3	663.8	63.6%	50.6%
2016	Feb	179.9	339.0	274.6	663.6	65.5%	51.1%
2016	Mar	182.6	340.8	280.1	663.7	65.2%	51.3%
2016	Apr	182.2	339.5	287.0	663.5	63.5%	51.2%
2016	May	183.9	341.1	301.5	663.5	61.0%	51.4%
2016	Jun	178.8	340.5	302.4	663.6	59.1%	51.3%
2016	Jul	165.2	337.5	273.3	663.5	60.4%	50.9%
2016	Aug	165.8	338.5	283.2	663.5	58.5%	51.0%
2016	Sep	160.9	341.4	279.9	663.6	57.5%	51.4%
2016	Oct	168.6	340.0	283.0	663.5	59.6%	51.2%
2016	Nov	156.2	338.0	259.8	664.3	60.1%	50.9%
2016	Dec	162.2	342.7	274.7	663.6	59.0%	51.6%
2016 Average		172.8	339.6	282.9	663.7	61.1%	51.2%
2017	Jan	187.1	334.9	318.0	673.9	58.8%	49.7%
2017	Feb	192.7	337.8	296.6	674.2	65.0%	50.1%
2017	Mar	172.2	315.3	297.5	638.5	57.9%	49.4%
2017	Apr	159.9	306.4	255.0	639.6	62.7%	47.9%
2017	May	167.6	297.0	265.7	639.7	63.1%	46.4%
2017	Jun	178.6	315.6	284.3	696.9	62.8%	45.3%
2017	Jul	171.9	310.3	290.0	703.1	59.3%	44.1%
2017	Aug	176.7	314.0	286.3	700.9	61.7%	44.8%
2017	Sep	156.9	297.8	259.0	640.4	60.6%	46.5%
2017	Oct	158.6	295.3	263.7	639.7	60.1%	46.2%
2017	Nov	158.6	298.1	261.7	640.4	60.6%	46.5%
2017	Dec	147.7	290.8	260.6	674.0	56.7%	43.1%
2017 Average		169.0	293.8	278.2	663.4	60.8%	46.7%
2018	Jan	130.6	274.3	247.4	673.8	52.8%	40.7%
2018	Feb	131.1	276.6	245.5	674.0	53.4%	41.0%
2018	Mar	126.6	270.9	249.4	639.8	50.8%	42.3%
2018	Apr	124.8	266.5	232.3	639.6	53.7%	41.7%
2018	May	124.7	275.7	223.0	639.6	55.9%	43.1%
2018	Jun	136.0	298.4	241.5	696.8	56.3%	42.8%
2018	Jul	138.5	294.6	248.3	696.9	55.8%	42.3%
2018	Aug	159.6	274.3	271.6	697.0	58.8%	39.4%
2018	Sep	150.1	256.7	251.4	644.3	59.7%	39.8%
2018	Oct	148.0	266.6	256.6	639.6	57.7%	41.7%
2018	Nov	144.0	252.9	274.8	640.4	52.4%	39.5%
2018	Dec	172.0	273.0	308.5	674.0	55.7%	40.5%
2018 Average		140.5	263.8	254.2	663.0	55.2%	41.2%
2019	Jan	223.0	303.6	345.8	674.0	64.5%	45.0%
2019	Feb	243.3	311.5	350.8	673.9	69.4%	46.2%
2019	Mar	240.9	314.2	347.0	647.6	69.4%	48.5%
2019	Apr	230.5	305.2	332.6	639.6	69.3%	47.7%
2019	May	213.2	297.2	330.9	639.9	64.4%	46.4%
2019	Jun	206.3	289.1	331.9	697.6	62.1%	41.4%
2019	Jul	188.5	290.3	285.9	703.1	65.9%	41.3%
2019	Aug	200.3	290.2	309.4	696.9	64.7%	41.6%
2019	Sep	198.9	269.4	312.2	639.8	63.7%	42.1%
2019 Average		216.1	312.1	327.4	334.2	65.9%	44.5%

Increased self scheduled regulation lowers the requirement for cleared regulation, resulting in fewer MW cleared in the market and lower clearing prices. Of the LSEs' obligation to provide regulation in the first nine months of 2019, 52.6 percent was purchased in the PJM market, 42.2 percent was self scheduled, and 5.2 percent was purchased bilaterally (Table 10-47). Table 10-48 shows the total regulation by source including spot market regulation, self scheduled regulation, and bilateral regulation for the first nine months of each year from 2012 to 2019. Table 10-47 and Table 10-48 are based on settled (purchased) MW.

Table 10-47 Regulation sources: spot market, self scheduled, bilateral purchases: January 2018 through September 2019

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)
2018	Jan	241,902.0	60.7%	134,251.7	33.7%	22,447.0	5.6%	398,600.6
2018	Feb	222,860.7	62.0%	120,581.1	33.6%	15,846.5	4.4%	359,288.3
2018	Mar	213,265.0	57.0%	141,161.2	37.7%	19,749.0	5.3%	374,175.3
2018	Apr	221,787.2	60.9%	125,524.8	34.5%	16,941.5	4.7%	364,253.5
2018	May	237,448.1	64.3%	115,879.6	31.4%	15,670.0	4.2%	368,997.7
2018	Jun	253,593.9	64.5%	120,041.8	30.5%	19,547.5	5.0%	393,183.2
2018	Jul	259,675.4	63.3%	128,317.0	31.3%	22,103.0	5.4%	410,095.4
2018	Aug	247,312.4	60.3%	132,757.8	32.4%	29,987.0	7.3%	410,057.2
2018	Sep	226,706.5	63.0%	117,025.7	32.5%	16,302.0	4.5%	360,034.2
2018	Oct	221,319.3	59.9%	129,259.5	35.0%	19,042.5	5.2%	369,621.3
2018	Nov	196,229.7	54.8%	136,284.0	38.0%	25,716.0	7.2%	358,229.7
2018	Dec	213,255.5	54.6%	157,304.7	40.3%	20,237.5	5.2%	390,797.7
Total		2,755,355.7	60.5%	1,558,388.9	34.2%	243,589.5	5.3%	4,557,334.1
2019	Jan	190,256.0	50.0%	170,091.0	44.7%	20,426.0	5.4%	380,773.0
2019	Feb	173,403.6	50.4%	154,652.2	45.0%	15,841.0	4.6%	343,896.8
2019	Mar	176,012.6	48.1%	175,580.7	47.9%	14,679.0	4.0%	366,272.3
2019	Apr	170,454.4	49.1%	158,313.1	45.6%	18,133.0	5.2%	346,900.4
2019	May	165,667.4	46.4%	166,367.6	46.6%	25,305.0	7.1%	357,340.1
2019	Jun	210,077.0	54.5%	155,567.8	40.3%	19,950.0	5.2%	385,594.8
2019	Jul	249,261.1	61.9%	134,210.8	33.3%	19,405.5	4.8%	402,877.5
2019	Aug	232,920.9	58.3%	146,362.4	36.6%	20,246.5	5.1%	399,529.8
2019	Sep	187,018.5	53.2%	144,562.1	41.1%	20,200.0	5.7%	351,780.6
Total		1,755,071.5	52.6%	1,405,707.9	42.2%	174,186.0	5.2%	3,334,965.3

Table 10-48 Regulation sources: January through September, 2012 through 2019

Jan-Sep	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	5,110,747.9	79.7%	1,122,671.9	17.5%	180,121.0	2.8%	6,413,540.8
2013	2,528,830.3	60.8%	1,478,608.5	35.5%	152,328.5	3.7%	4,159,767.3
2014	1,836,488.7	51.8%	1,543,266.0	43.5%	166,857.0	4.7%	3,546,611.7
2015	1,897,225.7	54.7%	1,380,004.7	39.8%	193,529.1	5.6%	3,470,759.5
2016	1,672,795.5	47.8%	1,598,231.6	45.7%	226,803.5	6.5%	3,497,830.6
2017	1,849,333.5	54.1%	1,372,996.2	40.2%	196,759.5	5.8%	3,419,089.2
2018	2,124,551.1	61.8%	1,135,540.8	33.0%	178,593.5	5.2%	3,438,685.4
2019	1,755,071.5	52.6%	1,405,707.9	42.2%	174,186.0	5.2%	3,334,965.3

In the first nine months of 2019, DR provided an average of 17.0 MW of regulation per hour during ramp hours (12.2 MW of regulation per hour during ramp hours in the first nine months of 2018), and an average of 14.3 MW of regulation per hour during nonramp hours (10.8 MW of regulation per hour during off peak hours in the first nine months of 2018). Generating units supplied an average of 706.9 MW of regulation per hour during ramp hours in the first nine months of 2019 (738.4 MW of regulation per hour during ramp hours in the first nine months of 2018), and an average of 456.7 MW per hour during nonramp hours in the first nine months of 2019 (476.1 MW of regulation per hour during nonramp hours in the first nine months of 2018).

Market Performance

Price

Table 10-52 shows the regulation price and regulation cost per MW for the first nine months of each year from 2009 through 2019. The weighted average RMCP for the first nine months of 2019 was $14.97 per MW. This is a decrease of $13.25 per MW, or 47.0 percent, from the weighted average RMCP of $28.21 per MW in the first nine months of 2018. This decrease in the regulation clearing price was the result of a decrease in energy prices in the first nine months of 2019 and the related decrease in the opportunity cost component of RMCP.

Figure 10-19 shows the daily weighted average regulation market clearing price, the capability price, performance price, and the opportunity cost component for the PJM Regulation Market on a performance adjusted MW basis. The regulation clearing price is determined based on the marginal unit's total offer (RCP + RPP + PJM calculated LOC), then the maximum performance offer price (RPP) of any of the cleared units is used to set the marginal performance clearing price for the purposes of settlements. The difference between the marginal total clearing price and the highest performance clearing price (RMPCP) is the marginal capability clearing price (RMCCP). This means that the capability price presented here is equal to the clearing price, minus the maximum cleared performance offer price. This data is based on actual five minute interval operational data.

Figure 10-19 illustrates that the opportunity cost (dark blue line) is the largest component of the clearing price.

Figure 10-19 Regulation market-clearing price, opportunity cost and offer price components (Dollars per MW): January through September, 2019

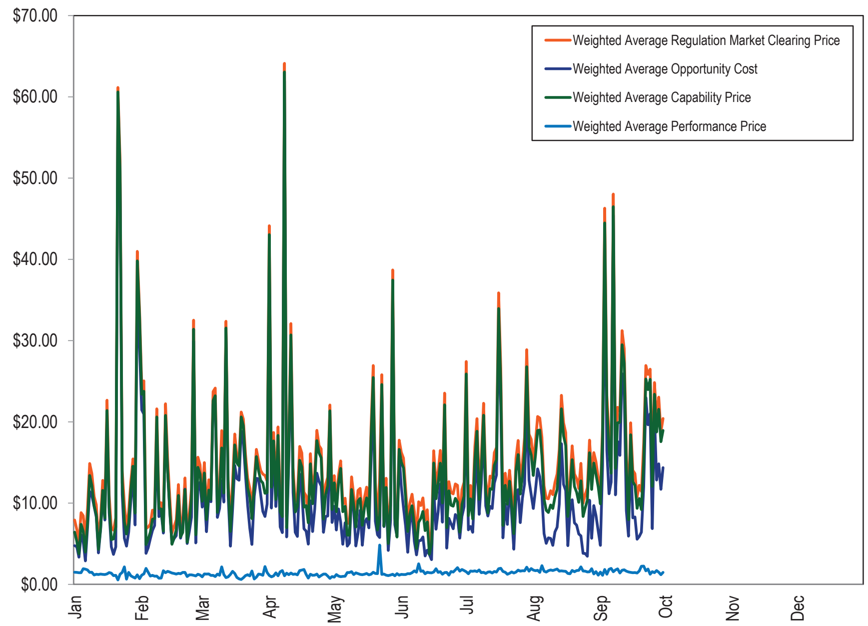


Table 10-49 shows the capability and performance components of the monthly average regulation prices. These components differ from the components of the marginal unit's offers in Figure 10-19 because the performance component of the settlement price for each hour is determined from the average of the highest performance offers in each five minute interval, calculated independent of the marginal unit's offers in those intervals.

Table 10-49 PJM regulation market monthly component of price (Dollars per MW): January through September, 2019

Month	Weighted Average Regulation Market Capability Clearing Price ($/Perf. Adj. Actual MW)	Weighted Average Regulation Market Performance Clearing Price ($/Perf. Adj. Actual MW)	Weighted Average Regulation Market Clearing Price ($/Perf. Adj. Actual MW)
Jan	$13.42	$1.29	$14.71
Feb	$11.05	$1.25	$12.30
Mar	$13.84	$1.16	$15.00
Apr	$15.75	$1.22	$16.96
May	$11.57	$1.33	$12.90
Jun	$9.84	$1.53	$11.37
Jul	$14.57	$1.58	$16.16
Aug	$12.97	$1.64	$14.62
Sep	$19.30	$1.61	$20.91
Average	$12.58	$1.30	$13.88

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 10-50. Total scheduled regulation is based on settled performance adjusted MW. The total of all regulation charges for the first nine months of 2019 was $63.8 million, compared to $120.5 million for the first nine months of 2018.

Table 10-50 Total regulation charges: January 2018 through September 2019

Year	Month	Scheduled Regulation (MW)	Total Regulation Charges ($)	Weighted Average Regulation Market Price ($/MW)	Cost of Regulation ($/MW)	Price as Percent of Cost
2018	Jan	398,600.6	$39,149,046	$80.73	$98.22	82.2%
2018	Feb	359,288.3	$6,270,251	$12.80	$17.45	73.4%
2018	Mar	374,175.3	$10,735,641	$23.73	$28.69	82.7%
2018	Apr	364,253.5	$12,882,261	$27.70	$35.37	78.3%
2018	May	368,997.7	$14,087,966	$30.84	$38.18	80.8%
2018	Jun	393,183.2	$8,933,758	$18.64	$22.72	82.0%
2018	Jul	410,095.4	$9,716,064	$19.42	$23.69	82.0%
2018	Aug	410,057.2	$9,079,650	$17.22	$22.14	77.8%
2018	Sep	360,034.2	$9,660,676	$20.92	$26.83	78.0%
2018	Oct	369,621.3	$10,342,063	$20.81	$27.98	74.4%
2018	Nov	358,229.7	$7,530,728	$15.28	$21.02	72.7%
2018	Dec	390,797.7	$7,118,936	$13.39	$18.22	73.5%
Yearly		4,554,652.8	$145,465,939	$25.33	$31.94	79.3%
2019	Jan	380,773.0	$7,272,344	$14.71	$19.10	77.0%
2019	Feb	343,896.8	$5,651,921	$12.30	$16.43	74.9%
2019	Mar	366,272.3	$7,204,760	$15.00	$19.67	76.3%
2019	Apr	346,900.4	$7,528,065	$16.96	$21.70	78.2%
2019	May	357,340.1	$6,111,192	$12.90	$17.10	75.5%
2019	Jun	385,594.8	$5,747,998	$11.37	$14.91	76.3%
2019	Jul	402,877.5	$8,166,587	$16.16	$20.27	79.7%
2019	Aug	399,529.8	$7,351,497	$14.62	$18.40	79.5%
2019	Sep	351,780.6	$8,803,781	$20.91	$25.03	83.5%
Year to date		3,334,965.3	$63,838,145	$14.97	$19.14	78.2%

The capability, performance, and opportunity cost components of the cost of regulation are shown in Table 10-51. Total scheduled regulation is based on settled performance adjusted MW. In the first nine months of 2019, the average total cost of regulation was $19.14 per MW, 45.4 percent lower than $35.05 in the first nine months of 2018. In the first nine months of 2019, the monthly average capability component cost of regulation was $14.10, 48.1 percent lower than $27.16 in the first nine months of 2018. In the first nine months of 2019, the monthly average performance component cost of regulation was $2.87, 19.4 percent lower than $3.55 in the first nine months of 2018. The reduction of the average total cost in the first nine months of 2019 versus the first nine months of 2018, was primarily a result of lower LOC values due to lower prices in the energy market.

Table 10-51 Components of regulation cost: January 2018 through September 2019

Year	Month	Scheduled Regulation (MW)	Cost of Regulation Capability ($/MW)	Cost of Regulation Performance ($/MW)	Opportunity Cost ($/MW)	Total Cost ($/MW)
2018	Jan	398,600.6	$80.22	$3.76	$14.24	$98.22
	Feb	359,288.3	$11.17	$4.46	$1.82	$17.45
	Mar	374,175.3	$22.92	$2.91	$2.86	$28.69
	Apr	364,253.5	$26.78	$3.57	$5.02	$35.37
	May	368,997.7	$29.85	$3.78	$4.55	$38.18
	Jun	393,183.2	$17.76	$2.92	$2.04	$22.72
	Jul	410,095.4	$18.25	$3.08	$2.36	$23.69
	Aug	410,057.2	$16.04	$3.48	$2.62	$22.14
	Sep	360,034.2	$19.46	$4.15	$3.23	$26.83
	Oct	369,621.3	$19.19	$4.99	$3.80	$27.98
	Nov	358,229.7	$14.20	$3.36	$3.46	$21.02
	Dec	390,797.7	$12.31	$3.29	$2.61	$18.22
Yearly		4,554,652.8	$24.22	$3.63	$4.08	$31.94
2019	Jan	380,773.0	$13.91	$2.68	$2.51	$19.10
	Feb	343,896.8	$11.51	$2.67	$2.26	$16.43
	Mar	366,272.3	$14.33	$2.63	$2.71	$19.67
	Apr	346,900.4	$16.18	$2.65	$2.88	$21.70
	May	357,340.1	$12.27	$2.46	$2.37	$17.10
	Jun	385,594.8	$10.35	$3.10	$1.46	$14.91
	Jul	402,877.5	$15.06	$3.19	$2.01	$20.27
	Aug	399,529.8	$13.59	$3.31	$1.50	$18.40
	Sep	351,780.6	$20.01	$2.98	$2.03	$25.03
Year to date		3,334,965.3	$14.10	$2.87	$2.18	$19.14

Table 10-52 provides a comparison of the average price and cost for PJM regulation. The ratio of regulation market price to the cost of regulation in the first nine months of 2019 was 78.2 percent, a 2.9 percent decrease from 80.5 percent in the first nine months of 2018.

Table 10-52 Comparison of average price and cost for PJM regulation: January through September, 2009 through 2019

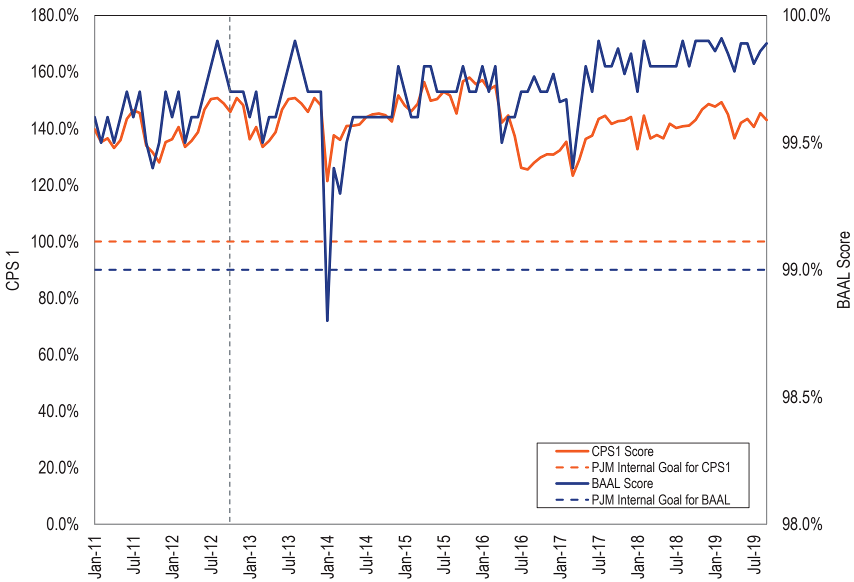
Jan-Sep	Weighted Regulation Market Price	Weighted Regulation Market Cost	Regulation Price as Percent Cost
2009	$24.94	$32.28	77.3%
2010	$19.47	$34.54	56.4%
2011	$17.04	$32.70	52.1%
2012	$15.16	$21.07	71.9%
2013	$33.29	$38.49	86.5%
2014	$50.19	$60.94	82.4%
2015	$35.56	$43.00	82.7%
2016	$16.52	$18.99	87.0%
2017	$15.70	$21.70	72.4%
2018	$28.21	$35.05	80.5%
2019	$14.97	$19.14	78.2%

Performance Standards

PJM's performance as measured by CPS1 and BAAL standards is shown in Figure 10-20 for every month from January 2011 through September 2019 with the dashed vertical line marking the date (October 1, 2012) of the implementation of the Performance Based Regulation Market design.[93] 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.

93 See *2018 State of the Market Report for PJM*, Appendix F: Ancillary Services.

Figure 10-20 PJM monthly CPS1 and BAAL performance: January 2011 through September 2019



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.[94] [95] 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.

On February 1, 2018, PJM issued its second RTO wide request for proposals (RFP) in accordance with the five year black start selection process. The RFP process is a two–tiered process. Level one submissions were due March 8, 2018. On March 30, 2018, PJM notified participants if a level two response would be requested. Level two bidders were requested by PJM to provide their detailed proposal by May 31, 2018. From November 28, 2018, through December 21, 2018, PJM awarded seven proposals.

On February 1, 2019, PJM issued an incremental RFP for additional black start service in the BGE Zone. The RFP is a two stage process. Level one

94 See PJM. "RTO-Wide Five-Year Selection Process Request for Proposal for Black Start Service," (July 1, 2013).
95 RFPs issued can be found on the PJM website. See PJM. <http://www.pjm.com/markets-and-operations/ancillary-services.aspx>.

submissions were due February 25, 2019. On March 8, 2019, PJM notified participants if a level two response would be requested. Level two bidders were requested by PJM to provide their detailed proposals by May 1, 2019. Bids have been received and PJM plans to complete the review of the level two proposals and issue an award by September 1, 2019. The expected in service date is April 1, 2021.

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.[96]

In the first nine months of 2019, total black start charges were $48.368 million, a decrease of $0.762 million (-1.6 percent) from the same nine month period in 2018. Operating reserve charges for black start service decreased from $0.191 million in the first nine months of 2018 to $0.160 million in the first nine months of 2019. Table 10-53 shows total revenue requirement charges from 2010 through 2019. Prior to December 2012, PJM did not define a separate black start operating reserve category. Starting December 1, 2012, PJM defined a separate black start operating reserve category. By April 2015, all ALR units had been replaced and no longer provided black start service which resulted in decreased operating reserve charges.

96 OATT Schedule 6A (paras. 25, 26 and 27 outline how charges are to be applied).

Table 10-53 Black start revenue requirement charges: January through September, 2010 through 2019

Jan-Sep	Revenue Requirement Charges	Operating Reserve Charges	Total
2010	$8,527,000	$0	$8,527,000
2011	$9,996,898	$0	$9,996,898
2012	$13,288,491	$0	$13,288,491
2013	$15,728,447	$68,903,357	$84,631,804
2014	$18,395,320	$26,661,658	$45,056,978
2015	$39,718,855	$5,070,944	$44,789,799
2016	$51,565,656	$180,265	$51,745,921
2017	$52,422,434	$186,752	$52,609,186
2018	$48,940,298	$190,781	$49,131,080
2019	$48,208,418	$159,867	$48,368,284

Black start zonal charges in the first nine months of 2019 ranged from $0.04 per MW-day in the DLCO Zone (total charges were $33,657) to $4.03 per MW-day in the PENELEC Zone (total charges were $3,299,265). For each zone, Table 10-54 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 $1.05 per MW-day of reserve capacity during the first nine months of 2019.

Table 10-54 Black start zonal charges: January through September, 2018 and 2019[97]

	Jan-Sep 2018						Jan-Sep 2019					
Zone	Revenue Requirement Charges	Operating Reserve Charges	Total Charges	Peak Load (MW)	Days	Black Start Rate ($/MW-day)	Revenue Requirement Charges	Operating Reserve Charges	Total Charges	Peak Load (MW)	Days	Black Start Rate ($/MW-day)
AECO	$2,057,440	$14,518	$2,071,958	2,541	273	$2.99	$2,028,149	$8,011	$2,036,161	2,591	273	$2.88
AEP	$13,142,244	$39,193	$13,181,437	21,647	273	$2.23	$12,971,807	$45,020	$13,016,827	22,739	273	$2.10
APS	$2,930,362	$3,945	$2,934,307	8,755	273	$1.23	$2,922,052	$1,102	$2,923,155	9,342	273	$1.15
ATSI	$2,297,019	$934	$2,297,953	12,052	273	$0.70	$3,979,965	$1,482	$3,981,448	12,825	273	$1.14
BGE	$944,860	$3,371	$948,231	6,448	273	$0.54	$283,260	$956	$284,215	6,627	273	$0.16
ComEd	$3,468,613	$13,815	$3,482,428	20,351	273	$0.63	$3,156,493	$12,470	$3,168,963	21,349	273	$0.54
DAY	$179,681	$2,330	$182,011	3,225	273	$0.21	$157,663	$1,176	$158,840	3,337	273	$0.17
DEOK	$661,568	$0	$661,568	5,036	273	$0.48	$264,062	$0	$264,062	5,195	273	$0.19
DLCO	$36,936	$0	$36,936	2,682	273	$0.05	$33,657	$0	$33,657	2,795	273	$0.04
Dominion	$3,047,547	$9,576	$3,057,123	19,661	273	$0.57	$2,659,768	$19,300	$2,679,068	21,232	273	$0.46
DPL	$1,691,436	$9,602	$1,701,039	3,813	273	$1.63	$1,663,278	$12,448	$1,675,726	4,002	273	$1.53
EKPC	$287,245	$844	$288,089	2,860	273	$0.37	$250,757	$1,964	$252,721	3,431	273	$0.27
JCPL	$5,126,105	$9,035	$5,135,141	5,721	273	$3.29	$5,073,428	$7,186	$5,080,614	5,977	273	$3.11
Met-Ed	$447,524	$46,466	$493,990	2,897	273	$0.62	$344,957	$16,637	$361,594	3,028	273	$0.44
OVEC	$0	$0	$0	NA	273	NA	$0	$0	$0	NA	273	NA
PECO	$1,170,817	$2,460	$1,173,277	8,141	273	$0.53	$1,016,448	$3,169	$1,019,617	8,608	273	$0.43
PENELEC	$3,391,667	$3,319	$3,394,986	2,890	273	$4.30	$3,297,981	$1,284	$3,299,265	2,997	273	$4.03
Pepco	$1,888,538	$14,986	$1,903,524	6,097	273	$1.14	$1,846,793	$8,759	$1,855,553	6,412	273	$1.06
PPL	$895,260	$7,873	$903,134	7,401	273	$0.45	$837,500	$7,279	$844,779	7,681	273	$0.40
PSEG	$3,156,191	$861	$3,157,052	9,567	273	$1.21	$3,115,037	$4,526	$3,119,564	9,978	273	$1.15
RECO	$0	$0	$0	NA	273	NA	$0	$0	$0	NA	273	NA
(Imp/Exp/Wheels)	$2,119,244	$7,653	$2,126,896	6,890	273	$1.13	$2,305,361	$7,096	$2,312,457	8,067	273	$1.05
Total	$48,940,298	$190,781	$49,131,080	158,675		$1.13	$48,208,418	$159,867	$48,368,284	168,213		$1.05

Table 10-55 provides a revenue requirement estimate by zone for the 2019/2020, 2020/2021 and 2021/2022 delivery years.[98] 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. Prior to November 26, 2017, new black start units were not paid until their costs had been provided with appropriate support and approved. In some cases black start units were completed and went into service before costs had been supported and therefore costs were not approved. In these cases the unit did not receive any payments until the costs were appropriately supported. Once their costs were approved the units received all payments going back to the in service date. The result was a lumpy payment by load for black start service. After November 26, 2017, PJM accrued payments for the black start units each month, until the units costs were supported and approved in order to smooth out monthly payments for black start service.

97 Peak load for each zone is used to calculate the black start rate per MW day.
98 The System Restoration Strategy Task Force requested that the MMU provide estimated black start revenue requirements.

Table 10-55 Black start zonal revenue requirement estimate: 2019/2020 through 2021/2022 delivery years

Zone	2019 / 2020 Revenue Requirement	2020 / 2021 Revenue Requirement	2021 / 2022 Revenue Requirement
AECO	$2,850,000	$2,700,000	$2,150,000
AEP	$18,750,000	$21,550,000	$21,650,000
APS	$4,100,000	$5,150,000	$10,400,000
ATSI	$5,900,000	$5,900,000	$5,900,000
BGE	$350,000	$50,000	$50,000
ComEd	$5,450,000	$9,700,000	$9,850,000
DAY	$250,000	$250,000	$300,000
DEOK	$400,000	$400,000	$450,000
DLCO	$100,000	$400,000	$2,150,000
Dominion	$4,350,000	$6,000,000	$6,100,000
DPL	$2,350,000	$2,350,000	$1,450,000
EKPC	$400,000	$400,000	$400,000
JCPL	$7,150,000	$800,000	$850,000
Met-Ed	$500,000	$450,000	$550,000
OVEC	$0	$0	$0
PECO	$1,450,000	$1,450,000	$1,600,000
PENELEC	$4,650,000	$4,600,000	$4,700,000
Pepco	$2,600,000	$750,000	$450,000
PPL	$1,800,000	$4,700,000	$4,750,000
PSEG	$4,350,000	$1,850,000	$1,900,000
RECO	$0	$0	$0
Total	$67,750,000	$69,450,000	$75,650,000

NERC – CIP

Currently, no black start units have requested new or additional black start NERC – CIP Capital Costs.[99]

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.

Figure 10-21 illustrates that the size of the oil tank does not change with the addition of the black start unit. Figure 10-22 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.

99 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 10-21 Oil tank MTSL not changed from addition of black start generator

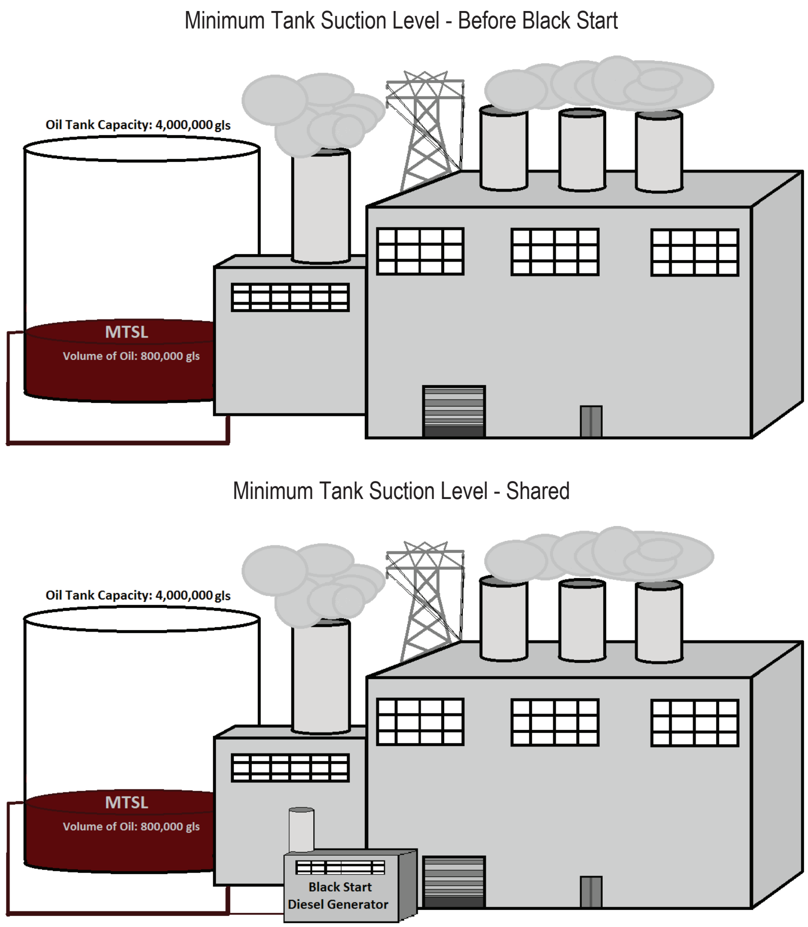
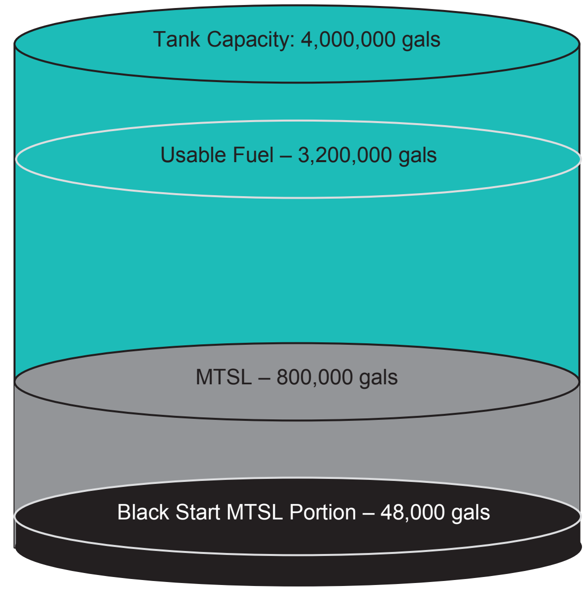


Figure 10-22 Oil tank black start MTSL portion



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 separately for each resource or resource group by FERC per Schedule 2 of the OATT. Resources may obtain FERC approval to recover a share of resources' fixed costs by calculating a reactive revenue requirement, the reactive capability rate, and to collect such rates from PJM transmission customers.[100]

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.

100 See "PJM Manual 27: Open Access Transmission Tariff Accounting,"§ 3.2 Reactive Supply and Voltage Control Credits, Rev. 90, (Dec. 6, 2018).

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).[101] PJM in its role as the independent RTO and transmission provider determines the reactive capability it needs from all sources in order to reliably operate the grid. While a fixed requirement for reactive power is not established, reactive power helps maintain appropriate voltages on the transmission system and must be sourced locally.

Total reactive capability charges are the sum of FERC approved reactive supply revenue requirements which are posted monthly on the PJM website.[102] 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.[103]

In 2016, the FERC began to reexamine its policies on reactive compensation.[104] 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.[105] 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.[106] 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 markets.[107] The Commission has recently extended the interconnection service requirement to have reactive capability to wind and solar units, which previously had been exempt.[108] 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.

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. 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

Reactive compensation must be integrated into PJM's competitive market design. Reactive capability rates recover through cost of service rates exactly the same investment that capacity markets price at market based rates.

101 OATT Schedule 2.

102 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).

103 OATT Schedule 2.

104 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).

105 See 88 FERC ¶ 61,141 (1999).

106 See 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.").

107 See 18 CFR § 35.28(f)(1); 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); 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).

108 Order No. 827, 155 FERC ¶ 61,277 (2016); see also 151 FERC ¶ 61,097 at P 28 (2015).

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 PJM needs to maintain system stability and do not constitute double recovery.

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.[109] The only FERC proceeding that has provided an opportunity for the MMU to raise its concerns at hearing has been *Panda Stonewall LLC*.[110] The initial decision issued in that case sidesteps the issues identified by the MMU.[111] These issues must be squarely addressed for PJM to have an even minimally satisfactory market design related to compensating investment in reactive capability that cannot be differentiated from investment in capacity.

Power Factor Capped at PJM Determined Level of Need

Under the *AEP* method, units must establish their MVAR rating based on "the capability of the generators to produce VARs."[112] Typically this has meant reliance on manufacturers' specified nameplate power factor.[113] More recently, the Commission has, in the *Wabash* Orders, required that "reactive power revenue requirement filings must include reactive power test reports."[114] 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.[115]

The Commission has identified a significant issue.[116] 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. However, power ratings, whether based on nameplate or testing, do not establish MVAR capability that is properly relevant to reactive capability rates in PJM. PJM determines the level of reactive capability it needs in its role as the independent RTO and transmission provider. Generation owners should not be permitted through uncoordinated reactive capability rates to substitute their assessment for PJM's.

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. Only operator evaluation of reactive capability can provide a meaningful measure of reactive capability.

The most fundamental point about power factors is that PJM requires that all generating units have a 0.90 power factor in order to obtain interconnection service.[117] There is no reason to pay any provider of reactive capability based on a power factor exceeding the 0.90 power factor that PJM has determined is necessary.

The PJM required power factor value is the only value reasonably included in reactive capability rates because that is what PJM has determined it needs from each generator. Generators should not be permitted to make investment decisions that unnecessarily increase the cost of reactive capability. Individual owners have a conflict of interest concerning such decisions and are not authorized under the OATT to change PJM's determinations on the required power factor.

Reactive capability rates should not be confused with compensation for operating to provide reactive power at PJM's direction. 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.

109 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.
110 See Docket No. EL17-1821.
111 167 FERC ¶ 63,010 (April 26, 2019).
112 AEP mimeo at 31.
113 See, e.g., id.
114 154 FERC ¶ 61,246 at P 28 (2016); see also 154 FERC ¶ 61,246 at P 29 (Wabash Orders).
115 See, e.g., 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.").
116 154 FERC ¶ 61,246 at P 28 (2016); see also 154 FERC ¶ 61,246 at P 29.
117 See supra footnote 27.

Offset Cap on Reactive Capability Rates

In addition to effectively capping the appropriate level of the power factor, the PJM market rules also effectively cap the appropriate level of reactive capability rates overall.

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 included in the offset is not part of net CONE.[118] 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.

The revenue offset is defined as a fixed number in the OATT and is currently set equal at $2,199/MW-year.[119] This 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 PJM market rules explicitly account for recovery of reactive revenues of $2,199 per MW-year. Reactive capability rates up to that level do not result in double recovery. Reactive capability rates above that level do result in double recovery because costs that would support a rate exceeding $2,199 per MW-year continue to be recoverable in the PJM Capacity Market.

The $2,199 offset is a simple rule that established a just and reasonable reconciliation of different regulatory approaches in the same market design. The offset assumes a defined level of revenues are received under cost of service rates and nets them from the parameters used in the capacity market. Those parameters define the operation of the market so that just and reasonable capacity prices are established. Reactive rates cannot be just and reasonable if they do not account for the market design in which PJM units operate.

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. Double compensation should not be permitted as a combined result of market based capacity prices and cost of service rates.

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.[120] 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 these issues through participation in proceedings at FERC concerning reactive capability rates for PJM units.[121]

Losses

The estimated capability costs also include estimated heating losses relative to MVAR output.[122] Heating losses are variable costs and not fixed costs and should not be included in the definition of reactive capability costs.[123] 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

118 See OATT Attachment DD § 5.10(a)(iv).
119 See OATT Attachment DD § 5.10(a)(v).

120 See OATT Attachment DD §§ 6.4, 6.8(d).
121 The MMUs has to date participated in nearly 150 reactive matters. 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.
122 See, e.g., *id.* at P 10 n12, citing *PPL Energy Plus, LLC*, Letter Order, Docket No. ER08-1462-000 (Sept. 24, 2008); 125 FERC ¶ 61,280 at P 35 (2008).
123 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.

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.

Fleet Rates

Cost of service rates are established under Schedule 2 of the OATT and may cover rates for single units or a fleet of units.[124] 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.[125] 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.[126]

Fleet rates create confusion about what revenue is properly attributable to each unit in the fleet. Reactive rates should be stated separately for each unit, even if multiple plants or units are considered in a single proceeding. The MMU filed with the Commission to require unit specific rates when PJM proposed limited reforms that could have corrected the oversight and compliance problems posed by fleet rates.[127] But PJM rules require fleet owners only to submit informational filings when a reactive unit is transferred or deactivated.[128] The current rules do not require a rate filing, which would place the burden of proof on the company and allow for cost review.[129]

The MMU also raised issues related to fleet rates in a settlement establishing a fleet rate without specifying the actual portion of the fleet rate attributable to each unit in the fleet.[130] The approach could prevent or inhibit an appropriate adjustment of the fleet requirement if a unit receiving an unspecified portion of such requirement is deactivated or transferred because third parties without access to cost information would bear the burden of proof in a complaint proceeding.[131] The MMU also explained that the approach makes it impossible to calculate cost-based offers from such units in the PJM Capacity Market. The settlement was approved over the MMU's objection on the grounds that the tariff does not prohibit fleet rates.[132]

The MMU recommends that fleet rates be eliminated and that compensation be based on unit specific costs and rates.

Reactive Costs

In the first nine months of 2019, total reactive charges were $258.7 million, a 3.2 percent increase from the $250.8 million for the first nine months of 2018. Reactive capability charges increased from $238.3 million in the first nine months 2018 to $258.2 million in 2019 and reactive service charges decreased from $12.4 million in the first nine months of 2018 to $0.45 million in the first nine months of 2019. All $0.45 million in the first nine months of 2019 were paid for reactive service provided by 23 units in 104 hours.

Table 10-56 shows reactive service charges in the first nine months of 2018 and 2019, reactive capability charges and total charges. Reactive service charges show charges to each zone for reactive service provided and not credits to plants in each zone. Reactive capability charges show charges to each zone for reactive capability.

124 See, e.g., OATT Schedule 2; 114 FERC ¶ 61,318 (2006).
125 See 149 FERC ¶ 61,132 (2014); 151 FERC ¶ 61,224 (2015); OATT Schedule 2.
126 Id.
127 151 FERC ¶ 61,224 at P 29 (2015).
128 OATT Schedule 2.
129 Id.
130 See Letter Opposing Settlement, Docket No ER06-554 et al. (June 14, 2017).
131 Id.
132 162 FERC ¶ 61,029 (2018).

Table 10-56 Reactive service charges and reactive capability charges by zone: January through September, 2018 and 2019

	Jan-Sep 2018			Jan-Sep 2019		
Zone	Reactive Service Charges	Reactive Capability Charges	Total Charges	Reactive Service Charges	Reactive Capability Charges	Total Charges
AECO	$7	$3,262,827	$3,262,834	$0	$3,220,440	$3,220,440
AEP	$775,231	$30,906,777	$31,682,008	$14,233	$35,983,652	$35,997,885
APS	$0	$11,686,243	$11,686,243	$13,823	$11,774,288	$11,788,111
ATSI	$0	$16,213,493	$16,213,493	$696	$19,700,232	$19,700,929
BGE	$30,956	$6,095,433	$6,126,390	$0	$5,543,285	$5,543,285
ComEd	$10,790,803	$28,786,314	$39,577,117	$0	$29,683,563	$29,683,563
DAY	$0	$3,382,775	$3,382,775	$0	$2,112,619	$2,112,619
DEOK	$0	$5,951,863	$5,951,863	$0	$7,505,391	$7,505,391
Dominion	$22,293	$28,629,559	$28,651,851	$182,436	$28,920,858	$29,103,294
DPL	$257,310	$7,629,540	$7,886,850	$102,319	$7,393,200	$7,495,519
DLCO	$0	$430,486	$430,486	$0	$428,142	$428,142
EKPC	$175,743	$1,644,625	$1,820,368	$0	$1,635,666	$1,635,666
JCPL	$0	$7,095,604	$7,095,604	$0	$5,474,178	$5,474,178
Met-Ed	$0	$3,355,219	$3,355,219	$0	$4,473,048	$4,473,048
OVEC	$0	$0	$0	$0	$0	$0
PECO	$0	$17,067,202	$17,067,202	$0	$16,145,838	$16,145,838
PENELEC	$357,599	$8,976,358	$9,333,958	$137,176	$9,721,968	$9,859,145
Pepco	$0	$7,078,887	$7,078,887	$0	$8,475,942	$8,475,942
PPL	$0	$18,322,300	$18,322,300	$0	$26,117,160	$26,117,160
PSEG	$0	$20,552,524	$20,552,524	$0	$20,736,024	$20,736,024
RECO	$0	$0	$0	$0	$0	$0
(Imp/Exp/Wheels)	$0	$11,278,069	$11,278,069	$0	$13,181,067	$13,181,067
Total	$12,409,942	$238,346,098	$250,756,040	$450,685	$258,226,560	$258,677,245

Frequency Response

On February 15, 2018, the Commission issued Order No. 842, which modified the proforma large and small generator interconnection agreements and procedures to require newly interconnecting generating facilities, both synchronous and nonsynchronous, to include equipment for primary frequency response capability as a condition to receive interconnection service.[133] Such equipment must include a governor or equivalent controls with the capability of operating at a maximum 5 percent droop and ±0.036 Hz deadband (or the equivalent or better).

133 157 FERC ¶ 61,122 (2016).

PJM filed revisions in compliance with Order No. 842 that substantively incorporated the pro forma agreements into its market rules.[134]

The MMU recommends that the same capability be required of both new and existing resources. The MMU agrees with Order No. 842 that RTOs not be required to provide additional compensation specifically for frequency response. The current PJM market design provides compensation for all capacity costs, including these, in the capacity market. The current market design provides compensation, through heat rate adjusted energy offers, for any costs associated with providing frequency response. Because the PJM market design already compensates resources for frequency response capability and any costs associated with providing frequency response, any separate filings submitted on behalf of resources for compensation under section 205 of the Federal Power Act should be rejected as double recovery.

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 (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.

134 See 164 FERC ¶ 61,224 (2018).

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

When there are binding transmission constraints and locational price differences, load pays more for energy than generation is paid to produce that energy.[1] The difference is congestion.[2]

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 (CLMP), and the marginal loss component (MLMP). 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. The relative values of SMP and CLMP are arbitrary and depend on the reference bus.

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.

1 Withdrawals are generically referred to as load and injections are generically referred to as generation, unless specified otherwise.
2 The difference in losses is not part of congestion.

Congestion is neither good nor bad, but is a direct measure of the extent to which there are multiple marginal generating units with different offers 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. Load in the constrained area pays the higher price for all energy including energy from low cost and energy from high cost generation while generators are paid the price at their bus.

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 charges plus net explicit congestion charges plus net inadvertent congestion charges. The net implicit congestion charges are the implicit withdrawal congestion charges less implicit injection 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]

Local congestion is calculated on a constraint specific basis. This constraint based congestion is the total congestion charges to load at the buses within a defined area minus total congestion credits received by all generation that supplied that load, given the transmission constraints, regardless of location. Constraint based congestion reflects the underlying characteristics of the complete power system as it affects the defined area, including the nature and

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 for the first nine months of 2019 were calculated as of October 10, 2019, and are subject to change, based on continued PJM billing updates.

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.

Overview

Congestion Cost

- **Total Congestion.** Total congestion costs decreased by $697.2 million or 62.5 percent, from $1,116.2 million in the first nine months of 2018 to $419.1 million in the first nine months of 2019.
- **Day-Ahead Congestion.** Day-ahead congestion costs decreased by $640.3 million or 55.6 percent, from $1,151.7 million in the first nine months of 2018 to $511.4 million in the first nine months of 2019.
- **Balancing Congestion.** Negative balancing congestion costs increased by $56.9 million or 160.3 percent, from -$35.5 million in the first nine months of 2018 to -$92.4 million in the first nine months of 2019. Negative balancing explicit costs increased by $55.8 million, from -$3.6 million in the first nine months of 2018 to -$59.4 million in the first nine months of 2019.
- **Real-Time Congestion.** Real-time congestion costs decreased by $746.4 million or 59.1 percent, from $1,263.6 million in the first nine months of 2018 to $517.2 million in the first nine months of 2019.
- **Monthly Congestion.** Monthly total congestion costs in the first nine months of 2019 ranged from $22.2 million in April to $100.2 million in January.
- **Geographic Differences in CLMP.** Differences in CLMP among eastern, southern and western control zones in PJM were primarily a result of congestion on the Conastone - Peach Bottom Line, the Coolspring – Milford Line, the Tanners Creek - Miami Fort Flowgate, the Siegfried Transformer, and the AP South Interface.
- **Congestion Frequency.** Congestion frequency continued to be significantly higher in the Day-Ahead Energy Market than in the Real-Time Energy Market in the first nine months of 2019. The number of congestion event hours in the Day-Ahead Energy Market was about six times the number of congestion event hours in the Real-Time Energy Market.

  Day-ahead congestion frequency decreased by 25.9 percent from 105,437 congestion event hours in the first nine months of 2018 to 78,155 congestion event hours in the first nine months of 2019. The majority (103.1 percent) of the decrease occurred in January and February of 2019. The decrease was largely a result of the decrease in cleared up to congestion (UTC) transactions between January and February, 2018 and January and February, 2019.[5] Day-ahead congestion frequency increased in March, June and July of 2019.

  Real-time congestion frequency decreased by 20.2 percent from 16,915 congestion event hours in the first nine months of 2018 to 13,495 congestion event hours in the first nine months of 2019.
- **Congested Facilities.** Day-ahead, congestion event hours decreased on all types of facilities largely as a result of the decrease in cleared up to congestion (UTC) transactions from January and February, 2018, to January and February, 2019.

  The Conastone - Peach Bottom Line was the largest contributor to congestion costs in the first nine months of 2019. With $83.3 million in total congestion costs, it accounted for 19.9 percent of the total PJM congestion costs in the first nine months of 2019.
- **CT Price Setting Logic and Closed Loop Interface Related Congestion.** CT Price Setting Logic caused -$0.2 million of day-ahead congestion in the first nine months of 2019 and -$5.0 million of balancing congestion in the first nine months of 2019. None of the closed loop interfaces was binding in the first nine months of 2019 or 2018.
- **Zonal Congestion.** AEP had the largest zonal congestion costs among all control zones in the first nine months of 2019. AEP had $71.6 million in zonal congestion costs, comprised of $86.7 million in zonal day-ahead congestion costs and -$15.1 million in zonal balancing congestion costs. The Conastone - Peach Bottom Line, the Tanners Creek - Miami Fort Flowgate, the AP South Interface, the Conastone - Northwest Line, and

5 162 FERC ¶ 61,139.

the Coolspring - Milford Line contributed $23.6 million, or 32.9 percent of the AEP zonal congestion costs.

Marginal Loss Cost

- **Total Marginal Loss Costs.** Total marginal loss costs decreased by $253.1 million or 33.5 percent, from $755.8 million in the first nine months of 2018 to $502.7 million in the first nine months of 2019. The loss MWh in PJM decreased by 259.6 GWh or 2.2 percent, from 11,860.3 GWh in the first nine months of 2018 to 11,600.8 GWh in the first nine months of 2019. The loss component of real-time LMP in the first nine months of 2019 was $0.02, compared to $0.02 in the first nine months of 2018.
- **Monthly Total Marginal Loss Costs.** Monthly total marginal loss costs in the first nine months of 2019 ranged from $38.8 million in April to $86.5 million in January.
- **Day-Ahead Marginal Loss Costs.** Day-ahead marginal loss costs decreased by $237.2 million or 30.4 percent, from $779.7 million in the first nine months of 2018 to $542.6 million in the first nine months of 2019.
- **Balancing Marginal Loss Costs.** Negative balancing marginal loss costs increased by $16.0 million or 66.7 percent, from -$23.9 million in the first nine months of 2018 to -$39.9 million in the first nine months of 2019.
- **Total Marginal Loss Surplus.** The total marginal loss surplus decreased in the first nine months of 2019 by $93.2 million or 36.5 percent, from $255.3 million in the first nine months of 2018, to $162.1 million in the first nine months of 2019.

Energy Cost

- **Total Energy Costs.** Total energy costs increased by $159.3 million or 32.0 percent, from -$498.7 million in the first nine months of 2018 to -$339.3 million in the first nine months of 2019.
- **Day-Ahead Energy Costs.** Day-ahead energy costs increased by $143.9 million or 26.1 percent, from -$551.4 million in the first nine months of 2018 to -$407.6 million in the first nine months of 2019.
- **Balancing Energy Costs.** Balancing energy costs increased by $20.9 million or 44.5 percent, from $47.1 million in the first nine months of 2018 to $68.0 million in the first nine months of 2019.
- **Monthly Total Energy Costs.** Monthly total energy costs in the first nine months of 2019 ranged from -$59.3 million in January to -$25.7 million in April.

Recommendations

- The MMU recommends that PJM's logic for the calculation of implicit balancing congestion charges revert to the method used prior to April 1, 2018. (Priority: Medium. New recommendation. Not adopted.)

Conclusion

Congestion is defined to be the total congestion charges 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.

Total congestion in the first nine months of 2019 decreased significantly from the first nine months of 2018. The decrease was a result of high day-ahead congestion in January 2018 which was a result of high gas costs and associated LMPs in the early part of January 2018.

The monthly total congestion costs ranged from $22.2 million in April to $100.2 million in January 2019.

The impact of UTCs on the frequency of day-ahead congestion was illustrated by the significant reduction in day-ahead congestion event hours following the decrease in up to congestion (UTC) transaction activities that resulted from the February 20, 2018, FERC order that limited UTC trading to hubs, residual metered load, and interfaces.

The current ARR/FTR design does not serve as an efficient way to ensure that load receives all the congestion revenues, and 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 only 74.5 percent of total congestion costs including congestion in the Day-Ahead Energy Market and the balancing energy market, for the 2011/2012 planning period through the 2016/2017 planning period, before the FERC decision to allocate balancing congestion and M2M payments to load.[6] For the 2017/2018 planning period, after the implementation of the FERC decision to reallocate balancing congestion and M2M payments to load, ARR and self scheduled FTR revenue offset 50.0 percent of total congestion. For the 2018/2019 planning period, ARR and self scheduled FTR revenue offset 92.1 percent of total congestion. For a number of reasons, the first four months of the 2019/2020 planning period, over 100 percent of total congestion was offset by ARR credit allocations to ARR holders, including full allocation of all surplus. This reflects the same pattern as the first four months of the 2018/2019 planning period.

Issues

Closed Loop Interfaces and CT Pricing Logic

PJM uses closed loop interfaces and CT pricing logic to force otherwise uneconomic resources to be marginal and set price in the day-ahead or real-time market solution. PJM uses a closed loop interface or CT pricing logic to create an artificial constraint with a variable flow limit, paired with an artificial override of the inflexible resource's economic minimum, to make the resource marginal in PJM LMP security constraint pricing logic.

Through the assumption of artificial flexibility on the affected unit and artificially creating a constraint for which the otherwise inflexible resource can be marginal, PJM's use of both the closed loop interface and CT pricing logic forces the affected resource bus LMP to match the marginal offer of the resource. In the case of a closed loop interface, all buses within the interface are modeled as having a distribution factor (DFAX) of 1.0 to the constraint and therefore have the same constraint related congestion component of price at the marginal resource's bus. In the CT pricing logic case, the constraint affects the CLMP of downstream (constrained side) buses in proportion to their DFAX to that constraint.[7] The objective of making inflexible resources marginal is to minimize the uplift costs associated with the inflexible resources that PJM commits for system security reasons.

The use of closed loop interfaces and CT pricing logic can be a source of modeling differences between the day-ahead and real-time market. If closed loop interfaces and CT pricing logic are not included in the day-ahead market in exactly the same way as in the real-time market, including specific constraints and limits, the differences between the day-ahead and real-time market model will result in positive or negative balancing congestion.

Failure to model the same constraint in the day-ahead market will result in pricing and congestion settlement differences between the day-ahead and real-time market. Any modeling differences create false arbitrage opportunities for virtual bids and contribute to negative balancing congestion. PJM attempts to incorporate its real-time use of closed loop interfaces and CT pricing logic in the day-ahead market, although the matching is necessarily imperfect and with a lag.

Use of closed loop interfaces and CT price setting logic requires the manipulation of the economic dispatch model. Closed loop interfaces and CT price setting logic force higher cost inflexible units to be marginal. Unlike constraints that restrict the use of lower cost output in the system solution, the closed loop interface and CT price setting logic constraints are forcing the use of the relatively high cost resource. The sign of the shadow price of this artificial constraint in the optimization solution, unlike normal security constraints in a least cost dispatch optimization, is therefore positive because relaxing this constraint will cause system costs to go up, not down. Increasing the limit (relaxing) a closed loop interface or CT price setting logic constraint requires an increase in the output from the high cost unit from within the artificially constrained area, and a decrease in output from low price generation from outside the artificially constrained area. This means that increasing the limit of closed loop interface or CT price setting logic constraint causes a net

6 On September 15, 2016, FERC ordered PJM to allocate balancing congestion to load, rather than to FTRs, to modify PJM's Stage 1A ARR allocation process and to continue to use portfolio netting. 153 FERC ¶ 61,180.

7 The constrained side means the higher priced side with a positive CLMP created by the constraint.

increase in incremental cost for any increase in the flow limit of the constraint and a positive, rather than the usual negative, shadow price for the modeled transmission constraint.

The nature of the closed loop interface or CT price setting logic constraint is that more power is produced than consumed in the artificial closed loop or constrained area than would result without the closed loop. This means that there are more high CLMP generation credits than high CLMP load charges associated within the constrained area within the closed loop interface or CT price setting logic constraint. The rest of the system receives power from the closed loop/constrained area, the higher cost generators outside the closed loop/constrained area are backed down and prices are lower outside the loop than they would have been without the closed loop. While all of the generation within the artificially constrained area is paid the higher CLMP in the form of generation credits, a smaller amount of load (in some cases no load) pays this higher CLMP in the form of load charges within the loop. The residual energy is delivered and paid for at a lower CLMP outside the closed loop/constrained area. The result is that PJM pays out more to generators in the closed loop than it collects from load. The result of using closed loops and CT price setting logic is that uneconomic generation costs that would otherwise be collected as uplift are being realized as negative congestion. In the day-ahead market this reduces the total congestion dollars that are available to FTR holders. In the balancing market these costs are allocated directly to load as negative balancing rather than to deviations as uplift charges.

Balancing Congestion Cost Calculation Logic Change

Effective April 1, 2018, PJM made a significant change to the calculation and allocation of balancing congestion costs.[8]

Prior to April 1, 2018, implicit balancing congestion charges calculated at the zonal and aggregate level were determined by bus specific deviations between day-ahead and real-time MWh priced at the bus specific congestion price in the Real-Time Energy Market.

8 See PJM, "Manual 28: Operating Agreement Accounting," Rev. 82 (July 25, 2019).

As of April 1, 2018, with the introduction of five minute settlements, implicit zonal and aggregate balancing congestion costs are determined by netting the bus specific hourly deviations across every bus in a zone or aggregate and pricing the resulting deviation in zone or aggregate total deviations at the zonal or aggregate congestion price in the Real Time Energy Market. As a result of the introduction of netting hourly deviations across every bus in a zone or aggregate, the allocation of implicit balancing congestion was reduced for MW deviations associated with load and virtual bids that settle at zones and aggregates.

The result of the new rules has been to increase negative balancing charges billed to load on a load ratio basis. While total load deviations and associated balancing charges at load aggregates have been reduced by netting under the April 1, 2018, rules, the rules for determining balancing congestion credits and charges to all other balancing MW deviations at all other bus or aggregates have not changed. This means that relative to the calculation of benefits and credits under the old rule, the new rules have resulted in a decrease in total implicit balancing charges (outlays from withdrawals) while having no effect on the calculation of total implicit credits (payments to injection). The net result has been an increase in negative balancing congestion costs, which is the difference between balancing congestion charges from deviations at aggregates and zones (which has been reduced due to the rule change) and bus specific balancing congestion credits (which has not been affected by the rule change). This has caused an increase in total negative balancing charges. Negative balancing congestion is allocated on a load ratio share to load and exports.

The netting of zonal and aggregate deviations decreased the allocation of balancing charges to load deviations and increased total negative balancing congestion which is allocated, on a load ratio share, to real-time load plus real-time exports.

Table 11-1 shows the total implicit balancing congestion charges that would have resulted from applying either the pre or post April 1, 2018 settlement rules for the first nine months of 2017, 2018 and 2019. Table 11-1 also shows the actual total implicit balancing congestion charges for the first nine months of 2017, 2018 and 2019 based on the methods in place at the time.[9] The only difference is that the actual implicit balancing congestion charges in 2018 reflect the fact that in the first quarter of 2018 the implicit balancing congestion charges were calculated under the pre April 1, 2018, settlement rule and in the rest of 2018, the implicit balancing congestion charges were calculated under the post April 1, 2018, settlement rule. Table 11-1 shows that the post April 1, 2018, settlement rule, if applied to the first nine months of 2017, 2018 and 2019, would have caused negative balancing congestion costs to increase relative to the pre April 1, 2018, settlement rule. Table 11-1 shows that the post April 1, 2018, settlement rule caused negative total implicit balancing charges to increase by $6.4 million (23.9 percent) in the first nine months of 2019, and would have caused such charges to increase by $3.9 million (19.3 percent) in the first nine months of 2017 and to increase by $12.1 million (42.1 percent) in the first nine months of 2018.

Table 11-1 Total implicit balancing congestion charge (Dollars (Millions)) (old method and new method): January through September, 2017 through 2019

	Implicit Balancing Congestion Charges ($ Million)									
	Old Method			New Method			Actual			
(Jan - Sep)	Withdrawal Charges	Injection Credits	Total	Withdrawal Charges	Injection Credits	Total	Withdrawal Charges	Injection Credits	Total	Change Between New and Old
2017	$12.5	$32.9	($20.4)	$8.5	$32.8	($24.3)	$12.5	$32.9	($20.4)	($3.9)
2018	$21.7	$50.5	($28.8)	$6.8	$47.8	($41.0)	$18.2	$50.1	($31.9)	($12.1)
2019	$14.4	$41.0	($26.6)	$6.2	$39.2	($33.0)	$6.2	$39.2	($33.0)	($6.4)

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 of LMP is a load-weighted system price. No congestion or losses are included in the load-weighted reference bus price.

LMP at a bus reflects the incremental price of energy at that bus. LMP at any bus can be disaggregated into three components: the system marginal price (SMP), marginal loss component (MLMP), and congestion component (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.[10] The first derivative of total losses with respect to the power flow is 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.[11] 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. Load in the constrained area pays the higher price for all energy including energy from low cost generation and energy from high cost generation. Congestion is the difference between the total cost of energy by withdrawals in the transmission

9 In 2017, the actual total implicit balancing congestion charges were calculated using the old method. In 2018, the actual total implicit balancing congestion charges were calculated using the old method in the first quarter and using the new method in the rest of the year. In 2019, the actual total implicit balancing congestion charges were calculated using the new method.

10 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>.

11 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.

constrained area and the total revenue received by injections to meet the withdrawals in the transmission constrained area, net of losses. Congestion equals the sum of day-ahead and balancing congestion.

Table 11-2 shows the PJM real-time, load-weighted average LMP components for January through September, 2008 through 2019.[12]

The load-weighted average real-time LMP decreased $11.83 or 30.0 percent from $39.43 in the first nine months of 2018 to $27.60 in the first nine months of 2019. The load-weighted, average real-time congestion component decreased by $0.02 from $0.04 in the first nine months of 2018 to $0.02 in the first nine months of 2019. The load-weighted average real-time loss component in the first nine months of 2019 was $0.02 compared to $0.02 in the first nine months of 2018. The load-weighted, average real-time energy component decreased by $11.81 or 30.0 percent from $39.37 in the first nine months of 2018 to $27.56 in the first nine months of 2019.

Table 11-2 PJM real-time, load-weighted average LMP components (Dollars per MWh): January through September, 2008 through 2019[13]

(Jan - Sep)	Real-Time LMP	Energy Component	Congestion Component	Loss Component
2008	$77.27	$77.15	$0.07	$0.05
2009	$39.57	$39.49	$0.04	$0.03
2010	$49.91	$49.81	$0.06	$0.04
2011	$49.48	$49.40	$0.05	$0.03
2012	$35.02	$34.97	$0.04	$0.01
2013	$39.75	$39.72	$0.01	$0.02
2014	$58.60	$58.61	($0.03)	$0.02
2015	$38.94	$38.89	$0.03	$0.02
2016	$29.32	$29.27	$0.04	$0.02
2017	$30.36	$30.32	$0.02	$0.01
2018	$39.43	$39.37	$0.04	$0.02
2019	$27.60	$27.56	$0.02	$0.02

Table 11-3 shows the PJM day-ahead, load-weighted average LMP components for January through September, 2008 through 2019.[14] The load-weighted average day-ahead LMP decreased $11.01, or 28.4 percent, from $38.71 in the first nine months of 2018 to $27.70 in the first nine months of 2019. The load-weighted, average congestion component decreased $0.04 from $0.12 in the first nine months of 2018 to $0.08 in the first nine months of 2019. The load-weighted, average loss component was -$0.01 in the first nine months of 2018 and -$0.01 in the first nine months of 2019. The load-weighted average energy component decreased $10.97, or 28.4 percent, from $38.60 in the first nine months of 2018 to $27.63 in the first nine months of 2019.

Table 11-3 PJM day-ahead, load-weighted average LMP components (Dollars per MWh): January through September, 2008 through 2019

(Jan - Sep)	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
2008	$75.96	$76.30	($0.09)	($0.24)
2009	$39.35	$39.50	($0.05)	($0.10)
2010	$49.12	$49.05	$0.11	($0.03)
2011	$48.34	$48.55	($0.05)	($0.16)
2012	$34.29	$34.19	$0.12	($0.02)
2013	$39.49	$39.35	$0.14	($0.00)
2014	$59.08	$58.84	$0.26	($0.01)
2015	$39.51	$39.25	$0.28	($0.02)
2016	$29.69	$29.54	$0.17	($0.01)
2017	$30.26	$30.24	$0.04	($0.02)
2018	$38.71	$38.60	$0.12	($0.01)
2019	$27.70	$27.63	$0.08	($0.01)

12 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 average 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. Without these adjustments, the congestion component of system average LMP would be zero.

13 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.

14 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 shows the PJM real-time, load-weighted average LMP by constrained and unconstrained hours.

Table 11-4 PJM real-time, load-weighted average LMP by constrained and unconstrained hours (Dollars per MWh): January 2018 through September 2019

	2018		2019	
	Constrained Hours	Unconstrained Hours	Constrained Hours	Unconstrained Hours
Jan	$96.69	$24.03	$33.75	$21.61
Feb	$27.00	$23.93	$28.99	$23.33
Mar	$33.35	$23.64	$30.81	$24.22
Apr	$35.74	$24.92	$27.04	$24.43
May	$38.78	$17.24	$24.92	$20.27
Jun	$34.55	$21.81	$24.94	$19.28
Jul	$37.08	$26.09	$32.29	$20.04
Aug	$38.64	$25.11	$24.63	$21.02
Sep	$36.83	$26.29	$29.79	$17.03
Oct	$35.27	$26.11		
Nov	$37.64	$26.58		
Dec	$34.60	$24.19		
Avg	$41.15	$24.71	$28.84	$21.35

Zonal Components

The real-time components of LMP for each control zone are presented in Table 11-5 for January through September, 2018 and 2019. In the first nine months of 2019, BGE had the highest real-time congestion component of all control zones, $2.34, and PPL had the lowest real-time congestion component, -$2.06.

Table 11-5 Zonal and PJM real-time, load-weighted average LMP components (Dollars per MWh): January through September, 2018 and 2019

	2018 (Jan - Sep)				2019 (Jan - Sep)			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AECO	$37.27	$38.62	($2.30)	$0.95	$25.95	$27.57	($1.94)	$0.31
AEP	$38.79	$39.38	($0.02)	($0.57)	$28.19	$27.50	$0.80	($0.11)
APS	$41.51	$39.74	$1.51	$0.26	$28.02	$27.61	$0.39	$0.03
ATSI	$41.48	$38.63	$2.31	$0.55	$28.12	$27.40	$0.33	$0.38
BGE	$46.51	$40.19	$4.85	$1.47	$31.03	$27.80	$2.34	$0.90
ComEd	$29.97	$38.39	($6.42)	($1.99)	$25.20	$27.38	($1.28)	($0.89)
DAY	$39.98	$39.27	$0.11	$0.60	$29.32	$27.60	$0.81	$0.91
DEOK	$40.56	$39.21	$2.38	($1.04)	$28.23	$27.52	$0.83	($0.13)
DLCO	$41.19	$38.71	$2.38	$0.10	$27.79	$27.41	$0.44	($0.06)
Dominion	$45.28	$40.45	$4.28	$0.54	$29.16	$27.69	$1.23	$0.24
DPL	$44.03	$40.44	$1.76	$1.82	$29.26	$27.89	$0.70	$0.68
EKPC	$36.98	$41.38	($2.99)	($1.41)	$28.07	$28.01	$0.35	($0.29)
JCPL	$38.10	$39.14	($1.83)	$0.79	$26.10	$27.81	($1.92)	$0.22
Met-Ed	$37.97	$39.28	($1.79)	$0.48	$26.92	$27.59	($0.57)	($0.11)
OVEC	NA	NA	NA	NA	$26.33	$26.76	$0.35	($0.77)
PECO	$37.63	$39.24	($2.16)	$0.55	$25.67	$27.56	($1.84)	($0.05)
PENELEC	$38.83	$38.82	($0.43)	$0.45	$26.56	$27.36	($0.78)	($0.01)
Pepco	$44.76	$39.96	$3.82	$0.99	$29.79	$27.73	$1.50	$0.56
PPL	$37.33	$39.63	($2.46)	$0.15	$25.21	$27.62	($2.06)	($0.35)
PSEG	$37.70	$38.56	($1.61)	$0.75	$26.06	$27.42	($1.47)	$0.11
RECO	$38.30	$38.78	($1.18)	$0.70	$26.37	$27.68	($1.41)	$0.09
PJM	$39.43	$39.37	$0.04	$0.02	$27.60	$27.56	$0.02	$0.02

The day-ahead components of LMP for each control zone are presented in Table 11-6 for January through September, 2018 and 2019. In the first nine months of 2019, BGE had the highest day-ahead congestion component of all control zones, $2.79, and PECO had the lowest day-ahead congestion component, -$2.21.

Table 11-6 Zonal and PJM day-ahead, load-weighted average LMP components (Dollars per MWh): January through September, 2018 and 2019

	2018 (Jan - Sep)				2019 (Jan - Sep)			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AECO	$36.95	$38.13	($1.72)	$0.55	$25.76	$27.65	($2.09)	$0.21
AEP	$37.90	$38.67	($0.32)	($0.46)	$28.23	$27.68	$0.65	($0.10)
APS	$40.21	$38.67	$1.34	$0.20	$28.22	$27.67	$0.54	$0.01
ATSI	$39.53	$37.94	$1.06	$0.54	$28.42	$27.48	$0.53	$0.40
BGE	$45.54	$39.22	$5.04	$1.28	$31.38	$27.82	$2.79	$0.77
ComEd	$29.80	$37.71	($6.23)	($1.68)	$25.35	$27.40	($1.28)	($0.76)
DAY	$39.43	$38.50	$0.21	$0.72	$29.43	$27.66	$0.89	$0.88
DEOK	$41.25	$38.41	$3.48	($0.63)	$28.77	$27.66	$1.17	($0.07)
DLCO	$39.70	$38.10	$1.49	$0.11	$28.02	$27.47	$0.63	($0.08)
Dominion	$44.78	$39.68	$4.52	$0.57	$29.70	$27.81	$1.71	$0.18
DPL	$42.98	$39.75	$1.94	$1.30	$28.73	$28.04	$0.18	$0.51
EKPC	$36.25	$40.66	($3.17)	($1.24)	$28.11	$28.20	$0.32	($0.41)
JCPL	$37.44	$38.42	($1.44)	$0.46	$25.75	$27.75	($2.14)	$0.13
Met-Ed	$37.51	$38.34	($0.90)	$0.06	$26.35	$27.64	($1.05)	($0.24)
OVEC	NA	NA	NA	NA	$29.70	$29.41	$0.99	($0.70)
PECO	$36.96	$38.35	($1.58)	$0.20	$25.19	$27.58	($2.21)	($0.17)
PENELEC	$37.95	$38.50	($0.76)	$0.21	$27.38	$27.82	($0.50)	$0.06
Pepco	$44.15	$39.16	$4.02	$0.96	$30.33	$27.85	$1.96	$0.52
PPL	$36.66	$38.61	($1.69)	($0.27)	$25.05	$27.67	($2.15)	($0.47)
PSEG	$37.97	$38.22	($0.77)	$0.53	$25.94	$27.53	($1.65)	$0.06
RECO	$38.05	$38.27	($0.72)	$0.49	$26.78	$27.89	($1.19)	$0.08
PJM	$38.71	$38.60	$0.12	($0.01)	$27.70	$27.63	$0.08	($0.01)

Hub Components

The real-time components of LMP for each hub are presented in Table 11-7 for January through September, 2018 and 2019.[15]

Table 11-7 Hub real-time, average LMP components (Dollars per MWh): January through September, 2018 and 2019

	2018 (Jan - Sep)				2019 (Jan - Sep)			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AEP Gen Hub	$33.33	$36.46	($1.62)	($1.50)	$25.73	$26.26	$0.26	($0.79)
AEP-DAY Hub	$34.77	$36.46	($1.02)	($0.67)	$26.86	$26.26	$0.74	($0.14)
ATSI Gen Hub	$37.33	$36.46	$1.07	($0.20)	$26.50	$26.26	$0.33	($0.10)
Chicago Gen Hub	$27.81	$36.46	($6.31)	($2.34)	$23.68	$26.26	($1.41)	($1.17)
Chicago Hub	$28.36	$36.46	($6.27)	($1.83)	$24.14	$26.26	($1.33)	($0.79)
Dominion Hub	$40.41	$36.46	$3.76	$0.19	$27.22	$26.26	$0.96	$0.00
Eastern Hub	$37.96	$36.46	$0.13	$1.37	$26.31	$26.26	($0.46)	$0.51
N Illinois Hub	$28.15	$36.46	($6.29)	($2.02)	$23.98	$26.26	($1.34)	($0.94)
New Jersey Hub	$34.96	$36.46	($2.11)	$0.62	$24.71	$26.26	($1.64)	$0.09
Ohio Hub	$34.50	$36.46	($1.29)	($0.68)	$26.98	$26.26	$0.81	($0.10)
West Interface Hub	$38.87	$36.46	$2.74	($0.33)	$26.55	$26.26	$0.52	($0.23)
Western Hub	$37.64	$36.46	$1.02	$0.17	$26.58	$26.26	$0.36	($0.05)

The day-ahead components of LMP for each hub are presented in Table 11-8 for January through September, 2018 and 2019.

Table 11-8 Hub day-ahead, average LMP components (Dollars per MWh): January through September, 2018 and 2019

	2018 (Jan - Sep)				2019 (Jan - Sep)			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AEP Gen Hub	$33.09	$35.96	($1.54)	($1.33)	$25.88	$26.36	$0.28	($0.76)
AEP-DAY Hub	$34.52	$35.96	($0.90)	($0.55)	$26.89	$26.36	$0.65	($0.12)
ATSI Gen Hub	$36.16	$35.96	$0.30	($0.10)	$26.88	$26.36	$0.54	($0.02)
Chicago Gen Hub	$27.58	$35.96	($6.33)	($2.05)	$23.94	$26.36	($1.38)	($1.04)
Chicago Hub	$28.18	$35.96	($6.26)	($1.52)	$24.37	$26.36	($1.32)	($0.66)
Dominion Hub	$39.99	$35.96	$3.76	$0.27	$27.61	$26.36	$1.33	($0.08)
Eastern Hub	$37.69	$35.96	$0.69	$1.04	$26.14	$26.36	($0.63)	$0.41
N Illinois Hub	$27.94	$35.96	($6.28)	($1.75)	$24.19	$26.36	($1.33)	($0.83)
New Jersey Hub	$35.09	$35.96	($1.26)	$0.38	$24.62	$26.36	($1.79)	$0.05
Ohio Hub	$34.32	$35.96	($1.08)	($0.56)	$26.95	$26.36	$0.67	($0.08)
West Interface Hub	$37.92	$35.96	$2.21	($0.25)	$26.93	$26.36	$0.77	($0.20)
Western Hub	$37.02	$35.96	$0.96	$0.09	$26.95	$26.36	$0.62	($0.02)

15 The real-time components of LMP are the simple average of the hourly components for each hub. Some hubs include only generation buses and do not include load buses. The real-time components of LMP were previously reported as the real-time load-weighted average of the hourly components of LMP.

Congestion

Congestion Accounting

Total congestion costs equal net implicit congestion charges, plus net explicit congestion charges, plus net inadvertent congestion charges. Implicit congestion charges equal implicit withdrawal charges less implicit injection credits. Explicit congestion charges are the net congestion charges associated with the injection credits and withdrawal charges for point to point energy transactions. Each of these categories of congestion costs is comprised of day-ahead and balancing congestion costs. Congestion occurs in the Day-Ahead and Real-Time Energy Markets.[16] Day-ahead congestion costs are based on day-ahead MWh while balancing congestion costs are based on deviations between day-ahead and real-time MWh priced at the congestion price in the Real-Time Energy Market.

Prior to April 1, 2018, implicit balancing congestion charges calculated at the zonal and aggregate level were determined by bus specific deviations between day ahead and real time MWh priced at the bus specific congestion price in the Real-Time Energy Market. As of April 1, 2018, with the introduction of five minute settlement, implicit zonal and aggregate balancing congestion costs are determined by netting the bus specific hourly deviations across every bus in a zone or aggregate and pricing the resulting deviation in zone or aggregate total deviations at the zonal or aggregate congestion price in the Real-Time Energy Market.

Congestion charges and congestion credits are calculated for both the Day-Ahead and balancing energy markets.

- **Implicit Day-Ahead Withdrawal Congestion Charges.** Implicit day-ahead withdrawal charges are calculated for all cleared demand, decrement bids and day-ahead energy market sale transactions. Implicit day-ahead withdrawal charges 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.
- **Implicit Day-Ahead Injection Congestion Credits.** Implicit day-ahead injection credits are calculated for all cleared generation, increment offers and day-ahead energy market purchase transactions. Implicit day-ahead injection 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.
- **Implicit Balancing Withdrawal Congestion Charges.** Implicit balancing withdrawal charges 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. Implicit balancing withdrawal charges are calculated using MW deviations and the real-time CLMP for each bus or aggregate where a deviation exists.
- **Implicit Balancing Injection Congestion Credits.** Implicit balancing injection 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. Implicit balancing injection credits are calculated using MW deviations and the real-time CLMP for each bus or aggregate where a deviation exists.
- **Explicit Congestion Charges.** Explicit congestion charges are the net congestion costs associated with point to point energy transactions. Day-ahead explicit congestion charges equal the product of the transacted MW and CLMP differences between sources (origins) and sinks (destinations) in the Day-Ahead Energy Market. Balancing explicit congestion charges 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 charges 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

16 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.

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.[17]

The congestion costs associated with specific constraints are the sum of the total day-ahead and balancing congestion costs associated with those constraints. Zonal congestion is calculated on a constraint by constraint basis. The congestion calculations are the total difference between what the zonal load pays in congestion charges and what the generation that serves that load is paid, regardless of whether the zone is a net importer or a net exporter of generation. Congestion costs can be both positive and negative and congestion charges and congestion credits can be both positive and negative. Congestion charges, positive or negative, are paid by withdrawals and congestion credits, positive or negative, are paid to injections. Total congestion costs (the sum of charges and credits), when positive, measure the net congestion payment by a participant group and when negative, measure the net congestion credit paid to a participant group. Explicit congestion charges, when positive, measure the congestion payment to a PJM member and when negative, measure the congestion credit paid to a PJM member. Explicit congestion charges are calculated for up to congestion transactions (UTCs).

The accounting definitions can be misleading. Load pays congestion. Congestion is the difference between what withdrawals (load) are paying for energy and what injections (generation) are being paid for energy due to binding transmission constraints. Generation does not pay congestion. Some generation receives a price lower than SMP and some generation receives a price greater than SMP but that does not mean that generation is paying congestion. It means that generation is being paid an LMP that is higher or lower than the system load-weighted average LMP.

The CLMP is calculated with respect to the LMP at the system reference bus, 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 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.[18]

Load-weighted LMP components are calculated relative to a load weighted average LMP. At the load weighted reference bus, which represents the load center of the system, the LMP includes no congestion or loss components, by definition. The average CLMP across all load buses, calculated relative to that reference bus, is equal to, or very close to, zero, with non-zero results caused by state estimator error and after the fact meter updates. The sum of load related congestion charges is logically zero and the small differences are the result of accounting issues. A positive CLMP at a load bus indicates that the load at that bus has a total energy price higher than the average LMP due to transmission constraints. A negative CLMP at a load bus indicates that the load at that bus has a total energy price lower than the average LMP due to transmission constraints. The LMPs at the load buses are a function of marginal generation bus LMPs determined through the least cost security constrained economic dispatch which accounts for transmission constraints and marginal losses. The marginal generator is the highest cost generator required to meet the load subject to constraints. This means that the average generation weighted CLMP for generation resources is lower than the LMP at the load weighted reference bus price. Calculated relative to the load reference bus which has a CLMP of zero, this means that the average of the generation bus CLMPs is negative. This means that total generation congestion credits are negative. Total congestion is the difference between the load charges and the negative generation credits.

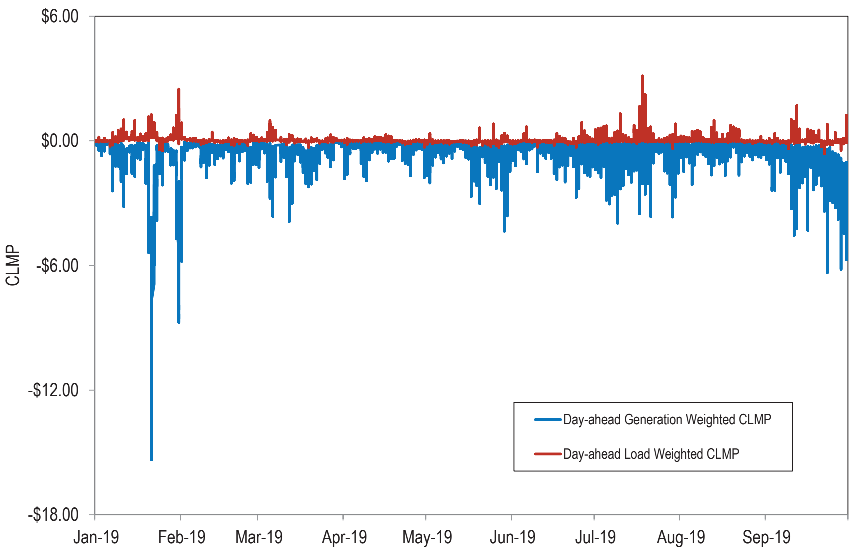
Figure 11-1 shows the CLMPs of generation and load in the day-ahead market. Figure 11-1 shows that in the first nine months of 2019, day-ahead generation weighted CLMPs were generally negative and day-ahead load weighted CLMPs

17 PJM Operating Agreement Schedule 1 §3.7.

18 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>.

were generally equal to or slightly greater than zero. Figure 11-1 also shows that in the first nine months of 2019, load paid more for energy as a result of transmission constraints than generation was paid to provide that energy.

Figure 11-1 Day-ahead generation weighted CLMPs and day-ahead load weighted CLMPs: January through September, 2019



Total Congestion

Total congestion costs in PJM in the first nine months of 2019 were $419.1 million, comprised of implicit withdrawal charges of $184.5 million, implicit injection credits of -$256.0 million and explicit charges of -$21.5 million. Total congestion is the difference between that withdrawals (load) are paying for energy and what injections (generation) are being paid for energy due to binding transmission constraints.

Table 11-9 shows total congestion for January through September, 2008 through 2019. 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.[19 20]

Table 11-9 Total PJM congestion component costs (Dollars (Millions)): January through September, 2008 through 2019

Congestion Costs (Millions)				
(Jan - Sep)	Congestion Cost	Percent Change	Total PJM Billing	Percent of PJM Billing
2008	$1,778	NA	$26,979	6.6%
2009	$544	(69.4%)	$19,927	2.7%
2010	$1,134	108.7%	$26,249	4.3%
2011	$875	(22.9%)	$28,836	3.0%
2012	$425	(51.4%)	$22,119	1.9%
2013	$510	19.9%	$25,153	2.0%
2014	$1,705	234.6%	$40,770	4.2%
2015	$1,143	(33.0%)	$33,710	3.4%
2016	$822	(28.1%)	$29,490	2.8%
2017	$455	(44.6%)	$29,510	1.5%
2018	$1,116	145.1%	$37,950	2.9%
2019	$419	(62.5%)	$29,980	1.4%

Congestion charges and credits are not in and of themselves congestion. Congestion charges and credits are adjustments to energy charges and credits reflecting marginal energy price differences caused by binding system constraints. Congestion is the sum of all congestion related charges and credits. In a two settlement system all virtual bids have net zero MW after their day-ahead and balancing positions are cleared, which means that virtual bids are fully settled in terms of congestion credits and charges at the close of the market for any particular day, with either a net loss or profit due to differences between day-ahead and real-time prices. Net payouts (negative credits) to virtual bids appear as negative adjustments to either day-ahead or balancing congestion and net charges to virtual bids appear as positive adjustments to either day-ahead or balancing congestion.

Table 11-10 shows total congestion by day-ahead and balancing component for January through September, 2008 through 2019. Table 11-11 and Table 11-12 show that the decrease in balancing explicit charges was the result of

19 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>.
20 See "NYISO Tariffs New York Independent System Operator, Inc.," (June 21, 2017) 35.12.1, Effective Date: May 1, 2017. <http://www.pjm.com/documents/agreements.aspx>.

the decrease in balancing explicit charges incurred by up to congestion transactions (UTCs) in the first nine months of 2019 from the first nine months of 2018. The market results were affected by large CLMP differences resulting from high gas prices from January 5, 2018, through January 8, 2018. Table 11-37 shows that the balancing explicit charges incurred by UTCs were $29.5 million in January of 2018.

Table 11-10 Total PJM congestion credits and charges by accounting category by market (Dollars (Millions)): January through September, 2008 through 2019

	Congestion Costs (Millions)									
	Day-Ahead				Balancing					
(Jan - Sep)	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Inadvertent Charges	Grand Total
2008	$1,126.9	($971.2)	$152.8	$2,250.9	($204.9)	$90.5	($177.3)	($472.7)	$0.0	$1,778.2
2009	$245.7	($385.0)	$73.8	$704.6	($35.1)	$4.1	($121.9)	($161.0)	$0.0	$543.6
2010	$301.7	($932.7)	$69.5	$1,303.9	($11.5)	$39.3	($118.7)	($169.6)	($0.0)	$1,134.3
2011	$389.3	($628.2)	$45.6	$1,063.2	$52.7	$92.6	($148.4)	($188.3)	$0.0	$874.9
2012	$106.6	($409.8)	$86.7	$603.2	($3.3)	$37.1	($137.6)	($178.0)	$0.0	$425.2
2013	$227.1	($452.6)	$121.6	$801.4	$6.8	$112.2	($186.4)	($291.8)	$0.0	$509.6
2014	$505.4	($1,497.8)	($38.5)	$1,964.6	$73.1	$224.4	($107.9)	($259.2)	$0.0	$1,705.4
2015	$539.3	($783.2)	$24.6	$1,347.1	$11.4	$69.9	($145.6)	($204.1)	$0.0	$1,143.0
2016	$313.0	($529.0)	$35.7	$877.8	$1.9	$20.0	($37.3)	($55.5)	($0.0)	$822.2
2017	$105.1	($375.1)	$2.3	$482.5	$12.5	$32.9	($6.7)	($27.1)	$0.0	$455.4
2018	$249.0	($931.9)	($29.3)	$1,151.7	$18.2	$50.1	($3.6)	($35.5)	$0.0	$1,116.2
2019	$178.3	($295.2)	$37.9	$511.4	$6.2	$39.2	($59.4)	($92.4)	$0.0	$419.1

Table 11-11 and Table 11-12 show the total congestion charges and credits for each transaction type in the first nine months of 2019 and 2018. Table 11-11 shows that in the first nine months of 2019 DECs paid $11.6 million in congestion charges in the day-ahead market, were paid $11.1 million in congestion credits in the balancing energy market, resulting in a net payment of $0.5 million in total congestion charges. In the first nine months of 2019, INCs paid $11.7 million in congestion charges in the day-ahead market, were paid $20.2 million in congestion credits in the balancing energy market resulting in a net payment of $8.6 million in total congestion credits. In the first nine months of 2019, up to congestion (UTCs) paid $37.4 million in congestion charges in the day-ahead market, were paid $58.6 million in congestion credits in the balancing market resulting in a total payment of $21.2 million in total congestion credits.

Table 11-11 Total PJM congestion credits and charges by transaction type by market (Dollars (Millions)): January through September, 2019

	Congestion Costs (Millions)									
	Day-Ahead				Balancing					
Transaction Type	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Inadvertent Charges	Grand Total
DEC	$11.6	$0.0	$0.0	$11.6	($11.1)	$0.0	$0.0	($11.1)	$0.0	$0.5
Demand	$38.9	$0.0	$0.0	$38.9	$20.1	$0.0	$0.0	$20.1	$0.0	$59.0
Demand Response	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Explicit Congestion Only	$0.0	$0.0	$0.8	$0.8	$0.0	$0.0	($0.1)	($0.1)	$0.0	$0.7
Explicit Congestion and Loss Only	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Export	($19.6)	$0.0	($0.3)	($19.9)	($2.3)	$0.0	($0.2)	($2.5)	$0.0	($22.3)
Generation	$0.0	($431.3)	$0.0	$431.3	$0.0	$22.5	$0.0	($22.5)	$0.0	$408.8
Import	$0.0	$0.5	$0.0	($0.5)	$0.0	($3.1)	($0.2)	$2.8	$0.0	$2.4
INC	$0.0	($11.7)	$0.0	$11.7	$0.0	$20.2	$0.0	($20.2)	$0.0	($8.6)
Internal Bilateral	$147.4	$147.4	($0.0)	($0.0)	($0.5)	($0.5)	$0.0	$0.0	$0.0	($0.0)
Up to Congestion	$0.0	$0.0	$37.4	$37.4	$0.0	$0.0	($58.6)	($58.6)	$0.0	($21.2)
Wheel In	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.3)	($0.2)	$0.0	($0.2)
Wheel Out	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.0	($0.0)	$0.0	($0.0)
Total	$178.3	($295.2)	$37.9	$511.4	$6.2	$39.2	($59.4)	($92.4)	$0.0	$419.1

Table 11-12 Total PJM congestion credits and charges by transaction type by market (Dollars (Millions)): January through September, 2018

	Congestion Costs (Millions)									
	Day-Ahead				Balancing					
Transaction Type	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Inadvertent Charges	Grand Total
DEC	$18.0	$0.0	$0.0	$18.0	($23.2)	$0.0	$0.0	($23.2)	$0.0	($5.2)
Demand	$53.9	$0.0	$0.0	$53.9	$51.6	$0.0	$0.0	$51.6	$0.0	$105.5
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	$1.6	$1.6	$0.0	$0.0	($0.7)	($0.7)	$0.0	$0.9
Explicit Congestion and Loss Only	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.0
Export	($51.3)	$0.0	($0.9)	($52.2)	($12.4)	$0.0	($5.7)	($18.1)	$0.0	($70.3)
Generation	$0.0	($1,135.2)	$0.0	$1,135.2	$0.0	$62.6	$0.0	($62.6)	$0.0	$1,072.6
Grandfathered Overuse	$0.0	$0.0	($0.6)	($0.6)	$0.0	$0.0	$0.0	$0.0	$0.0	($0.5)
Import	$0.0	($6.5)	$0.0	$6.5	$0.0	($41.3)	($3.1)	$38.2	$0.0	$44.6
INC	$0.0	($18.8)	$0.0	$18.8	$0.0	$26.5	$0.0	($26.5)	$0.0	($7.6)
Internal Bilateral	$228.4	$228.6	$0.2	($0.0)	$3.1	$3.1	$0.0	($0.0)	$0.0	($0.0)
Up to Congestion	$0.0	$0.0	($29.6)	($29.6)	$0.0	$0.0	$6.3	$6.3	$0.0	($23.2)
Wheel In	$0.0	$0.0	$0.0	$0.0	$0.0	($0.8)	($0.4)	$0.3	$0.0	$0.3
Wheel Out	$0.0	$0.0	$0.0	$0.0	($0.8)	$0.0	$0.0	($0.8)	$0.0	($0.8)
Total	$249.0	($931.9)	($29.3)	$1,151.7	$18.2	$50.1	($3.6)	($35.5)	$0.0	$1,116.2

Table 11-13 shows the change in total congestion credits and charges incurred by transaction type from the first nine months of 2018 to the first nine months of 2019. Total negative congestion credits incurred by generation decreased by $663.8 million, and total congestion charges incurred by demand decreased by $46.5 million. The total congestion credits incurred up to congestion transactions (UTCs) decreased by $2.0 million, from $23.2 million in the first nine months of 2018 to $21.2 million in the first nine months of 2019. Total day-ahead congestion credits to UTCs decreased by $66.9 million from $29.6 million in the first nine months of 2018 to -$37.4 million in the first nine months of 2019. Over the same period balancing congestion credits to UTCs increased by $64.9 million, from -$6.3 million in the first nine months of 2018 to $58.6 million in the first nine months of 2019.

Table 11-13 Change in total PJM congestion credits and charges by transaction type by market: January through September, 2018 to 2019 (Dollars (Millions))

	Change in Congestion Costs (Millions)										
	Day-Ahead				Balancing						
Transaction Type	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Inadvertent Charges	Grand Total
DEC	($6.4)	$0.0	$0.0	($6.4)	$12.1	$0.0	$0.0	$12.1	$0.0	$5.7
Demand	($15.1)	$0.0	$0.0	($15.1)	($31.4)	$0.0	$0.0	($31.4)	$0.0	($46.5)
Demand Response	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.0	($0.0)	$0.0	$0.0
Explicit Congestion Only	$0.0	$0.0	($0.7)	($0.7)	$0.0	$0.0	$0.5	$0.5	$0.0	($0.2)
Explicit Congestion and Loss Only	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Export	$31.7	$0.0	$0.6	$32.3	$10.1	$0.0	$5.5	$15.7	$0.0	$48.0
Generation	$0.0	$703.9	$0.0	($703.9)	$0.0	($40.1)	$0.0	$40.1	$0.0	($663.8)
Grandfathered Overuse	$0.0	$0.0	$0.6	$0.6	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.5
Import	$0.0	$7.0	$0.0	($7.0)	$0.0	$38.2	$2.9	($35.3)	$0.0	($42.3)
INC	$0.0	$7.1	$0.0	($7.1)	$0.0	($6.2)	$0.0	$6.2	$0.0	($0.9)
Internal Bilateral	($81.0)	($81.2)	($0.2)	$0.0	($3.6)	($3.6)	($0.0)	$0.0	$0.0	$0.0
Up to Congestion	$0.0	$0.0	$66.9	$66.9	$0.0	$0.0	($64.9)	($64.9)	$0.0	$2.0
Wheel In	$0.0	$0.0	$0.0	$0.0	$0.0	$0.7	$0.2	($0.6)	$0.0	($0.6)
Wheel Out	$0.0	$0.0	$0.0	$0.0	$0.7	$0.0	$0.0	$0.7	$0.0	$0.7
Total	($70.7)	$636.8	$67.2	($640.3)	($12.0)	($10.9)	($55.8)	($56.9)	$0.0	($697.2)

Zonal Congestion

Zonal congestion is calculated on a constraint specific basis. Constraint based congestion is the difference between what withdrawals (load) pay for energy and what injections (generation) are paid for energy due by individual binding transmission constraints. Constraint based congestion includes all energy charges or credits incurred to serve zonal load. Constraint based congestion calculations account for the total difference between what the zonal load pays in congestion charges and what the generation that serves that load is paid, regardless of whether the zone is a net importer or a net exporter of generation.

Local congestion is calculated on a constraint specific basis. This constraint based congestion is the total congestion payments by withdrawals (load) at the buses within a defined area minus total congestion credits received by all injections (generation) that supplied that load, given the transmission constraints, regardless of location. Constraint based congestion reflects the underlying characteristics of the complete power system as it affects the defined area, 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.

On a system wide basis, congestion results from transmission constraints that prevent the lowest cost generation from serving some load that must be served by higher cost generation. Transmission constraints cause differences in LMP, defined by the marginal cost of resolving the constraint given the need to meet power balance requirements, indicated by the shadow price of the constraint. The LMP at any point is equal to the system marginal price (SMP) plus the shadow price of the constraint times the DFAX of the binding constraint to the bus in question (the CLMP of the constraint at that bus), plus marginal losses (MLMP).

The total congestion caused by a constraint is equal to the product of the constraint shadow price times the net flow on the binding constraint. Total congestion caused by the constraint can also be calculated using the CLMPs caused by the constraint at every bus and the net MW injections or MW withdrawals at every affected bus. Congestion associated with a specific constraint is equal to load congestion charges (CLMP of that specific constraint at each bus times load MW at each bus) caused by that constraint in excess of generation congestion credits (CLMP of that specific constraint at each bus times generation MW at each bus) caused by that constraint.

Constraint specific CLMPs are determined relative to a reference bus, where there is no congestion and no losses. For purposes of allocating the congestion of an individual constraint, the reference bus for each constraint calculation is moved to the point that is just upstream of the constraint (the bus with the greatest negative price effect from the constraint), allowing any positive price effects of the constraint to be reflected as a positive CLMP.

In order to define the load that is actually paying congestion (withdrawal payments in excess of injection credits), constraint specific congestion is assigned to downstream (positive CLMP) load buses that paid the congestion caused by the constraint, in proportion to the congestion charges collected from that load due to that constraint. The congestion collected from each load bus due to a constraint is equal to the CLMP caused by that constraint times the MW of load at that load bus. This calculation is done for both day-ahead congestion and balancing congestion.

Table 11-14 shows the day-ahead and balancing congestion by zone for the first nine months of 2019. Table 11-15 shows the congestion costs by zone for the first nine months of 2018.

Table 11-14 Day-ahead and balancing congestion by zone (Dollars (Millions)): January through September, 2019

	Congestion Costs (Millions)								
	Day-Ahead				Balancing				
Control Zone	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Grand Total
AECO	$3.2	($3.2)	$0.7	$7.0	$0.1	$0.5	($0.8)	($1.1)	$5.9
AEP	$34.9	($44.6)	$7.2	$86.7	$1.0	$6.5	($9.6)	($15.1)	$71.6
APS	$14.6	($17.4)	$1.6	$33.6	$0.5	$2.4	($3.5)	($5.4)	$28.2
ATSI	$11.9	($22.4)	$2.4	$36.8	$0.5	$3.0	($4.9)	($7.4)	$29.4
BGE	$8.0	($10.4)	$0.8	$19.1	$0.1	$1.8	($2.4)	($4.0)	$15.1
ComEd	$14.7	($43.9)	$9.3	$67.8	$1.2	$5.0	($5.5)	($9.3)	$58.5
DAY	$3.7	($5.5)	$0.8	$10.1	$0.1	$0.9	($1.4)	($2.1)	$8.0
DEOK	$7.0	($8.1)	$1.3	$16.4	$0.2	$1.3	($2.2)	($3.3)	$13.1
DLCO	$1.9	($3.3)	$0.3	$5.6	$0.1	$0.6	($1.0)	($1.5)	$4.1
Dominion	$21.7	($35.2)	$2.7	$59.6	$1.1	$5.2	($7.5)	($11.6)	$48.1
DPL	$15.0	($8.0)	$2.1	$25.0	$0.0	$0.8	($1.7)	($2.5)	$22.5
EKPC	$3.1	($4.1)	$0.6	$7.8	$0.1	$0.6	($1.0)	($1.5)	$6.3
EXT	$0.2	($0.0)	$0.1	$0.4	($0.3)	$0.3	($2.4)	($3.1)	($2.7)
JCPL	$3.5	($10.2)	$0.8	$14.5	$0.2	$1.1	($1.7)	($2.6)	$11.9
Met-Ed	$3.9	($6.6)	$0.5	$11.1	($0.1)	$0.8	($1.3)	($2.2)	$8.9
OVEC	($0.0)	$0.0	$0.2	$0.2	$0.0	$0.0	$0.1	$0.1	$0.3
PECO	$3.5	($17.6)	$1.1	$22.3	$0.4	$1.9	($3.0)	($4.5)	$17.7
PENELEC	$5.8	($6.5)	$0.7	$13.0	$0.0	$0.9	($1.2)	($2.0)	$11.0
Pepco	$7.1	($9.2)	$0.7	$17.0	$0.3	$1.5	($2.1)	($3.4)	$13.6
PPL	$7.5	($18.2)	$2.1	$27.9	$0.3	$1.8	($2.8)	($4.4)	$23.5
PSEG	$6.9	($20.0)	$1.6	$28.5	$0.2	$2.2	($3.1)	($5.0)	$23.4
RECO	$0.3	($0.7)	$0.2	$1.2	($0.0)	$0.1	($0.4)	($0.4)	$0.7
Total	$178.3	($295.2)	$37.9	$511.4	$6.2	$39.2	($59.4)	($92.4)	$419.1

Table 11-15 Day-ahead and balancing congestion by zone (Dollars (Millions)): January through September, 2018

	Congestion Costs (Millions)								
	Day-Ahead				Balancing				
Control Zone	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Grand Total
AECO	$2.6	($11.2)	($0.2)	$13.6	$0.2	$0.5	($0.1)	($0.4)	$13.2
AEP	$51.0	($153.9)	($3.7)	$201.2	$2.9	$7.5	($1.0)	($5.6)	$195.6
APS	$17.2	($51.7)	($2.0)	$66.9	$1.4	$2.6	($0.1)	($1.4)	$65.5
ATSI	$18.5	($69.9)	($2.1)	$86.3	$1.5	$2.9	($1.2)	($2.7)	$83.7
BGE	$12.2	($32.1)	($1.8)	$42.5	$0.9	$1.9	$0.1	($0.9)	$41.6
ComEd	$2.3	($139.4)	$0.6	$142.3	$2.1	$6.3	($1.2)	($5.3)	$137.0
DAY	$4.0	($20.8)	($0.7)	$24.2	$0.4	$0.8	($0.2)	($0.6)	$23.5
DEOK	$6.4	($38.1)	($0.7)	$43.7	$0.6	$1.2	($0.4)	($0.9)	$42.8
DLCO	$2.1	($12.9)	($0.4)	$14.6	$0.4	$0.6	($0.3)	($0.6)	$14.0
Dominion	$42.9	($100.2)	($5.5)	$137.5	$3.6	$7.0	$0.8	($2.6)	$134.9
DPL	$33.8	($21.3)	$0.9	$56.0	($0.2)	$0.6	($0.6)	($1.4)	$54.5
EKPC	$4.1	($17.7)	($0.8)	$21.0	$0.5	$0.7	$0.1	($0.1)	$20.9
EXT	$0.2	($0.4)	$0.5	$1.2	($0.1)	$5.7	$0.7	($5.1)	($3.9)
JCPL	$5.7	($28.8)	($1.1)	$33.4	$0.5	$1.1	($0.2)	($0.8)	$32.6
Met-Ed	$4.3	($23.6)	($1.0)	$26.9	$0.3	$1.4	$0.1	($1.0)	$25.9
PECO	$6.8	($48.4)	($2.6)	$52.6	$0.9	$2.0	($0.1)	($1.2)	$51.4
PENELEC	$2.1	($25.6)	($1.1)	$26.5	($0.1)	$1.0	($0.1)	($1.1)	$25.4
Pepco	$13.0	($28.1)	($1.7)	$39.4	$0.9	$1.7	$0.1	($0.7)	$38.7
PPL	$10.2	($51.7)	($3.7)	$58.2	$1.0	$2.1	$0.4	($0.7)	$57.5
PSEG	$9.3	($54.5)	($2.2)	$61.6	$0.6	$2.2	($0.3)	($1.9)	$59.6
RECO	$0.4	($1.6)	$0.2	$2.2	$0.0	$0.1	($0.3)	($0.3)	$1.9
Total	$249.0	($931.9)	($29.3)	$1,151.7	$18.2	$50.1	($3.6)	($35.5)	$1,116.2

In cases where the constraint causes net negative congestion and/or there is no load bus on the constrained side of a binding constraint, the congestion of the constraint is handled as a special case. In these special cases the associated congestion is assigned to the control zone or residual load aggregate where the congestion is incurred and/or there are positive CLMPs from that constraint. Table 11-14 and Table 11-15 include congestion allocations from these special case constraints.

There are five basic categories of constraint specific allocation special cases: congestion associated with constraints with no downstream load bus (no load bus); congestion associated with constraints with downstream load buses with zero value CLMPs (zero CLMP); congestion associated with closed loop interface (closed loop interfaces); CT price setting logic; and congestion associated with nontransmission facility constraints in the Day-Ahead Energy Market and/or any unaccounted for difference between PJM billed congestion charges and calculated congestion costs including rounding errors (unclassified).

Table 11-16 and Table 11-17 show the allocation of total congestion by each special case allocation method, congestion allocated by the standard method and total allocation by zone. Closed loop interfaces and CT pricing logic generally result in negative congestion on a constraint specific basis. Through the assumption of artificial flexibility (an assumption of a dispatchable range where none exists) on the affected unit and artificially creating a constraint for which the otherwise inflexible resource can be marginal, PJM's use of both the closed loop interface and CT Pricing Logic forces the affected resource bus LMP to match the marginal offer of the resource. Price forcing caused by the closed loop interfaces and CT pricing logic artificial constraint causes higher CLMP payments to the affected generation than the CLMP load charges to any affected load, resulting in negative congestion to be associated with the constraint. None of the closed loop interfaces were binding in 2018 or in the first nine months of 2019.

Table 11-16 Day-ahead and total balancing congestion assigned by zone and special case logic (Dollars (Millions)): January through September, 2019

	Congestion Costs (Millions)														
	Day-Ahead							Balancing							
Control Zone	Load Bus Zero CLMP	CT Price Setting Logic	Closed Loop Interfaces	No Load Buses	Unclassified	Allocation	Total	Load Bus Zero CLMP	CT Price Setting Logic	Closed Loop Interfaces	No Load Buses	Unclassified	Allocation	Total	Grand Total
AECO	($0.0)	$0.0	$0.0	$0.0	$0.0	$7.0	$7.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($1.1)	($1.1)	$5.9
AEP	$0.0	($0.0)	$0.0	$2.0	($0.0)	$84.8	$86.7	($0.0)	($0.6)	$0.0	$0.0	($0.3)	($14.3)	($15.1)	$71.6
APS	$0.0	($0.0)	$0.0	$0.0	($0.0)	$33.6	$33.6	$0.0	$0.0	$0.0	($0.0)	$0.0	($5.4)	($5.4)	$28.2
ATSI	$0.0	$0.0	$0.0	$0.0	$0.0	$36.7	$36.8	$0.0	($0.3)	$0.0	$0.0	($0.0)	($7.1)	($7.4)	$29.4
BGE	$0.0	($0.0)	$0.0	$0.1	$0.0	$19.0	$19.1	($0.0)	($0.0)	$0.0	$0.0	$0.0	($4.0)	($4.0)	$15.1
ComEd	$0.0	($0.0)	$0.0	$1.6	($0.0)	$66.3	$67.8	($0.0)	($0.7)	$0.0	($0.0)	($0.0)	($8.6)	($9.3)	$58.5
DAY	$0.0	$0.0	$0.0	$0.0	$0.0	$10.1	$10.1	$0.0	($0.1)	$0.0	$0.0	($0.0)	($2.0)	($2.1)	$8.0
DEOK	$0.0	$0.0	$0.0	$0.0	$0.0	$16.4	$16.4	$0.0	($0.1)	$0.0	($0.0)	($0.0)	($3.2)	($3.3)	$13.1
DLCO	$0.0	($0.0)	$0.0	$0.0	$0.0	$5.6	$5.6	$0.0	($0.0)	$0.0	$0.0	($0.0)	($1.5)	($1.5)	$4.1
Dominion	$0.0	$0.0	$0.0	$0.1	$0.0	$59.6	$59.6	$0.0	$0.0	$0.0	($0.0)	($0.1)	($11.5)	($11.6)	$48.1
DPL	$0.0	($0.0)	$0.0	$0.1	$0.0	$25.0	$25.0	($0.0)	$0.0	$0.0	$0.0	($0.0)	($2.5)	($2.5)	$22.5
EKPC	$0.0	$0.0	$0.0	$0.0	$0.0	$7.8	$7.8	$0.0	($0.0)	$0.0	$0.0	$0.0	($1.5)	($1.5)	$6.3
EXT	$0.0	($0.1)	$0.0	$0.3	$0.1	$0.0	$0.4	($0.0)	($2.8)	$0.0	($0.0)	($0.2)	$0.0	($3.1)	($2.7)
JCPL	($0.0)	($0.0)	$0.0	$0.0	$0.0	$14.5	$14.5	$0.0	($0.1)	$0.0	($0.0)	$0.0	($2.5)	($2.6)	$11.9
Met-Ed	$0.0	$0.0	$0.0	$0.6	($0.0)	$10.5	$11.1	$0.0	$0.0	$0.0	($0.1)	($0.0)	($2.1)	($2.2)	$8.9
OVEC	$0.0	($0.0)	$0.0	$0.2	($0.0)	$0.0	$0.2	$0.0	$0.1	$0.0	$0.0	$0.0	($0.0)	$0.1	$0.3
PECO	$0.0	$0.0	$0.0	$0.0	($0.0)	$22.2	$22.3	$0.0	($0.1)	$0.0	($0.0)	($0.0)	($4.4)	($4.5)	$17.7
PENELEC	$0.0	($0.1)	$0.0	$0.2	($0.0)	$12.9	$13.0	$0.0	$0.0	$0.0	($0.1)	$0.0	($2.0)	($2.0)	$11.0
Pepco	$0.0	($0.0)	$0.0	($0.0)	$0.0	$17.0	$17.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($3.4)	($3.4)	$13.6
PPL	$0.0	($0.0)	$0.0	$0.1	($0.0)	$27.8	$27.9	($0.0)	($0.1)	$0.0	$0.0	$0.0	($4.3)	($4.4)	$23.5
PSEG	($0.0)	$0.1	$0.0	$0.0	($0.0)	$28.4	$28.5	$0.0	($0.0)	$0.0	$0.0	$0.0	($5.0)	($5.0)	$23.4
RECO	$0.0	$0.0	$0.0	$0.0	$0.0	$1.2	$1.2	$0.0	($0.3)	$0.0	$0.0	$0.0	($0.2)	($0.4)	$0.7
Total	$0.0	($0.2)	$0.0	$5.3	$0.1	$506.2	$511.4	($0.0)	($5.0)	$0.0	($0.2)	($0.6)	($86.6)	($92.3)	$419.1

Table 11-17 Day-ahead and total balancing congestion assigned by zone and special case logic (Dollars (Millions)): January through September, 2018

	Congestion Costs (Millions)														
	Day-Ahead							Balancing							
Control Zone	Load Bus Zero CLMP	CT Price Setting Logic	Closed Loop Interfaces	No Load Buses	Unclassified	Allocation	Total	Load Bus Zero CLMP	CT Price Setting Logic	Closed Loop Interfaces	No Load Buses	Unclassified	Allocation	Total	Grand Total
AECO	($0.0)	$0.1	$0.0	$0.3	$0.0	$13.1	$13.6	$0.0	($0.0)	$0.0	$0.0	($0.0)	($0.3)	($0.4)	$13.2
AEP	$0.3	$0.0	$0.0	$0.5	($0.0)	$200.3	$201.2	$0.0	($2.2)	$0.0	($0.0)	$0.3	($3.7)	($5.6)	$195.6
APS	$0.0	($0.3)	$0.0	$0.0	($0.0)	$67.2	$66.9	$0.0	($0.1)	$0.0	$0.0	($0.0)	($1.3)	($1.4)	$65.5
ATSI	$0.0	$0.5	$0.0	$0.2	$0.0	$85.6	$86.3	$0.0	($0.1)	$0.0	$0.0	($0.0)	($2.5)	($2.7)	$83.7
BGE	$0.0	$0.0	$0.0	$0.0	$0.0	$42.5	$42.5	$0.0	($0.1)	$0.0	($0.0)	($0.0)	($0.8)	($0.9)	$41.6
ComEd	$1.4	($1.0)	$0.0	$5.6	($0.0)	$136.2	$142.3	($0.0)	($2.1)	$0.0	$0.3	$0.3	($3.8)	($5.3)	$137.0
DAY	$0.0	$0.1	$0.0	$0.0	$0.0	$24.1	$24.2	$0.0	($0.2)	$0.0	$0.0	$0.2	($0.7)	($0.6)	$23.5
DEOK	$0.2	$0.2	$0.0	$2.0	$0.0	$41.4	$43.7	$0.0	$0.1	$0.0	$0.0	$0.2	($1.1)	($0.9)	$42.8
DLCO	$0.0	$0.0	$0.0	$0.0	($0.0)	$14.5	$14.6	$0.0	($0.0)	$0.0	$0.0	$0.0	($0.5)	($0.6)	$14.0
Dominion	$0.0	$0.2	$0.0	$0.3	$0.0	$137.0	$137.5	$0.0	($0.0)	$0.0	($0.0)	($0.0)	($2.6)	($2.6)	$134.9
DPL	$0.0	$0.6	$0.0	$0.3	$0.0	$55.1	$56.0	$0.0	($0.1)	$0.0	$0.0	($0.1)	($1.3)	($1.4)	$54.5
EKPC	$0.0	($0.0)	$0.0	$0.0	$0.0	$21.0	$21.0	$0.0	$0.0	$0.0	$0.0	$0.1	($0.3)	($0.1)	$20.9
EXT	$0.0	$0.1	$0.0	$0.7	$0.3	$0.0	$1.2	$0.0	($4.1)	$0.0	($0.0)	($1.0)	$0.0	($5.1)	($3.9)
JCPL	$0.0	$0.7	$0.0	($0.0)	($0.0)	$32.6	$33.4	$0.0	($0.0)	$0.0	$0.0	($0.0)	($0.8)	($0.8)	$32.6
Met-Ed	$0.0	$0.2	$0.0	$3.1	$0.0	$23.6	$26.9	$0.0	($0.0)	$0.0	($0.5)	$0.0	($0.4)	($1.0)	$25.9
PECO	$0.0	($0.7)	$0.0	$0.4	($0.0)	$52.8	$52.6	$0.0	($0.1)	$0.0	$0.0	$0.0	($1.1)	($1.2)	$51.4
PENELEC	$0.3	$0.1	$0.0	$0.7	($0.0)	$25.3	$26.5	$0.0	$0.1	$0.0	($0.0)	$0.0	($1.2)	($1.1)	$25.4
Pepco	$0.0	$0.1	$0.0	$0.0	$0.0	$39.3	$39.4	$0.0	$0.1	$0.0	$0.0	($0.0)	($0.8)	($0.7)	$38.7
PPL	$0.0	($2.0)	$0.0	$0.8	($0.0)	$59.3	$58.2	$0.0	$0.1	$0.0	$0.0	($0.0)	($0.8)	($0.7)	$57.5
PSEG	$0.0	($0.3)	$0.0	$1.0	($0.0)	$60.9	$61.6	$0.0	($0.4)	$0.0	$0.0	($0.0)	($1.6)	($1.9)	$59.6
RECO	$0.0	$0.0	$0.0	$0.0	$0.0	$2.2	$2.2	$0.0	($0.3)	$0.0	$0.0	$0.0	($0.1)	($0.3)	$1.9
Total	$2.3	($1.2)	$0.0	$16.1	$0.3	$1,134.2	$1,151.7	($0.0)	($9.5)	$0.0	($0.2)	($0.0)	($25.7)	($35.5)	$1,116.2

Monthly Congestion

Table 11-18 shows day-ahead, balancing and inadvertent congestion costs by month for 2018 and the first nine months of 2019.

Table 11-18 Monthly PJM congestion costs by market (Dollars (Millions)): January 2018 through September 2019

	Congestion Costs (Millions)							
	2018				2019			
	Day-Ahead	Balancing	Inadvertent Charges	Total	Day-Ahead	Balancing	Inadvertent Charges	Total
Jan	$517.7	$18.2	$0.0	$535.9	$120.7	($20.6)	$0.0	$100.2
Feb	$43.8	$1.4	($0.0)	$45.2	$36.4	($5.5)	$0.0	$30.9
Mar	$80.2	($0.3)	$0.0	$79.9	$45.0	($12.2)	$0.0	$32.8
Apr	$57.4	($3.3)	$0.0	$54.1	$25.4	($3.2)	$0.0	$22.2
May	$122.2	($16.0)	$0.0	$106.2	$47.5	($9.5)	($0.0)	$38.0
Jun	$95.2	($19.9)	$0.0	$75.3	$36.4	($6.5)	$0.0	$29.9
Jul	$70.8	($5.8)	$0.0	$65.0	$75.1	($6.5)	$0.0	$68.5
Aug	$69.2	($3.5)	$0.0	$65.7	$40.2	($5.0)	($0.0)	$35.2
Sep	$95.2	($6.3)	($0.0)	$88.9	$84.6	($23.4)	($0.0)	$61.2
Oct	$95.0	($11.8)	($0.0)	$83.3				
Nov	$69.1	($14.2)	($0.0)	$54.9				
Dec	$63.0	($7.6)	$0.0	$55.5				
Total	$1,378.9	($69.0)	$0.0	$1,309.9	$511.4	($92.4)	$0.0	$419.1

Figure 11-2 shows PJM monthly total congestion cost for January 1, 2008 through September 30, 2019.

Figure 11-2 PJM monthly total congestion cost (Dollars (Millions)): January 2008 through September 2019

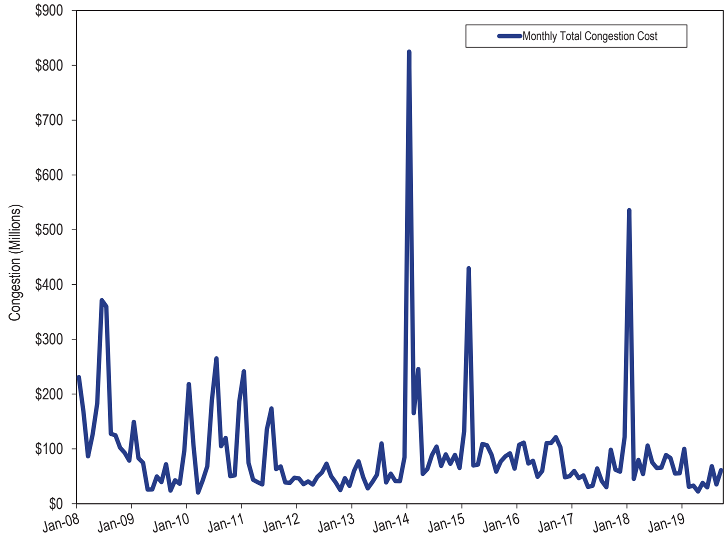


Table 11-19 shows monthly total congestion credits and charges for each virtual transaction type in 2018 and the first nine months of 2019. Virtual transaction congestion charges, when positive, are the total congestion charges to the virtual transactions and when negative, are the total congestion credits to the virtual transactions. The negative totals in Table 11-19 show that virtuals were paid, in net, congestion credits in the first nine months of 2019 and in 2018. More than half the total credits to virtuals went to UTCs in 2018 and in the first nine months of 2019.

Table 11-19 Monthly PJM congestion charges by virtual transaction type and by market (Dollars (Millions)): January 2018 through September 2019

		Congestion Costs (Millions)									
		DEC			INC			Up to Congestion			
Year		Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Grand Total
2018	Jan	$4.1	($6.5)	($2.4)	$4.5	($8.1)	($3.6)	($40.8)	$29.5	($11.3)	($17.2)
	Feb	$1.8	$0.4	$2.2	$1.2	($0.8)	$0.4	($0.5)	$1.3	$0.9	$3.5
	Mar	$0.9	($2.8)	($1.9)	$1.4	($3.2)	($1.8)	($5.1)	$2.0	($3.1)	($6.8)
	Apr	$0.4	($0.7)	($0.4)	$1.8	($1.4)	$0.4	($1.0)	$1.0	($0.1)	($0.1)
	May	$1.5	($4.1)	($2.6)	$4.5	($6.9)	($2.5)	$1.7	($10.6)	($8.9)	($14.0)
	Jun	$3.6	($2.4)	$1.1	$3.0	($3.7)	($0.7)	$5.6	($4.4)	$1.2	$1.6
	Jul	$1.3	($2.4)	($1.1)	$0.8	($0.7)	$0.1	$2.3	($2.8)	($0.5)	($1.5)
	Aug	$2.4	($3.1)	($0.6)	$0.2	($0.2)	$0.1	$3.4	($2.8)	$0.7	$0.1
	Sep	$2.1	($1.6)	$0.5	$1.4	($1.5)	($0.1)	$4.8	($6.9)	($2.1)	($1.7)
	Oct	$1.5	($2.6)	($1.1)	$2.4	($3.2)	($0.8)	$2.5	($3.3)	($0.8)	($2.7)
	Nov	$2.1	($3.3)	($1.2)	$0.4	($2.3)	($1.9)	$4.3	($7.5)	($3.2)	($6.3)
	Dec	$3.7	($3.5)	$0.1	($1.2)	$2.0	$0.8	$3.4	($3.5)	($0.1)	$0.8
	Total	$25.3	($32.7)	($7.4)	$20.5	($30.0)	($9.5)	($19.4)	($7.9)	($27.4)	($44.3)
2019	Jan	$3.5	($4.0)	($0.6)	$1.2	($3.6)	($2.4)	$5.1	($4.6)	$0.5	($2.5)
	Feb	$0.8	($1.4)	($0.6)	$1.0	($1.1)	($0.1)	$2.0	($3.2)	($1.2)	($1.8)
	Mar	$0.7	($1.5)	($0.7)	$1.4	($2.3)	($0.8)	$4.0	($8.4)	($4.4)	($6.0)
	Apr	$0.6	($0.1)	$0.5	$1.1	($1.4)	($0.3)	$2.8	($2.3)	$0.5	$0.7
	May	$0.4	($0.0)	$0.4	$2.4	($3.0)	($0.6)	$5.4	($6.3)	($0.9)	($1.2)
	Jun	$0.8	($0.6)	$0.2	$1.2	($1.3)	($0.2)	$3.3	($5.0)	($1.7)	($1.7)
	Jul	$2.2	($0.7)	$1.5	$0.4	($2.0)	($1.6)	$4.1	($6.8)	($2.6)	($2.8)
	Aug	$1.1	($0.9)	$0.2	$0.1	($0.3)	($0.2)	$2.9	($4.0)	($1.1)	($1.1)
	Sep	$1.6	($2.0)	($0.3)	$3.0	($5.2)	($2.3)	$7.7	($17.9)	($10.3)	($12.9)
	Total	$11.6	($11.1)	$0.5	$11.7	($20.2)	($8.6)	$37.4	($58.6)	($21.2)	($29.3)

Congested Facilities

A congestion event exists when a unit or units must be dispatched out of merit order to control for the potential impact of a contingency on a monitored facility or to control an actual overload. A congestion event hour exists when a specific facility is constrained for one or more five-minute intervals within an hour. A congestion event hour differs from a constrained hour, which is any hour during which one or more facilities are congested. Thus, if two facilities are constrained during an hour, the result is two congestion event hours and one constrained hour. Constraints are often simultaneous, so the number of congestion event hours usually exceeds the number of constrained hours and the number of congestion event hours usually exceeds the number of hours in a year.

In order to have a consistent metric for real-time and day-ahead congestion frequency, real-time congestion frequency is measured using the convention that an hour is constrained if any of its component five-minute intervals is constrained. This is consistent with the way in which PJM reports real-time congestion. In the first nine months of 2019, there were 78,155 day-ahead, congestion event hours compared to 105,437 day-ahead congestion event hours in the first nine months of 2018. Of the day-ahead congestion event hours in the first nine months of 2019, only 5,802 (7.4 percent) were also constrained in the Real-Time Energy Market. In the first nine months of 2019, there were 13,495 real-time, congestion event hours compared to 16,915 real-time, congestion event hours in the first nine months of 2018. Of the real-time congestion event hours in the first nine months of 2019, 6,004 (44.5 percent) were also constrained in the Day-Ahead Energy Market.

The top five constraints by congestion costs contributed $141.8 million, or 33.8 percent, of the total PJM congestion costs in the first nine months of 2019. The top five constraints were the Conastone - Peach Bottom Line, the Coolspring - Milford Line, the Tanners Creek - Miami Fort Flowgate, the Siegfried Transformer, and the AP South Interface.

The change in the location of the top 10 constraints between the first nine months of 2018 and the first nine months of 2019 was a result of the high gas prices in January 2018 (Figure 11-3).

Congestion by Facility Type and Voltage

Day-ahead, congestion event hours decreased on all types of facilities largely as a result of the decrease in cleared up to congestion (UTC) transactions from January and February, 2018, to January and February, 2019.[21]

Real-time, congestion event hours decreased on transformers, flowgates, interfaces and lines in the first nine months of 2019.

Day-ahead congestion costs decreased on all types of facilities in the first nine months of 2019 compared to the first nine months of 2018. Day-ahead negative implicit injection credits decreased on all types of facilities in the first nine months of 2019 compared to the first nine months of 2018.

Balancing congestion costs decreased on all types of facilities except lines in the first nine months of 2019 compared to the first nine months of 2018 (Table 11-21). Table 11-20 provides congestion event hour subtotals and congestion cost subtotals comparing the first nine months of 2019 results by facility type: line, transformer, interface, flowgate and unclassified facilities.[22] [23]

21 162 FERC ¶ 61,139.
22 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.
23 The term flowgate refers to MISO reciprocal coordinated flowgates and NYISO M2M flowgates.

Table 11-20 Congestion summary (By facility type): January through September, 2019

	Congestion Costs (Millions)										
	Day-Ahead				Balancing					Event Hours	
Type	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Grand Total	Day-Ahead	Real-Time
Flowgate	($16.1)	($65.5)	$5.2	$54.6	$2.8	$6.7	($38.5)	($42.4)	$12.2	8,152	3,983
Interface	$7.3	($32.9)	$0.2	$40.4	$1.1	$4.1	$0.7	($2.3)	$38.0	661	130
Line	$154.8	($140.0)	$26.7	$321.6	$3.7	$16.6	($16.4)	($29.3)	$292.3	50,568	7,540
Transformer	$23.1	($38.9)	$4.4	$66.4	($2.1)	$7.2	($3.3)	($12.6)	$53.9	15,354	967
Other	$9.1	($17.8)	$1.4	$28.3	$0.6	$4.4	($1.3)	($5.2)	$23.2	3,420	874
Unclassified	$0.1	($0.0)	$0.0	$0.1	$0.1	$0.2	($0.6)	($0.6)	($0.5)	NA	NA
Total	$178.3	($295.2)	$37.9	$511.4	$6.2	$39.2	($59.4)	($92.4)	$419.1	78,155	13,495

Table 11-21 Congestion summary (By facility type): January through September, 2018

	Congestion Costs (Millions)										
	Day-Ahead				Balancing					Event Hours	
Type	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Grand Total	Day-Ahead	Real-Time
Flowgate	($53.0)	($304.7)	($36.7)	$214.9	$1.5	$5.6	$1.6	($2.5)	$212.4	15,659	4,241
Interface	$64.0	($162.8)	($13.9)	$212.9	$15.2	$22.8	$11.1	$3.5	$216.5	2,171	391
Line	$166.2	($344.6)	$18.1	$528.9	($2.3)	$20.8	($14.6)	($37.7)	$491.2	60,726	10,366
Transformer	$59.2	($110.9)	$2.0	$172.2	($0.0)	$1.4	$3.3	$1.9	$174.0	23,484	1,344
Other	$12.4	($8.8)	$1.2	$22.4	$3.0	($1.1)	($4.7)	($0.6)	$21.8	3,397	573
Unclassified	$0.1	($0.1)	$0.1	$0.3	$0.9	$0.7	($0.3)	($0.0)	$0.3	NA	NA
Total	$249.0	($931.9)	($29.3)	$1,151.7	$18.2	$50.1	($3.6)	($35.5)	$1,116.2	105,437	16,915

Table 11-22 and Table 11-23 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 11-22. In the first nine months of 2019, there were 78,155 congestion event hours in the Day-Ahead Energy Market. Of those day-ahead congestion event hours, only 5,802 (7.4 percent) were also constrained in the Real-Time Energy Market. In the first nine months of 2018, of the 105,437 day-ahead congestion event hours, only 7,845 (7.4 percent) were binding in the Real-Time Energy Market.[24]

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 11-23. In the first nine months of 2019, of the 13,495 congestion event hours in the Real-Time Energy Market, 6,004 (44.5 percent) were also constrained in the Day-Ahead Energy Market. In the first nine months of 2018, of the 16,915 real-time congestion event hours, 7,931 (46.9 percent) were also in the Day-Ahead Energy Market.

24 Constraints are mapped to transmission facilities. In the Day-Ahead Energy Market, within a given hour, a single facility may be associated with multiple constraints. In such situations, the same facility accounts for more than one constraint-hour for a given hour in the Day-Ahead Energy Market. Similarly in the real-time market a facility may account for more than one constraint-hour within a given hour.

Table 11-22 Congestion event hours (day-ahead against real-time): January through September, 2018 and 2019

	Congestion Event Hours					
	2018 (Jan - Sep)			2019 (Jan - Sep)		
Type	Day-Ahead Constrained	Corresponding Real-Time Constrained	Percent	Day-Ahead Constrained	Corresponding Real-Time Constrained	Percent
Flowgate	15,659	1,707	10.9%	8,152	938	11.5%
Interface	2,171	239	11.0%	661	27	4.1%
Line	60,726	5,026	8.3%	50,568	3,882	7.7%
Transformer	23,484	585	2.5%	15,354	419	2.7%
Other	3,397	288	8.5%	3,420	536	15.7%
Total	105,437	7,845	7.4%	78,155	5,802	7.4%

Table 11-23 Congestion event hours (real-time against day-ahead): January through September, 2018 and 2019

	Congestion Event Hours					
	2018 (Jan - Sep)			2019 (Jan - Sep)		
Type	Real-Time Constrained	Corresponding Day-Ahead Constrained	Percent	Real-Time Constrained	Corresponding Day-Ahead Constrained	Percent
Flowgate	4,241	1,709	40.3%	3,983	949	23.8%
Interface	391	264	67.5%	130	31	23.8%
Line	10,366	5,078	49.0%	7,540	4,055	53.8%
Transformer	1,344	591	44.0%	967	416	43.0%
Other	573	289	50.4%	874	553	63.3%
Total	16,915	7,931	46.9%	13,495	6,004	44.5%

Table 11-24 shows congestion costs by facility voltage class for the first nine months of 2019. Congestion costs in the first nine months of 2019 decreased for all facilities except 69 kV facilities compared to the first nine months of 2018.

Table 11-24 Congestion summary (By facility voltage): January through September, 2019

	Congestion Costs (Millions)										
	Day-Ahead				Balancing					Event Hours	
Voltage (kV)	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Costs	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Costs	Total	Grand Total	Day-Ahead	Real-Time
765	($0.1)	($0.7)	$0.6	$1.3	($0.1)	$0.2	($0.2)	($0.5)	$0.7	175	46
500	$95.1	($40.0)	$0.4	$135.5	$5.1	$10.6	($0.8)	($6.3)	$129.2	4,811	3,023
345	($1.5)	($53.7)	$9.0	$61.2	$0.7	$2.4	($11.7)	($13.4)	$47.7	8,841	1,058
230	$48.2	($88.1)	$4.9	$141.2	($1.9)	$10.9	($5.6)	($18.3)	$122.9	11,527	2,874
212	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	117	0
161	($0.3)	($5.3)	($0.2)	$4.9	($0.1)	$0.2	($0.0)	($0.3)	$4.6	1,183	262
138	$15.2	($83.4)	$18.8	$117.3	$2.1	$7.4	($39.0)	($44.3)	$73.0	25,445	4,816
115	$7.7	($18.0)	$0.7	$26.4	($0.2)	$6.0	($1.0)	($7.2)	$19.2	6,958	884
69	$13.4	($6.1)	$3.6	$23.1	$0.5	$1.4	($0.4)	($1.3)	$21.7	16,849	531
35	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	17	0
34	$0.4	$0.1	$0.0	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	1,338	0
13	$0.1	$0.0	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	561	0
12	$0.1	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	333	0
Unclassified	$0.1	($0.0)	$0.0	$0.1	$0.1	$0.2	($0.6)	($0.6)	($0.5)	NA	NA
Total	$178.3	($295.2)	$37.9	$511.4	$6.2	$39.2	($59.4)	($92.4)	$419.1	78,155	13,495

Table 11-25 Congestion summary (By facility voltage): January through September, 2018

	Congestion Costs (Millions)										
	Day-Ahead				Balancing					Event Hours	
Voltage (kV)	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Grand Total	Day-Ahead	Real-Time
765	$0.6	($1.3)	$0.1	$2.1	$0.7	$0.3	($0.0)	$0.4	$2.4	94	21
500	$85.5	($182.3)	($13.5)	$254.3	$16.5	$21.1	$11.4	$6.8	$261.1	3,708	955
345	$16.4	($242.9)	($1.9)	$257.4	$0.1	($1.5)	($8.1)	($6.4)	$251.0	17,616	2,241
230	$145.5	($50.2)	$4.3	$200.0	($1.8)	$5.5	($2.1)	($9.3)	$190.7	18,259	4,435
212	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	43	0
161	$0.9	($4.2)	($0.3)	$4.8	$0.2	($0.4)	$0.4	$1.0	$5.8	218	55
138	($28.4)	($396.2)	($17.9)	$349.8	$2.4	$21.3	($3.0)	($21.9)	$327.9	40,091	6,959
115	$8.2	($54.9)	($3.0)	$60.0	($0.1)	$3.3	($1.0)	($4.4)	$55.7	11,895	1,550
69	$20.2	$0.8	$2.6	$21.9	($0.7)	($0.1)	($1.0)	($1.6)	$20.4	10,810	638
34	$0.1	$0.0	$0.3	$0.4	$0.0	$0.1	$0.0	($0.0)	$0.4	1,878	61
18	($0.0)	($0.3)	$0.1	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	309	0
13.2	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	55	0
13	($0.0)	($0.1)	($0.0)	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	160	0
12	($0.0)	($0.1)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	301	0
Unclassified	$0.1	($0.1)	$0.1	$0.3	$0.9	$0.7	($0.3)	($0.0)	$0.3	NA	NA
Total	$249.0	($931.9)	($29.3)	$1,151.7	$18.2	$50.1	($3.6)	($35.5)	$1,116.2	105,437	16,915

Constraint Duration

Table 11-26 lists the constraints for January through September, 2018 and 2019 that were most frequently binding and Table 11-27 shows the constraints which experienced the largest change in congestion event hours from the first nine months of 2018 to the first nine months of 2019. In Table 11-26, constraints are presented in descending order of total day-ahead event hours and real-time event hours for the first nine months of 2019. In Table 11-27, the constraints are presented in descending order of absolute value of day-ahead event hour changes plus real-time event hour changes from the first nine months of 2018 to the first nine months of 2019.

Table 11-26 Top 25 constraints with frequent occurrence: January through September, 2018 and 2019

			Event Hours						Percent of Annual Hours					
			Day-Ahead (Jan - Sep)			Real-Time (Jan - Sep)			Day-Ahead (Jan - Sep)			Real-Time (Jan - Sep)		
No.	Constraint	Type	2018	2019	Change	2018	2019	Change	2018	2019	Change	2018	2019	Change
1	Conastone - Peach Bottom	Line	997	3,870	2,873	393	2,576	2,183	15%	59%	44%	6%	39%	33%
2	Monroe - Vineland	Line	1,692	3,803	2,111	94	97	3	26%	58%	32%	1%	1%	0%
3	Easton - Emuni	Line	2,734	3,383	649	2	9	7	42%	52%	10%	0%	0%	0%
4	Berwick - Koonsville	Line	487	2,875	2,388	2	32	30	7%	44%	36%	0%	0%	0%
5	Face Rock	Other	541	1,956	1,415	71	290	219	8%	30%	22%	1%	4%	3%
6	Graceton - Safe Harbor	Line	2,986	1,292	(1,694)	1,804	440	(1,364)	46%	20%	(26%)	28%	7%	(21%)
7	Marblehead	Flowgate	396	1,105	709	452	474	22	6%	17%	11%	7%	7%	0%
8	Marquis - Dept of Energy	Line	227	1,494	1,267	0	0	0	3%	23%	19%	0%	0%	0%
9	Gardners - Texas Eastern	Line	2,305	1,383	(922)	341	105	(236)	35%	21%	(14%)	5%	2%	(4%)
10	Roxana - Praxair	Flowgate	769	984	215	405	457	52	12%	15%	3%	6%	7%	1%
11	DoeX530	Transformer	0	1,170	1,170	0	0	0	0%	18%	18%	0%	0%	0%
12	East Towanda - Hillside	Line	468	598	130	94	342	248	7%	9%	2%	1%	5%	4%
13	Preston - Tanyard	Line	586	889	303	11	1	(10)	9%	14%	5%	0%	0%	(0%)
14	New Carlisle - Olive	Line	291	883	592	0	0	0	4%	13%	9%	0%	0%	0%
15	Munster	Flowgate	0	709	709	0	170	170	0%	11%	11%	0%	3%	3%
16	Mountain	Transformer	846	875	29	0	0	0	13%	13%	0%	0%	0%	0%
17	Siegfried	Transformer	6	560	554	14	310	296	0%	9%	8%	0%	5%	5%
18	Powerton - Toulon	Line	156	768	612	3	74	71	2%	12%	9%	0%	1%	1%
19	Cedar Creek - Red Lion	Line	918	766	(152)	69	57	(12)	14%	12%	(2%)	1%	1%	(0%)
20	Bagley - Graceton	Line	458	709	251	182	92	(90)	7%	11%	4%	3%	1%	(1%)
21	Tanners Creek - Miami Fort	Flowgate	1,346	793	(553)	0	0	0	21%	12%	(8%)	0%	0%	0%
22	Lenox - North Meshoppen	Line	32	425	393	1	352	351	0%	6%	6%	0%	5%	5%
23	Ramapo (ConEd) - S Mahwah (RECO)	Line	65	774	709	0	0	0	1%	12%	11%	0%	0%	0%
24	New Castle	Transformer	195	756	561	0	0	0	3%	12%	9%	0%	0%	0%
25	Goodland - Reynolds	Flowgate	36	103	67	8	608	600	1%	2%	1%	0%	9%	9%

Table 11-27 Top 25 constraints with largest year to year change in occurrence: January through September, 2018 and 2019

			Event Hours						Percent of Annual Hours					
			Day-Ahead (Jan - Sep)			Real-Time (Jan - Sep)			Day-Ahead (Jan - Sep)			Real-Time (Jan - Sep)		
No.	Constraint	Type	2018	2019	Change	2018	2019	Change	2018	2019	Change	2018	2019	Change
1	Conastone - Peach Bottom	Line	997	3,870	2,873	393	2,576	2,183	15%	59%	44%	6%	39%	33%
2	Graceton - Safe Harbor	Line	2,986	1,292	(1,694)	1,804	440	(1,364)	46%	20%	(26%)	28%	7%	(21%)
3	Berwick - Koonsville	Line	487	2,875	2,388	2	32	30	7%	44%	36%	0%	0%	0%
4	Monroe - Vineland	Line	1,692	3,803	2,111	94	97	3	26%	58%	32%	1%	1%	0%
5	Quad Cities	Transformer	2,414	507	(1,907)	0	0	0	37%	8%	(29%)	0%	0%	0%
6	Face Rock	Other	541	1,956	1,415	71	290	219	8%	30%	22%	1%	4%	3%
7	Lakeview - Greenfield	Line	1,337	36	(1,301)	336	13	(323)	20%	1%	(20%)	5%	0%	(5%)
8	Newton	Flowgate	1,116	0	(1,116)	389	0	(389)	17%	0%	(17%)	6%	0%	(6%)
9	Brokaw - Leroy	Flowgate	1,232	0	(1,232)	261	0	(261)	19%	0%	(19%)	4%	0%	(4%)
10	Olive	Other	1,327	0	(1,327)	0	0	0	20%	0%	(20%)	0%	0%	0%
11	Marquis - Dept of Energy	Line	227	1,494	1,267	0	0	0	3%	23%	19%	0%	0%	0%
12	Flint Lake - Luchtman Road	Flowgate	890	0	(890)	365	0	(365)	14%	0%	(14%)	6%	0%	(6%)
13	Zion	Line	1,193	0	(1,193)	0	0	0	18%	0%	(18%)	0%	0%	0%
14	DoeX530	Transformer	0	1,170	1,170	0	0	0	0%	18%	18%	0%	0%	0%
15	Gardners - Texas Eastern	Line	2,305	1,383	(922)	341	105	(236)	35%	21%	(14%)	5%	2%	(4%)
16	Cedar Grove Sub - Roseland	Line	1,328	238	(1,090)	64	16	(48)	20%	4%	(17%)	1%	0%	(1%)
17	Waukegan	Transformer	1,083	19	(1,064)	0	0	0	17%	0%	(16%)	0%	0%	0%
18	Emilie - Falls	Line	1,321	425	(896)	242	95	(147)	20%	6%	(14%)	4%	1%	(2%)
19	Pleasant Prairie - Zion	Flowgate	1,011	117	(894)	60	0	(60)	15%	2%	(14%)	1%	0%	(1%)
20	Canton - South Troy	Line	949	0	(949)	0	0	0	14%	0%	(14%)	0%	0%	0%
21	Person - Sedge Hill	Line	814	17	(797)	136	10	(126)	12%	0%	(12%)	2%	0%	(2%)
22	Quad Cities - Cordova	Flowgate	1,035	147	(888)	0	0	0	16%	2%	(14%)	0%	0%	0%
23	Munster	Flowgate	0	709	709	0	170	170	0%	11%	11%	0%	3%	3%
24	Monroe - Lallendorf	Flowgate	945	83	(862)	0	0	0	14%	1%	(13%)	0%	0%	0%
25	Siegfried	Transformer	6	560	554	14	310	296	0%	9%	8%	0%	5%	5%

Constraint Costs

Table 11-28 and Table 11-29 show the top constraints affecting congestion costs by facility for the first nine months of 2019 and 2018. The Conastone - Peach Bottom Line was the largest contributor to congestion costs in the first nine months of 2019, with $83.3 million in total congestion costs and 19.9 percent of the total PJM congestion costs in the first nine months of 2019.

Table 11-28 Top 25 constraints affecting PJM congestion costs (By facility): January through September, 2019[25]

				Congestion Costs (Millions)									Percent of Total PJM Congestion Costs
				Day-Ahead				Balancing					
No.	Constraint	Type	Location	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Grand Total	2019 (Jan - Sep)
1	Conastone - Peach Bottom	Line	500	$81.5	($1.7)	$0.1	$83.3	$3.7	$5.4	$1.6	($0.1)	$83.3	19.9%
2	Coolspring - Milford	Line	DPL	($0.6)	($16.2)	$0.2	$15.9	($0.1)	($0.6)	($0.7)	($0.2)	$15.7	3.7%
3	Tanners Creek - Miami Fort	Flowgate	MISO	($5.9)	($20.5)	$0.3	$14.9	$0.0	$0.0	$0.0	$0.0	$14.9	3.6%
4	Siegfried	Transformer	PPL	$6.8	($13.7)	$0.4	$20.9	($1.6)	$5.2	($0.1)	($6.8)	$14.1	3.4%
5	AP South	Interface	500	$8.4	($5.5)	($0.2)	$13.7	$0.2	$0.1	$0.1	$0.1	$13.8	3.3%
6	East	Interface	500	($5.9)	($20.3)	$0.1	$14.5	$0.9	$4.0	$0.9	($2.2)	$12.3	2.9%
7	Roxana - Praxair	Flowgate	MISO	($1.1)	($2.7)	$2.1	$3.7	$2.6	$3.4	($13.8)	($14.6)	($10.8)	(2.6%)
8	Graceton - Safe Harbor	Line	BGE	$11.4	$0.7	$0.1	$10.9	$0.4	$0.9	$0.2	($0.2)	$10.6	2.5%
9	Conastone - Northwest	Line	BGE	$7.0	($3.0)	$0.4	$10.4	$0.0	($0.0)	($0.3)	($0.3)	$10.1	2.4%
10	Cedar Creek - Red Lion	Line	DPL	$1.6	($7.8)	$0.9	$10.3	($0.8)	($0.6)	($0.7)	($1.0)	$9.3	2.2%
11	Face Rock	Other	PPL	($0.0)	($9.6)	$0.7	$10.2	$1.0	$1.7	($0.3)	($1.0)	$9.3	2.2%
12	Bagley - Graceton	Line	BGE	$5.9	($2.0)	$0.1	$8.1	$0.2	$0.5	$0.4	$0.0	$8.1	1.9%
13	CPL - DOM	Interface	500	$3.5	($4.2)	$0.1	$7.8	$0.0	$0.0	$0.0	$0.0	$7.8	1.9%
14	Palisades - Argenta	Flowgate	MISO	($0.3)	($7.3)	$0.6	$7.6	$0.1	($0.3)	($0.6)	($0.3)	$7.3	1.7%
15	Pleasant View - Ashburn	Line	Dominion	$5.7	($1.2)	$0.3	$7.3	$0.4	$0.9	($0.2)	($0.7)	$6.5	1.6%
16	Greentown	Flowgate	MISO	($0.2)	($1.7)	($0.1)	$1.5	($0.6)	$0.9	($6.2)	($7.7)	($6.1)	(1.5%)
17	Conastone	Other	500	$5.7	($0.5)	$0.1	$6.2	($0.3)	$0.6	$0.3	($0.6)	$5.6	1.3%
18	Gardners - Texas Eastern	Line	Met-Ed	($0.5)	($6.7)	$0.2	$6.4	($0.8)	$0.2	($0.4)	($1.5)	$5.0	1.2%
19	Smithton - Yukon	Line	APS	($2.6)	($7.1)	$0.3	$4.8	$0.9	$0.2	($0.7)	($0.1)	$4.8	1.1%
20	Tanners Creek - Miami Fort	Line	AEP	$0.0	$0.0	$0.0	$0.0	($0.2)	$0.7	($3.6)	($4.6)	($4.6)	(1.1%)
21	Cedar Grove Sub - Roseland	Line	PSEG	($0.0)	($4.8)	($0.3)	$4.5	($0.0)	$0.1	$0.0	($0.1)	$4.4	1.0%
22	Riverside	Line	BGE	$0.4	($4.0)	$0.1	$4.5	$0.2	$0.2	($0.2)	($0.2)	$4.4	1.0%
23	Preston - Tanyard	Line	DPL	$4.7	$1.3	$0.6	$4.0	$0.0	($0.0)	($0.0)	$0.0	$4.0	1.0%
24	Blooming Grove - Paupack	Line	PPL	$1.4	($2.6)	$0.0	$3.9	$0.0	$0.0	$0.0	$0.0	$3.9	0.9%
25	Cloverdale	Transformer	AEP	$1.5	($1.8)	$0.3	$3.6	$0.0	($0.2)	($0.1)	$0.1	$3.7	0.9%
	Top 25 Total			$128.3	($143.2)	$7.6	$279.0	$6.2	$23.5	($24.4)	($41.7)	$237.3	56.6%
	All Other Constraints			$50.1	($152.0)	$30.3	$232.4	($0.0)	$15.6	($35.0)	($50.6)	$181.8	43.4%
	Total			$178.3	($295.2)	$37.9	$511.4	$6.2	$39.2	($59.4)	($92.4)	$419.1	100.0%

25 All flowgates are mapped to MISO as Location if they are flowgates coordinated by both PJM and MISO regardless of the location of the flowgates.

Table 11-29 Top 25 constraints affecting PJM congestion costs (By facility): January through September, 2018[26]

				Congestion Costs (Millions)									Percent of Total PJM Congestion Costs
				Day-Ahead				Balancing					
No.	Constraint	Type	Location	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Grand Total	2018 (Jan - Sep)
1	AEP - DOM	Interface	500	$55.2	($66.6)	($5.2)	$116.6	$13.4	$18.7	$9.0	$3.8	$120.4	10.8%
2	Cloverdale	Transformer	AEP	$46.0	($40.9)	($0.8)	$86.1	($1.6)	$0.6	$3.6	$1.4	$87.5	7.8%
3	Tanners Creek - Miami Fort	Flowgate	MISO	($19.7)	($90.0)	($2.9)	$67.3	$0.0	$0.0	$0.0	$0.0	$67.3	6.0%
4	Graceton - Safe Harbor	Line	BGE	$87.3	$29.2	$2.3	$60.4	$0.0	$4.4	($1.5)	($5.9)	$54.5	4.9%
5	5004/5005 Interface	Interface	500	($15.4)	($54.3)	($4.4)	$34.6	$0.8	$1.7	$2.1	$1.1	$35.7	3.2%
6	Batesville - Hubble	Flowgate	MISO	($13.1)	($55.9)	($10.3)	$32.5	($0.6)	($2.2)	$0.3	$2.0	$34.5	3.1%
7	Conastone - Peach Bottom	Line	500	$27.0	$0.7	($0.2)	$26.1	$1.5	$0.7	($0.1)	$0.7	$26.8	2.4%
8	Lakeview - Greenfield	Line	ATSI	($20.2)	($56.7)	($1.6)	$34.9	($1.4)	$8.9	$0.3	($10.0)	$24.9	2.2%
9	Bedington - Black Oak	Interface	500	$10.0	($13.9)	($1.4)	$22.5	$0.6	$0.7	$0.6	$0.5	$23.0	2.1%
10	AP South	Interface	500	$13.7	($8.1)	($1.5)	$20.2	$0.0	$0.1	($0.0)	($0.1)	$20.1	1.8%
11	Capitol Hill - Chemical	Line	AEP	$12.3	($5.0)	$0.5	$17.9	$0.8	($0.8)	($0.1)	$1.5	$19.4	1.7%
12	Gardners - Texas Eastern	Line	Met-Ed	($5.5)	($21.8)	($0.1)	$16.3	$0.1	($0.2)	$0.4	$0.7	$17.0	1.5%
13	Person - Sedge Hill	Line	Dominion	$16.9	$2.3	$1.7	$16.3	($0.2)	($0.9)	($1.0)	($0.4)	$15.9	1.4%
14	Cedar Creek - Red Lion	Line	DPL	$2.4	($12.1)	$0.8	$15.3	($0.8)	($1.8)	($0.6)	$0.4	$15.7	1.4%
15	Northport - Albion	Flowgate	MISO	($2.3)	($18.4)	($3.8)	$12.3	($0.2)	($1.1)	$1.3	$2.2	$14.5	1.3%
16	Maple - Jackson	Line	ATSI	($10.4)	($23.6)	$1.5	$14.7	$0.4	$0.7	($0.9)	($1.2)	$13.5	1.2%
17	Brokaw - Leroy	Flowgate	MISO	$0.8	($12.3)	($4.4)	$8.6	$0.5	($1.3)	$3.0	$4.8	$13.5	1.2%
18	Nottingham	Other	PECO	$12.8	$0.5	$0.4	$12.8	$0.0	$0.0	$0.0	$0.0	$12.8	1.1%
19	Conastone - Northwest	Line	BGE	$9.5	($1.0)	($0.7)	$9.8	($1.0)	($0.7)	$1.1	$0.8	$10.6	1.0%
20	Emilie - Falls	Line	PECO	$3.0	($6.7)	$0.3	$10.0	$0.3	$0.4	$0.4	$0.2	$10.2	0.9%
21	Monroe - Lallendorf	Flowgate	MISO	($1.4)	($11.7)	($0.4)	$9.9	$0.0	$0.0	$0.0	$0.0	$9.9	0.9%
22	Flint Lake - Luchtman Road	Flowgate	MISO	$0.2	($10.6)	($4.9)	$5.8	($0.2)	($1.4)	$1.8	$3.0	$8.8	0.8%
23	Krendale - Shanorma	Line	APS	($5.6)	($13.8)	$0.6	$8.7	$0.0	$0.0	$0.0	$0.0	$8.7	0.8%
24	Bagley - Graceton	Line	BGE	$7.5	($0.8)	$0.4	$8.7	$0.7	$1.0	($0.1)	($0.4)	$8.3	0.7%
25	Tanners Creek - Miami Fort	Line	AEP	($2.2)	($10.0)	($0.4)	$7.4	($1.3)	($2.0)	($0.3)	$0.5	$7.9	0.7%
	Top 25 Total			$208.7	($501.4)	($34.4)	$675.7	$12.0	$25.7	$19.2	$5.5	$681.2	61.0%
	All Other Constraints			$40.3	($430.5)	$5.1	$476.0	$6.2	$24.4	($22.8)	($41.0)	$435.0	39.0%
	Total			$249.0	($931.9)	($29.3)	$1,151.7	$18.2	$50.1	($3.6)	($35.5)	$1,116.2	100.0%

26 All flowgates are mapped to MISO as Location if they are flowgates coordinated by both PJM and MISO regardless the location of the flowgates.

Figure 11-3 shows the locations of the top 10 constraints by total congestion costs on a contour map of the real-time, load-weighted average CLMP in the first nine months of 2019.

Figure 11-3 Location of the top 10 constraints by PJM total congestion costs: January through September, 2019

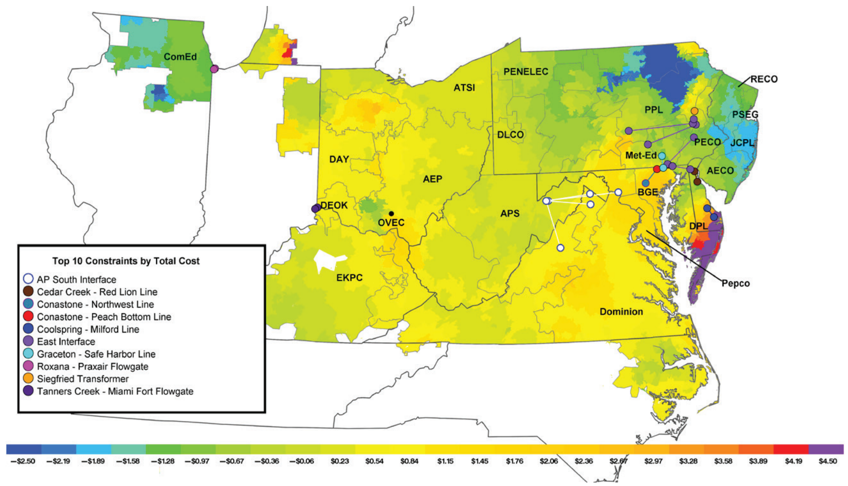


Figure 11-4 shows the locations of the top 10 constraints by balancing congestion costs on a contour map of the real-time, load-weighted average CLMP in the first nine months of 2019.

Figure 11-5 shows the locations of the top 10 constraints by day-ahead congestion costs on a contour map of the day-ahead, load-weighted average CLMP in the first nine months of 2019.

Figure 11-4 Top 10 constraints by balancing congestion costs: January through September, 2019

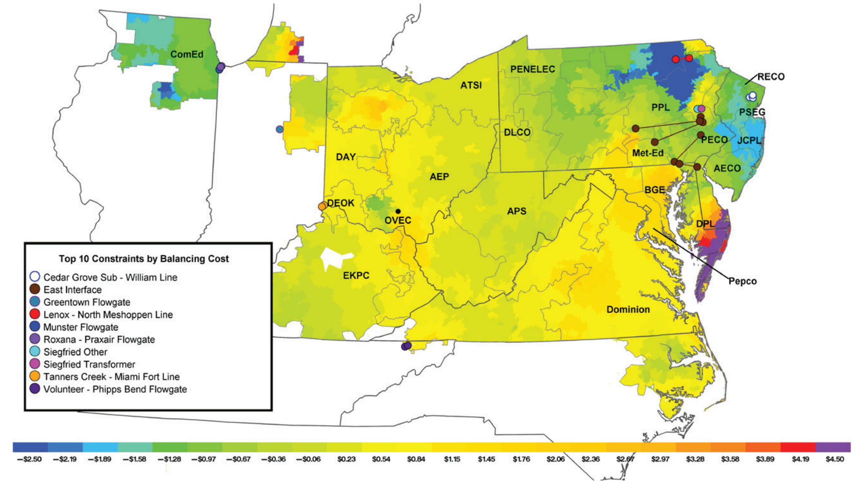
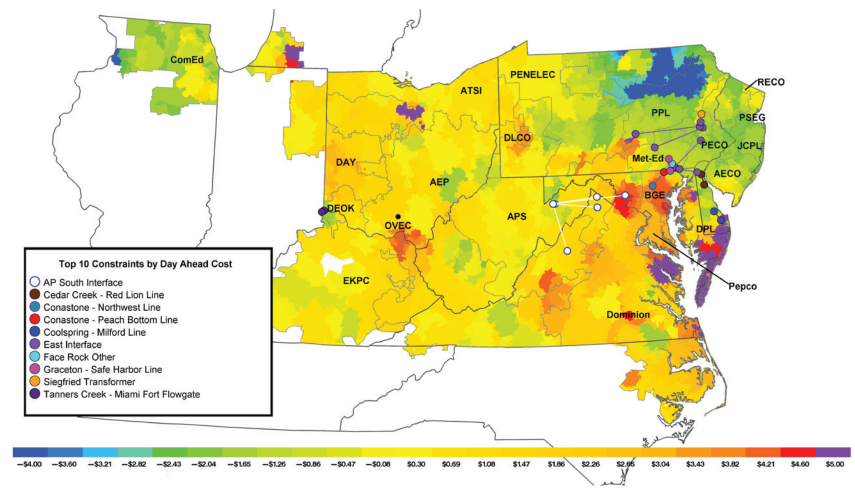


Figure 11-5 Location of the top 10 constraints by PJM day-ahead congestion costs: January through September, 2019



Congestion Event Summary: Impact of Changes in UTC Volumes

UTCs have a significant impact on congestion events in the day-ahead market and, as a result, contribute to differences between day-ahead and real-time congestion events. The greater the volume of UTCs, the greater the number of congestion events in the day-ahead market and the greater the differences between the day-ahead and real-time congestion events.

On August 29, 2014, FERC issued an order which created an obligation for UTCs to pay any uplift determined to be appropriate based on Commission review, effective September 8, 2014.[27]

As a result of the potential 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. (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..."[28]

On February 20, 2018, FERC issued an order limiting the eligible bidding points for up to congestion transactions to hubs, residual metered load and interfaces.[29] As a result, market participants reduced up to congestion trading effective February 22, 2018. UTC trading has increase since then.

Figure 11-6 shows that day-ahead congestion event hours decreased significantly after September 8, 2014, when UTC activity declined as a result of a FERC order, and increased after December 7, 2015, when UTC activity increased, as a result of a FERC order. Figure 11-6 also shows that day-ahead congestion event hours decreased again on February 22, 2018, when UTC activity declined, as a result of a FERC order.

27 148 FERC ¶ 61,144 (2014).
28 16 U.S.C. § 824e.
29 162 FERC ¶ 61,139 (2018).

In the first nine months of 2019, the average hourly cleared UTC MW decreased, compared to 2018. Day-ahead congestion event hours decreased by 25.9 percent from 105,437 congestion event hours in the first nine months of 2018 to 78,155 congestion event hours in the first nine months of 2019 (Table 11-22). The majority (103.1 percent) of decrease in day-ahead congestion event hours in the first nine months of 2019 occurred in January and February.

Figure 11-6 shows the daily day-ahead and real-time congestion event hours for January 1, 2014 through September 30, 2019.

Figure 11-6 Daily congestion event hours: January 2014 through September 2019

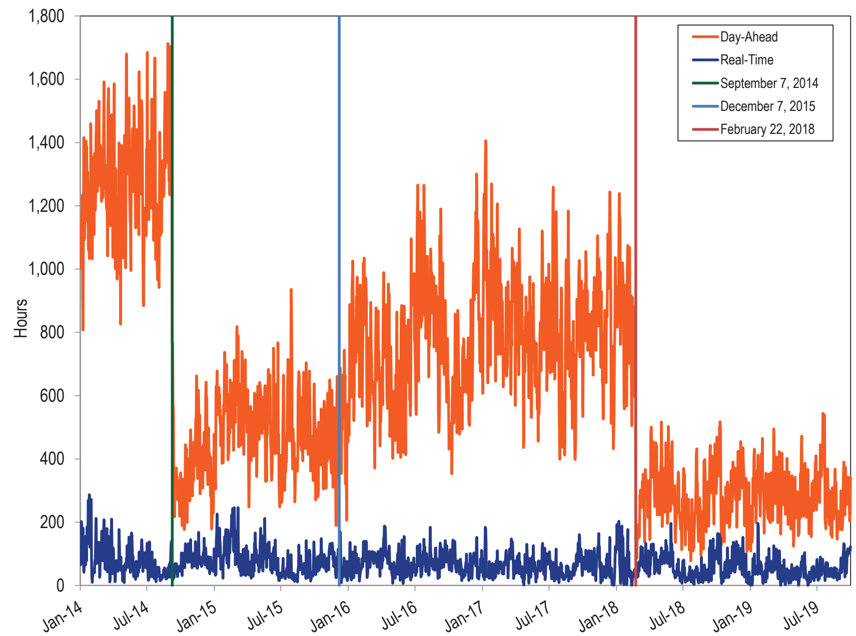
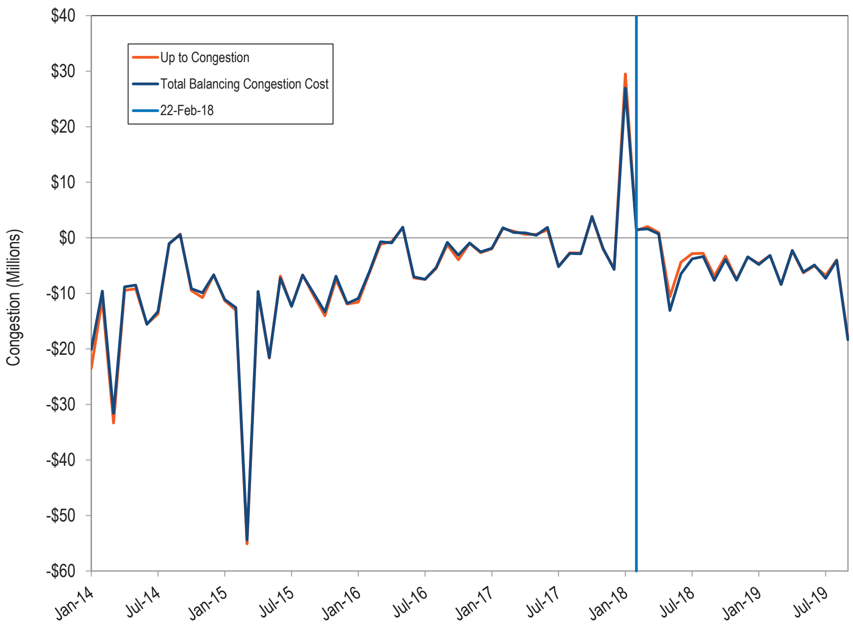


Figure 11-7 shows the change in up to congestion balancing explicit congestion costs from January 1, 2014, through December 31, 2018. Within this period, Figure 11-7 shows the highest monthly payment ($55.1 million) in balancing congestion credits to up to congestion transactions occurred in March 2015 and the highest monthly charge ($29.5 million) in balancing congestion charges occurred in January 2018. Figure 11-7 shows that UTCs are a significant net contributor to balancing congestion in PJM. As shown in Figure 11-7, UTCs are generally paid balancing congestion, which takes the form of negative balancing congestion charges being allocated to UTC positions.

Figure 11-7 Monthly balancing congestion cost incurred by up to congestion: January 2014 through September 2019



Balancing congestion is caused by settling real-time deviations from day-ahead positions at real-time prices. Whether balancing congestion is positive or negative depends on the differences that exist between the day-ahead and real-time market models including modeled constraints, transfer capability (line limits) of the modeled constraints, the location of deviations and deviations in flows caused by these modeling differences and the differences in day-ahead and real-time LMPs that result from the interaction among these elements. For example, one source of negative balancing congestion is that the PJM system has less transmission transfer capability in the real-time market than in the day-ahead market. Due to the complexity of the day-ahead unit commitment process, PJM only enforces or models a subset of its physical transmission limits in the day-ahead market. Transmission constraints not modeled in the day-ahead market have effectively unlimited transfer capability in the day-ahead market model. The reduction in transmission capability between the day-ahead and real-time market between high and low cost generation sources, holding load constant, requires the use of more high cost generation and the use of less low cost generation to serve load, which means a decrease in congestion. This results in a net increase in generation credits relative to what was incurred in the day-ahead and, holding load constant, no change in load charges. The increase in generation credits relative to load charges causes negative balancing congestion.

Due to the nature of the modeling differences between the day-ahead and real-time market, PJM has more system flow capability in the day-ahead market than it does in the real-time market. As a day-ahead spread bid, UTCs are uniquely suited to take advantage of and profit from LMP differences caused by market and transmission modeling differences between the day-ahead and real-time market. UTCs generate flows in the day ahead market that are not physically possible in the real-time market, clearing between source and sink points with little or no price differences in the day-ahead market, and settling the resulting deviations at higher real-time prices in the real-time market. The general result is negative balancing congestion is caused by and paid to UTCs.

Table 11-30 provides an example of how UTCs can interact with, and profit from, differences in day-ahead and real-time transmission limits and generate negative balancing congestion. In the example, Bus A and Bus B are linked by a transmission line. In the day-ahead market the transmission limit is modeled as 9,999 MW (no limit is enforced in the day-ahead market solution). In the real-time market the physical limit between bus A and bus B is 50 MW. Generation at A has a price of $1.00 and Generation at B has a price of $6. There is 100 MW of load at bus A and 100 MW of load at bus B. There is a

UTC of 200 MW that will source at bus A and sink at bus B if the spread in the prices between A and B is less than $1.

As a result of the fact that the transmission capability between A and B is unlimited in the day-ahead market, all of load at A and B can be met with the $1 generation at bus A. The constraint between A and B does not bind in day-ahead so the price at A and B is $1. The price spread between bus A and bus B is zero, which is less than the UTC spread requirement of $1, so the UTC clears. The UTC causes a 200 MW injection at A and 200 MW withdrawal at B, creating 200 MW of flow between bus A and bus B. The 300 MW of combined flow from generation at A and UTC injections at A to the load and UTC sink at B does not exceed the DA modeled limit between A and B. This means that all 200 MW of the UTC injection at A and 200 MW of withdrawal at B can clear without forcing a price spread between A and B. Total day-ahead congestion, which is the difference between congestion charges and credits, is zero. There is no price difference between the two nodes and every MW of injection and every MW of withdrawal at bus A and bus B settles at the same price.

In the real-time market, the transmission line between bus A and bus B has a 50 MW limit. The UTC does not physically exist in the real-time market and therefore generates deviations at Bus A (-200 MW) and at Bus B (+200 MW). The load at A (100 MW) and B (100 MW) does not change, so there are no load deviations. With only 50 MW of transmission capability between A and B, the generation at A cannot be used to meet total load on the system. Generation from A meets the load at A (100 MW) and can supply only 50 MW of the 100 MW of load at B. Due to the binding constraint between A and B, the remaining 50 MW of load at B must be met with local generation at B at a cost of $6 and the price at A remains $1.

The reduction in transmission capability between A and B requires a 50 MW reduction in relatively inexpensive $1 generation at A and the use of 50 MW of relatively expensive $6 generation at B. The UTC must settle its deviation MW (-200 MW at A and +200MW at B) at the real-time price of $1 at A and $6 at B. The UTC pays $200 to settle its position at A and is paid $1,200 to settle its position at B. The resulting net payment to the UTC is $1,000 in balancing credits.

Table 11-30 shows the balancing credits and charges generated by the real-time deviations by source in the example. Total congestion (day-ahead plus balancing congestion) in this example is negative $1,250, with net total congestion credits (payments) to generation and the UTC exceeding the total charges collected from load. The negative balance owed to generation and the UTC is billed to the load as negative balancing congestion, under the recent FERC order.

Due to the modeling differences, the UTC did not contribute to price convergence between the day-ahead and real-time market and did not improve efficiency in system dispatch or commitment. The UTC did significantly increase the cost of energy to the load, with load paying the UTC $1,000 in negative balancing, over and above the costs of generation that was needed to meet realized load at bus A and bus B.

Table 11-30 Example of UTC causing and profiting from negative balancing congestion

Prices	Bus A	Transfer Capability (Line Limit MW)	Bus B	
LMP DA	$1.00	9,999	$1.00	
LMP RT	$1.00	50	$6.00	
Day-Ahead MW	Bus A		Bus B	Total MW
Day-Ahead Generation	200		0	200
Day-Ahead Load	(100)		(100)	(200)
Day-Ahead UTC (+/-)	200		(200)	0
Total MW	300		(300)	0
Day-Ahead Credits and Charges	Bus A		Bus B	Total Day-Ahead Congestion
Total DA Gen Credits	$200.00		$0.00	
Total DA Load Charges	$100.00		$100.00	
Total DA UTC Credits	$200.00		($200.00)	
Total DA Credits	$300.00		($300.00)	$0.00
Total Day-Ahead Congestion (Charges - Credits)				$0.00
Balancing Deviation MW	Bus A		Bus B	Total Deviations
RT GEN Deviations	(50)		50	
RT Load Deviations	0		0	
DA UTC (+/-)	(200)		200	
Total Deviations	(250)		250	0
Balancing Credits and Charges	Bus A		Bus B	Balancing Congestion Credits
Total BA Gen Credits	($50.00)		$300.00	$250.00
Total BA Load Charges	$0.00		$0.00	
Total BA UTC Credits	($200.00)		$1,200.00	$1,000.00
Total BA Credits	($250.00)		$1,500.00	$1,250.00
Total Balancing Congestion (Charges - Credits)				($1,250.00)

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 withdrawal loss charges minus injection loss credits, plus explicit loss charges, 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 implicit marginal loss charges plus explicit marginal loss charges plus net inadvertent loss charges. Implicit marginal loss charges equal withdrawal loss charges minus injection 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.[30] 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.[31] 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 withdrawal loss charges and injection loss 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. Withdrawal loss charges, when positive, measure the total loss payment by a PJM member and when negative, measure the total loss credit paid to a PJM member. Injection loss credits, when negative, measure the total loss payment by a PJM member and when positive, measure the total loss credit paid to a PJM member.

The loss component of LMP is calculated with respect to the system marginal price (SMP). An increase in generation at a bus that results in an increase in losses will cause the marginal loss component of that bus to be negative. If the increase in generation at the bus results in a decrease of system losses, then the marginal loss component is positive.

30 PJM Operating Agreement Schedule 1 §3.7.
31 Id.

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.[32]

- **Implicit Day-Ahead Withdrawal Loss Charges.** Implicit day-ahead withdrawal loss charges are calculated for all cleared demand, decrement bids and day-ahead energy market sale transactions. Implicit day-ahead withdrawal loss charges are calculated using MW and the load bus MLMP, the decrement bid MLMP or the MLMP at the source of the sale transaction.
- **Implicit Day-Ahead Injection Loss Credits.** Implicit day-ahead injection loss credits are calculated for all cleared generation and increment offers and day-ahead energy market purchase transactions. Implicit day-ahead injection 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.
- **Implicit Balancing Withdrawal Loss Charges.** Implicit balancing withdrawal loss charges 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. Implicit balancing withdrawal loss charges are calculated using MW deviations and the real-time MLMP for each bus where a deviation exists.
- **Implicit Balancing Injection Loss Credits.** Implicit balancing injection 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. Implicit balancing injection loss credits are calculated using MW deviations and the real-time MLMP for each bus where a deviation exists.
- **Explicit Loss Charges.** Explicit loss charges are the net loss costs associated with point to point energy transactions, including UTCs. These costs equal the product of the transacted MW and MLMP differences between sources (origins) and sinks (destinations) in the Day-Ahead Energy Market. Balancing energy market explicit loss costs equal the product of the differences between the real-time and day-ahead transacted MW and the differences between the real-time MLMP at the transactions' sources and sinks.
- **Inadvertent Loss Charges.** Inadvertent loss charges are the net loss charges resulting from the differences between the net actual energy flow and the net scheduled energy flow into or out of the PJM control area each hour. This inadvertent interchange of energy may be positive or negative, where positive interchange typically results in a charge while negative interchange typically results in a credit. Inadvertent loss charges are common costs, not directly attributable to specific participants, that are distributed on a load plus export ratio basis.[33]

Total Marginal Loss Cost

The total marginal loss cost in PJM for the first nine months of 2019 was $502.7 million, which was comprised of implicit withdrawal loss charges of -$35.5 million, implicit injection loss credits of -$550.1 million, explicit loss

32 See PJM. "Manual 28: Operating Agreement Accounting," Rev. 882(July 25, 2019).

33 PJM Operating Agreement Schedule 1 §3.7.

charges of -$12.0 million and inadvertent loss charges of $0.0 million (Table 11-32).

Monthly marginal loss costs in the first nine months of 2019 ranged from $38.8 million in April to $86.5 million in January. Total marginal loss surplus decreased in the first nine months of 2019 by $93.2 million or 36.5 percent from $255.3 million in the first nine months of 2018 to $162.1 million in the first nine months of 2019.

Table 11-31 shows the total marginal loss component costs and the total PJM billing for January through September, 2008 through 2019.

Table 11-31 Total PJM loss component costs (Dollars (Millions)): January through September, 2008 through 2019[34]

(Jan - Sep)	Loss Costs	Percent Change	Total PJM Billing	Percent of PJM Billing
2008	$2,049	NA	$26,979	7.6%
2009	$992	(51.6%)	$19,927	5.0%
2010	$1,259	26.9%	$26,249	4.8%
2011	$1,153	(8.5%)	$28,836	4.0%
2012	$758	(34.3%)	$22,119	3.4%
2013	$797	5.2%	$25,153	3.2%
2014	$1,243	56.0%	$40,770	3.0%
2015	$830	(33.3%)	$33,710	2.5%
2016	$542	(34.7%)	$29,490	1.8%
2017	$501	(7.5%)	$29,510	1.7%
2018	$756	50.9%	$37,950	2.0%
2019	$503	(33.5%)	$29,980	1.7%

Table 11-32 shows PJM total marginal loss costs by accounting category for January through September, 2008 through 2019. Table 11-33 shows PJM total marginal loss costs by accounting category by market for January through September, 2008 through 2019.

Table 11-32 Total PJM marginal loss costs by accounting category (Dollars (Millions)): January through September, 2008 through 2019

	Marginal Loss Costs (Millions)				
(Jan - Sep)	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Inadvertent Charges	Total
2008	($210.3)	($2,185.9)	$73.3	$0.0	$2,048.9
2009	($62.0)	($1,028.3)	$26.1	$0.0	$992.4
2010	($73.8)	($1,301.6)	$31.5	($0.0)	$1,259.3
2011	($138.8)	($1,277.7)	$13.7	$0.0	$1,152.6
2012	($17.3)	($790.0)	($15.1)	$0.0	$757.6
2013	($3.3)	($834.4)	($34.1)	($0.0)	$797.0
2014	($47.6)	($1,343.7)	($52.9)	$0.0	$1,243.1
2015	($26.1)	($872.8)	($16.9)	$0.0	$829.8
2016	($41.7)	($605.4)	($21.8)	($0.0)	$541.9
2017	($38.6)	($568.1)	($28.4)	$0.0	$501.0
2018	($32.6)	($797.3)	($8.9)	$0.0	$755.8
2019	($35.5)	($550.1)	($12.0)	$0.0	$502.7

34 The loss costs include net inadvertent charges.

Table 11-33 Total PJM marginal loss costs by accounting category by market (Dollars (Millions)): January through September, 2008 through 2019

	Marginal Loss Costs (Millions)									
	Day-Ahead				Balancing					
(Jan - Sep)	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Inadvertent Charges	Grand Total
2008	($132.3)	($2,133.4)	$100.8	$2,101.8	($77.9)	($52.5)	($27.4)	($52.9)	$0.0	$2,048.9
2009	($65.9)	($1,025.7)	$53.2	$1,013.0	$3.9	($2.6)	($27.1)	($20.6)	$0.0	$992.4
2010	($94.4)	($1,307.1)	$61.5	$1,274.2	$20.6	$5.6	($30.0)	($14.9)	($0.0)	$1,259.3
2011	($174.3)	($1,313.6)	$51.7	$1,191.1	$35.5	$36.0	($38.0)	($38.5)	$0.0	$1,152.6
2012	($42.2)	($805.6)	$12.7	$776.0	$24.9	$15.6	($27.8)	($18.5)	$0.0	$757.6
2013	($30.3)	($857.9)	$44.0	$871.6	$27.0	$23.5	($78.1)	($74.6)	($0.0)	$797.0
2014	($95.5)	($1,380.8)	$62.7	$1,347.9	$47.9	$37.1	($115.6)	($104.8)	$0.0	$1,243.1
2015	($47.0)	($883.1)	$24.7	$860.8	$20.9	$10.3	($41.6)	($31.0)	$0.0	$829.8
2016	($48.4)	($606.0)	$37.8	$595.4	$6.6	$0.5	($59.5)	($53.4)	($0.0)	$541.9
2017	($45.9)	($568.9)	$43.1	$566.0	$7.3	$0.8	($71.5)	($65.0)	$0.0	$501.0
2018	($38.4)	($789.6)	$28.5	$779.7	$5.8	($7.7)	($37.4)	($23.9)	$0.0	$755.8
2019	($37.4)	($547.8)	$32.2	$542.6	$1.9	($2.3)	($44.2)	($39.9)	$0.0	$502.7

Table 11-34 and Table 11-35 show the total loss costs for each transaction type in the first nine months of 2019 and 2018. In the first nine months of 2019, generation paid loss costs of $529.5 million, 105.3 percent of total loss costs. In the first nine months of 2018, generation paid loss costs of $762.7 million, 100.9 percent of total loss costs.

Virtual transaction loss costs, when positive, measure the total loss costs to virtual transactions and when negative, measure the total loss credits to virtual transaction. In the first nine months of 2019, DECs were paid $3.9 million in loss credits in the day-ahead market, paid $5.2 million in loss charges in the balancing energy market and paid $1.2 million in total loss payments. In the first nine months of 2019, INCs paid $7.8 million in loss charges in the day-ahead market, were paid $9.2 million in loss credits in the balancing energy market and were paid $1.4 million in total loss credits. In the first nine months of 2019, up to congestion paid $32.5 million in loss charges in the day-ahead market, were paid $44.2 million in loss credits in the balancing energy market and received $11.7 million in total loss credits.

Table 11-34 Total PJM loss costs by transaction type by market (Dollars (Millions)): January through September, 2019

	Marginal Loss Costs (Millions)									
	Day-Ahead				Balancing					
Transaction Type	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Inadvertent Charges	Grand Total
DEC	($3.9)	$0.0	$0.0	($3.9)	$5.2	$0.0	$0.0	$5.2	$0.0	$1.2
Demand	($4.6)	$0.0	$0.0	($4.6)	$4.9	$0.0	$0.0	$4.9	$0.0	$0.4
Demand Response	($0.0)	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Explicit Congestion and Loss Only	$0.0	$0.0	($0.4)	($0.4)	$0.0	$0.0	($0.0)	($0.0)	$0.0	($0.5)
Export	($13.2)	$0.0	($0.0)	($13.2)	($7.5)	$0.0	$0.3	($7.2)	$0.0	($20.4)
Generation	$0.0	($523.1)	$0.0	$523.1	$0.0	($6.4)	$0.0	$6.4	$0.0	$529.5
Import	$0.0	($1.4)	$0.0	$1.4	$0.0	($4.4)	($0.1)	$4.4	$0.0	$5.8
INC	$0.0	($7.8)	$0.0	$7.8	$0.0	$9.2	$0.0	($9.2)	$0.0	($1.4)
Internal Bilateral	($15.7)	($15.5)	$0.1	($0.0)	($0.7)	($0.7)	$0.0	($0.0)	$0.0	($0.0)
Up to Congestion	$0.0	$0.0	$32.5	$32.5	$0.0	$0.0	($44.2)	($44.2)	$0.0	($11.7)
Wheel In	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.2)	($0.2)	$0.0	($0.2)
Total	($37.4)	($547.8)	$32.2	$542.6	$1.9	($2.3)	($44.2)	($39.9)	$0.0	$502.7

Table 11-35 Total PJM loss costs by transaction type by market (Dollars (Millions)): January through September, 2018

	Marginal Loss Costs (Millions)									
	Day-Ahead				Balancing					
Transaction Type	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Inadvertent Charges	Grand Total
DEC	($1.4)	$0.0	$0.0	($1.4)	$1.7	$0.0	$0.0	$1.7	$0.0	$0.3
Demand	($5.6)	$0.0	$0.0	($5.6)	$10.4	$0.0	$0.0	$10.4	$0.0	$4.9
Demand Response	($0.0)	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Explicit Congestion and Loss Only	$0.0	$0.0	($0.4)	($0.4)	$0.0	$0.0	($0.1)	($0.1)	$0.0	($0.5)
Export	($18.0)	$0.0	($0.1)	($18.1)	($6.9)	$0.0	$0.2	($6.7)	$0.0	($24.8)
Generation	$0.0	($763.7)	$0.0	$763.7	$0.0	$0.9	$0.0	($0.9)	$0.0	$762.7
Grandfathered Overuse	$0.0	$0.0	($0.4)	($0.4)	$0.0	$0.0	($0.1)	($0.1)	$0.0	($0.5)
Import	$0.0	($2.7)	$0.0	$2.7	$0.0	($20.4)	($0.4)	$20.0	$0.0	$22.7
INC	$0.0	($10.2)	$0.0	$10.2	$0.0	$11.3	$0.0	($11.3)	$0.0	($1.0)
Internal Bilateral	($13.3)	($13.0)	$0.4	$0.0	$0.5	$0.5	($0.0)	($0.0)	$0.0	($0.0)
Up to Congestion	$0.0	$0.0	$29.0	$29.0	$0.0	$0.0	($37.0)	($37.0)	$0.0	($8.0)
Wheel In	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.1)	($0.1)	$0.0	($0.1)
Total	($38.4)	($789.6)	$28.5	$779.7	$5.8	($7.7)	($37.4)	($23.9)	$0.0	$755.8

Monthly Marginal Loss Costs

Table 11-36 shows a monthly summary of marginal loss costs by market type for January 2018 through September 2019.

Table 11-36 Monthly marginal loss costs by market (Millions): January 2018 through September 2019

Marginal Loss Costs (Millions)								
	2018				2019			
	Day-Ahead	Balancing	Inadvertent Charges	Total	Day-Ahead	Balancing	Inadvertent Charges	Total
Jan	$227.1	($4.3)	$0.0	$222.8	$92.3	($5.8)	$0.0	$86.5
Feb	$52.7	($3.2)	$0.0	$49.5	$57.2	($3.3)	$0.0	$53.9
Mar	$66.0	($0.0)	$0.0	$66.0	$70.5	($7.0)	$0.0	$63.5
Apr	$56.3	($0.9)	$0.0	$55.4	$42.7	($3.9)	$0.0	$38.8
May	$64.5	($1.1)	$0.0	$63.4	$45.2	($3.9)	($0.0)	$41.3
Jun	$66.5	($3.4)	($0.0)	$63.2	$43.9	($2.8)	($0.0)	$41.1
Jul	$85.7	($3.5)	$0.0	$82.2	$77.3	($3.5)	$0.0	$73.8
Aug	$87.7	($4.6)	$0.0	$83.1	$60.6	($4.4)	($0.0)	$56.3
Sep	$73.2	($2.9)	$0.0	$70.2	$53.0	($5.4)	($0.0)	$47.6
Oct	$65.0	($3.0)	($0.0)	$62.1				
Nov	$77.6	($5.4)	($0.0)	$72.2				
Dec	$73.7	($4.8)	($0.0)	$68.9				
Total	$996.0	($37.1)	$0.0	$959.0	$542.6	($39.9)	$0.0	$502.7

Figure 11-8 shows PJM monthly marginal loss costs for January 2008 through September 2019.

Figure 11-8 PJM monthly marginal loss costs (Dollars (Millions)): January 2008 through September 2019

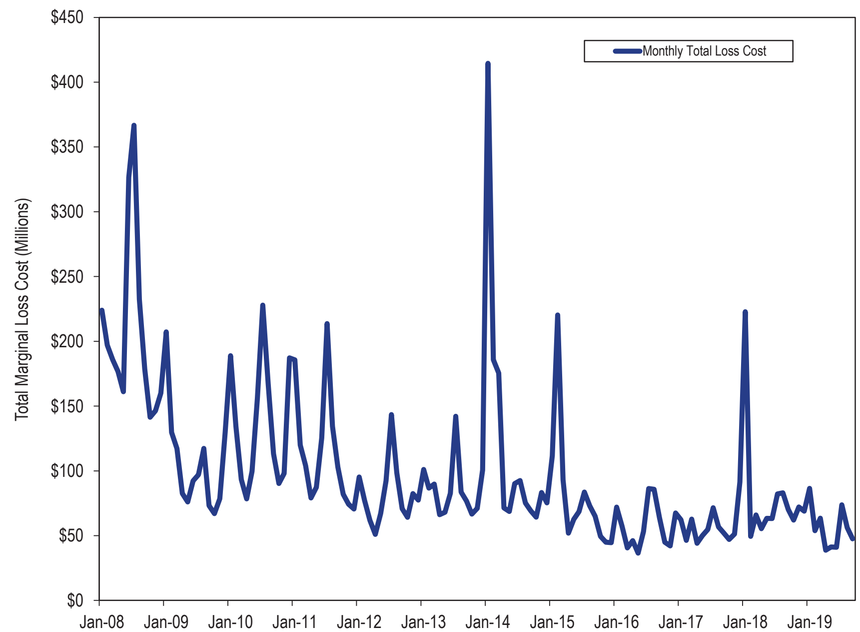


Table 11-37 shows the monthly total loss costs for each virtual transaction type in the first nine months of 2019 and year of 2018.

Table 11-37 Monthly PJM loss costs by virtual transaction type and by market (Dollars (Millions)): January 2018 through September 2019

		Marginal Loss Costs (Millions)									
		DEC			INC			Up to Congestion			
Year		Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Grand Total
2018	Jan	$0.2	($0.5)	($0.3)	$2.1	($2.4)	($0.2)	$6.6	($8.5)	($1.9)	($2.5)
	Feb	($0.2)	$0.0	($0.1)	$0.5	($0.5)	($0.1)	$2.5	($3.9)	($1.4)	($1.6)
	Mar	($0.0)	$0.2	$0.2	$1.3	($1.4)	($0.1)	$1.2	($1.5)	($0.3)	($0.2)
	Apr	($0.1)	$0.2	$0.1	$1.1	($1.2)	($0.2)	$1.5	($2.1)	($0.6)	($0.7)
	May	($0.5)	$0.5	$0.0	$1.1	($1.2)	($0.1)	$2.2	($2.8)	($0.6)	($0.7)
	Jun	($0.3)	$0.5	$0.2	$1.1	($1.1)	($0.0)	$3.0	($3.5)	($0.4)	($0.3)
	Jul	($0.1)	$0.2	$0.1	$0.8	($0.8)	($0.0)	$3.8	($4.4)	($0.7)	($0.6)
	Aug	($0.2)	$0.1	($0.1)	$1.0	($1.1)	($0.1)	$4.4	($5.8)	($1.3)	($1.5)
	Sep	($0.3)	$0.5	$0.3	$1.2	($1.4)	($0.1)	$3.8	($4.6)	($0.7)	($0.6)
	Oct	($0.3)	$0.4	$0.1	$1.2	($1.3)	($0.1)	$3.3	($4.0)	($0.7)	($0.6)
	Nov	($0.0)	$0.2	$0.1	$1.5	($1.6)	($0.1)	$5.4	($6.5)	($1.1)	($1.1)
	Dec	($0.2)	$0.4	$0.1	$0.7	($0.9)	($0.2)	$4.6	($5.8)	($1.3)	($1.3)
	Total	($2.0)	$2.7	$0.7	$13.6	($15.0)	($1.4)	$42.3	($53.3)	($11.0)	($11.8)
2019	Jan	($0.2)	$0.4	$0.2	$1.1	($1.4)	($0.3)	$5.4	($6.5)	($1.1)	($1.2)
	Feb	($0.4)	$0.3	($0.1)	$0.8	($1.0)	($0.3)	$3.1	($4.4)	($1.3)	($1.6)
	Mar	($0.2)	$0.2	$0.0	$1.4	($1.5)	($0.1)	$6.0	($6.9)	($0.9)	($1.0)
	Apr	($0.3)	$0.3	$0.0	$0.7	($0.8)	($0.1)	$3.3	($4.1)	($0.8)	($0.9)
	May	($0.7)	$0.9	$0.2	$0.9	($0.8)	$0.0	$3.2	($4.2)	($0.9)	($0.7)
	Jun	($0.5)	$0.7	$0.2	$0.6	($0.7)	($0.1)	$1.8	($3.4)	($1.6)	($1.5)
	Jul	($0.7)	$1.0	$0.3	$0.9	($1.1)	($0.2)	$3.3	($4.8)	($1.4)	($1.4)
	Aug	($0.5)	$0.5	$0.0	$0.6	($0.6)	($0.0)	$3.2	($4.5)	($1.3)	($1.3)
	Sep	($0.5)	$0.9	$0.4	$0.9	($1.2)	($0.4)	$3.1	($5.5)	($2.3)	($2.3)
	Total	($3.9)	$5.2	$1.2	$7.8	($9.2)	($1.4)	$32.5	($44.2)	($11.7)	($11.9)

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 charges (implicit withdrawal charges minus implicit injection credits) plus net inadvertent energy charges. Total marginal loss costs are equal to the net implicit marginal loss charges (implicit withdrawal loss charges less implicit injection loss credits) plus net explicit loss charges 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 injection credits than withdrawal charges 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 11-38 shows the total energy costs, the total marginal loss costs collected, the net residual market adjustments and total marginal loss surplus redistributed for January through September, 2008 through 2019. The total marginal loss surplus decreased $93.2 million in the first nine months of 2019 from the first nine months of 2018.

Table 11-38 Marginal loss surplus (Dollars (Millions)): January through September, 2008 through 2019[35]

Marginal Loss Surplus (Millions)						
			Net Residual Market Adjustment			
(Jan - Sep)	Energy Costs	Marginal Loss Costs	Known Day-Ahead Error	Day-Ahead Loss MW Congestion	Balancing Loss MW Congestion	Total
2008	($976.0)	$2,048.9	$0.0	$0.0	$0.0	$1,073.0
2009	($484.6)	$992.4	($0.0)	($0.4)	($0.1)	$508.3
2010	($618.6)	$1,259.3	$0.0	($0.6)	($0.1)	$641.5
2011	($651.3)	$1,152.6	$0.1	$1.3	($0.0)	$500.1
2012	($442.6)	$757.6	$0.1	($0.7)	$0.0	$315.7
2013	($527.2)	$797.0	$0.0	$1.7	$0.0	$268.0
2014	($833.9)	$1,243.1	($0.0)	$5.1	$0.1	$404.1
2015	($536.5)	$829.8	($0.3)	$4.7	($0.1)	$288.3
2016	($358.3)	$541.9	$0.0	$2.8	($0.2)	$181.0
2017	($344.0)	$501.0	$0.0	$0.7	($0.1)	$156.5
2018	($498.7)	$755.8	($0.0)	$1.9	($0.1)	$255.3
2019	($339.3)	$502.7	($0.0)	$1.3	($0.1)	$162.1

Energy Costs

Energy Accounting

The energy component of LMP is the system reference bus LMP, also called the system marginal price (SMP). The energy cost is based on the day-ahead and real-time energy components of LMP. Total energy costs, analogous to total congestion costs or total loss costs, are equal to the withdrawal energy charges minus injection energy credits, 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 the first nine months of 2019 was -$339.3 million, which was comprised of implicit withdrawal energy charges of $23,696.4 million, implicit injection energy credits of $24,035.9 million, explicit energy charges of $0.0 million and inadvertent energy charges of $0.2 million. The monthly energy costs for the first nine months of 2019 ranged from -$59.3 million in January to -$25.7 million in April.

Table 11-39 shows total energy component costs and total PJM billing, for January through September, 2008 through 2019.

Table 11-39 Total PJM energy costs (Dollars (Millions)): January through September, 2008 through 2019[36]

(Jan - Sep)	Energy Costs	Percent Change	Total PJM Billing	Percent of PJM Billing
2008	($976)	NA	$26,979	(3.6%)
2009	($485)	(50.3%)	$19,927	(2.4%)
2010	($619)	27.6%	$26,249	(2.4%)
2011	($651)	5.3%	$28,836	(2.3%)
2012	($443)	(32.0%)	$22,119	(2.0%)
2013	($527)	19.1%	$25,153	(2.1%)
2014	($834)	58.2%	$40,770	(2.0%)
2015	($537)	(35.7%)	$33,710	(1.6%)
2016	($358)	(33.2%)	$29,490	(1.2%)
2017	($344)	(4.0%)	$29,510	(1.2%)
2018	($499)	45.0%	$37,950	(1.3%)
2019	($339)	(32.0%)	$29,980	(1.1%)

Energy costs for January through September, 2008 through 2019 are shown in Table 11-40 and Table 11-41. Table 11-40 shows PJM energy costs by accounting category and Table 11-41 shows PJM energy costs by market category.

35 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.

36 The energy costs include net inadvertent charges.

Table 11-40 Total PJM energy costs by accounting category (Dollars (Millions)): January through September, 2008 through 2019

	Energy Costs (Millions)				
(Jan - Sep)	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Inadvertent Charges	Total
2008	$91,391.9	$92,368.9	$0.0	$1.0	($976.0)
2009	$32,472.4	$32,960.8	$0.0	$3.8	($484.6)
2010	$41,562.3	$42,169.5	$0.0	($11.4)	($618.6)
2011	$38,515.2	$39,193.0	$0.0	$26.5	($651.3)
2012	$28,303.5	$28,754.0	$0.0	$7.9	($442.6)
2013	$32,756.8	$33,279.9	$0.0	($4.2)	($527.2)
2014	$50,415.3	$51,245.6	$0.0	($3.6)	($833.9)
2015	$33,772.7	$34,311.9	$0.0	$2.6	($536.5)
2016	$25,858.3	$26,213.7	$0.0	($2.9)	($358.3)
2017	$26,082.1	$26,430.6	$0.0	$4.5	($344.0)
2018	$33,870.5	$34,374.8	$0.0	$5.7	($498.7)
2019	$23,696.4	$24,035.9	$0.0	$0.2	($339.3)

Table 11-41 Total PJM energy costs by market category (Dollars (Millions)): January through September, 2008 through 2019

	Energy Costs (Millions)									
	Day-Ahead				Balancing					
(Jan - Sep)	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Inadvertent Charges	Grand Total
2008	$67,568.7	$68,653.8	$0.0	($1,085.1)	$23,823.2	$23,715.1	$0.0	$108.1	$1.0	($976.0)
2009	$32,628.0	$33,162.4	$0.0	($534.4)	($155.6)	($201.6)	$0.0	$45.9	$3.8	($484.6)
2010	$41,665.6	$42,289.1	$0.0	($623.5)	($103.4)	($119.7)	$0.0	$16.3	($11.4)	($618.6)
2011	$38,908.1	$39,530.7	$0.0	($622.6)	($392.9)	($337.7)	$0.0	($55.3)	$26.5	($651.3)
2012	$28,423.3	$28,853.1	$0.0	($429.8)	($119.9)	($99.2)	$0.0	($20.7)	$7.9	($442.6)
2013	$32,797.0	$33,398.3	$0.0	($601.3)	($40.2)	($118.4)	$0.0	$78.2	($4.2)	($527.2)
2014	$50,428.5	$51,603.0	$0.0	($1,174.5)	($13.2)	($357.4)	$0.0	$344.2	($3.6)	($833.9)
2015	$33,910.7	$34,549.7	$0.0	($639.0)	($138.0)	($237.8)	$0.0	$99.8	$2.6	($536.5)
2016	$25,986.4	$26,469.9	$0.0	($483.5)	($128.1)	($256.2)	$0.0	$128.1	($2.9)	($358.3)
2017	$26,360.1	$26,844.5	$0.0	($484.4)	($278.0)	($413.9)	$0.0	$135.9	$4.5	($344.0)
2018	$33,957.1	$34,508.6	$0.0	($551.4)	($86.7)	($133.8)	$0.0	$47.1	$5.7	($498.7)
2019	$24,004.0	$24,411.6	$0.0	($407.6)	($307.7)	($375.7)	$0.0	$68.0	$0.2	($339.3)

Table 11-42 and Table 11-43 show the total energy costs for each transaction type in the first nine months of 2019 and 2018. In the first nine months of 2019, generation was paid $17,268.8 million and demand paid $16,283.8 million in net energy payment. In the first nine months of 2018, generation was paid $24,145.8 million and demand paid $23,355.8 million in net energy payment.

Table 11-42 Total PJM energy costs by transaction type by market (Dollars (Millions)): January through September, 2019

	Energy Costs (Millions)								
	Day-Ahead				Balancing				
Transaction Type	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Grand Total
DEC	$742.3	$0.0	$0.0	$742.3	($744.1)	$0.0	$0.0	($744.1)	($1.8)
Demand	$16,219.3	$0.0	$0.0	$16,219.3	$64.5	$0.0	$0.0	$64.5	$16,283.8
Demand Response	($0.6)	$0.0	$0.0	($0.6)	$0.6	$0.0	$0.0	$0.6	($0.0)
Export	$513.0	$0.0	$0.0	$513.0	$337.8	$0.0	$0.0	$337.8	$850.8
Generation	$0.0	$17,308.3	$0.0	($17,308.3)	$0.0	($39.5)	$0.0	$39.5	($17,268.8)
Import	$0.0	$59.5	$0.0	($59.5)	$0.0	$139.5	$0.0	($139.5)	($199.0)
INC	$0.0	$513.8	$0.0	($513.8)	$0.0	($509.2)	$0.0	$509.2	($4.6)
Internal Bilateral	$6,530.0	$6,530.0	$0.0	($0.0)	$17.8	$17.8	$0.0	($0.0)	($0.0)
Wheel In	$0.0	$0.0	$0.0	$0.0	$0.0	$15.7	$0.0	($15.7)	($15.7)
Wheel Out	$0.0	$0.0	$0.0	$0.0	$15.7	$0.0	$0.0	$15.7	$15.7
Total	$24,004.0	$24,411.6	$0.0	($407.6)	($307.7)	($375.7)	$0.0	$68.0	($339.5)

Table 11-43 Total PJM energy costs by transaction type by market (Dollars (Millions)): January through September, 2018

	Energy Costs (Millions)								
	Day-Ahead				Balancing				
Transaction Type	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Grand Total
DEC	$761.2	$0.0	$0.0	$761.2	($776.8)	$0.0	$0.0	($776.8)	($15.6)
Demand	$22,955.4	$0.0	$0.0	$22,955.4	$400.4	$0.0	$0.0	$400.4	$23,355.8
Demand Response	($0.9)	$0.0	$0.0	($0.9)	$0.9	$0.0	$0.0	$0.9	$0.0
Export	$638.3	$0.0	$0.0	$638.3	$271.5	$0.0	$0.0	$271.5	$909.8
Generation	$0.0	$24,176.1	$0.0	($24,176.1)	$0.0	($30.3)	$0.0	$30.3	($24,145.8)
Import	$0.0	$105.4	$0.0	($105.4)	$0.0	$503.0	$0.0	($503.0)	($608.4)
INC	$0.0	$623.2	$0.0	($623.2)	$0.0	($623.7)	$0.0	$623.7	$0.5
Internal Bilateral	$9,540.0	$9,540.0	$0.0	$0.0	$11.7	$11.7	$0.0	($0.0)	$0.0
Wheel In	$0.0	$0.0	$0.0	$0.0	$0.0	$7.6	$0.0	($7.6)	($7.6)
Wheel Out	$0.0	$0.0	$0.0	$0.0	$7.6	$0.0	$0.0	$7.6	$7.6
Total	$33,894.1	$34,444.6	$0.0	($550.5)	($84.7)	($131.7)	$0.0	$47.0	($503.5)

Monthly Energy Costs

Table 11-44 shows a monthly summary of energy costs by market type for January 2018 through September 2019. Total balancing energy costs in the first nine months of 2019 increased from the first nine months of 2018. Monthly total energy costs in the first nine months of 2019 ranged from -$59.3 million in January to -$25.7 million in April.

Table 11-44 Monthly energy costs by market type (Dollars (Millions)): January 2018 through September 2019

	Energy Costs (Millions)							
	2018				2019			
	Day-Ahead	Balancing	Inadvertent Charges	Total	Day-Ahead	Balancing	Inadvertent Charges	Total
Jan	($160.3)	$4.9	$4.6	($150.9)	($69.5)	$9.8	$0.4	($59.3)
Feb	($41.2)	$7.4	$0.1	($33.6)	($42.8)	$6.9	$0.5	($35.4)
Mar	($45.0)	$2.9	$0.1	($42.1)	($54.2)	$12.3	$0.2	($41.6)
Apr	($40.4)	$2.6	($0.0)	($37.8)	($34.2)	$8.1	$0.4	($25.7)
May	($46.5)	$5.4	$0.3	($40.8)	($34.5)	$6.6	($0.1)	($28.0)
Jun	($47.0)	$7.2	($0.1)	($39.9)	($32.8)	$4.2	($0.2)	($28.8)
Jul	($59.6)	$5.7	$0.5	($53.5)	($54.7)	$6.3	$0.1	($48.3)
Aug	($60.7)	$5.7	$0.3	($54.6)	($44.3)	$8.2	($0.6)	($36.7)
Sep	($50.8)	$5.3	($0.0)	($45.4)	($40.7)	$5.8	($0.5)	($35.4)
Oct	($47.2)	$4.5	($0.6)	($43.2)				
Nov	($57.2)	$9.8	($0.2)	($47.6)				
Dec	($55.2)	$8.4	($0.4)	($47.2)				
Total	($711.0)	$69.7	$4.6	($636.7)	($407.6)	$68.0	$0.2	($339.3)

Figure 11-9 shows PJM monthly energy costs for January 2008 through September 2019.

Figure 11-9 PJM monthly energy costs (Millions): January 2008 through September 2019

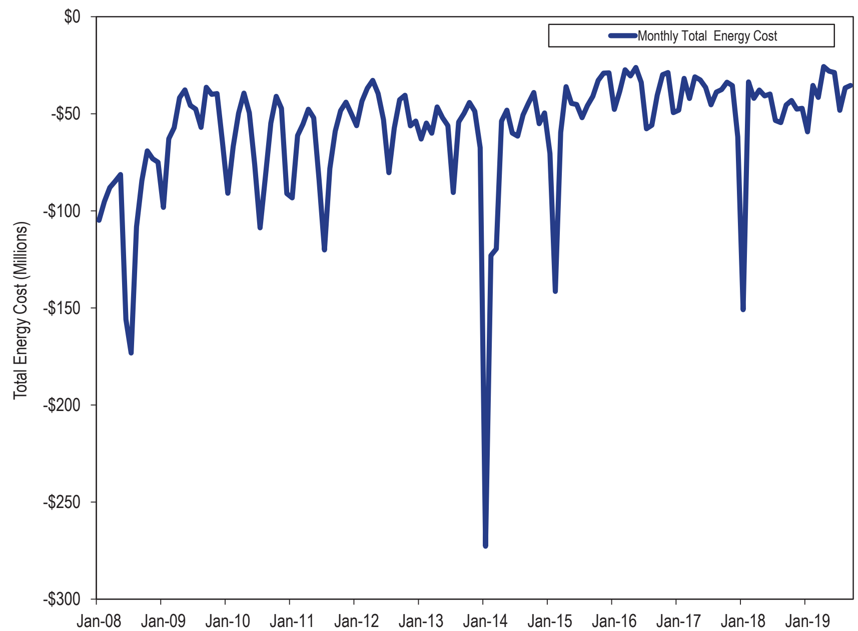


Table 11-45 shows the monthly total energy costs for each virtual transaction type in the first nine months of 2019 and year of 2018. In the first nine months of 2019, DECs paid $742.3 million in energy charges in the day-ahead market, were paid $744.1 million in energy credits in the balancing energy market and were paid $1.8 million in total energy credits. In the first nine months of 2019, INCs were paid $513.8 million in energy credits in the day-ahead market, paid $509.2 million in energy charges in the balancing market and were paid $4.6 million in total energy credits. In the first nine months of 2018, DECs paid $761.2 million in energy charges in the day-ahead market, were paid $776.8 million in energy credits in the balancing energy market and were paid $15.6 million in total energy credits. In the first nine months of 2018, INCs were paid $623.2 million in energy credits in the day-ahead market, paid $623.7 million in energy charges in the balancing energy market and paid $0.5 million in total energy costs.

Table 11-45 Monthly PJM energy costs by virtual transaction type and by market (Dollars (Millions)): January 2018 through September 2019

		Energy Costs (Millions)						
		DEC			INC			
Year		Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Grand Total
2018	Jan	$172.4	($183.2)	($10.8)	($136.9)	$138.3	$1.4	($9.4)
	Feb	$47.3	($45.1)	$2.2	($46.3)	$44.2	($2.1)	$0.1
	Mar	$64.7	($66.3)	($1.6)	($64.6)	$65.0	$0.4	($1.2)
	Apr	$66.2	($67.6)	($1.4)	($76.3)	$76.8	$0.5	($0.9)
	May	$86.7	($94.7)	($8.0)	($73.7)	$78.0	$4.3	($3.7)
	Jun	$77.1	($74.5)	$2.6	($53.8)	$52.7	($1.0)	$1.6
	Jul	$76.5	($71.6)	$4.9	($48.7)	$43.9	($4.7)	$0.2
	Aug	$75.8	($75.3)	$0.6	($57.4)	$57.4	($0.0)	$0.6
	Sep	$94.5	($98.5)	($4.0)	($65.6)	$67.4	$1.8	($2.2)
	Oct	$86.7	($82.4)	$4.3	($85.8)	$82.1	($3.7)	$0.6
	Nov	$83.1	($80.9)	$2.2	($88.9)	$86.6	($2.3)	($0.2)
	Dec	$79.0	($78.4)	$0.6	($60.8)	$59.2	($1.6)	($1.0)
	Total	$1,009.9	($1,018.5)	($8.6)	($858.6)	$851.6	($7.1)	($15.7)
2019	Jan	$104.4	($97.7)	$6.7	($71.7)	$67.1	($4.6)	$2.1
	Feb	$64.0	($66.8)	($2.8)	($52.5)	$54.0	$1.6	($1.2)
	Mar	$76.6	($77.4)	($0.8)	($66.7)	$65.4	($1.2)	($2.0)
	Apr	$60.3	($59.7)	$0.6	($59.0)	$58.5	($0.5)	$0.1
	May	$81.9	($79.1)	$2.9	($56.1)	$53.9	($2.2)	$0.6
	Jun	$75.8	($75.3)	$0.4	($47.1)	$46.5	($0.6)	($0.2)
	Jul	$105.6	($106.1)	($0.5)	($60.7)	$61.7	$1.0	$0.5
	Aug	$72.4	($69.7)	$2.7	($49.2)	$46.0	($3.2)	($0.5)
	Sep	$101.3	($112.4)	($11.0)	($50.9)	$56.2	$5.3	($5.7)
	Total	$742.3	($744.1)	($1.8)	($513.8)	$509.2	($4.6)	($6.4)

Generation and Transmission Planning[1]

Overview

Generation Interconnection Planning

Existing Generation Mix

- As of September 30, 2019, PJM had a total installed capacity of 198,501.1 MW, of which 54,856.6 MW (27.6 percent) are coal fired steam units, 48,641.6 MW (24.5 percent) are combined cycle units and 34,257.6 MW (17.3 percent) are nuclear units. This measure of installed capacity 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.
- The AEP Zone has the most total installed capacity of any PJM zone. Of the 198,501.1 MW of PJM total installed capacity, 30,843.0 MW (15.5 percent) are in the AEP Zone, of which 13,927.8 MW (45.2 percent) are coal fired steam units, 6,990.0 MW (22.7 percent) are combined cycle units and 2,071.0 MW (6.7 percent) are nuclear units.
- Pennsylvania has the most total installed capacity of any PJM state. Of the 198,501.1 MW of installed capacity, 46,985.4 MW (23.7 percent) are in Pennsylvania, of which 9,324.4 MW (19.8 percent) are coal fired steam units, 16,071.5 MW (34.2 percent) are combined cycle units and 9,648.8 MW (20.5 percent) are nuclear units.
- Of the 198,501.1 MW of installed capacity, 73,586.0 MW (37.1 percent) are from units older than 40 years, of which 38,867.2 MW (52.8 percent) are coal fired steam units, 532.0 MW (0.7 percent) are combined cycle units and 16,044.9 MW (21.8 percent) are nuclear units.

1 Totals presented in this section include corrections to historical data and may not match totals presented in previous reports.

Generation Retirements[2]

- There are 42,955.8 MW of generation that have been, or are planned to be, retired between 2011 and 2022, of which 31,039.2 MW (72.3 percent) are coal fired steam units. Coal unit retirements are primarily a result of the inability of coal units to compete with efficient combined cycle units burning low cost gas.
- In the first nine months of 2019, 4,249.0 MW of generation retired. The largest generators that retired in the first nine months of 2019 were the two 830.0 MW Mansfield coal fired steam units owned by FirstEnergy Corporation and located in the American Transmission Systems Inc. (ATSI) Zone. Of the 4,249.0 MW of generation that retired, 1,660.0 MW (39.1 percent) were located in the ATSI Zone.
- As of September 30, 2019, there are 7,335.7 MW of generation that have requested retirement after September 30, 2019, of which 1,507.0 MW (20.5 percent) are located in the ATSI Zone. Of the ATSI generation requesting retirement, 1,470.0 MW (97.5 percent) are coal fired steam units.

Generation Queue[3]

- There were 114,953.7 total MW in generation queues, in the status of active, under construction or suspended, at the end of 2018. In the first nine months of 2019, the AE2 and AF1 queue windows closed. Combined, these queue windows added 38,172.3 MW to the queue. As projects move through the queue process, projects can be removed from the queue due to incomplete or invalid data, withdrawn by the market participant or placed in service. On September 30, 2019, there were 124,399.7 total MW in generation queues, in the status of active, under construction or suspended, an increase of 9,446.0 MW (8.2 percent).
- 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 September 30, 2019, there were 39,204.9 MW of natural gas fired capacity active, suspended or under construction in PJM queues (including combined cycle units, CTs, RICE

2 See PJM. Planning. "Generator Deactivations," at <http://www.pjm.com/planning/services-requests/gen-deactivations.aspx>.
3 See PJM. Planning. "New Services Queue," at <https://www.pjm.com/planning/services-requests/interconnection-queues.aspx>.

units, and natural gas fired steam units).[4] As of September 30, 2019, there were only 132.0 MW of coal fired steam capacity active, suspended or under construction in PJM queues.

- As of September 30, 2019, 4,610 projects, representing 571,957.8 MW, have entered the queue process since its inception in 1998. Of those, 864 projects, representing 67,152.8 MW, went into service. Of the projects that entered the queue process, 2,642 projects, representing 380,405.3 MW (66.5 percent of the MW) withdrew prior to completion. Such projects may create barriers to entry for projects that would otherwise be completed by taking up queue positions, increasing interconnection costs and creating uncertainty.
- As of September 30, 2019, 124,399.7 MW of capacity were in generation request queues in the status of active, under construction or suspended. Of the total 124,399.7 MW in the queue, 64,966.0 MW (52.2 percent) have reached at least the system impact study (SIS) milestone and 59,433.7 MW (47.8 percent) have not received a completed SIS. Based on historical completion rates, (applying the unit type specific completion rates for those projects that have reached the system impact study, facility study agreement or construction service agreement milestone, and using the overall completion rates for those projects that have not yet reached the system impact study milestone), 35,269.3 MW of new generation in the queue are expected to go into service.

Regional Transmission Expansion Plan (RTEP)

Market Efficiency Process

- There are significant issues with PJM's benefit/cost analysis that should be addressed prior to approval of additional projects. PJM's benefit/cost analysis does not correctly account for the costs of increased congestion associated with market efficiency projects.
- Through September 30, 2019, PJM has completed three market efficiency cycles under Order No. 1000. The fourth market efficiency cycle is currently in progress for the 2018/2019 long term window.

4 The unit type RICE refers to Reciprocating Internal Combustion Engines.

PJM MISO Targeted Market Efficiency Process (TMEP) and Interregional Market Efficiency Process (IMEP)

- 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).[5] The allocation of costs to each RTO for TMEPs will be in proportion to the benefits received.[6]

Supplemental Transmission Projects

- Supplemental projects are defined to be "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."[7] Supplemental projects are exempt from the competitive planning process.
- The average number of supplemental projects in each expected in service year increased by 600.0 percent, from 20 for years 1998 through 2007 (pre Order No. 890) to 140 for years 2008 through 2019 (post Order 890).
- The process for designating projects as supplemental projects should be reviewed and modified to ensure that the supplemental project designation is not used to exempt transmission projects from a transparent, robust and clearly defined mechanism to permit competition to build the project or to effectively replace the RTEP process.

End of Life Transmission Projects

- An end of life transmission project is a project submitted for the purpose of replacing existing infrastructure that is at, or is approaching, the end of its useful life. Some Transmission Owners include end of life transmission

5 See PJM Interconnection, L.L.C, Docket No. ER17-718-000 (December 30, 2016).
6 See PJM Interconnection, L.L.C, Docket No. ER17-729-000 (December 30, 2016).
7 See PJM. "Transmission Construction Status," (Accessed on September 30, 2019) <http://www.pjm.com/planning/rtep-upgrades-status/construct-status.aspx>.

projects in their Transmission Owner Form 715 Planning Criteria. These projects were exempt from the competitive planning process.[8]

- End of life transmission projects should be included in the RTEP process and should be subject to a transparent, robust and clearly defined mechanism to permit competition to build the project.

Board Authorized Transmission Upgrades

- The Transmission Expansion Advisory Committee (TEAC) reviews internal and external proposals to improve transmission reliability throughout PJM. These proposals, which include reliability baseline, network, market efficiency and targeted market efficiency projects, but exclude supplemental and end of life projects, are periodically presented to the PJM Board of Managers for authorization.[9] In the first nine months of 2019, the PJM Board approved $845.8 million in upgrades. As of September 30, 2019, the PJM Board has approved $39.1 billion in system enhancements since 1999.

Transmission Competition

- The MMU makes several recommendations related to the competitive transmission planning process. The recommendations include improved process transparency, incorporation of competition between transmission and generation alternatives and the removal of barriers to competition from nonincumbent transmission. These recommendations would help ensure that the process is an open and transparent process that results in the most competitive solutions.
- On May 24, 2018, the PJM Markets and Reliability Committee (MRC) approved a motion that required PJM, with input from the MMU, to develop a comparative framework to evaluate the quality and effectiveness of competitive transmission proposals with binding cost containment proposals compared to proposals from incumbent and nonincumbent transmission companies without cost containment provisions.

8 See PJM. Operating Agreement Schedule 6 § 1.5.8(o).
9 Supplemental Projects, including the end of life subset of supplemental projects, do not require PJM Board of Managers authorization.

Qualifying Transmission Upgrades (QTU)

- A Qualifying Transmission Upgrade (QTU) is an upgrade to the transmission system that increases the Capacity Emergency Transfer Limit (CETL) into an LDA and can be offered into capacity auctions as capacity. Once a QTU is in service, the upgrade is eligible to continue to offer the approved incremental import capability into future RPM Auctions. As of September 30, 2019, no QTUs have cleared a BRA.

Transmission Facility Outages

- PJM maintains a list of reportable transmission facilities. When the reportable transmission facilities need to be taken out of service, PJM transmission owners are required to report planned transmission facility outages as early as possible. PJM processes the transmission facility outage requests according to rules in PJM's Manual 3 to decide if the outage is on time or late and whether or not they will allow the outage.[10]
- There were 6,601 transmission outage requests submitted in the first four months of the 2019/2020 planning period. Of the requested outages, 73.3 percent of the requested outages were planned for less than or equal to five days and 12.5 percent of requested outages were planned for greater than 30 days. Of the requested outages, 50.9 percent were late according to the rules in PJM's Manual 3.

Recommendations

Generation Retirements

- The MMU recommends that the question of whether Capacity Injection Rights (CIRs) should persist after the retirement of a unit, or the conversion from Capacity Performance (CP) to energy only status, be addressed. The rules need to ensure that incumbents cannot exploit control of CIRs to block or postpone entry of competitors.[11] (Priority: Low. First reported 2013. Status: Not adopted.)

10 See PJM. "PJM Manual 03: Transmission Operations," Rev. 55 (May 31, 2019).
11 See "Comments of the Independent Market Monitor for PJM," Docket No. ER12-1177-000 (March 12, 2012) <http://www.monitoringanalytics.com/Filings/2012/IMM_Comments_ER12-1177-000_20120312.PDF>.

- The MMU recommends that rules be implemented to ensure that CIRs are terminated within one year if units cannot qualify to be capacity resources and, if requested, after one CP must offer exception to permit the issue of CP status to be addressed. (Priority: Low. First reported 2018. Status: Not adopted.)

Generation Queue

- 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 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 continuing 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 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.)

Market Efficiency Process

- The MMU recommends that the market efficiency process be eliminated because it is not consistent with a competitive market design. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that, if the market efficiency process is retained, PJM modify the rules governing benefit/cost analysis, the evaluation process for selecting among competing market efficiency projects and cost allocation for economic projects in order to ensure that all costs, including increased congestion costs and the risk of project cost increases, in all zones are included and in order to ensure that the correct metrics are used for defining benefits. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that, if the market efficiency process is retained, PJM modify the rules governing the market efficiency process benefit/cost analysis so that competing projects with different in service dates are evaluated on a symmetric, comparable basis. (Priority: Medium. First reported 2018. Status: Not adopted.)

Transmission Competition

- The MMU recommends, to increase the role of competition, that the exemption of supplemental projects from the Order No. 1000 competitive process be terminated and that the basis for all such exemptions be reviewed and modified to ensure that the supplemental project designation is not used to exempt transmission projects from a transparent, robust and clearly defined mechanism to permit competition to build such projects or to effectively replace the RTEP process. (Priority: Medium. First reported 2017. Status: Not adopted.)
- The MMU recommends, to increase the role of competition, that the exemption of end of life projects from the Order No. 1000 competitive process be terminated and that end of life transmission projects should be included in the RTEP process and should be subject to a transparent, robust and clearly defined mechanism to permit competition to build such projects. (Priority: Medium. First reported Q1, 2019. Status: Not adopted.)

- The MMU recommends that PJM enhance the transparency and queue management process for nonincumbent 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 nonincumbent transmission providers. (Priority: Medium. First reported 2015. Status: Not adopted.)
- 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 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 nonincumbent transmission providers in the RTEP. (Priority: Medium. First reported 2014. 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: Medium. First reported 2015. Status: Not adopted.)

Cost Allocation

- 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.[12] (Priority: Medium. First reported 2015. Status: Not adopted.)

Transmission Facility Outages

- 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.)

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

12 See the 2015 State of the Market Report for PJM, Volume 2, Section 12: Generation and Transmission Planning, at p. 463, Cost Allocation Issues.

direct competition between transmission and generation to meet loads in the affected area. In addition, despite FERC Order No. 1000, there is not yet a transparent, robust and clearly defined mechanism to permit competition to build transmission projects, to ensure that competitors provide a total project cost cap, or to obtain least cost financing through the capital markets.

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

The current market efficiency process does exactly the opposite by permitting transmission projects to be approved without competition from generation. The broader issue is that the market efficiency project approach explicitly allows transmission projects to compete against future generation projects, but without allowing the generation projects to compete. Projecting speculative transmission related benefits for 15 years based on the existing generation fleet and existing patterns of congestion eliminates the potential for new generation to respond to market signals. The market efficiency process allows assets built under the cost of service regulatory paradigm to displace generation assets built under the competitive market paradigm. The MMU recommends that the market efficiency process be eliminated.

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 nonincumbent transmission providers. The ability of transmission owners to block competition for supplemental projects and end of life projects and reasons for that policy should be reevaluated. PJM should enhance the transparency and queue management process for nonincumbent 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 nonincumbent 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, paid for by customers. 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.

The process for determining the reasonableness or purpose of supplemental transmission projects that are asserted to be not needed for reliability, economic efficiency or operational performance as defined under the RTEP process needs additional oversight and transparency. If there is a need for a supplemental project, that need should be clearly defined and there should be a transparent, robust and clearly defined mechanism to permit competition to build the project. If there is no defined need for of a supplemental project for reliability, economic efficiency or operational performance then the project should not be included in rates.

If it is retained, there are significant issues with PJM's benefit/cost analysis that should be addressed prior to approval of additional projects. The current benefit/cost analysis for a regional project, for example, explicitly and incorrectly ignores the increased congestion in zones that results from an RTEP project when calculating the energy market benefits. All costs should be included in all zones and LDAs. The definition of benefits should also be reevaluated.

The benefit/cost analysis should also account for the fact that the transmission project costs are not subject to cost caps and may exceed the estimated costs by a wide margin. When actual costs exceed estimated costs, the cost benefit analysis is effectively meaningless and low estimated costs may result in inappropriately favoring transmission projects over market generation projects. The risk of cost increases for transmission projects should be incorporated in the cost benefit analysis.

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.

Generation Interconnection Planning

Existing Generation Mix

Table 12-1 shows the existing PJM capacity by control zone and unit type.[13] As of September 30, 2019, PJM had an installed capacity of 198,501.1 MW, of which 54,856.6 MW (27.6 percent) are coal fired steam units, 48,641.6 MW (24.5 percent) are combined cycle units and 34,257.6 MW (17.3 percent) are nuclear units. This measure of installed capacity differs from capacity market installed capacity because it includes energy only units, external units and uses nameplate values for solar and wind resources.

The AEP Zone has the most total installed capacity of any PJM zone. Of the 198,501.1 MW of PJM total installed capacity, 30,843.0 MW (15.5 percent) are in the AEP Zone, of which 13,927.8 MW (45.2 percent) are coal fired steam units, 6,990.0 MW (22.7 percent) are combined cycle units and 2,071.0 MW (6.7 percent) are nuclear units.

13 The unit type RICE refers to Reciprocating Internal Combustion Engines.

Table 12-1 Existing PJM capacity: September 30, 2019 (By zone and unit type (MW))[14]

Zone	Battery	Combined Cycle	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Total
AECO	0.0	901.9	544.7	26.0	0.0	1.6	0.0	0.0	0.0	0.0	4.0	10.6	59.4	458.9	0.0	0.0	0.0	7.5	2,014.5
AEP	6.0	6,990.0	3,661.2	16.2	4.8	0.0	66.0	486.9	2,071.0	0.0	0.0	20.4	14.7	13,927.8	738.0	0.0	50.0	2,790.0	30,843.0
APS	80.4	2,179.0	1,223.3	0.0	2.0	0.0	0.0	129.2	0.0	29.6	0.0	18.3	55.1	5,409.0	0.0	0.0	0.0	1,191.5	10,317.4
ATSI	0.0	2,150.5	958.0	653.0	6.4	0.0	0.0	0.0	2,134.0	0.0	18.5	46.1	0.0	3,734.0	325.0	0.0	0.0	0.0	10,025.5
BGE	0.0	0.0	500.1	248.8	0.0	0.0	0.0	0.4	1,716.0	0.0	0.0	7.2	1.1	1,713.0	143.5	397.0	57.0	0.0	4,784.1
ComEd	148.5	2,621.1	6,969.3	226.2	0.0	0.0	0.0	0.0	10,473.5	0.0	0.0	38.3	9.0	4,124.1	1,326.0	0.0	0.0	3,584.9	29,520.9
DAY	0.0	0.0	1,344.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	34.0	4.5	1.1	0.0	0.0	0.0	0.0	0.0	1,384.1
DEOK	20.0	522.2	598.0	56.0	0.0	0.0	0.0	112.0	0.0	0.0	0.0	4.8	0.0	1,857.0	47.0	0.0	0.0	0.0	3,217.0
DLCO	0.0	244.0	0.0	15.0	0.0	0.0	0.0	6.3	1,777.0	0.0	0.0	0.0	0.0	565.0	0.0	0.0	0.0	0.0	2,607.3
Dominion	0.0	9,099.6	3,835.3	256.4	10.0	0.0	3,003.0	586.3	3,581.3	0.0	39.0	112.8	802.0	3,917.6	35.0	1,586.0	368.4	208.0	27,440.7
DPL	0.0	1,742.5	978.2	478.2	0.0	30.0	0.0	0.0	0.0	0.0	88.0	14.1	225.4	410.0	812.0	153.0	70.0	0.0	5,001.4
EKPC	0.0	0.0	774.0	0.0	0.0	0.0	0.0	70.0	0.0	0.0	0.0	0.0	0.0	1,687.0	0.0	0.0	0.0	0.0	2,531.0
JCPL	40.0	2,402.5	531.1	225.6	0.0	0.4	400.0	0.0	0.0	0.0	0.0	16.1	303.7	0.0	0.0	0.0	0.0	0.0	3,919.5
Met-Ed	0.0	2,101.0	2.0	398.5	0.0	0.0	0.0	19.0	805.0	0.0	0.0	33.4	0.0	115.0	0.0	0.0	60.0	0.0	3,533.9
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	2,388.8	0.0	0.0	0.0	0.0	2,388.8
PECO	0.0	4,089.0	0.0	828.0	6.0	0.0	1,070.0	572.0	4,546.8	0.0	2.0	0.9	3.0	0.0	762.0	0.0	163.0	0.0	12,042.7
PENELEC	28.4	1,900.0	350.5	57.0	0.0	0.0	513.0	77.8	0.0	100.2	28.0	17.8	0.0	6,053.5	610.0	0.0	42.0	1,028.8	10,807.0
Pepco	0.0	1,729.5	764.2	308.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	11.1	2.5	2,433.0	1,164.1	0.0	52.0	0.0	6,464.4
PPL	20.0	5,558.5	252.0	129.5	20.6	0.0	0.0	706.6	2,520.0	12.0	5.0	24.7	15.0	2,590.9	2,449.0	0.0	29.0	216.5	14,549.3
PSEG	5.7	4,410.3	1,039.2	0.0	0.0	0.0	0.0	5.0	3,493.0	0.0	0.0	15.0	218.8	0.0	3.0	0.0	179.1	0.0	9,369.0
XIC	0.0	0.0	858.6	0.0	0.0	0.0	0.0	269.1	1,140.0	0.0	0.0	0.0	0.0	3,472.0	0.0	0.0	0.0	0.0	5,739.7
Total	349.0	48,641.6	25,184.2	3,922.4	49.8	32.0	5,052.0	3,040.6	34,257.6	141.8	218.5	396.0	1,710.8	54,856.6	8,414.6	2,136.0	1,070.5	9,027.2	198,501.1

14 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.

Table 12-2 shows the installed capacity by state for each fuel type. Pennsylvania has the most total installed capacity of any PJM state. Of the 198,501.1 MW of installed capacity, 46,985.4 MW (23.7 percent) are in Pennsylvania, of which 9,324.4 MW (19.8 percent) are coal fired steam units, 16,071.5 MW (34.2 percent) are combined cycle units and 9,648.8 MW (20.5 percent) are nuclear units.

Table 12-2 Existing PJM capacity: September 30, 2019 (By state and unit type (MW))

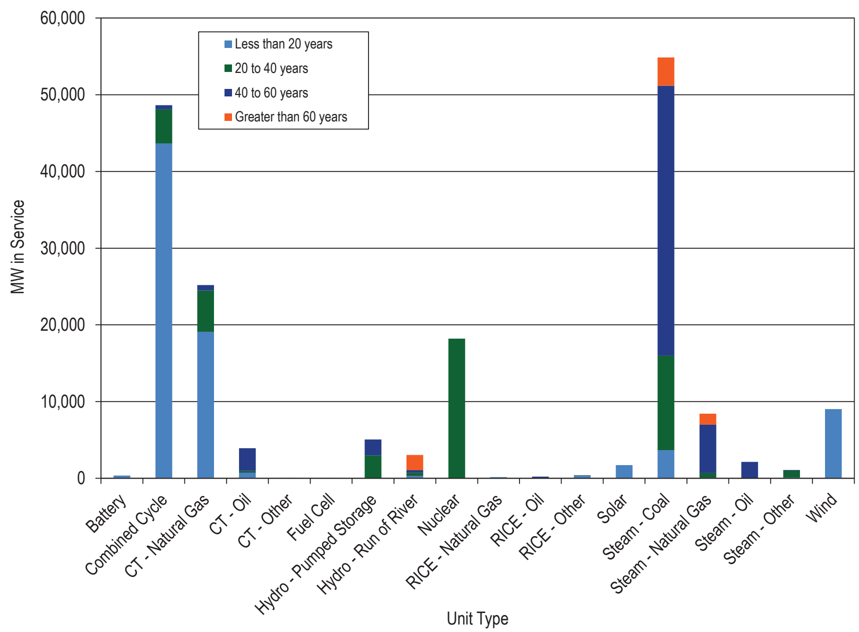
State	Battery	Combined Cycle	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Total
DC	0.0	19.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	19.5
DE	0.0	742.5	325.5	116.3	0.0	30.0	0.0	0.0	0.0	0.0	0.0	8.1	0.0	410.0	812.0	0.0	70.0	0.0	2,514.4
IL	148.5	2,621.1	6,969.3	226.2	0.0	0.0	0.0	0.0	10,473.5	0.0	0.0	38.3	9.0	4,124.1	1,326.0	0.0	0.0	3,584.9	29,520.9
IN	0.0	1,835.0	441.4	0.0	0.0	0.0	0.0	8.2	0.0	0.0	0.0	3.2	10.1	3,923.8	0.0	0.0	0.0	2,023.2	8,244.9
KY	0.0	0.0	1,618.1	0.0	0.0	0.0	0.0	136.0	0.0	0.0	0.0	0.0	0.0	1,687.0	278.0	0.0	0.0	0.0	3,719.1
MD	20.0	2,710.0	1,917.0	572.7	0.0	0.0	0.0	0.4	1,716.0	0.0	76.0	24.3	254.1	4,386.0	1,307.6	550.0	109.0	295.0	13,938.1
MI	0.0	1,200.0	0.0	0.0	4.8	0.0	0.0	11.8	2,071.0	0.0	0.0	3.2	4.6	0.0	0.0	0.0	0.0	0.0	3,295.4
NC	0.0	165.0	0.0	0.0	0.0	0.0	0.0	315.0	0.0	0.0	18.0	0.0	512.6	0.0	0.0	0.0	0.0	208.0	1,218.6
NJ	45.7	7,714.7	2,115.0	251.6	0.0	2.0	400.0	5.0	3,493.0	0.0	4.0	41.7	581.9	458.9	3.0	0.0	179.1	7.5	15,303.0
OH	24.0	6,627.7	4,201.2	725.2	6.4	0.0	0.0	200.0	2,134.0	0.0	52.5	55.4	1.1	11,623.8	372.0	0.0	0.0	766.8	26,790.1
PA	49.9	16,071.5	1,491.9	1,428.0	26.6	0.0	1,583.0	1,445.7	9,648.8	141.8	35.0	95.1	18.0	9,324.4	3,821.0	0.0	294.0	1,510.7	46,985.4
TN	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	50.0	0.0	50.0
VA	0.0	8,934.6	4,172.3	591.4	12.0	0.0	3,069.0	460.1	3,581.3	0.0	33.0	118.8	319.4	2,912.6	495.0	1,586.0	368.4	0.0	26,653.9
WV	60.9	0.0	1,073.9	11.0	0.0	0.0	0.0	189.3	0.0	0.0	0.0	8.0	0.0	12,534.0	0.0	0.0	0.0	631.1	14,508.2
XIC	0.0	0.0	858.6	0.0	0.0	0.0	0.0	269.1	1,140.0	0.0	0.0	0.0	0.0	3,472.0	0.0	0.0	0.0	0.0	5,739.7
Total	349.0	48,641.6	25,184.2	3,922.4	49.8	32.0	5,052.0	3,040.6	34,257.6	141.8	218.5	396.0	1,710.8	54,856.6	8,414.6	2,136.0	1,070.5	9,027.2	198,501.1

Table 12-3 and Figure 12-1 show the age of existing PJM generators, by unit type, as of September 30, 2019. Of the 198,501.1 MW of installed capacity, 73,586.0 MW (37.1 percent) are from units older than 40 years, of which 38,867.2 MW (52.8 percent) are coal fired steam units, 532.0 MW (0.7 percent) are combined cycle units and 16,044.9 MW (21.8 percent) are nuclear units.

Table 12-3 PJM capacity (MW) by unit type and age (years): September 30, 2019

Age (years)	Battery	Combined Cycle	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Total
Less than 20	349.0	43,666.1	19,109.7	740.8	43.8	32.0	0.0	297.2	0.0	129.8	20.0	341.6	1,710.8	3,655.0	82.0	0.0	97.4	9,027.2	79,302.3
20 to 40	0.0	4,443.5	5,372.3	219.2	6.0	0.0	3,003.0	427.2	18,212.7	12.0	25.0	54.4	0.0	12,334.4	600.0	0.0	903.1	0.0	45,612.8
40 to 60	0.0	532.0	702.2	2,962.4	0.0	0.0	2,049.0	340.0	`	0.0	173.5	0.0	0.0	35,196.4	6,321.1	2,136.0	70.0	0.0	50,482.6
Greater than 60	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,976.2	0.0	0.0	0.0	0.0	0.0	3,670.8	1,411.5	0.0	0.0	0.0	7,058.5
Total	349.0	48,641.6	25,184.2	3,922.4	49.8	32.0	5,052.0	3,040.6	18,212.7	141.8	218.5	396.0	1,710.8	54,856.6	8,414.6	2,136.0	1,070.5	9,027.2	182,456.2

Figure 12-1 PJM capacity (MW) by age (years): September 30, 2019



Generation Retirements[15]

Generating units generally plan to retire when they are not economic and do not expect to be economic. The MMU performs an analysis of the economics of all units that plan to retire in order to verify that the units are not economic and there is no potential exercise of market power through physical withholding that could advantage the owner's portfolio.[16] The definition of economic is that unit net revenues are greater than or equal to the unit's avoidable or going forward costs.

PJM does not have the authority to order generating plants to continue operating. PJM's responsibility is to ensure system reliability. When a unit retirement creates reliability issues based on existing and planned generation facilities and on existing and planned transmission facilities, PJM identifies transmission solutions.[17]

Rules that preserve the Capacity Injection Rights (CIRs) associated with retired units, and with the conversion from Capacity Performance (CP) to energy only status, impose significant costs on new entrants. Currently, CIRs persist for one year if unused, and they can be further extended, at no cost, if assigned to a new project in the interconnection queue at the same point of interconnection.[18] There are currently no rules governing the retention of CIRs when units want to convert to energy only status or require time to upgrade to retain CP status. The rules governing conversion or upgrades should be the same as the rules governing retired units. Reforms that require the holders of CIRs to use or lose them, and/or impose costs to holding or transferring them, could make new entry appropriately more attractive. The economic and policy rationale for extending CIRs for inactive units is not clear. Incumbent providers receive a significant advantage simply by imposing on new entrants the entire cost of system upgrades needed to accommodate new entrants. The policy question of whether CIRs should persist after the retirement of a unit should be addressed. Even if the policy treatment of such CIRs remains unchanged, the rules need to ensure that incumbents cannot exploit control of CIRs to block or postpone entry of competitors.

In May 2012, PJM stakeholders (through the Interconnection Process Senior Task Force (IPSTF)) modified the rules to reduce the length of time for which CIRs are retained by the current owner after unit retirements from three years to one.[19] The MMU recognized the progress made in this rule change, but it did not fully address the issues. The MMU recommends that the question of whether CIRs should persist after the retirement of a unit, or conversion from CP to energy only status, be addressed. The rules need to ensure that incumbents cannot exploit control of CIRs to block or postpone entry of competitors.[20]

15 See PJM. Planning. "Generator Deactivations," at <http://www.pjm.com/planning/services-requests/gen-deactivations.aspx>.
16 See OATT Section V and Attachment M–Appendix § IV.
17 See PJM. "Explaining Power Plant Retirements in PJM," at <http://learn.pjm.com/three-priorities/planning-for-the-future/explaining-power-plant-retirements.aspx>.
18 See OATT § 230.3.3.
19 See PJM Interconnection, L.L.C., Docket No. ER12-1177 (Feb. 29, 2012).
20 See "Comments of the Independent Market Monitor for PJM," Docket No. ER12-1177 (March 12, 2012) <http://www.monitoringanalytics.com/Filings/2012/IMM_Comments_ER12-1177-000_20120312.PDF>.

Generation Retirements 2011 through 2022

Table 12-4 shows that as of September 30, 2019, there are 42,955.8 MW of generation that have been, or are planned to be, retired between 2011 and 2022, of which 31,039.2 MW (72.3 percent) are coal fired steam units. Retirements are primarily a result of the inability of coal and other units to compete with efficient combined cycle units burning low cost gas.

Table 12-4 Summary of PJM unit retirements by unit type (MW): 2011 through 2022

	Battery	Combined Cycle	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Total
Retirements 2011	0.0	0.0	0.0	0.0	128.3	0.0	0.0	0.0	0.0	0.0	2.7	0.0	0.0	543.0	522.5	0.0	0.0	0.0	1,196.5
Retirements 2012	0.0	0.0	250.0	0.0	240.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5,907.9	0.0	548.0	16.0	0.0	6,961.9
Retirements 2013	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.9	7.0	0.0	2,589.9	82.0	166.0	8.0	0.0	2,858.8
Retirements 2014	0.0	0.0	136.0	0.0	422.0	0.0	0.0	0.0	0.0	0.0	0.0	15.3	0.0	2,239.0	158.0	0.0	0.0	0.0	2,970.3
Retirements 2015	0.0	0.0	1,319.0	0.0	858.2	0.0	0.0	0.0	0.0	0.0	10.3	0.0	0.0	7,064.8	0.0	0.0	0.0	10.4	9,262.7
Retirements 2016	0.0	0.0	0.0	0.0	71.0	0.0	0.5	0.0	0.0	0.0	8.0	3.9	0.0	243.0	74.0	0.0	0.0	0.0	400.4
Retirements 2017	40.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8	0.0	2,038.0	34.0	0.0	0.0	0.0	2,112.8
Retirements 2018	1.0	425.0	0.0	0.0	39.6	0.0	0.0	0.0	614.5	0.0	17.2	6.9	0.0	3,251.5	996.0	148.0	108.0	0.0	5,607.7
Retirements 2019	0.0	0.0	50.8	0.0	37.4	0.0	0.0	0.0	805.0	0.0	0.0	5.0	0.0	3,233.8	97.0	10.0	10.0	0.0	4,249.0
Planned Retirements (October 2019 and later)	0.0	0.0	608.5	0.0	50.0	0.0	0.0	0.0	1,777.0	0.0	13.0	10.9	0.0	3,928.3	102.0	786.0	60.0	0.0	7,335.7
Total	41.0	425.0	2,364.3	0.0	1,846.5	0.0	0.5	0.0	3,196.5	0.0	57.1	49.8	0.0	31,039.2	2,065.5	1,658.0	202.0	10.4	42,955.8

Table 12-5 shows the capacity, average size, and average age of units retiring in PJM, from 2011 through 2022, while Table 12-6 shows these retirements by state. Of the 42,955.8 MW of units that has been, or are planned to be, retired between 2011 and 2022, 31,039.2 MW (72.3 percent) are coal fired steam units. These coal fired steam units have an average age of 52.5 years and an average size of 189.3 MW. Over half of the retiring coal fired steam units, 50.5 percent, are located in either Ohio or Pennsylvania.

Table 12-5 Retirements by unit type: 2011 through 2022

Unit Type	Number of Units	Avg. Size (MW)	Avg. Age at Retirement (Years)	Total MW	Percent
Battery	2	20.5	7.0	41.0	0.1%
Combined Cycle	2	212.5	25.5	425.0	1.0%
Combustion Turbine	115	36.5	41.2	4,210.8	9.8%
Natural Gas	60	39.4	40.9	2,364.3	5.5%
Oil	0	0.0	0.0	0.0	0.0%
Other	55	33.6	41.4	1,846.5	4.3%
Fuel Cell	0	0.0	0.0	0.0	0.0%
Hydro	1	0.5	113.8	0.5	0.0%
Pumped Storage	1	0.5	113.8	0.5	0.0%
Run of River	0	0.0	0.0	0.0	0.0%
Nuclear	4	799.1	43.4	3,196.5	7.4%
RICE	24	4.5	28.3	106.9	0.2%
Natural Gas	0	0.0	0.0	0.0	0.0%
Oil	11	5.2	46.1	57.1	0.1%
Other	13	3.8	10.4	49.8	0.1%
Solar	0	0.0	0.0	0.0	0.0%
Steam	195	152.3	46.0	34,964.7	81.4%
Coal	164	189.3	52.5	31,039.2	72.3%
Natural Gas	18	114.8	60.8	2,065.5	4.8%
Oil	6	276.3	45.7	1,658.0	3.9%
Other	7	28.9	25.1	202.0	0.5%
Wind	1	10.4	15.6	10.4	0.0%
Total	344	124.9	46.2	42,955.8	100.0%

Figure 12-2 is a map of unit retirements between 2011 and 2022, with a mapping to unit names in Table 12-7.

Figure 12-2 Map of PJM unit retirements: 2011 through 2022

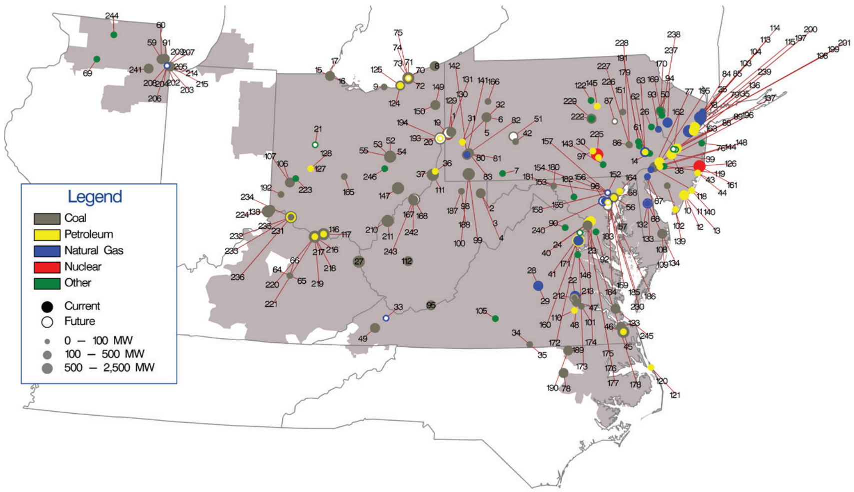


Table 12-6 Retirements (MW) by unit type and state: 2011 through 2022

State	Battery	Combined Cycle	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Total
DC	0.0	0.0	0.0	0.0	240.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	548.0	0.0	0.0	788.0
DE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	254.0	136.0	0.0	0.0	0.0	390.0
IL	0.0	0.0	296.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	12.5	0.0	1,624.0	0.0	0.0	0.0	0.0	1,932.5
IN	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	982.0	0.0	0.0	0.0	0.0	982.0
KY	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	995.0	0.0	0.0	0.0	0.0	995.0
MD	0.0	0.0	347.5	0.0	105.6	0.0	0.0	0.0	0.0	0.0	0.0	0.8	0.0	635.0	171.0	0.0	0.0	0.0	1,259.9
NC	0.0	0.0	0.0	0.0	31.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	324.5	0.0	0.0	0.0	0.0	355.5
NJ	0.0	158.0	1,590.0	0.0	1,046.6	0.0	0.5	0.0	614.5	0.0	8.0	9.8	0.0	1,543.0	932.5	148.0	10.0	0.0	6,060.9
OH	40.0	0.0	0.0	0.0	286.0	0.0	0.0	0.0	0.0	0.0	32.3	5.4	0.0	13,179.4	0.0	0.0	0.0	0.0	13,543.1
PA	1.0	0.0	50.8	0.0	58.0	0.0	0.0	0.0	2,582.0	0.0	13.9	13.0	0.0	4,844.3	283.0	176.0	109.0	10.4	8,141.4
VA	0.0	267.0	80.0	0.0	79.3	0.0	0.0	0.0	0.0	0.0	2.9	8.4	0.0	2,739.0	543.0	786.0	83.0	0.0	4,588.6
WV	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3,919.0	0.0	0.0	0.0	0.0	3,919.0
Total	41.0	425.0	2,364.3	0.0	1,846.5	0.0	0.5	0.0	3,196.5	0.0	57.1	49.8	0.0	31,039.2	2,065.5	1,658.0	202.0	10.4	42,955.8

Table 12-7 Unit identification for map of PJM unit retirements: 2011 through 2022

ID	Unit	ID	Unit	ID	Unit	ID	Unit	ID	Unit
1	AES Beaver Valley	51	Colver Power Project	101	Hopewell James River Cogeneration	151	Northeastern Power NEPCO	201	Sewaren 6
2	Albright 1	52	Conesville 3	102	Howard Down 10	152	Notch Cliff GT1	202	Southeast Chicago CT11
3	Albright 2	53	Conesville 4	103	Hudson 1	153	Notch Cliff GT2	203	Southeast Chicago CT12
4	Albright 3	54	Conesville 5	104	Hudson 2	154	Notch Cliff GT3	204	Southeast Chicago CT5
5	Armstrong 1	55	Conesville 6	105	Hurt NUG	155	Notch Cliff GT4	205	Southeast Chicago CT6
6	Armstrong 2	56	Crane 1	106	Hutchings 1-3, 5-6	156	Notch Cliff GT5	206	Southeast Chicago CT7
7	Arnold (Green Mtn. Wind Farm	57	Crane 2	107	Hutchings 4	157	Notch Cliff GT6	207	Southeast Chicago CT8
8	Ashtabula 5	58	Crane GT1	108	Indian River 1	158	Notch Cliff GT7	208	Southeast Chicago GT10
9	Avon Lake 7	59	Crawford 7	109	Indian River 3	159	Notch Cliff GT8	209	Southeast Chicago GT9
10	BL England 1	60	Crawford 8	110	Ingenco Petersburg	160	Occoquan 1 LF	210	Sporn 1-4
11	BL England 2	61	Cromby 1	111	Kammer 1-3	161	Oyster Creek	211	Sporn 5
12	BL England 3	62	Cromby 2	112	Kanawha River 1-2	162	Pennsbury Generator Landfill 1	212	Spruance NUG1 (Rich 1-2)
13	BL England Diesel Units 1-4	63	Cromby D	113	Kearny 10	163	Pennsbury Generator Landfill 2	213	Spruance NUG2 (Rich 3-4)
14	Barbados AES Battery	64	Dale 1-2	114	Kearny 11	164	Perryman 2	214	State Line 3
15	Bay Shore 2	65	Dale 3	115	Kearny 9	165	Picway 5	215	State Line 4
16	Bay Shore 3	66	Dale 4	116	Killen 2	166	Piney Creek NUG	216	Stuart 1
17	Bay Shore 4	67	Deepwater 1	117	Killen CT	167	Pleasants Power Station U1	217	Stuart 2
18	Bayonne Cogen Plant (CC)	68	Deepwater 6	118	Kimberly Clark Generator	168	Pleasants Power Station U2	218	Stuart 3
19	Beaver Valley U1 Nuclear Generating Unit	69	Dixon Lee Landfill Generator	119	Kinsley Landfill	169	Portland 1	219	Stuart 4
20	Beaver Valley U2 Nuclear Generating Unit	70	Eastlake 1	120	Kitty Hawk GT 1	170	Portland 2	220	Stuart Diesels 1-4
21	Bellefontaine Landfill Generating Station	71	Eastlake 2	121	Kitty Hawk GT 2	171	Possum Point 3	221	Stuart Diesels 1-4
22	Bellemeade	72	Eastlake 3	122	Koppers Co. IPP	172	Possum Point 4	222	Sunbury 1-4
23	Benning 15	73	Eastlake 4	123	Lake Kingman	173	Possum Point 5	223	Tait Battery
24	Benning 16	74	Eastlake 5	124	Lake Shore 18	174	Potomac River 1	224	Tanners Creek 1-4
25	Bergen 3	75	Eastlake 6	125	Lake Shore EMD	175	Potomac River 2	225	Three Mile Island Unit 1
26	Bethlehem Renewable Energy Generator (Landfill)	76	Eddystone 1	126	MH50 Markus Hook Co-gen	176	Potomac River 3	226	Titus 1
27	Big Sandy 2	77	Eddystone 2	127	Mad River CTs A	177	Potomac River 4	227	Titus 2
28	Bremo 3	78	Edgecomb NUG (Rocky 1-2)	128	Mad River CTs B	178	Potomac River 5	228	Titus 3
29	Bremo 4	79	Edison 1-3	129	Mansfield 1	179	Pottstown LF (Moser)	229	Viking Energy NUG
30	Brunner Island Diesels	80	Elrama 1	130	Mansfield 2	180	R Paul Smith 3	230	Wagner 2
31	Brunot Island 1B	81	Elrama 2	131	Mansfield 3	181	R Paul Smith 4	231	Walter C Beckjord 1
32	Brunot Island 1C	82	Elrama 3	132	McKee 1	182	Reichs Ford Road Landfill Generator	232	Walter C Beckjord 2
33	Buchanan 1-2	83	Elrama 4	133	McKee 2	183	Riverside 4	233	Walter C Beckjord 3
34	Buggs Island 1 (Mecklenberg)	84	Essex 10-11	134	McKee 3	184	Riverside 6	234	Walter C Beckjord 4
35	Buggs Island 2 (Mecklenberg)	85	Essex 12	135	Mercer 1	185	Riverside 7	235	Walter C Beckjord 5-6
36	Burger 3	86	Evergreen Power United Corstack	136	Mercer 2	186	Riverside 8	236	Walter C Beckjord GT 1-4
37	Burger EMD	87	FRACKVILLE WHEELABRATOR 1	137	Mercer 3	187	Riversville 5	237	Warren County Landfill
38	Burlington 8,11	88	Fairless Hills Landfill A	138	Miami Fort 6	188	Riversville 6	238	Warren County NUG
39	Burlington 9	89	Fairless Hills Landfill B	139	Middle 1-3	189	Roanoke Valley 1	239	Werner 1-4
40	Buzzard Point East Banks 1,2,4-8	90	Fauquier County Landfill	140	Missouri Ave B,C,D	190	Roanoke Valley 2	240	Westport 5
41	Buzzard Point West Banks 1-9	91	Fisk Street 19	141	Mitchell 2	191	Rolling Hills Landfill Generator	241	Will County 3
42	Cambria CoGen	92	GUDE Landfill	142	Mitchell 3	192	SMART Paper	242	Willow Island 1
43	Cedar 1	93	Gilbert 1-4	143	Modern Power Landfill NUG	193	Sammis 1-4	243	Willow Island 2
44	Cedar 2	94	Glen Gardner 1-8	144	Monmouth NUG landfill	194	Sammis Diesel	244	Winnebago Landfill
45	Chesapeake 1-4	95	Glen Lyn 5-6	145	Montour ATG	195	Schuylkill 1	245	Yorktown 1-2
46	Chesapeake 7-10	96	Gould Street Generation Station	146	Morris Landfill Generator	196	Schuylkill Diesel	246	Zanesville Landfill
47	Chesterfield 3	97	Harrisburg 4 CT	147	Muskingum River 1-5	197	Sewaren 1		
48	Chesterfield 4	98	Hatfield's Ferry 1	148	National Park 1	198	Sewaren 2		
49	Clinch River 3	99	Hatfield's Ferry 2	149	Niles 1	199	Sewaren 3		
50	Columbia Dam Hydro	100	Hatfield's Ferry 3	150	Niles 2	200	Sewaren 4		

Current Year Generation Retirements

Table 12-8 shows that in the first nine months of 2019, 4,249.0 MW of generation retired. The largest generators that retired in the first nine months of 2019 were the two 830.0 MW Mansfield coal fired steam units owned by FirstEnergy Corporation and located in the American Transmission Systems Incorporated (ATSI) Zone. Of the 4,249.0 MW of generation that retired, 1,660.0 MW (39.1 percent) were located in the ATSI Zone.

Table 12-8 Unit deactivations: January through September, 2019

Company	Unit Name	ICAP (MW)	Unit Type	Zone Name	Age (Years)	Retirement Date
FirstEnergy Corp.	Mansfield 1	830.0	Steam-Coal	ATSI	42.9	05-Feb-19
FirstEnergy Corp.	Mansfield 2	830.0	Steam-Coal	ATSI	41.4	05-Feb-19
Riverstone Holdings LLC	Montour ATG	10.0	Steam-Oil	PPL	45.9	18-Feb-19
Dominion Resources, Inc.	Yorktown 1-2	164.0	Steam-Coal	Dominion	60.2	08-Mar-19
Dominion Resources, Inc.	Yorktown 1-2	159.0	Steam-Coal	Dominion	61.7	08-Mar-19
Exelon Corporation	Riverside 7	19.0	CT-Other	BGE	48.6	14-Mar-19
Ares Management LP	Edgecomb NUG (aka Edgecomb Rocky 1-2)	115.5	Steam-Coal	Dominion	28.5	22-Apr-19
Rockland Capital Energy Investments, LLC	BL England 2	155.0	Steam-Coal	AECO	54.5	30-Apr-19
Dominion Resources, Inc.	Chesapeake GT2	12.0	CT-Other	Dominion	50.3	31-May-19
American Electric Power Company, Inc.	Conesville 5	400.0	Steam-Coal	AEP	42.6	01-Jun-19
American Electric Power Company, Inc.	Conesville 6	400.0	Steam-Coal	AEP	41.0	01-Jun-19
Covanta Holding Corporation	Warren County NUG	10.0	Steam-Other	JCPL	31.4	01-Jun-19
Exelon Corporation	Gould Street Generation Station	97.0	Steam-Natural Gas	BGE	66.5	01-Jun-19
Starwood Capital Group LLC	MH50 Markus Hook Co-gen	50.8	CT-Natural Gas	PECO	31.6	01-Jun-19
Novi Energy LLC	Hopewell James River Cogeneration	89.0	Steam-Coal	Dominion	35.1	25-Jun-19
Exelon Corporation	Bethlehem Renewable Energy Generator (Landfill)	5.0	RICE-Other	PPL	11.5	31-Aug-19
Kimberly-Clark Corporation	Kimberly Clark Generator	3.3	Steam-Coal	PECO	33.7	04-Sep-19
Northern Star Generation Services, Llc	Cambria CoGen	88.0	Steam-Coal	PENELEC	28.6	17-Sep-19
Exelon Corporation	Three Mile Island Unit 1 Nuclear Generating Station	805.0	Nuclear	Met-Ed	45.5	20-Sep-19
NextEra Energy, Inc.	Monmouth NUG landfill	6.4	CT-Other	JCPL	21.8	27-Sep-19
Total		4,249.0				

Planned Generation Retirements

Table 12-9 shows that, as of September 30, 2019, there are 7,335.7 MW of generation that have requested retirement after September 30, 2019, of which 1,507.0 MW (20.5 percent) are located in the ATSI Zone. Of the ATSI generation requesting retirement, 1,470.0 MW (97.5 percent) are coal fired steam units.

Table 12-9 Planned retirement of PJM units: September 30, 2019

Company	Unit Name	ICAP (MW)	Unit Type	Zone Name	Projected Deactivation Date
Public Service Enterprise Group Incorporated	Occoquan 1 LF	6.4	RICE-Other	Dominion	07-Nov-19
Exelon Corporation	Riverside 8	20.0	CT-Other	BGE	01-Dec-19
Exelon Corporation	Southeast Chicago CT11	37.0	CT-Natural Gas	ComEd	17-Dec-19
Exelon Corporation	Southeast Chicago CT12	37.0	CT-Natural Gas	ComEd	17-Dec-19
Exelon Corporation	Southeast Chicago CT5	37.0	CT-Natural Gas	ComEd	17-Dec-19
Exelon Corporation	Southeast Chicago CT6	37.0	CT-Natural Gas	ComEd	17-Dec-19
Exelon Corporation	Southeast Chicago CT7	37.0	CT-Natural Gas	ComEd	17-Dec-19
Exelon Corporation	Southeast Chicago CT8	37.0	CT-Natural Gas	ComEd	17-Dec-19
Exelon Corporation	Southeast Chicago GT10	37.0	CT-Natural Gas	ComEd	17-Dec-19
Exelon Corporation	Southeast Chicago GT9	37.0	CT-Natural Gas	ComEd	17-Dec-19
DTE Energy Company	Bellefontaine Landfill Generating Station	4.5	RICE-Other	DAY	31-Dec-19
Ares Management LP	Spruance NUG1 (aka Spruance 1 Rich 1-2)	115.5	Steam-Coal	Dominion	12-Jan-20
Macquarie Group Limited	FRACKVILLE WHEELABRATOR 1	43.0	Steam-Coal	PPL	03-Mar-20
FirstEnergy Corp.	Sammis 1-4	640.0	Steam-Coal	ATSI	31-May-20
American Electric Power Company, Inc.	Conesville 4	337.0	Steam-Coal	AEP	01-Jun-20
The AES Corporation	Conesville 4	127.8	Steam-Coal	AEP	01-Jun-20
Vistra Energy Corp	Conesville 4	312.0	Steam-Coal	AEP	01-Jun-20
Exelon Corporation	Fairless Hills Landfill A	30.0	Steam-Other	PECO	01-Jun-20
Exelon Corporation	Fairless Hills Landfill B	30.0	Steam-Other	PECO	01-Jun-20
Exelon Corporation	Notch Cliff GT1	14.0	CT-Natural Gas	BGE	01-Jun-20
Exelon Corporation	Notch Cliff GT2	14.0	CT-Natural Gas	BGE	01-Jun-20
Exelon Corporation	Notch Cliff GT3	14.0	CT-Natural Gas	BGE	01-Jun-20
Exelon Corporation	Notch Cliff GT4	14.0	CT-Natural Gas	BGE	01-Jun-20
Exelon Corporation	Notch Cliff GT5	14.6	CT-Natural Gas	BGE	01-Jun-20
Exelon Corporation	Notch Cliff GT6	15.6	CT-Natural Gas	BGE	01-Jun-20
Exelon Corporation	Notch Cliff GT7	14.5	CT-Natural Gas	BGE	01-Jun-20
Exelon Corporation	Notch Cliff GT8	16.0	CT-Natural Gas	BGE	01-Jun-20
Exelon Corporation	Pennsbury Generator Landfill 1	3.0	CT-Other	PECO	01-Jun-20
Exelon Corporation	Pennsbury Generator Landfill 2	3.0	CT-Other	PECO	01-Jun-20
Riverstone Holdings LLC	Wagner 2	135.0	Steam-Coal	BGE	01-Jun-20
Exelon Corporation	Westport 5	115.8	CT-Natural Gas	BGE	01-Jun-20
FirstEnergy Corp.	Colver Power Project	110.0	Steam-Coal	PENELEC	01-Sep-20
FirstEnergy Corp.	Beaver Valley U1 Nuclear Generating Unit	892.0	Nuclear	DLCO	31-May-21
Dominion Resources, Inc.	Possum Point 5	786.0	Steam-Oil	Dominion	31-May-21
FirstEnergy Corp.	Eastlake 6	24.0	CT-Other	ATSI	01-Jun-21
FirstEnergy Corp.	Mansfield 3	830.0	Steam-Coal	ATSI	01-Jun-21
City of Dover	McKee 3	102.0	Steam-Natural Gas	DPL	01-Jun-21
FirstEnergy Corp.	Sammis Diesel	13.0	RICE-Oil	ATSI	01-Jun-21
FirstEnergy Corp.	Beaver Valley U2 Nuclear Generating Unit	885.0	Nuclear	DLCO	31-Oct-21
FirstEnergy Corp.	Pleasants Power Station U1	639.0	Steam-Coal	APS	01-Jun-22
FirstEnergy Corp.	Pleasants Power Station U2	639.0	Steam-Coal	APS	01-Jun-22
LS Power Equity Partners, L.P.	Buchanan 1-2	80.0	CT-Natural Gas	AEP	01-Jun-23
Total		7,335.7			

Generation Queue

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.[21] 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 MMU recommends that barriers to entry be addressed in a timely manner in order to help ensure that the market will result in the entry of new capacity to meet the needs of PJM market participants.

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. Queues A and B were open for one year. Queues C through T were open for six months. Starting in February 2008, Queues U through Y1 were open for three months. In May 2012, the duration of the queue period was reset to six months, starting with Queue Y2. Queue AE2 began on October 1, 2018 and closed on March 31, 2019. Queue AF1 began on April 1, 2019 and closed on September 30, 2019.

Projects that do not meet submission requirements are removed from the queue. All projects that have entered a queue and have met the submission requirements 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. 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.[22] 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.[23]

The PJM queue evaluation process has been substantially improved in recent years and it is more efficient and effective as a result.[24] The PJM queue evaluation process should continue to be improved to help ensure that barriers to competition from new generation investments are not created. 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.

Process Timelines

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 12-10 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.

In 2016, the PJM Earlier Queue Submitted Task Force stakeholder group made changes to the interconnection process to address some of the issues related to delays observed in the various stages of the study phase. The changes became effective with the AC2 Queue that closed on March 31, 2017. The MMU recommends continuing 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.

21 See OATT Parts IV & VI.
22 See PJM. "PJM Manual 14C: Generation and Transmission Interconnection Process," Rev. 13 (August 23, 2018).
23 PJM does not track the duration of suspensions or PJM termination of projects.
24 See *PJM Interconnection, L.L.C.*, Docket No. ER12-1177 (Feb. 29, 2012).

Table 12-10 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

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 September 30, 2019, 124,399.7 MW of capacity were in generation request queues for construction through 2029. Although it is clear that not all generation in the queues will be built, PJM has added capacity steadily since markets were implemented on April 1, 1999.[25]

There were 114,953.7 total MW in generation queues, in the status of active, under construction or suspended, at the end of 2018. In the first nine months of 2019, the AE2 and AF1 queue windows closed. Combined, these queue windows added 38,172.3 MW to the queue. As projects move through the queue process, projects can be removed from the queue due to incomplete or invalid data, withdrawn by the market participant or placed in service. On September 30, 2019, there were 124,399.7 total MW in generation queues, in the status of active, under construction or suspended, an increase of 9,446.0 MW (8.2 percent). Table 12-11 shows MW in queues by expected completion year and MW changes in the queue between December 31, 2018, and September 30, 2019, for ongoing projects, i.e. projects with the status active, under construction or suspended.[26]

25 See "PJM Generation Capacity and Funding Sources 2007/2008 through 2021/2022 Delivery Years," <http://www.monitoringanalytics.com/reports/Reports/2019/IMM_PJM_Generation_Capacity_and_Funding_Sources_20072008_through_20212022_Delivery_Years_20190912.pdf>.
26 Expected completion dates are entered when the project enters the queue. Actual completion dates are generally different than expected completion dates.

Table 12-11 Queue comparison by expected completion year (MW): December 31, 2018 and September 30, 2019[27]

			Year Change	
Year	As of 12/31/2018	As of 09/30/2019	MW	Percent
2008	0.0	0.0	0.0	0.0%
2009	0.0	0.0	0.0	0.0%
2010	0.0	0.0	0.0	0.0%
2011	102.5	40.0	(62.5)	(61.0%)
2012	59.6	20.6	(39.0)	(65.4%)
2013	20.0	20.0	0.0	0.0%
2014	25.0	10.0	(15.0)	(60.0%)
2015	417.1	201.3	(215.8)	(51.7%)
2016	1,003.6	642.4	(361.2)	(36.0%)
2017	3,025.1	1,765.6	(1,259.5)	(41.6%)
2018	9,975.7	4,146.5	(5,829.2)	(58.4%)
2019	15,265.5	15,096.3	(169.2)	(1.1%)
2020	22,508.9	20,009.6	(2,499.3)	(11.1%)
2021	4,804.6	33,805.4	29,000.8	603.6%
2022	1,200.9	30,690.1	29,489.2	2455.6%
2023	0.0	7,744.3	7,744.3	0.0%
2024	0.0	4,995.3	4,995.3	0.0%
2025	0.0	3,166.9	3,166.9	0.0%
2026	0.0	445.2	445.2	0.0%
2027	0.0	800.1	800.1	0.0%
2028	0.0	0.0	0.0	0.0%
2029	0.0	800.1	800.1	0.0%
Total	58,408.4	124,399.7	65,991.2	113.0%

Table 12-12 shows the project status changes in more detail and how scheduled queue capacity has changed between December 31, 2018, and September 30, 2019. For example, 98,908.8 MW entered the queue in the first nine months of 2019. Of those 98,908.8 MW, 32,876.2 MW have been withdrawn. Of the total 71,171.0 MW marked as active on December 31, 2018, 21,185.7 MW were withdrawn, 4,100.4 MW were suspended, 3,373.4 MW started construction, and 1,205.9 MW went into service by September 30, 2019. Analysis of projects that were suspended on December 31, 2018 show that 3,071.1 MW came out of suspension and are now active as of September 30, 2019.

Table 12-12 Change in project status (MW): December 31, 2018 to September 30, 2019

		Status at 9/30/2019				
Status at 12/31/2018	Total at 12/31/2018	Active	In Service	Under Construction	Suspended	Withdrawn
(Entered during 2019)	0.0	65,931.9	41.3	14.3	45.0	32,876.2
Active	71,171.0	41,305.6	1,205.9	3,373.4	4,100.4	21,185.7
In Service	51,580.8	0.0	51,579.8	0.0	0.0	1.0
Under Construction	18,678.6	791.3	14,185.9	2,927.0	410.4	364.0
Suspended	8,771.1	3,071.1	140.0	39.9	2,389.4	3,130.7
Withdrawn	322,847.7	0.0	0.0	0.0	0.0	322,847.7
Total	473,049.0	111,099.9	67,152.8	6,354.6	6,945.1	380,405.3

On September 30, 2019, 124,399.7 MW of capacity were in generation request queues in the status of active, suspended or under construction. Table 12-13 shows each status by unit type. Of the 111,099.9 MW in the status of Active on September 30, 2019, 24,324.2 MW (21.9 percent) were combined cycle projects. Of the 6,354.6 MW in the status of under construction, 3,564.5 MW (56.1 percent) were combined cycle projects.

27 Wind and solar capacity in Table 12-11 through Table 12-15 have not been adjusted to reflect derating.

Table 12-13 Current project status (MW) by unit type: September 30, 2019

	Battery	Combined Cycle	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Total
Active	3,588.6	24,324.2	5,847.1	14.0	0.0	0.0	1,000.0	114.0	123.5	52.0	0.0	0.8	50,204.1	96.0	94.0	0.0	40.0	25,601.7	111,099.9
Suspended	62.3	4,779.1	230.0	0.0	0.0	0.0	0.0	0.0	0.0	39.8	0.0	0.0	645.6	0.0	0.0	0.0	16.0	1,172.4	6,945.2
Under Construction	4.5	3,564.5	253.0	0.0	0.0	0.0	0.0	22.7	44.0	21.2	4.0	0.0	666.1	36.0	0.0	0.0	62.5	1,676.1	6,354.6
Total	3,655.3	32,667.8	6,330.1	14.0	0.0	0.0	1,000.0	136.7	167.5	113.0	4.0	0.8	51,515.8	132.0	94.0	0.0	118.5	28,450.2	124,399.7

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 September 30, 2019, there were 39,204.9 MW of natural gas fired capacity active, suspended or under construction in PJM queues (including combined cycle units, CTs, RICE units, and natural gas fired steam units). As of September 30, 2019, there were only 132.0 MW of coal fired steam capacity active, suspended or under construction in PJM queues.

There are 3,928.3 MW of coal fired steam capacity and 710.5 MW of natural gas capacity slated for deactivation between October 1, 2019, and December 31, 2022 (See Table 12-9). The replacement of coal fired steam units by natural gas units will significantly affect future congestion, the role of firm and interruptible gas supply, and natural gas supply infrastructure.

Table 12-14 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 September 30, 2019, there are 124,399.7 MW of capacity in queues that are not yet in service or withdrawn, of which 5.6 percent are suspended, 5.1 percent are under construction and 89.3 percent have not begun construction.

Table 12-14 Capacity in PJM queues (MW): September 30, 2019[28]

Queue	Active	In Service	Under Construction	Suspended	Withdrawn	Total
A Expired 31-Jan-98	0.0	9,094.0	0.0	0.0	17,252.0	26,346.0
B Expired 31-Jan-99	0.0	4,645.5	0.0	0.0	14,956.7	19,602.2
C Expired 31-Jul-99	0.0	531.0	0.0	0.0	3,558.3	4,089.3
D Expired 31-Jan-00	0.0	850.6	0.0	0.0	7,358.0	8,208.6
E Expired 31-Jul-00	0.0	795.2	0.0	0.0	8,021.8	8,817.0
F Expired 31-Jan-01	0.0	52.0	0.0	0.0	3,092.5	3,144.5
G Expired 31-Jul-01	0.0	1,189.6	0.0	0.0	17,961.8	19,151.4
H Expired 31-Jan-02	0.0	702.5	0.0	0.0	8,421.9	9,124.4
I Expired 31-Jul-02	0.0	103.0	0.0	0.0	3,728.4	3,831.4
J Expired 31-Jan-03	0.0	42.0	0.0	0.0	846.0	888.0
K Expired 31-Jul-03	0.0	93.1	0.0	0.0	485.3	578.4
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	39.0	2,398.8	0.0	0.0	8,090.3	10,528.0
O Expired 31-Jul-05	0.0	1,665.2	225.0	0.0	5,466.8	7,357.0
P Expired 31-Jan-06	0.0	3,227.8	62.5	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	1,892.5	0.0	440.0	20,268.9	22,601.4
S Expired 31-Jul-07	70.0	3,543.5	0.0	0.0	12,396.5	16,010.0
T Expired 31-Jan-08	0.0	4,046.5	150.0	0.0	23,313.3	27,509.8
U1 Expired 30-Apr-08	0.0	218.9	0.0	0.0	7,937.8	8,156.7
U2 Expired 31-Jul-08	400.0	267.5	260.0	166.4	15,952.2	17,046.1
U3 Expired 31-Oct-08	100.0	333.0	0.0	0.0	2,535.6	2,968.6
U4 Expired 31-Jan-09	200.0	85.2	0.0	0.0	4,745.0	5,030.2
V1 Expired 30-Apr-09	40.0	197.9	0.0	0.0	2,532.8	2,770.7
V2 Expired 31-Jul-09	0.0	989.9	16.1	150.0	3,475.1	4,631.1
V3 Expired 31-Oct-09	200.0	912.0	0.0	20.0	3,822.7	4,954.7
V4 Expired 31-Jan-10	0.0	748.8	0.0	200.0	3,508.0	4,456.8
W1 Expired 30-Apr-10	13.5	553.9	0.0	0.0	5,139.5	5,706.9
W2 Expired 31-Jul-10	10.0	351.7	0.0	23.0	3,018.7	3,403.4
W3 Expired 31-Oct-10	0.0	511.1	37.7	100.0	8,573.2	9,222.0
W4 Expired 31-Jan-11	0.0	1,101.8	367.9	0.0	4,152.6	5,622.3
X1 Expired 30-Apr-11	0.0	1,103.8	0.0	0.0	6,200.6	7,304.4
X2 Expired 31-Jul-11	0.0	3,544.4	187.5	0.0	5,578.4	9,310.2
X3 Expired 31-Oct-11	0.0	89.2	20.0	894.0	6,771.9	7,775.1
X4 Expired 31-Jan-12	0.0	2,948.9	0.0	0.0	2,419.4	5,368.3
Y1 Expired 30-Apr-12	486.0	1,795.5	0.0	72.0	5,721.7	8,075.2
Y2 Expired 31-Oct-12	360.0	1,434.4	22.8	200.0	9,276.5	11,293.7
Y3 Expired 30-Apr-13	0.0	1,389.5	241.0	0.0	4,609.2	6,239.6
Z1 Expired 31-Oct-13	1,013.3	2,928.0	146.5	0.0	4,037.0	8,124.8
Z2 Expired 30-Apr-14	0.0	2,861.4	201.6	43.0	2,994.8	6,100.8
AA1 Expired 31-Oct-14	838.0	1,242.7	3,582.0	389.2	6,096.8	12,148.7
AA2 Expired 30-Apr-15	4,293.2	1,100.7	210.9	1,276.0	9,185.5	16,066.3
AB1 Expired 31-Oct-15	8,820.8	1,056.5	98.3	211.2	10,265.8	20,452.6
AB2 Expired 31-Mar-16	5,300.9	207.5	198.9	1,349.6	8,160.5	15,217.4
AC1 Expired 30-Sep-16	10,275.3	234.7	198.0	1,288.7	8,076.9	20,073.6
AC2 Expired 30-Apr-17	4,830.2	94.0	0.6	42.1	7,634.8	12,601.6
AD1 Expired 30-Sep-17	7,242.5	26.7	113.0	35.0	3,890.9	11,308.1
AD2 Expired 31-Mar-18	9,374.3	41.3	13.2	45.0	10,930.4	20,404.2
AE1 Expired 30-Sep-18	19,020.6	0.0	1.1	0.0	15,250.1	34,271.7
AE2 Through 31-Mar-19	26,844.4	0.0	0.0	0.0	7,337.3	34,181.7
AF1 Through 30-Sep-19	11,327.9	0.0	0.0	0.0	909.9	12,237.8
Total	111,099.9	67,152.8	6,354.6	6,945.2	380,405.3	571,957.8

28 Projects listed as partially in service are counted as in service for the purposes of this analysis.

Table 12-15 shows the projects with a status of active, suspended or under construction, by unit type, and control zone. As of September 30, 2019, 124,399.7 MW of capacity were in generation request queues for construction through 2029.[29] Table 12-15 also shows the planned retirements for each zone.

29 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 derated wind resources to 13 percent of nameplate capacity until there is operational data to support a different conclusion. PJM derated solar resources to 38 percent of nameplate capacity. Effective June 1, 2017, PJM adjusted the derates of wind and solar resources. The capacity factor derates for wind resources are dependent on the wind farm locations and have an average derate of 16.2 percent. The capacity factor derates for solar resources are dependent on the solar installation type and have an average derate of 46.7 percent. Based on the derating of 28,450.2 MW of wind resources and 51,515.8 MW of solar resources, using the average derate factors, the 124,399.7 MW currently under construction, suspended or active in the queue would be reduced to 73,100.5 MW.

Table 12-15 Queue totals for projects (active, suspended and under construction) by LDA, control zone and unit type (MW): September 30, 2019[30]

LDA	Zone	Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Total Queue Capacity	Planned Retirements
EMAAC	AECO	120.0	1,068.6	230.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	748.8	0.0	0.0	0.0	0.0	3,939.6	6,107.0	0.0
	DPL	31.0	451.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,715.0	0.0	0.0	0.0	0.0	679.1	2,876.1	102.0
	JCPL	563.0	600.0	200.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	227.5	0.0	0.0	0.0	0.0	4,159.2	5,749.7	0.0
	PECO	0.0	102.0	29.0	0.0	0.0	0.0	0.0	0.0	94.0	0.0	4.0	0.0	47.8	0.0	0.0	0.0	0.0	0.0	276.8	66.0
	PSEG	2.0	882.6	675.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	78.8	0.0	0.0	0.0	0.0	0.0	1,638.4	0.0
	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	40.0	0.0	0.0	0.0	0.0	0.0	40.0	0.0
	EMAAC Total	716.0	3,104.2	1,134.0	0.0	0.0	0.0	0.0	0.0	94.0	0.0	4.0	0.0	2,857.8	0.0	0.0	0.0	0.0	8,777.9	16,687.9	168.0
SWMAAC	BGE	200.0	0.0	153.6	14.0	0.0	0.0	0.0	0.0	45.5	1.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	414.4	387.5
	Pepco	0.0	1,177.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	191.8	0.0	0.0	0.0	0.0	0.0	1,369.4	0.0
	SWMAAC Total	200.0	1,177.6	153.6	14.0	0.0	0.0	0.0	0.0	45.5	1.3	0.0	0.0	191.8	0.0	0.0	0.0	0.0	0.0	1,783.8	387.5
WMAAC	Met-Ed	0.0	113.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	872.1	0.0	0.0	0.0	0.0	0.0	986.0	0.0
	PENELEC	160.0	1,348.0	573.0	0.0	0.0	0.0	0.0	0.0	0.0	59.8	0.0	0.0	2,244.8	0.0	0.0	0.0	0.0	400.2	4,785.8	110.0
	PPL	254.0	1,327.8	0.0	0.0	0.0	0.0	1,000.0	0.0	0.0	0.0	0.0	0.0	596.2	0.0	0.0	0.0	16.0	530.1	3,724.1	43.0
	WMAAC Total	414.0	2,789.7	573.0	0.0	0.0	0.0	1,000.0	0.0	0.0	59.8	0.0	0.0	3,713.1	0.0	0.0	0.0	16.0	930.3	9,495.9	153.0
Non-MAAC	AEP	1,043.6	6,169.0	567.5	0.0	0.0	0.0	0.0	99.0	28.0	12.0	0.0	0.8	14,216.9	112.0	30.0	0.0	40.0	6,053.7	28,372.5	856.8
	APS	94.0	6,729.7	112.0	0.0	0.0	0.0	0.0	15.0	0.0	39.9	0.0	0.0	2,097.9	0.0	0.0	0.0	0.0	1,183.4	10,271.9	1,278.0
	ATSI	20.3	4,635.0	70.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,072.3	0.0	0.0	0.0	0.0	816.1	7,613.7	1,507.0
	ComEd	202.9	4,072.6	1,255.2	0.0	0.0	0.0	0.0	22.7	0.0	0.0	0.0	0.0	4,137.5	0.0	64.0	0.0	0.0	7,019.7	16,774.5	296.0
	DAY	59.9	1,150.0	23.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,276.2	0.0	0.0	0.0	0.0	0.0	3,509.6	4.5
	DEOK	72.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	380.0	20.0	0.0	0.0	0.0	0.0	472.0	0.0
	DLCO	0.0	0.0	205.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	71.3	0.0	0.0	0.0	0.0	0.0	276.3	1,777.0
	Dominion	832.6	2,840.0	2,236.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	17,535.0	0.0	0.0	0.0	62.5	3,669.2	27,175.6	907.9
	EKPC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,966.0	0.0	0.0	0.0	0.0	0.0	1,966.0	0.0
	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	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	RMU	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Non-MAAC Total	2,325.3	25,596.3	4,469.5	0.0	0.0	0.0	0.0	136.7	28.0	51.9	0.0	0.8	44,753.1	132.0	94.0	0.0	102.5	18,742.0	96,432.1	6,627.2
	Total	3,655.3	32,667.8	6,330.1	14.0	0.0	0.0	1,000.0	136.7	167.5	113.0	4.0	0.8	51,515.8	132.0	94.0	0.0	118.5	28,450.2	124,399.7	7,335.7

Withdrawn Projects

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 are withdrawn. 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, but the actual calculation of commercial probability factors is less than transparent.[31] 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 12-16 and Table 12-17.

30 This data includes only projects with a status of active, under construction, or suspended.

31 See PJM. "PJM Manual 14B: PJM Region Transmission Planning Process," Rev. 46 (August 28, 2019).

Table 12-16 shows the milestone status when projects were withdrawn, for all withdrawn projects. Of the 2,642 projects withdrawn, 1,319 (49.9 percent) were withdrawn before the system impact study was completed. Once a Construction Service Agreement (CSA) is executed, the financial obligation for any necessary transmission upgrades cannot be retracted. Of the 2,642 projects withdrawn, 513 (19.4 percent) were withdrawn after the completion of a Construction Service Agreement.

Table 12-16 Last milestone at time of withdrawal: January 1997 through September 2019

Milestone Completed	Projects Withdrawn	Percent	Average Days	Maximum Days
Never Started	459	17.4%	378	1,580
Feasibility Study	860	32.6%	276	1,633
System Impact Study	523	19.8%	740	3,248
Facilities Study	287	10.9%	1,078	3,810
Construction Service Agreement (CSA) or beyond	513	19.4%	1,319	4,682
Total	2,642	100.0%		

Average Time in Queue

Table 12-17 shows 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 1,052 days, or 2.9 years, between entering a queue and going into service. For withdrawn projects, there is an average time of 624 days, or 1.7 years, between entering a queue and withdrawing.

Table 12-17 Project queue times by status (days): September 30, 2019[32]

Status	Average (Days)	Standard Deviation	Minimum	Maximum
Active	614	599	7	5,481
In-Service	1,052	765	0	4,986
Suspended	1,759	911	550	4,759
Under Construction	2,061	1,078	463	5,251
Withdrawn	624	713	0	4,682

32 The queue data shows that some projects were withdrawn and a withdrawal date was not identified. These projects were removed for the purposes of this analysis.

Table 12-18 presents information on the time in the stages of the queue for those projects not yet in service or already withdrawn. Of the 1,104 projects in the queue as of September 30, 2019, 362 (32.8 percent) had a completed feasibility study and 271 (24.5 percent) had a completed construction service agreement.

Table 12-18 Project queue times by milestone (days): September 30, 2019

Milestone Reached	Number of Projects	Percent of Total Projects	Average Days	Maximum Days
Under Review	163	14.8%	98	565
Feasibility Study	362	32.8%	415	1,250
System Impact Study	282	25.5%	750	4,019
Facilities Study	26	2.4%	1,546	3,827
Construction Service Agreement (CSA) or beyond	271	24.5%	1,522	5,481
Total	1,104	100.0%		

Completion Rates

The probability of a project going into service increases as each step of the planning process is completed.

Table 12-19 shows the historic completion rates (MW energy) by unit type for projects that have completed the system impact study (SIS), facilities study agreement (FSA) and construction service agreement (CSA) milestones as well as the historic completion rates for all projects including those withdrawn before reaching the SIS milestone. For each unit type, the total MW in service was divided by the total energy MW entered in the queue. To calculate the completion rates for projects that reached the individual milestones, only those projects that reached a final status of withdrawn or in service were evaluated. For example, if a project was withdrawn after the completion of its SIS, but before the completion of the FSA, the totals would be included in the calculation of the SIS completion rate, but not in the calculation of the FSA or CSA completion rates. Similarly, if a project was withdrawn after the completion of its FSA, but before the completion of the CSA, the totals would be included in the calculation of the SIS and FSA completion rates, but not in the calculation of the CSA completion rate. The completion rates show that of all wind projects to ever enter the queue and complete the system impact study stage, 17.7 percent of the queued MW has gone into service. The completion rate for wind projects increases to 31.6 percent when wind projects complete the facility study agreement and further increases to 48.9 percent when wind projects complete the construction service agreement. Of all wind projects to enter the queue, only 7.7 percent of the queued MW has gone into service.

Table 12-19 Historic completion rates (MW energy) by unit type for projects with a completed SIS, FSA and CSA: January 1997 through September 2019

Unit Type	Completion Rate (SIS)	Completion Rate (FSA)	Completion Rate (CSA)	Completion Rate (ALL)
Battery	27.2%	44.8%	56.1%	4.3%
CC	33.1%	53.1%	87.1%	13.0%
CT - Natural Gas	77.0%	83.5%	87.5%	44.5%
CT - Oil	35.6%	60.2%	90.8%	25.1%
CT - Other	12.3%	18.6%	29.5%	10.7%
Fuel Cell	6.6%	6.8%	6.8%	5.0%
Hydro - Pumped Storage	100.0%	100.0%	100.0%	20.6%
Hydro - Run of River	43.7%	62.3%	69.1%	21.6%
Nuclear	34.8%	41.7%	51.1%	28.6%
RICE - Natural Gas	33.0%	47.3%	53.8%	23.4%
RICE - Oil	30.6%	55.9%	55.9%	23.8%
RICE - Other	89.0%	91.4%	92.0%	77.9%
Solar	14.5%	28.9%	36.6%	1.8%
Steam - Coal	13.3%	24.9%	36.9%	6.0%
Steam - Natural Gas	90.1%	90.1%	90.1%	81.4%
Steam - Oil	0.0%	0.0%	0.0%	0.0%
Steam - Other	27.9%	37.2%	45.2%	23.5%
Wind	17.1%	31.6%	48.9%	7.7%

On September 30, 2019, 124,399.7 MW of capacity were in generation request queues in the status of active, under construction or suspended. Of the total 124,399.7 MW in the queue, 64,966.0 MW (52.2 percent) have reached at least the SIS milestone and 59,433.7 MW (47.8 percent) have not received a completed SIS. Based on historical completion rates, (applying the unit type specific completion rates for those projects that have reached the SIS, FSA or CSA milestone, and using the overall completion rates for those projects that have not yet reached the SIS milestone), 35,269.3 MW of new generation in the queue are expected to go into service.

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 12-20 shows the number of projects that entered the queue by year and by fuel group. The fuel groups are nuclear units, renewable units (including solar, hydro, storage, biomass and wind) and traditional units (all other fuels). The number of queue entries has increased during the past several years, primarily by renewable projects. Of the 1,958 projects entered from January 2015 through June 2019, 1,642 projects, 83.9 percent, were renewable. Of the 455 projects entered in the first nine months of 2019, 435 projects, 95.6 percent, were renewable.

Table 12-20 Number of projects entered in the queue: September 30, 2019

	Fuel Group			
Year Entered	Nuclear	Renewable	Traditional	Total
1997	2	0	11	13
1998	0	0	18	18
1999	1	5	84	90
2000	2	3	78	83
2001	4	6	81	91
2002	3	15	33	51
2003	1	34	18	53
2004	4	17	33	54
2005	3	75	55	133
2006	9	67	81	157
2007	9	65	145	219
2008	3	109	104	216
2009	10	109	54	173
2010	5	375	61	441
2011	6	268	81	355
2012	2	70	87	159
2013	1	75	78	154
2014	0	121	71	192
2015	0	196	113	309
2016	2	320	77	399
2017	2	300	53	355
2018	1	391	48	440
2019	0	435	20	455
Total	70	3,056	1,484	4,610

Renewable projects comprise the majority of projects entered in the queue, as well as what is currently active in the queue. Renewable projects make up 68.1 percent of the nameplate MW currently active, suspended or under construction in the queue (Table 12-21).

Table 12-21 Queue details by fuel group: September 30, 2019

Fuel Group	Number of Projects	Percent of Projects	MW	Percent MW
Nuclear	9	0.8%	167.5	0.1%
Renewable	940	85.1%	84,758.0	68.1%
Traditional	155	14.0%	39,474.2	31.7%
Total	1,104	100.0%	124,399.7	100.0%

Queue Analysis by Unit Type and Project Classification

Table 12-22 shows the current status of all generation queue projects by unit type and project classification from January 1, 1997, through September 30, 2019. As of September 30, 2019, 4,610 projects, representing 571,957.8 MW, have entered the queue process since its inception. Of those, 864 projects, representing 67,152.8 MW, went into service. Of the projects that entered the queue process, 2,642 projects, representing 380,405.3 MW (66.5 percent of the MW) withdrew prior to completion. Such projects may create barriers to entry for projects that would otherwise be completed by taking up queue positions, increasing interconnection costs and creating uncertainty.

A total of 3,755 projects have been classified as new generation and 855 projects have been classified as upgrades. Wind, solar and natural gas projects have accounted for 3,694 projects, or 80.1 percent, of all 4,610 generation queue projects.

Table 12-22 Status of all generation queue projects: January 1997 through September 2019

		Number of Projects																		
Project Status	Project Classification	Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Total
In Service	New Generation	21	60	48	10	25	3	0	10	2	9	0	55	139	8	5	0	4	81	480
	Upgrade	5	89	92	15	5	0	3	18	41	8	1	15	18	53	7	0	7	7	384
Under Construction	New Generation	1	3	1	0	0	0	0	2	0	2	0	0	18	0	0	0	0	10	37
	Upgrade	0	9	2	0	0	0	0	0	1	1	1	0	2	1	0	0	1	3	21
Suspended	New Generation	6	5	0	0	0	0	0	0	0	2	0	0	25	0	0	0	1	9	48
	Upgrade	2	6	2	0	0	0	0	0	0	0	0	0	1	0	0	0	0	1	12
Withdrawn	New Generation	134	419	23	9	81	26	2	39	9	23	12	16	1,098	55	1	0	33	425	2,405
	Upgrade	17	83	11	13	13	2	0	4	9	0	2	3	37	14	0	0	2	27	237
Active	New Generation	52	28	14	1	0	0	2	1	1	3	0	0	600	0	0	0	0	83	785
	Upgrade	30	35	27	0	0	0	0	3	7	0	0	1	76	5	3	0	1	13	201
Total Projects	New Generation	214	515	86	20	106	29	4	52	12	39	12	71	1,880	63	6	0	38	608	3,755
	Upgrade	54	222	134	28	18	2	3	25	58	9	4	19	134	73	10	0	11	51	855

Table 12-23 shows the totals in Table 12-22 by share of classification as new generation or upgrade. Within a unit type the shares of upgrades add to 100 percent and the shares of new generation add to 100 percent. For example, 72.0 percent of all hydro run of river projects classified as upgrades are currently in service in PJM, 16.0 percent of hydro run of river upgrades were withdrawn and 12.0 percent of hydro run of river upgrades are active in the queue.

Table 12-23 Status of all generation queue projects as a percent of total projects by classification: January 1997 through September 2019

		Percent of Projects																		
Project Status	Project Classification	Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Total
In Service	New Generation	9.8%	11.7%	55.8%	50.0%	23.6%	10.3%	0.0%	19.2%	16.7%	23.1%	0.0%	77.5%	7.4%	12.7%	83.3%	0.0%	10.5%	13.3%	12.8%
	Upgrade	9.3%	40.1%	68.7%	53.6%	27.8%	0.0%	100.0%	72.0%	70.7%	88.9%	25.0%	78.9%	13.4%	72.6%	70.0%	0.0%	63.6%	13.7%	44.9%
Under Construction	New Generation	0.5%	0.6%	1.2%	0.0%	0.0%	0.0%	0.0%	3.8%	0.0%	5.1%	0.0%	0.0%	1.0%	0.0%	0.0%	0.0%	0.0%	1.6%	1.0%
	Upgrade	0.0%	4.1%	1.5%	0.0%	0.0%	0.0%	0.0%	0.0%	1.7%	11.1%	25.0%	0.0%	1.5%	1.4%	0.0%	0.0%	9.1%	5.9%	2.5%
Suspended	New Generation	2.8%	1.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	5.1%	0.0%	0.0%	1.3%	0.0%	0.0%	0.0%	2.6%	1.5%	1.3%
	Upgrade	3.7%	2.7%	1.5%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.7%	0.0%	0.0%	0.0%	0.0%	2.0%	1.4%
Withdrawn	New Generation	62.6%	81.4%	26.7%	45.0%	76.4%	89.7%	50.0%	75.0%	75.0%	59.0%	100.0%	22.5%	58.4%	87.3%	16.7%	0.0%	86.8%	69.9%	64.0%
	Upgrade	31.5%	37.4%	8.2%	46.4%	72.2%	100.0%	0.0%	16.0%	15.5%	0.0%	50.0%	15.8%	27.6%	19.2%	0.0%	0.0%	18.2%	52.9%	27.7%
Active	New Generation	24.3%	5.4%	16.3%	5.0%	0.0%	0.0%	50.0%	1.9%	8.3%	7.7%	0.0%	0.0%	31.9%	0.0%	0.0%	0.0%	0.0%	13.7%	20.9%
	Upgrade	55.6%	15.8%	20.1%	0.0%	0.0%	0.0%	0.0%	12.0%	12.1%	0.0%	0.0%	5.3%	56.7%	6.8%	30.0%	0.0%	9.1%	25.5%	23.5%

Table 12-24 shows the nameplate generating capacity of projects in the PJM generation queue by technology type and project classification. For example, the 425 new generation wind projects that have been withdrawn from the queue as of September 30, 2019, (as shown in Table 12-22) constitute 72,508.0 MW of nameplate capacity. The 502 new generation and upgrade combined cycle projects that have been withdrawn in the same time period constitute 216,949.4 MW of nameplate capacity.

Table 12-24 Status of all generation capacity (MW) in the PJM generation queue: January 1997 through September 2019

		Project MW																		
Project Status	Project Classification	Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Total
In Service	New Generation	216.9	31,678.5	6,600.5	676.5	151.3	1.9	0.0	371.5	1,639.0	138.1	0.0	440.1	1,573.4	1,343.0	723.0	0.0	60.9	8,160.7	53,775.3
	Upgrade	46.4	6,031.4	2,323.5	127.8	12.3	0.0	390.0	385.2	2,282.8	15.7	23.3	49.9	22.4	909.5	131.5	0.0	605.3	20.5	13,377.5
Under Construction	New Generation	4.5	3,202.0	205.0	0.0	0.0	0.0	0.0	22.7	0.0	19.6	0.0	0.0	507.2	0.0	0.0	0.0	0.0	1,468.6	5,429.6
	Upgrade	0.0	362.5	48.0	0.0	0.0	0.0	0.0	0.0	44.0	1.6	4.0	0.0	158.9	36.0	0.0	0.0	62.5	207.5	925.0
Suspended	New Generation	39.3	4,084.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	39.8	0.0	0.0	625.6	0.0	0.0	0.0	16.0	1,156.1	5,960.8
	Upgrade	23.0	695.1	230.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20.0	0.0	0.0	0.0	0.0	16.3	984.4
Withdrawn	New Generation	1,908.5	206,720.2	2,746.8	1,721.0	1,244.2	5.5	500.0	1,986.9	8,161.0	388.1	63.9	88.6	31,928.1	33,511.6	27.0	0.0	1,034.9	72,508.0	364,544.3
	Upgrade	354.1	10,229.3	499.5	589.0	72.5	0.9	0.0	57.1	916.0	0.0	13.0	10.0	943.5	865.0	0.0	0.0	37.1	1,274.0	15,861.0
Active	New Generation	2,625.5	20,682.4	4,508.4	14.0	0.0	0.0	1,000.0	15.0	28.0	52.0	0.0	0.0	47,196.7	0.0	0.0	0.0	0.0	24,873.9	100,995.9
	Upgrade	963.1	3,641.8	1,338.7	0.0	0.0	0.0	0.0	99.0	95.5	0.0	0.0	0.8	3,007.4	96.0	94.0	0.0	40.0	727.8	10,104.1
Total Projects	New Generation	4,794.6	266,367.1	14,060.7	2,411.5	1,395.6	7.4	1,500.0	2,396.1	9,828.0	637.6	63.9	528.7	81,830.9	34,854.6	750.0	0.0	1,111.8	108,167.3	530,705.8
	Upgrade	1,386.6	20,960.1	4,439.7	716.8	84.8	0.9	390.0	541.3	3,338.3	17.3	40.3	60.7	4,152.2	1,906.5	225.5	0.0	744.9	2,246.1	41,252.0

Table 12-25 shows the MW totals in Table 12-24 by share by classification as new generation or upgrade. Within a unit type the shares of upgrades add to 100 percent and the shares of new generation add to 100 percent. For example, 67.0 percent of wind project MW classified as new generation have been withdrawn from the queue between January 1, 1997, and September 30, 2019.

Table 12-25 Status of all generation queue projects as percent of total MW in project classification: January 1997 through September 2019

		Percent of Total Projects by Classification																		
Project Status	Project Classification	Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Total
In Service	New Generation	4.5%	11.9%	46.9%	28.1%	10.8%	26.2%	0.0%	15.5%	16.7%	21.7%	0.0%	83.2%	1.9%	3.9%	96.4%	0.0%	5.5%	7.5%	10.1%
	Upgrade	3.3%	28.8%	52.3%	17.8%	14.5%	0.0%	100.0%	71.2%	68.4%	90.8%	57.8%	82.2%	0.5%	47.7%	58.3%	0.0%	81.3%	0.9%	32.4%
Under Construction	New Generation	0.1%	1.2%	1.5%	0.0%	0.0%	0.0%	0.0%	0.9%	0.0%	3.1%	0.0%	0.0%	0.6%	0.0%	0.0%	0.0%	0.0%	1.4%	1.0%
	Upgrade	0.0%	1.7%	1.1%	0.0%	0.0%	0.0%	0.0%	0.0%	1.3%	9.2%	9.9%	0.0%	3.8%	1.9%	0.0%	0.0%	8.4%	9.2%	2.2%
Suspended	New Generation	0.8%	1.5%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	6.2%	0.0%	0.0%	0.8%	0.0%	0.0%	0.0%	1.4%	1.1%	1.1%
	Upgrade	1.7%	3.3%	5.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.5%	0.0%	0.0%	0.0%	0.0%	0.7%	2.4%
Withdrawn	New Generation	39.8%	77.6%	19.5%	71.4%	89.2%	73.8%	33.3%	82.9%	83.0%	60.9%	100.0%	16.8%	39.0%	96.1%	3.6%	0.0%	93.1%	67.0%	68.7%
	Upgrade	25.5%	48.8%	11.3%	82.2%	85.5%	100.0%	0.0%	10.6%	27.4%	0.0%	32.3%	16.5%	22.7%	45.4%	0.0%	0.0%	5.0%	56.7%	38.4%
Active	New Generation	54.8%	7.8%	32.1%	0.6%	0.0%	0.0%	66.7%	0.6%	0.3%	8.2%	0.0%	0.0%	57.7%	0.0%	0.0%	0.0%	0.0%	23.0%	19.0%
	Upgrade	69.5%	17.4%	30.2%	0.0%	0.0%	0.0%	0.0%	18.3%	2.9%	0.0%	0.0%	1.3%	72.4%	5.0%	41.7%	0.0%	5.4%	32.4%	24.5%

Table 12-26 shows the project MW that entered the PJM generation queue by unit type and year of entry. Since 2016, 91.8 percent of all new projects entering the generation queue have been either combined cycle (23.7 percent), wind (21.5 percent) or solar projects (46.6 percent).

Table 12-26 Queue project MW by unit type and queue entry year: January 1997 through September 2019

Year	Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Total
1997	0.0	4,148.0	321.0	315.0	0.0	0.0	0.0	0.0	50.0	0.0	0.0	0.0	0.0	6.0	0.0	0.0	0.0	0.0	4,840.0
1998	0.0	7,006.0	1,775.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8,781.0
1999	0.0	29,412.7	2,412.1	0.0	10.0	0.0	0.0	196.0	45.0	0.0	0.0	0.0	0.0	47.0	0.0	0.0	525.0	115.4	32,763.2
2000	0.0	21,144.8	493.6	31.5	8.8	0.0	0.0	0.0	95.0	0.0	0.0	1.2	0.0	37.0	2.5	0.0	0.0	95.6	21,909.9
2001	0.0	25,411.7	264.0	0.0	0.0	0.0	0.0	107.0	90.0	0.0	0.0	15.6	0.0	1,244.6	10.0	0.0	0.0	252.9	27,395.8
2002	0.0	4,154.0	11.7	0.0	70.5	0.0	0.0	293.0	236.0	8.0	23.3	4.5	0.0	1,895.0	0.0	0.0	0.0	790.9	7,486.9
2003	0.0	2,361.4	10.0	8.0	0.8	0.0	0.0	2.0	0.0	29.0	0.0	27.5	0.0	522.0	0.0	0.0	165.0	997.0	4,122.7
2004	0.0	3,610.0	43.3	20.0	49.1	0.0	0.0	0.0	1,911.0	0.0	35.5	17.5	0.0	1,187.0	0.0	0.0	0.0	1,614.7	8,488.1
2005	0.0	5,824.6	961.0	281.0	51.4	0.0	340.0	174.2	242.0	21.5	0.0	65.1	0.0	6,360.0	0.0	0.0	24.0	6,020.0	20,364.9
2006	0.0	4,188.1	454.3	607.5	73.1	0.0	0.0	159.0	6,894.0	0.0	0.0	93.0	0.0	9,586.0	0.0	0.0	258.5	7,650.7	29,964.2
2007	0.0	13,944.6	941.2	215.9	149.5	0.0	16.0	161.6	368.0	0.0	0.0	56.5	3.3	9,078.0	190.0	0.0	50.5	18,525.6	43,700.6
2008	121.0	26,001.0	129.7	1,113.0	488.8	0.0	0.0	1,254.5	105.0	6.0	0.0	32.0	66.3	1,198.0	0.0	0.0	192.3	11,066.1	41,773.7
2009	34.0	5,548.4	14.0	66.0	214.2	0.0	0.0	133.9	1,933.8	4.5	16.0	15.2	636.5	1,273.0	5.5	0.0	148.0	6,672.6	16,715.6
2010	72.4	9,185.4	176.0	7.9	117.3	0.0	0.0	132.6	426.0	0.0	2.4	57.8	3,690.0	64.0	0.0	0.0	173.5	9,848.4	23,953.7
2011	24.1	19,769.5	29.5	0.0	174.6	0.0	0.0	30.0	182.0	0.0	14.0	75.3	2,022.9	357.0	0.0	0.0	49.0	5,576.4	28,304.3
2012	142.6	18,014.8	282.1	42.5	48.4	0.0	0.0	11.8	369.0	37.2	0.0	4.0	284.6	1,837.0	0.0	0.0	143.1	1,529.8	22,746.8
2013	217.4	10,493.1	1,201.8	5.0	11.2	0.0	0.0	89.4	102.0	59.7	0.0	1.6	231.7	158.0	40.0	0.0	44.7	1,407.9	14,063.4
2014	246.9	11,704.5	1,532.5	401.0	7.7	0.0	0.0	60.5	0.0	48.0	0.0	17.7	1,595.7	1,730.5	27.0	0.0	43.1	1,763.7	19,178.8
2015	546.9	27,540.8	1,324.5	0.0	0.9	2.3	34.0	0.0	0.0	320.4	13.0	31.4	2,931.6	47.0	606.5	0.0	0.0	2,160.6	35,559.7
2016	111.1	18,802.5	1,392.0	0.0	0.0	3.4	0.0	12.5	50.3	23.5	0.0	38.9	11,771.5	80.0	77.0	0.0	0.0	3,467.5	35,830.2
2017	24.6	5,465.8	702.0	0.0	4.1	2.7	0.0	20.5	39.1	97.1	0.0	33.8	13,883.9	14.0	17.0	0.0	0.0	5,432.0	25,736.7
2018	1,567.6	11,080.1	2,647.4	14.0	0.0	0.0	1,000.0	0.0	28.1	0.0	0.0	0.8	24,375.3	29.0	0.0	0.0	40.0	17,772.3	58,554.6
2019	3,072.6	2,515.5	1,381.7	0.0	0.0	0.0	500.0	99.0	0.0	0.0	0.0	0.0	24,489.8	11.0	0.0	0.0	0.0	7,653.3	39,722.9
Total	6,181.2	287,327.2	18,500.4	3,128.3	1,480.3	8.3	1,890.0	2,937.4	13,166.3	654.9	104.2	589.4	85,983.2	36,761.1	975.5	0.0	1,856.7	110,413.4	571,957.8

Combined Cycle Project Analysis

Table 12-27 shows the status of all combined cycle projects by number of projects that entered PJM generation queues from January 1, 1997, through September 30, 2019, by zone. Of the 86 combined cycle projects classified either as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, 41 projects (47.7 percent) are located within AEP, ComEd and APS.

Table 12-27 Status of all combined cycle queue projects by zone (number of projects): January 1997 through September 2019

		Number of Projects																					
Project Status	Project Classification	AECO	AEP	APS	ATSI	BGE	ComEd	DAY	DEOK	DLCO	Dominion	DPL	EKPC	JCPL	Met-Ed	OVEC	PECO	PENELEC	Pepco	PPL	PSEG	RECO	Total
In Service	New Generation	1	4	2	2	2	1	0	2	0	7	2	0	7	4	0	5	1	4	10	6	0	60
	Upgrade	3	9	7	3	0	4	0	0	0	14	5	0	6	2	0	10	3	2	7	14	0	89
Under Construction	New Generation	0	0	0	2	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	3
	Upgrade	0	2	0	2	0	0	0	0	0	0	0	0	0	0	0	2	1	2	0	0	0	9
Suspended	New Generation	0	0	2	0	0	0	0	0	0	1	0	0	1	0	0	0	0	1	0	0	0	5
	Upgrade	0	0	1	0	0	0	0	0	0	0	1	0	2	0	0	0	0	2	0	0	0	6
Withdrawn	New Generation	21	19	42	13	8	14	0	1	2	17	17	3	25	25	0	43	40	33	40	54	2	419
	Upgrade	6	7	5	3	0	3	0	1	0	10	4	0	5	7	0	3	5	3	6	15	0	83
Active	New Generation	2	7	6	2	0	5	1	0	0	1	0	0	0	0	0	0	1	0	1	2	0	28
	Upgrade	2	6	8	1	0	4	0	0	0	3	0	0	1	2	0	1	2	0	4	1	0	35
Total Projects	New Generation	24	30	52	19	10	20	1	3	2	26	19	3	33	29	0	48	43	38	51	62	2	515
	Upgrade	11	24	21	9	0	11	0	1	0	27	10	0	14	11	0	16	11	9	17	30	0	222

Table 12-28 shows the status of all combined cycle projects by MW that entered PJM generation queues from January 1, 1997 through September 30, 2019, by zone. Of the 32,667.8 MW of combined cycle projects classified either as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, 16,971.3 MW (52.0 percent) are located within AEP, ComEd and APS.

Table 12-28 Status of all combined cycle queue projects by zone (MW): January 1997 through September 2019

		Project MW																					
Project Status	Project Classification	AECO	AEP	APS	ATSI	BGE	ComEd	DAY	DEOK	DLCO	Dominion	DPL	EKPC	JCPL	Met-Ed	OVEC	PECO	PENELEC	Pepco	PPL	PSEG	RECO	Total
In Service	New Generation	650.0	3,032.0	1,455.0	1,599.0	140.0	600.0	0.0	533.0	0.0	5,854.1	319.2	0.0	1,665.8	2,557.0	0.0	2,665.0	850.0	1,560.0	5,750.0	2,448.5	0.0	31,678.5
	Upgrade	229.0	230.0	790.0	306.0	0.0	633.6	0.0	0.0	0.0	873.0	102.0	0.0	110.0	45.0	0.0	973.5	92.3	89.1	712.0	845.9	0.0	6,031.4
Under Construction	New Generation	0.0	0.0	0.0	2,152.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,050.0	0.0	0.0	0.0	0.0	3,202.0
	Upgrade	0.0	100.0	0.0	38.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	35.0	50.0	139.5	0.0	0.0	0.0	362.5
Suspended	New Generation	0.0	0.0	1,690.0	0.0	0.0	0.0	0.0	0.0	0.0	1,060.0	0.0	0.0	440.0	0.0	0.0	0.0	0.0	894.0	0.0	0.0	0.0	4,084.0
	Upgrade	0.0	0.0	45.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	451.0	0.0	55.0	0.0	0.0	0.0	0.0	144.1	0.0	0.0	0.0	695.1
Withdrawn	New Generation	7,515.4	12,509.5	18,982.1	8,641.0	3,122.1	10,142.0	0.0	134.5	665.0	11,261.0	5,436.4	991.8	13,122.6	13,001.0	0.0	23,340.0	15,951.0	20,414.2	17,270.7	24,213.1	6.9	206,720.2
	Upgrade	115.4	711.0	579.0	86.0	0.0	1,375.0	0.0	36.0	0.0	580.4	668.0	0.0	253.0	1,742.0	0.0	240.0	1,040.6	85.0	500.0	2,217.9	0.0	10,229.3
Active	New Generation	1,027.0	5,329.0	4,056.0	1,895.0	0.0	3,600.9	1,150.0	0.0	0.0	1,600.0	0.0	0.0	0.0	0.0	0.0	0.0	163.0	0.0	1,030.0	831.5	0.0	20,682.4
	Upgrade	41.6	740.0	938.7	550.0	0.0	471.7	0.0	0.0	0.0	180.0	0.0	0.0	105.0	113.9	0.0	67.0	85.0	0.0	297.8	51.1	0.0	3,641.8
Total Projects	New Generation	9,192.4	20,870.5	26,183.1	14,287.0	3,262.1	14,342.9	1,150.0	667.5	665.0	19,775.1	5,755.6	991.8	15,228.4	15,558.0	0.0	26,005.0	18,014.0	22,868.2	24,050.7	27,493.1	6.9	266,367.1
	Upgrade	386.0	1,781.0	2,352.7	980.0	0.0	2,480.3	0.0	36.0	0.0	1,633.4	1,221.0	0.0	523.0	1,900.9	0.0	1,315.5	1,267.9	457.7	1,509.8	3,114.9	0.0	20,960.1

Combustion Turbine - Natural Gas Project Analysis

Table 12-29 shows the status of all combustion turbine natural gas projects by number of projects that entered PJM generation queues from January 1, 1997, through September 30, 2019, by zone. Of the 46 combustion turbine natural gas projects classified either as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, 24 projects (52.2 percent) are located within AEP, ComEd and APS.

Table 12-29 Status of all combustion turbine - natural gas generation queue projects by zone (number of projects): January 1997 through September 2019

		Number of Projects																						
Project Status	Project Classification	AECO	AEP	APS	ATSI	BGE	ComEd	DAY	DEOK	DLCO	Dominion	DPL	EKPC	JCPL	Met-Ed	OVEC	PECO	PENELEC	Pepco	PPL	PSEG	RECO	Total
In Service	New Generation	5	0	6	0	3	0	0	0	0	2	7	0	3	1	0	2	4	2	4	9	0	48
	Upgrade	4	7	7	1	0	9	6	0	0	25	7	0	0	1	0	2	2	3	4	14	0	92
Under Construction	New Generation	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	1
	Upgrade	0	0	0	0	0	1	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	2
Suspended	New Generation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Upgrade	0	0	1	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	2
Withdrawn	New Generation	1	5	0	0	0	1	1	0	0	2	0	1	0	0	0	1	5	0	1	5	0	23
	Upgrade	2	1	1	1	0	1	0	0	0	3	0	0	0	1	0	0	1	0	0	0	0	11
Active	New Generation	1	1	0	0	2	2	0	0	0	5	0	0	0	0	0	1	1	0	0	1	0	14
	Upgrade	0	2	3	1	0	14	1	0	0	3	0	0	0	0	0	1	2	0	0	0	0	27
Total Projects	New Generation	7	6	6	0	5	3	1	0	1	9	7	1	3	1	0	4	10	2	5	15	0	86
	Upgrade	6	10	12	3	0	25	7	0	0	31	7	0	2	2	0	3	5	3	4	14	0	134

Table 12-30 shows the status of all combustion turbine natural gas projects by MW that entered PJM generation queues from January 1, 1997 through September 30, 2019, by zone. Of the 6,330.1 MW of combustion turbine natural gas projects classified either as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, 1,934.7 MW (30.6 percent) are located within AEP, ComEd and APS.

Table 12-30 Status of all combustion turbine - natural gas queue projects by zone (MW): January 1997 through September 2019

		Project MW																						
Project Status	Project Classification	AECO	AEP	APS	ATSI	BGE	ComEd	DAY	DEOK	DLCO	Dominion	DPL	EKPC	JCPL	Met-Ed	OVEC	PECO	PENELEC	Pepco	PPL	PSEG	RECO	Total
In Service	New Generation	360.7	0.0	1,176.0	0.0	23.0	0.0	0.0	0.0	0.0	1,015.0	1,491.0	0.0	522.1	10.0	0.0	559.0	361.9	5.0	150.9	925.9	0.0	6,600.5
	Upgrade	43.7	190.0	187.7	40.0	0.0	257.0	60.0	0.0	0.0	887.7	86.0	0.0	0.0	34.1	0.0	13.0	25.0	32.0	252.3	215.0	0.0	2,323.5
Under Construction	New Generation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	205.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	205.0
	Upgrade	0.0	0.0	0.0	0.0	0.0	48.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	48.0
Suspended	New 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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Upgrade	0.0	0.0	30.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	200.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	230.0
Withdrawn	New Generation	7.5	989.5	0.0	0.0	0.0	10.0	104.0	0.0	0.0	75.5	0.0	73.0	0.0	0.0	0.0	0.5	326.8	0.0	19.9	1,140.1	0.0	2,746.8
	Upgrade	165.5	6.0	4.0	25.0	0.0	7.0	0.0	0.0	0.0	57.0	0.0	0.0	0.0	0.0	0.0	0.0	235.0	0.0	0.0	0.0	0.0	499.5
Active	New Generation	230.0	529.5	0.0	0.0	153.6	230.0	0.0	0.0	0.0	2,198.3	0.0	0.0	0.0	0.0	0.0	29.0	463.0	0.0	0.0	675.0	0.0	4,508.4
	Upgrade	0.0	38.0	82.0	70.0	0.0	977.2	23.5	0.0	0.0	38.0	0.0	0.0	0.0	0.0	0.0	0.0	110.0	0.0	0.0	0.0	0.0	1,338.7
Total Projects	New Generation	598.2	1,519.0	1,176.0	0.0	176.6	240.0	104.0	0.0	205.0	3,288.8	1,491.0	73.0	522.1	10.0	0.0	588.5	1,151.7	5.0	170.8	2,741.0	0.0	14,060.7
	Upgrade	209.2	234.0	303.7	135.0	0.0	1,289.2	83.5	0.0	0.0	982.7	86.0	0.0	200.0	34.1	0.0	13.0	370.0	32.0	252.3	215.0	0.0	4,439.7

Wind Project Analysis

Table 12-31 shows the status of all wind generation projects by number of projects that entered PJM generation queues from January 1, 1997, through September 30, 2019, by zone. Of the 88 wind projects to achieve in service status, 51 projects (58.0 percent) are located within AEP, ComEd and APS. Of the 119 wind projects currently active, suspended or under construction in the PJM generation queue, 81 projects (68.1 percent) are located within AEP, ComEd and APS.

Table 12-31 Status of all wind generation queue projects by zone (number of projects): January 1997 through September 2019

		Number of Projects																					
Project Status	Project Classification	AECO	AEP	APS	ATSI	BGE	ComEd	DAY	DEOK	DLCO	Dominion	DPL	EKPC	JCPL	Met-Ed	OVEC	PECO	PENELEC	Pepco	PPL	PSEG	RECO	Total
In Service	New Generation	1	14	14	0	0	20	0	0	0	2	0	0	0	0	0	0	22	0	8	0	0	81
	Upgrade	0	0	0	0	0	3	0	0	0	0	0	0	0	0	0	0	4	0	0	0	0	7
Under Construction	New Generation	0	1	3	0	0	4	0	0	0	1	0	0	0	0	0	0	1	0	0	0	0	10
	Upgrade	0	0	1	0	0	1	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	3
Suspended	New Generation	0	4	2	0	0	0	0	0	0	1	0	0	0	0	0	0	1	0	1	0	0	9
	Upgrade	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Withdrawn	New Generation	16	98	41	8	0	105	15	0	0	21	10	1	1	0	0	0	63	0	45	1	0	425
	Upgrade	2	1	6	0	0	7	0	0	0	3	0	0	0	0	0	0	6	0	2	0	0	27
Active	New Generation	7	25	7	3	0	21	0	0	0	5	4	0	6	0	0	0	1	0	4	0	0	83
	Upgrade	0	1	3	0	0	7	0	0	0	0	1	0	0	0	0	0	1	0	0	0	0	13
Total Projects	New Generation	24	142	67	11	0	150	15	0	0	30	14	1	7	0	0	0	88	0	58	1	0	608
	Upgrade	2	2	11	0	0	18	0	0	0	3	1	0	0	0	0	0	12	0	2	0	0	51

Table 12-32 shows the status of all wind projects by MW that entered PJM generation queues from January 1, 1997 through September 30, 2019, by zone. Of the 8,181.2 MW of wind generation capacity to achieve the in service status, 6,641.2 MW (81.2 percent) of nameplate capacity is located within AEP, ComEd and APS. Of the 28,450.2 MW of wind generation capacity currently active, suspended or under construction in the PJM generation queue, 14,256.7 MW of generation capacity (50.1 percent) is located within AEP, ComEd and APS.

Table 12-32 Status of all wind generation queue projects by zone (MW): January 1997 through September 2019

		Project MW																					
Project Status	Project Classification	AECO	AEP	APS	ATSI	BGE	ComEd	DAY	DEOK	DLCO	Dominion	DPL	EKPC	JCPL	Met-Ed	OVEC	PECO	PENELEC	Pepco	PPL	PSEG	RECO	Total
In Service	New Generation	7.5	2,738.7	1,004.0	0.0	0.0	2,878.5	0.0	0.0	0.0	310.5	0.0	0.0	0.0	0.0	0.0	0.0	995.0	0.0	226.5	0.0	0.0	8,160.7
	Upgrade	0.0	0.0	0.0	0.0	0.0	20.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.5	0.0	0.0	0.0	0.0	20.5
Under Construction	New Generation	0.0	150.0	310.6	0.0	0.0	926.0	0.0	0.0	0.0	12.0	0.0	0.0	0.0	0.0	0.0	0.0	70.0	0.0	0.0	0.0	0.0	1,468.6
	Upgrade	0.0	0.0	0.0	0.0	0.0	187.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20.0	0.0	0.0	0.0	0.0	207.5
Suspended	New Generation	0.0	588.4	293.1	0.0	0.0	0.0	0.0	0.0	0.0	76.6	0.0	0.0	0.0	0.0	0.0	0.0	100.0	0.0	98.0	0.0	0.0	1,156.1
	Upgrade	0.0	0.0	16.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	16.3
Withdrawn	New Generation	3,646.4	20,153.2	3,134.1	1,295.6	0.0	24,519.2	2,128.0	0.0	0.0	4,988.4	2,816.8	150.3	1,104.0	0.0	0.0	0.0	5,277.0	0.0	3,275.1	20.0	0.0	72,508.0
	Upgrade	5.0	200.0	100.0	0.0	0.0	605.7	0.0	0.0	0.0	114.0	0.0	0.0	0.0	0.0	0.0	0.0	243.4	0.0	6.0	0.0	0.0	1,274.0
Active	New Generation	3,939.6	5,145.3	539.0	816.1	0.0	5,480.5	0.0	0.0	0.0	3,580.6	671.8	0.0	4,159.2	0.0	0.0	0.0	109.9	0.0	432.1	0.0	0.0	24,873.9
	Upgrade	0.0	170.0	24.4	0.0	0.0	425.7	0.0	0.0	0.0	0.0	7.3	0.0	0.0	0.0	0.0	0.0	100.3	0.0	0.0	0.0	0.0	727.8
Total Projects	New Generation	7,593.5	28,775.6	5,280.8	2,111.7	0.0	33,804.1	2,128.0	0.0	0.0	8,968.1	3,488.6	150.3	5,263.2	0.0	0.0	0.0	6,551.9	0.0	4,031.7	20.0	0.0	108,167.3
	Upgrade	5.0	370.0	140.7	0.0	0.0	1,238.9	0.0	0.0	0.0	114.0	7.3	0.0	0.0	0.0	0.0	0.0	364.2	0.0	6.0	0.0	0.0	2,246.1

Solar Project Analysis

Table 12-33 shows the status of all solar generation projects by number of projects that entered PJM generation queues from January 1, 1997, through September 30, 2019, by zone. Of the 157 solar projects to achieve in service status, 9 projects (5.7 percent) are located within AEP, ComEd and APS. Of the 722 solar projects currently active, suspended or under construction in the PJM generation queue, 224 projects (31.0 percent) are located within AEP, ComEd and APS.

Table 12-33 Status of all solar generation queue projects by zone (number of projects): January 1997 through September 2019

		Number of Projects																					
Project Status	Project Classification	AECO	AEP	APS	ATSI	BGE	ComEd	DAY	DEOK	DLCO	Dominion	DPL	EKPC	JCPL	Met-Ed	OVEC	PECO	PENELEC	Pepco	PPL	PSEG	RECO	Total
In Service	New Generation	7	4	4	0	1	1	1	0	0	22	11	0	44	0	0	1	0	0	2	41	0	139
	Upgrade	0	0	0	0	0	0	0	0	0	3	8	0	7	0	0	0	0	0	0	0	0	18
Under Construction	New Generation	0	0	1	0	0	0	0	0	0	5	1	0	3	0	0	0	0	1	0	7	0	18
	Upgrade	0	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	10	0	0	0	1	0	0	3	0	0	3	2	0	0	0	0	0	1	0	25
	Upgrade	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	1
Withdrawn	New Generation	175	92	70	14	13	33	17	14	0	171	126	7	184	15	1	6	18	16	33	93	0	1,098
	Upgrade	2	4	1	0	0	3	0	0	0	13	1	0	8	0	0	0	0	1	0	3	1	37
Active	New Generation	18	113	51	21	0	31	18	3	4	184	38	19	11	17	0	3	34	14	16	4	1	600
	Upgrade	2	9	1	2	0	3	4	3	1	34	4	2	2	2	0	0	0	0	5	2	0	76
Total Projects	New Generation	200	214	136	35	14	65	37	17	4	385	176	26	245	34	1	10	52	31	51	146	1	1,880
	Upgrade	4	13	2	2	0	6	4	3	1	51	14	2	17	3	0	0	0	1	5	5	1	134

Table 12-34 shows the status of all solar projects by MW that entered PJM generation queues from January 1, 1997 through September 30, 2019, by zone. Of the 1,595.8 MW of solar generation capacity to achieve in service status, 76.7 MW (4.8 percent) of nameplate capacity is located within AEP, ComEd and APS. Of the 51,515.8 MW of solar generation capacity currently active, suspended or under construction in the PJM generation queue, 20,452.3 MW of generation capacity (39.7 percent) is located within AEP, ComEd and APS.

Table 12-34 Status of all solar generation queue projects by zone (MW): January 1997 through September 2019

		Project MW																					
Project Status	Project Classification	AECO	AEP	APS	ATSI	BGE	ComEd	DAY	DEOK	DLCO	Dominion	DPL	EKPC	JCPL	Met-Ed	OVEC	PECO	PENELEC	Pepco	PPL	PSEG	RECO	Total
In Service	New Generation	57.3	14.7	53.0	0.0	1.1	9.0	2.5	0.0	0.0	750.8	130.4	0.0	322.8	0.0	0.0	3.3	0.0	0.0	15.0	213.5	0.0	1,573.4
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8.1	0.0	0.0	14.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	22.4
Under Construction	New Generation	0.0	0.0	10.0	0.0	0.0	0.0	0.0	0.0	0.0	388.4	20.0	0.0	51.9	0.0	0.0	0.0	0.0	2.5	0.0	34.4	0.0	507.2
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8.9	150.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	158.9
Suspended	New Generation	0.0	60.0	202.6	0.0	0.0	0.0	20.0	0.0	0.0	291.0	0.0	0.0	8.0	38.0	0.0	0.0	0.0	0.0	0.0	6.0	0.0	625.6
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20.0
Withdrawn	New Generation	1,763.3	7,086.7	1,907.7	628.2	57.3	2,126.8	1,023.9	429.4	0.0	10,580.9	1,668.4	779.9	1,440.0	546.0	78.0	51.4	476.7	187.6	548.6	547.3	0.0	31,928.1
	Upgrade	10.0	126.0	0.0	0.0	0.0	40.0	0.0	0.0	0.0	718.8	0.0	0.0	23.8	0.0	0.0	0.0	0.0	3.6	0.0	1.3	20.0	943.5
Active	New Generation	588.8	13,603.1	1,810.3	2,012.3	0.0	3,777.5	2,097.7	295.0	63.0	15,606.9	1,470.0	1,846.0	160.0	774.1	0.0	47.8	2,244.8	189.3	536.2	34.0	40.0	47,196.7
	Upgrade	160.0	553.8	75.0	60.0	0.0	360.0	158.5	85.0	8.3	1,239.8	75.0	120.0	7.6	40.0	0.0	0.0	0.0	0.0	60.0	4.4	0.0	3,007.4
Total Projects	New Generation	2,409.4	20,764.6	3,983.6	2,640.5	58.4	5,913.3	3,144.1	724.4	63.0	27,618.0	3,288.8	2,625.9	1,982.6	1,358.1	78.0	102.5	2,721.5	379.4	1,099.8	835.2	40.0	81,830.9
	Upgrade	170.0	679.8	75.0	60.0	0.0	400.0	158.5	85.0	8.3	1,975.6	225.0	120.0	45.7	60.0	0.0	0.0	0.0	3.6	60.0	5.7	20.0	4,152.2

Relationship Between Project Developer and Transmission Owner

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."[33] 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 nonincumbent transmission developer which is a competitor of the transmission owner. The MMU recommends outsourcing interconnection studies to an independent party to avoid potential conflicts of interest.

Table 12-35 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 September 30, 2019, by transmission owner and unit type. A project where the developer 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 combined cycle 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 667.5 MW of combined cycle projects that have entered the PJM generation queue in DEOK by developers not affiliated with Duke Energy. These project MW are classified as unrelated.

Of the 571,957.8 MW that have entered the queue during the time period of January 1, 1997, through September 30, 2019, 64,836.4 MW (11.3 percent) have been submitted by transmission owners building in their own service territory. PSEG is the transmission owner with the highest percentage of affiliates building in their own service territory. Of the 36,600.1 MW that entered the queue during the time period of January 1, 1997, through September 30, 2019, 14,287.9 MW (39.0 percent) have been submitted by PSEG or one of their affiliated companies.

33 See OATT § 1 (Transmission Owner).

Table 12-35 Relationship between project developer and transmission owner for all interconnection queue projects MW by unit type: September 30, 2019

Parent Company	Transmission Owner	Related to Developer	Number of Projects	MW by Unit Type: Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Total
AEP	AEP	Related	48	16.0	678.0	0.0	0.0	0.0	0.0	34.0	0.0	214.0	0.0	0.0	0.0	142.7	3,918.0	90.0	0.0	0.0	0.0	5,092.7
		Unrelated	557	1,586.6	21,973.5	1,753.0	7.5	127.3	0.0	0.0	453.6	0.0	12.0	0.0	75.4	21,301.7	10,379.0	0.0	0.0	492.0	29,145.6	87,307.1
AES	DAY	Related	13	20.0	0.0	38.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	21.5	1,347.5	0.0	0.0	0.0	0.0	1,427.0
		Unrelated	65	79.9	1,150.0	149.5	0.0	1.9	0.0	0.0	0.0	0.0	0.0	0.0	10.0	3,281.1	0.0	0.0	0.0	0.0	2,128.0	6,800.4
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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	25	20.0	665.0	205.0	40.0	19.2	0.0	0.0	106.0	1,879.0	0.0	0.0	0.0	71.3	2,810.0	0.0	0.0	0.0	0.0	5,815.5
Dominion	Dominion	Related	108	0.0	12,364.0	2,045.7	100.0	0.0	0.0	340.0	0.0	1,944.0	0.0	0.0	60.0	1,574.4	301.0	0.0	0.0	4.0	1,026.0	19,759.1
		Unrelated	547	943.6	9,044.5	2,225.8	0.5	227.3	0.0	0.0	35.0	0.0	0.0	10.0	119.4	28,019.2	20.0	0.0	0.0	316.3	8,056.1	49,017.8
Duke	DEOK	Related	7	23.8	36.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6.4	0.0	0.0	0.0	0.0	0.0	66.2
		Unrelated	30	120.4	667.5	0.0	0.0	0.0	0.0	0.0	112.0	0.0	0.0	0.0	4.8	803.0	120.0	0.0	0.0	0.0	0.0	1,827.7
EKPC	EKPC	Related	2	0.0	821.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	821.8
		Unrelated	32	20.3	170.0	73.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,745.9	0.0	0.0	0.0	0.0	150.3	3,159.5
Exelon	AECO	Related	5	0.0	730.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8.3	0.0	0.0	0.0	0.0	0.0	738.3
		Unrelated	314	161.0	8,848.4	807.4	388.0	20.7	2.8	0.0	0.0	0.0	2.0	5.0	10.3	2,571.1	15.0	5.5	0.0	10.0	7,598.5	20,445.7
	BGE	Related	14	20.0	250.0	10.0	0.0	0.0	0.0	0.0	0.0	108.5	0.0	0.0	8.5	20.0	10.0	101.0	0.0	0.0	0.0	528.0
		Unrelated	59	240.6	3,012.1	166.6	18.0	133.0	0.0	0.0	0.4	3,280.0	1.3	0.0	0.0	38.4	0.0	2.5	0.0	25.0	0.0	6,917.9
	ComEd	Related	16	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,185.0	0.0	0.0	0.0	9.0	0.0	0.0	0.0	0.0	0.0	1,194.0
		Unrelated	368	659.5	16,823.2	1,529.2	42.0	65.2	0.0	0.0	22.7	0.0	35.0	0.0	67.7	6,304.3	1,926.0	91.0	0.0	90.0	35,043.0	62,698.7
	DPL	Related	7	0.0	1,365.0	351.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7.4	0.0	0.0	0.0	0.0	0.0	1,723.4
		Unrelated	295	153.0	5,611.6	1,226.0	600.9	42.6	0.0	0.0	0.0	0.0	0.0	0.0	84.6	3,506.4	653.0	15.0	0.0	65.0	3,495.9	15,454.0
	PECO	Related	33	40.0	6,965.0	5.0	89.5	0.0	0.0	0.0	265.0	437.8	0.0	0.0	0.0	0.0	7.0	0.0	0.0	0.0	0.0	7,809.3
		Unrelated	82	5.3	20,355.5	596.5	2.0	15.0	0.0	0.0	0.0	0.0	0.0	17.0	3.7	102.5	0.0	0.0	0.0	0.0	0.0	21,097.5
	Pepco	Related	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	95	20.0	23,325.9	37.0	30.0	9.0	0.0	0.0	0.0	1,640.0	32.0	0.0	3.5	383.0	0.0	0.0	0.0	0.0	0.0	25,480.4
FirstEnergy	APS	Related	4	0.0	1,453.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,710.0	0.0	0.0	0.0	0.0	3,163.0
		Unrelated	396	280.9	27,082.8	1,479.7	0.0	84.4	0.0	0.0	623.3	0.0	140.0	53.8	25.4	4,058.6	4,092.0	0.0	0.0	184.4	5,421.5	43,526.8
	ATSI	Related	6	0.0	1,678.0	0.0	0.0	0.0	0.0	0.0	0.0	16.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,694.0
		Unrelated	96	76.4	13,589.0	135.0	5.0	166.4	0.0	0.0	0.0	0.0	59.7	0.0	6.9	2,700.5	0.0	16.5	0.0	0.0	2,111.7	18,867.1
	JCPL	Related	2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20.0	0.0	0.0	0.0	0.0	12.0	0.0	0.0	0.0	0.0	0.0	32.0
		Unrelated	380	835.0	15,751.4	722.1	0.0	4.8	0.6	0.0	1.6	0.0	0.6	0.0	12.8	2,016.3	0.0	0.0	0.0	30.0	5,263.2	24,638.4
	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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	111	23.0	17,458.9	44.1	1,196.9	52.1	0.0	0.0	0.0	93.0	0.0	8.0	23.2	1,418.1	0.0	0.0	0.0	84.0	0.0	20,401.3
	PENELEC	Related	4	0.0	534.0	5.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,860.0	0.0	0.0	0.0	0.0	2,399.0
		Unrelated	280	257.4	18,747.9	1,516.7	0.0	214.4	0.0	16.0	46.3	0.0	341.8	8.0	14.8	2,721.5	561.0	590.0	0.0	525.0	6,916.1	32,476.6
OVEC	OVEC	Related	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	78.0	0.0	0.0	0.0	0.0	0.0	78.0
PPL	PPL	Related	21	0.0	2,261.0	0.0	0.0	0.0	0.0	0.0	109.0	1,600.0	0.0	0.0	0.0	19.8	111.0	0.0	0.0	0.0	0.0	4,100.8
		Unrelated	258	564.0	23,299.5	423.1	8.0	234.5	0.0	1,500.0	142.6	388.0	19.9	2.4	44.7	1,140.0	6,896.6	0.0	0.0	31.0	4,037.7	38,732.0
PSEG	PSEG	Related	109	0.0	11,836.1	1,818.1	0.0	0.0	0.0	0.0	0.0	381.0	0.0	0.0	0.0	184.7	24.0	44.0	0.0	0.0	0.0	14,287.9
		Unrelated	216	14.5	18,771.9	1,137.9	600.0	62.5	4.9	0.0	1,000.0	0.0	10.6	0.0	13.7	656.2	0.0	20.0	0.0	0.0	20.0	22,312.2
Con Ed	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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	4	0.0	6.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	60.0	0.0	0.0	0.0	0.0	0.0	66.9
Total		Related	399	119.8	40,971.9	4,272.8	189.5	0.0	0.0	374.0	394.0	5,886.3	0.0	0.0	68.5	2,006.1	9,288.5	235.0	0.0	4.0	1,026.0	64,836.4
		Unrelated	4211	6,061.4	246,355.3	14,227.6	2,938.8	1,480.3	8.3	1,516.0	2,543.4	7,280.0	654.9	104.2	520.9	83,977.0	27,472.6	740.5	0.0	1,852.7	109,387.4	507,121.4

Combined Cycle Project Developer and Transmission Owner Relationships

Table 12-36 shows the relationship between the project developer and transmission owner for all combined cycle project MW that have entered the PJM generation queue from January 1, 1997 through September 30, 2019, by transmission owner and project status. Of the 41,274.4 combined cycle project MW that have achieved in service or under construction status during this time period, 9,156.0 MW (22.2 percent) have been developed by transmission owners building in their own service territory. EKPC is the transmission owner with the highest percentage of affiliates building combined cycle projects in their own service territory. Of the 991.8 MW that entered the queue during the time period of January 1, 1997, through September 30, 2019, 821.8 MW (82.9 percent) have been submitted by EKPC or one of their affiliated companies.

Table 12-36 Relationship between project developer and transmission owner for all combined cycle project MW in PJM interconnection queue: September 30, 2019

			MW by Project Status					
Parent Company	Transmission Owner	Related to Developer	Active	In Service	Under Construction	Suspended	Withdrawn	Total
AEP	AEP	Related	98.0	580.0	0.0	0.0	0.0	678.0
		Unrelated	5,971.0	2,682.0	100.0	0.0	13,220.5	21,973.5
AES	DAY	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	1,150.0	0.0	0.0	0.0	0.0	1,150.0
DLCO	DLCO	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	0.0	0.0	665.0	665.0
Dominion	Dominion	Related	90.0	4,773.0	0.0	0.0	7,501.0	12,364.0
		Unrelated	1,690.0	1,954.1	0.0	1,060.0	4,340.4	9,044.5
Duke	DEOK	Related	0.0	0.0	0.0	0.0	36.0	36.0
		Unrelated	0.0	533.0	0.0	0.0	134.5	667.5
EKPC	EKPC	Related	0.0	0.0	0.0	0.0	821.8	821.8
		Unrelated	0.0	0.0	0.0	0.0	170.0	170.0
Exelon	AECO	Related	0.0	0.0	0.0	0.0	730.0	730.0
		Unrelated	1,068.6	879.0	0.0	0.0	6,900.8	8,848.4
	BGE	Related	0.0	130.0	0.0	0.0	120.0	250.0
		Unrelated	0.0	10.0	0.0	0.0	3,002.1	3,012.1
	ComEd	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	4,072.6	1,233.6	0.0	0.0	11,517.0	16,823.2
	DPL	Related	0.0	60.0	0.0	0.0	1,305.0	1,365.0
		Unrelated	0.0	361.2	0.0	451.0	4,799.4	5,611.6
	PECO	Related	0.0	0.0	0.0	0.0	6,965.0	6,965.0
		Unrelated	67.0	3,638.5	35.0	0.0	16,615.0	20,355.5
	Pepco	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	1,649.1	139.5	1,038.1	20,499.2	23,325.9
FirstEnergy	APS	Related	0.0	525.0	0.0	0.0	928.0	1,453.0
		Unrelated	4,994.7	1,720.0	0.0	1,735.0	18,633.1	27,082.8
	ATSI	Related	0.0	0.0	0.0	0.0	1,678.0	1,678.0
		Unrelated	2,445.0	1,905.0	2,190.0	0.0	7,049.0	13,589.0
	JCPL	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	105.0	1,775.8	0.0	495.0	13,375.6	15,751.4
	Met-Ed	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	113.9	2,602.0	0.0	0.0	14,743.0	17,458.9
	PENELEC	Related	0.0	0.0	0.0	0.0	534.0	534.0
		Unrelated	248.0	942.3	1,100.0	0.0	16,457.6	18,747.9
OVEC	OVEC	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
PPL	PPL	Related	0.0	600.0	0.0	0.0	1,661.0	2,261.0
		Unrelated	1,327.8	5,862.0	0.0	0.0	16,109.7	23,299.5
PSEG	PSEG	Related	51.1	2,488.0	0.0	0.0	9,297.0	11,836.1
		Unrelated	831.5	806.4	0.0	0.0	17,134.0	18,771.9
Con Ed	RECO	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	0.0	0.0	6.9	6.9
Total		Related	239.1	9,156.0	0.0	0.0	31,576.8	40,971.9
		Unrelated	24,085.1	28,553.9	3,564.5	4,779.1	185,372.6	246,355.3

Combustion Turbine – Natural Gas Project Developer and Transmission Owner Relationships

Table 12-37 shows the relationship between the project developer and transmission owner for all CT – natural gas project MW that have entered the PJM generation queue from January 1, 1997 through September 30, 2019, by transmission owner and project status. Of the 9,177.0 CT – natural gas project MW that have achieved in service or under construction status during this time period, 2,107.0 (23.0 percent) have been developed by Transmission Owners building in their own service territory. PSEG is the transmission owner with the highest percentage of affiliates building CT – natural gas projects in their own service territory. Of the 2,956.0 MW that entered the queue during the time period of January 1, 1997, through September 30, 2019, 1,818.1 MW (61.5 percent) have been submitted by PSEG or one of their affiliated companies.

Table 12-37 Relationship between project developer and transmission owner for all CT – natural gas project MW in PJM interconnection queue: September 30, 2019

			MW by Project Status					
Parent Company	Transmission Owner	Related to Developer	Active	In Service	Under Construction	Suspended	Withdrawn	Total
AEP	AEP	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	567.5	190.0	0.0	0.0	995.5	1,753.0
AES	DAY	Related	0.0	38.0	0.0	0.0	0.0	38.0
		Unrelated	23.5	22.0	0.0	0.0	104.0	149.5
DLCO	DLCO	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	205.0	0.0	0.0	205.0
Dominion	Dominion	Related	1,202.7	786.0	0.0	0.0	57.0	2,045.7
		Unrelated	1,033.6	1,116.7	0.0	0.0	75.5	2,225.8
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	0.0	73.0	73.0
Exelon	AECO	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	230.0	404.4	0.0	0.0	173.0	807.4
	BGE	Related	0.0	10.0	0.0	0.0	0.0	10.0
		Unrelated	153.6	13.0	0.0	0.0	0.0	166.6
	ComEd	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	1,207.2	257.0	48.0	0.0	17.0	1,529.2
	DPL	Related	0.0	351.0	0.0	0.0	0.0	351.0
		Unrelated	0.0	1,226.0	0.0	0.0	0.0	1,226.0
	PECO	Related	0.0	5.0	0.0	0.0	0.0	5.0
		Unrelated	29.0	567.0	0.0	0.0	0.5	596.5
	Pepco	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	37.0	0.0	0.0	0.0	37.0
FirstEnergy	APS	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	82.0	1,363.7	0.0	30.0	4.0	1,479.7
	ATSI	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	70.0	40.0	0.0	0.0	25.0	135.0
	JCPL	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	522.1	0.0	200.0	0.0	722.1
	Met-Ed	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	44.1	0.0	0.0	0.0	44.1
	PENELEC	Related	0.0	5.0	0.0	0.0	0.0	5.0
		Unrelated	573.0	381.9	0.0	0.0	561.8	1,516.7
OVEC	OVEC	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
PPL	PPL	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	403.2	0.0	0.0	19.9	423.1
PSEG	PSEG	Related	0.0	912.0	0.0	0.0	906.1	1,818.1
		Unrelated	675.0	228.9	0.0	0.0	234.0	1,137.9
Con Ed	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	1,202.7	2,107.0	0.0	0.0	963.1	4,272.8
		Unrelated	4,644.4	6,817.0	253.0	230.0	2,283.2	14,227.6

Wind Project Developer and Transmission Owner Relationships

Table 12-38 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 September 30, 2019, by transmission owner and project status. Of the 9,857.3 wind project MW that have achieved in service or under construction status during this time period, 12.0 MW (0.1 percent) have been developed by transmission owners building in their own service territory. Dominion is the transmission owner with the highest percentage of affiliates building wind projects in their own service territory. Of the 9,082.1 MW that entered the queue during the time period of January 1, 1997, through September 30, 2019, 1,026.0 MW (11.3 percent) have been submitted by Dominion or one of their affiliated companies.

Table 12-38 Relationship between project developer and transmission owner for all wind project MW in PJM interconnection queue: September 30, 2019

			MW by Project Status					
Parent Company	Transmission Owner	Related to Developer	Active	In Service	Under Construction	Suspended	Withdrawn	Total
AEP	AEP	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	5,315.3	2,738.7	150.0	588.4	20,353.2	29,145.6
AES	DAY	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	0.0	0.0	2,128.0	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	880.0	0.0	12.0	0.0	134.0	1,026.0
		Unrelated	2,700.6	310.5	0.0	76.6	4,968.4	8,056.1
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	0.0	150.3	150.3
Exelon	AECO	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	3,939.6	7.5	0.0	0.0	3,651.4	7,598.5
	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	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	5,906.2	2,898.5	1,113.5	0.0	25,124.8	35,043.0
	DPL	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	679.1	0.0	0.0	0.0	2,816.8	3,495.9
	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
FirstEnergy	APS	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	563.4	1,004.0	310.6	309.4	3,234.1	5,421.5
	ATSI	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	816.1	0.0	0.0	0.0	1,295.6	2,111.7
	JCPL	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	4,159.2	0.0	0.0	0.0	1,104.0	5,263.2
	Met-Ed	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
	PENELEC	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	210.2	995.5	90.0	100.0	5,520.3	6,916.1
OVEC	OVEC	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
PPL	PPL	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	432.1	226.5	0.0	98.0	3,281.1	4,037.7
PSEG	PSEG	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	0.0	0.0	20.0	20.0
Con Ed	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	880.0	0.0	12.0	0.0	134.0	1,026.0
		Unrelated	24,721.7	8,181.2	1,664.1	1,172.4	73,648.0	109,387.4

Solar Project Developer and Transmission Owner Relationships

Table 12-39 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 September 30, 2019, by transmission owner and project status. Of the 2,261.9 solar project MW that have achieved in service or under construction status during this time period, 816.9 MW (36.1 percent) have been developed by transmission owners building in their own service territory. BGE is the transmission owner with the highest percentage of affiliates building solar projects in their own service territory. Of the 58.4 MW that entered the queue during the time period of January 1, 1997, through September 30, 2019, 20.0 MW (34.2 percent) have been submitted by BGE or one of their affiliated companies.

Table 12-39 Relationship between project developer and transmission owner for all solar project MW in PJM interconnection queue: September 30, 2019

			MW by Project Status					
Parent Company	Transmission Owner	Related to Developer	Active	In Service	Under Construction	Suspended	Withdrawn	Total
AEP	AEP	Related	68.0	14.7	0.0	10.0	50.0	142.7
		Unrelated	14,088.9	0.0	0.0	50.0	7,162.7	21,301.7
AES	DAY	Related	0.0	0.0	0.0	0.0	21.5	21.5
		Unrelated	2,256.2	2.5	0.0	20.0	1,002.4	3,281.1
DLCO	DLCO	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	71.3	0.0	0.0	0.0	0.0	71.3
Dominion	Dominion	Related	696.1	429.1	217.3	0.0	231.9	1,574.4
		Unrelated	16,150.6	329.8	180.0	291.0	11,067.8	28,019.2
Duke	DEOK	Related	0.0	0.0	0.0	0.0	6.4	6.4
		Unrelated	380.0	0.0	0.0	0.0	423.0	803.0
EKPC	EKPC	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	1,966.0	0.0	0.0	0.0	779.9	2,745.9
Exelon	AECO	Related	0.0	0.0	0.0	0.0	8.3	8.3
		Unrelated	748.8	57.3	0.0	0.0	1,765.0	2,571.1
	BGE	Related	0.0	0.0	0.0	0.0	20.0	20.0
		Unrelated	0.0	1.1	0.0	0.0	37.3	38.4
	ComEd	Related	0.0	9.0	0.0	0.0	0.0	9.0
		Unrelated	4,137.5	0.0	0.0	0.0	2,166.8	6,304.3
	DPL	Related	0.0	7.4	0.0	0.0	0.0	7.4
		Unrelated	1,545.0	123.0	170.0	0.0	1,668.4	3,506.4
	PECO	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	47.8	3.3	0.0	0.0	51.4	102.5
	Pepco	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	189.3	0.0	2.5	0.0	191.2	383.0
FirstEnergy	APS	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	1,885.3	53.0	10.0	202.6	1,907.7	4,058.6
	ATSI	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	2,072.3	0.0	0.0	0.0	628.2	2,700.5
	JCPL	Related	0.0	0.0	0.0	0.0	12.0	12.0
		Unrelated	167.6	337.1	51.9	8.0	1,451.8	2,016.3
	Met-Ed	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	814.1	0.0	0.0	58.0	546.0	1,418.1
	PENELEC	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	2,244.8	0.0	0.0	0.0	476.7	2,721.5
OVEC	OVEC	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	0.0	0.0	78.0	78.0
PPL	PPL	Related	19.8	0.0	0.0	0.0	0.0	19.8
		Unrelated	576.4	15.0	0.0	0.0	548.6	1,140.0
PSEG	PSEG	Related	4.4	121.1	18.3	0.0	40.9	184.7
		Unrelated	34.0	92.4	16.1	6.0	507.7	656.2
Con Ed	RECO	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	40.0	0.0	0.0	0.0	20.0	60.0
Total		Related	788.3	581.3	235.6	10.0	391.0	2,006.1
		Unrelated	49,415.8	1,014.5	430.5	635.6	32,480.7	83,977.0

Regional Transmission Expansion Plan (RTEP)[34]

The PJM RTEP process is designed to identify needed transmission system additions and improvements to continue to provide reliable service throughout the RTO. The objective of the RTEP process is to provide PJM with an optimal set of solutions necessary to solve reliability issues, operational performance issues and transmission constraints.

The RTEP process initially considered only factors such as load growth and the generation interconnection requests in its development of the 15 year plan. Currently, the RTEP process includes a broader range of inputs including the effects of public policy, market efficiency, interregional coordination and the effects of aging infrastructure.

RTEP Process

The PJM RTEP process is a 24 month planning process that identifies reliability issues for the next 15 year period. This 24 month planning process includes a process to build power flow models that represent the expected future system topology, studies to identify issues, stakeholder input and PJM Board of Manager approvals. The 24 month planning process is made up of overlapping 18 month planning cycles to identify and develop shorter lead time transmission upgrades and one 24 month planning cycle to provide sufficient time for the identification and development of longer lead time transmission upgrades that may be required to satisfy planning criteria.

Market Efficiency Process

PJM's Regional Transmission Expansion Plan (RTEP) process includes a market efficiency analysis. The stated 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 based on production cost analyses.[35] PJM presents the RTEP market efficiency enhancements to the PJM Board, along with stakeholder input, for Board approval.

To be recommended to the PJM Board of Managers for approval, the relative benefits and costs of the economic based enhancement or 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 to the present value of the total annual cost for 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 projects for years five through 15. This long-term proposal window takes place concurrent with the long-term proposal window for reliability projects.[36]

PJM's first market efficiency analysis was performed in 2013, prior to Order 1000. The 2013 window was open from August 12, 2013, through September 26, 2013. This window accepted proposals to address historical congestion on 25 identified flowgates. PJM received 17 proposals from six entities. One project was approved by the PJM Board.

The first market efficiency cycle conducted under Order 1000 was performed during the 2014/2015 RTEP long term window. The 2014/2015 long term window was open from November 1, 2014, through February 28, 2015. This window accepted proposals to address historical congestion on 12 identified flowgates. PJM received 93 proposals from 19 entities. Thirteen projects were approved by the PJM Board.

The second market efficiency cycle was performed during the 2016/2017 RTEP long term window. The 2016/2017 long term window was open from

34 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. 46 (August, 28, 2019).

35 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>.

36 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>.

November 1, 2016, through February 28, 2017. This window accepted proposals to address historical congestion on four identified flowgates. PJM received 96 proposals from 20 entities. Four projects were approved by the PJM Board.

PJM also held an addendum 2016/2017 long term window. This 2016/2017 1A long term window was open from September 14, 2017, through September 28, 2017. This window accepted proposals to address historical congestion on one identified flowgate. PJM received three proposals from two entities. One project was approved by the PJM Board.

The fourth market efficiency cycle is currently being performed for the 2018/2019 RTEP long term window. The 2018/2019 long term window was open from November 2, 2018, through March 15, 2019. This window accepted proposals to address historical congestion on four identified flowgates. PJM received 33 proposals from 10 entities. As of September 30, 2019, the projects were still being considered for recommendation to the PJM Board.

In 2018, the PJM Board of Managers received correspondence from several officials, representing regions in Pennsylvania and Maryland, requesting an updated benefit/cost evaluation and the cancellation of the previously approved Transource AP-South market efficiency project.[37] [38] [39] [40] Approved market efficiency projects periodically undergo a reevaluation process to ensure that the benefit/cost ratio continues to meet the 1.25:1 threshold. The Transource AP-South project was reevaluated in September 2017, February 2018 and again in September 2018. The project exceeded the 1.25:1 threshold in all reevaluations based on the PJM method. PJM also concluded that there would be significant reliability violations with the project removed from the model.[41]

37 See Letter from Governor Larry Hogan, State of Maryland, Office of the Governor (July 10, 2018) <https://www.pjm.com/-/media/about-pjm/who-we-are/public-disclosures/20180828-gov-hogan-transource-july-2018-letter-to-pjm-board.ashx?la=en>.

38 See Letter from State Representative Kristin Phillips Hill, 93rd District, Pennsylvania House of Representatives (September 6, 2018) <https://www.pjm.com/-/media/about-pjm/who-we-are/public-disclosures/20180906-pa-rep-phillips-hill-letter-re-transource-llc.ashx?la=en>.

39 See Letter from State Representative Stanley E. Saylor, 94th District, Pennsylvania House of Representatives (August 1, 2018) <https://www.pjm.com/-/media/about-pjm/who-we-are/public-disclosures/20180907-pa-rep-saylor-letter-re-transource-llc.ashx?la=en>.

40 See Letter from Paula M. Carmody, Peoples Counsel, State of Maryland Office of People's Counsel (September 6, 2018) <https://www.pjm.com/-/media/about-pjm/who-we-are/public-disclosures/20180907-opc-letter-to-pjm-board-re-sept-2018-transource-retool.ashx?la=en>.

41 See PJM. "Transource AP-South (2014/15_9A) Project Reevaluation," <https://www.pjm.com/-/media/committees-groups/committees/teac/20180913/20180913-ap-south-9a-project-reevaluation-sept-2018.ashx>.

The Benefit/Cost Evaluation

For an RTEP project to be recommended to the PJM Board of Managers for approval as a market efficiency project, the relative benefits and costs of the economic based enhancement or expansion must meet a benefit/cost ratio threshold of at least 1.25:1.

The total benefit of a project is calculated as the sum of the net present value of calculated energy market benefits and calculated reliability pricing model (RPM) benefits for a 15 year period, starting with the projected in service date of the project. PJM measures benefits as reductions in estimated load charges and production costs in the energy market and reductions in estimated load capacity payments and in system capacity costs in the capacity market but does not weight increases and decreases in benefits equally. The method for calculating energy market benefits and reliability pricing model benefits used to measure the benefit of an RTEP project for purposes of the 1.25:1 benefit/cost ratio threshold depends on whether the project is regional or subregional. A regional project is any project rated at or above 230 kV. A subregional project is any project rated at less than 230 kv.

The energy market benefit analysis uses an energy market simulation tool that produces an hourly least-cost, security constrained market solution, including total operational costs, hourly LMPs, bus specific injections and bus specific withdrawals for each modeled year with and without the proposed RTEP project. Using the output from the model, PJM calculates changes in energy production costs and load energy payments.

The definition of the energy benefit analysis depends on whether the project is regional or subregional. For a regional project, the energy benefit for each modeled year is equal to 50 percent of the change in system wide total system energy production costs with and without the project plus 50 percent of the change in zonal load payments with and without the project, including only those zones where the project reduced the load payments. For subregional projects, the calculation of benefits for each modeled year ignores any impact on system wide energy production costs and is instead based only the change in zonal load energy payments with and without the project, but including only those zones where the project reduced the load energy payments.

In both the regional and subregional analysis, changes in zonal load energy payments are netted against changes in the estimated value of any Auction Revenue Rights (ARR) that sink in that zone for purposes of determining whether a zone benefits from a proposed RTEP project. Estimated ARR credits are calculated for each simulated year using the most recent planning year's actual ARR MW combined with FTR prices assumed to be equal to the market simulation's CLMP differences between ARR source and sink points. The value of the ARR rights with and without the RTEP project is evaluated based on changes in modeled CLMPs on the latest allocation of ARR rights. ARR MW allocations are not adjusted to reflect any potential changes in ARR allocations which may be allowed by the RTEP upgrade.

The Reliability Pricing Model (RPM) Benefit analysis is conducted using the RPM solution software, with and without the proposed RTEP project, using a set of estimated capacity offers.

The definition of the benefit in the RPM benefit analysis depends on whether the project is regional or subregional. For a regional project, the RPM benefit for each modeled year is equal to 50 percent of the change in system wide total system capacity payments with and without the project plus 50 percent of the change in zonal capacity payments with and without the project, including only those zones where the project reduced the capacity payments. For subregional projects, the reliability pricing model benefits for each modeled year ignores any impact on system wide total capacity payments and is equal to the change in zonal capacity payments with and without the project, including only those zones where the project reduced the capacity payments.

The difference in the benefits calculation used in the regional and subregional cost benefit threshold tests are related to how costs are allocated for approved regional and subregional projects. The costs of an approved regional project are allocated so that 50 percent of the total costs are allocated on a system wide load ratio share basis and the remaining 50 percent of the total costs are allocated to zones with projected energy market benefits and reliability pricing model benefits in proportion to those projected positive benefits. The costs of an approved subregional project are allocated so that the total costs of the project is allocated to zones with projected energy market benefits and reliability pricing model benefits in proportion to those projected positive benefits.

The current rules governing benefit/cost analysis of competing transmission projects do not correctly measure the relative costs and benefits of transmission projects. The current rules explicitly ignore the increased load costs that an RTEP project may create in some zones when calculating the energy and capacity market benefits. The current rules do not account for the risk associated with the fact that the project costs are nonbinding estimates. All costs should be included in all zones and LDAs. If the approach is retained, a more appropriate measure of the benefits of a competing transmission project would be either the change in total system wide load costs, after the allocation of congestion, with and without the project or the change in total system production costs with and without the project. The current rules regarding cost allocation for regional project do not result in the beneficiary paying all of the costs of the project. The current rules do not account for the risk associated with the fact that the benefits of projects are uncertain and highly sensitive to the modeling assumptions used.

The broader issue is that the market efficiency project approach explicitly allows transmission projects to compete against future generation projects, but without allowing the generation projects to compete. Projecting speculative transmission related benefits for 15 years based on the existing generation fleet and existing patterns of congestion eliminates the potential for new generation to respond to market signals. The market efficiency process allows assets built under the cost of service regulatory paradigm to displace generation assets built under the competitive market paradigm. The MMU recommends that the market efficiency process be eliminated.

PJM MISO Targeted Market Efficiency Process (TMEP) and Interregional Market Efficiency Process (IMEP)

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).[42] The allocation of costs to each RTO for TMEPs will be in proportion to the benefits received. [43]

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.[44] [45]

The first Targeted Market Efficiency Process (TMEP) analysis occurred in 2017 and included the investigation of historical congestion on an initial set of 50 market to market flowgates. The causes of congestion on these flowgates were analyzed. If the historical congestion was a result of outages, or if the congestion was expected to be mitigated by planned upgrades already included in the PJM RTEP or MISO MTEP, then the flowgate was eliminated from consideration in the TMEP process. As a result of this analysis, potential short term upgrades were identified for 13 of the initial 50 flowgates. PJM and MISO conducted a market efficiency and power flow analysis to determine the potential to eliminate the identified congestion on the 13 flowgates. As a result of this analysis, the RTOs recommended five TMEP projects. The five projects address $59.0 million in historical congestion, with a TMEP benefit of $99.6 million. The projects have a total cost of $20.0 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.[46]

The second Targeted Market Efficiency Process analysis occurred in 2018 and included the investigation of historical congestion on an initial set of 61 market to market flowgates. The causes of congestion on these flowgates were analyzed. If the historical congestion was a result of outages, or if the congestion was expected to be mitigated by planned upgrades already included in the PJM RTEP or MISO MTEP, then the flowgate was eliminated from consideration in the TMEP process. As a result of this analysis, potential short term upgrades were identified for 20 of the initial 61 flowgates. PJM and MISO conducted a market efficiency and power flow analysis to determine the potential to eliminate the identified congestion on the 20 flowgates. As a result of this analysis, the RTOs recommended two TMEP projects. The two projects address $25.0 million in historical congestion, with a TMEP benefit of $31.9 million. The projects have a total cost of $4.5 million, with a 7.1 average benefit/cost ratio. PJM and MISO presented the two recommended projects to their boards in December 2018, and both boards approved the projects.[47]

With only one additional year of historical information, and the fact that many of the same constraints were evaluated in the 2018 TMEP process, PJM and MISO did not conduct a TMEP study in 2019. PJM and MISO are currently conducting a two year interregional market efficiency project study in 2018/2019. Proposals were received during the 2018/2019 long term window, which was open from November 2, 2018 through March 15, 2019. PJM and MISO received 10 proposals from seven entities. As of September 30, 2019, the projects were still being considered for recommendation to the PJM Board.

Supplemental Transmission Projects

Supplemental projects are asserted to be "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."[48] Supplemental projects are selected solely by the transmission owner and no PJM approval is needed. Supplemental projects are currently exempt from the Order No. 1000 competitive process. Transmission owners have a

42 See PJM Interconnection, L.L.C, Docket No. ER17-718-000 (December 30, 2016).
43 See PJM Interconnection, L.L.C, Docket No. ER17-729-000 (December 30, 2016).
44 See PJM Interconnection, L.L.C, Docket No. ER17-718-000, ER17-721-000 and ER17-729-000 (Not Consolidated) (November 2, 2017).
45 161 FERC ¶ 61,005.
46 See PJM. "MISO PJM IPSAC," (January 12, 2018) <http://www.pjm.com/-/media/committees-groups/stakeholder-meetings/ipsac/20180112/20180112-ipsac-presentation.ashx>.
47 See PJM. "MISO PJM IPSAC," (January 18, 2019) <https://www.pjm.com/-/media/committees-groups/stakeholder-meetings/ipsac/20190118/20190118-ipsac-presentation.ashx>.
48 See PJM. Planning. "Transmission Construction Status," (Accessed on September 30, 2019) <http://www.pjm.com/planning/rtep-upgrades-status/construct-status.aspx>.

clear incentive to increase investments in rate base given that transmission owners are paid for these projects on a cost of service basis.

Figure 12-3 shows the latest cost estimate of all baseline and supplemental projects by expected in service year. FERC Order 890 was issued on February 16, 2007, and implemented in PJM starting in 2008. Order 890 required Transmission Providers to participate in a coordinated, open and transparent planning process. Prior to the implementation of Order 890, there were transmission projects planned by transmission owners and included in the PJM planning models, that were not included in the totals shown in Figure 12-3, Table 12-40 and Table 12-41. There has been a significant increase in supplemental projects coincident with the coordinated, open and transparent planning process introduced by the implementation of Order 890 starting in 2008 and the competitive planning process introduced by the implementation of FERC Order No. 1000 starting in 2011.

Figure 12-3 Latest cost estimate of baseline and supplemental projects by expected in service year: 1998 through 2020

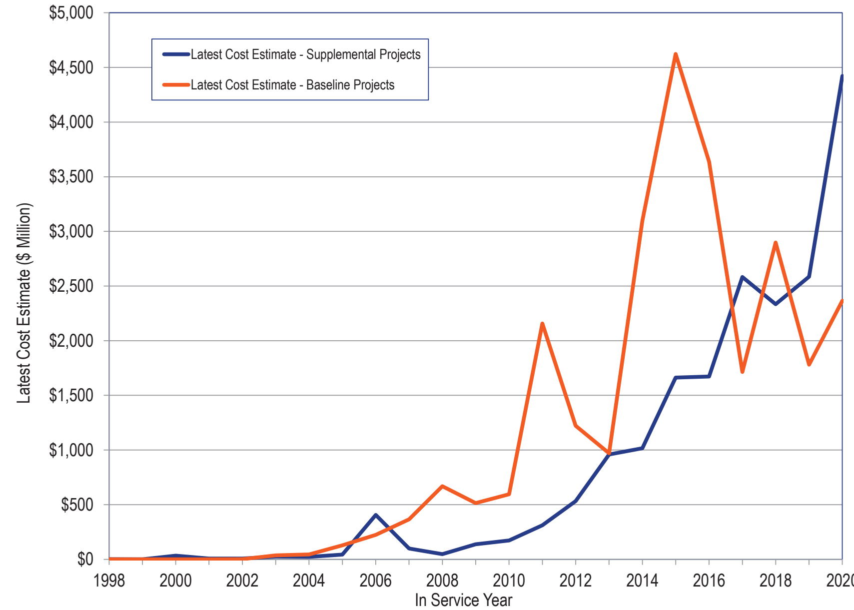


Table 12-40 shows the number of supplemental projects by expected in service year for each transmission zone. The average number of supplemental projects in each expected in service year increased by 600.0 percent, from 20 for years 1998 through 2007 (pre Order 890) to 140 for years 2008 through 2019 (post Order 890).

Table 12-40 Number of supplemental projects by expected in service year and zone: 1998 through 2040

Year	AECO	AEP	APS	ATSI	BGE	ComEd	DAY	DEOK	DLCO	Dominion	DPL	EKPC	JCPL	Met-Ed	OVEC	PECO	PENELEC	Pepco	PPL	PSEG	RECO	Total
1998	0	0	0	0	0	0	0	0	0	0	3	0	0	0	0	0	0	0	0	0	0	3
1999	0	0	0	0	0	0	0	0	0	0	2	0	0	0	0	0	0	0	0	0	0	2
2000	0	0	0	0	0	0	0	0	0	0	11	0	0	0	0	0	0	0	0	0	0	11
2001	0	0	0	0	0	0	0	0	0	0	14	0	0	0	0	0	0	0	0	0	0	14
2002	0	0	0	0	0	0	0	0	0	0	10	0	0	0	0	0	0	0	0	0	0	10
2003	3	0	0	0	0	0	0	0	0	0	10	0	0	0	0	0	2	0	0	0	0	15
2004	5	0	10	0	0	9	0	0	0	0	12	0	2	0	0	0	0	0	0	2	0	40
2005	4	2	8	0	0	4	0	0	0	1	14	0	1	0	0	1	2	0	0	2	0	39
2006	4	2	5	0	0	6	0	0	0	0	9	0	1	0	0	0	1	0	2	1	0	31
2007	1	1	5	0	4	5	0	0	4	0	6	0	0	0	0	0	2	0	1	6	0	35
2008	3	0	15	0	1	6	0	0	1	7	3	0	0	1	0	0	0	0	3	1	0	41
2009	3	1	6	0	1	8	0	0	3	3	5	0	0	0	0	5	1	0	1	2	0	39
2010	0	6	7	0	3	4	0	0	6	3	0	0	1	2	0	2	0	0	3	5	0	42
2011	0	8	8	0	0	2	0	0	5	2	0	0	1	0	0	4	0	0	6	4	0	40
2012	0	5	6	4	1	2	0	7	3	16	1	0	2	0	0	1	0	0	5	11	0	64
2013	5	21	4	5	0	11	0	6	5	13	1	0	1	1	0	1	0	1	14	19	0	108
2014	2	31	2	8	2	14	0	5	6	18	3	2	2	0	0	1	2	0	9	16	0	123
2015	4	15	2	9	1	37	0	8	4	17	5	4	2	0	0	1	0	4	7	24	0	144
2016	5	13	4	17	0	26	0	6	2	13	4	2	0	1	0	3	2	3	11	30	0	142
2017	8	103	3	26	1	23	0	3	8	33	11	5	0	3	0	0	3	1	21	43	0	295
2018	10	133	4	13	1	20	0	15	4	24	6	4	0	0	0	2	0	1	19	28	0	284
2019	4	164	2	33	6	16	2	23	2	17	7	4	0	16	0	1	30	1	15	19	0	362
2020	9	141	0	18	2	6	0	5	1	7	5	4	0	7	0	0	35	0	30	28	0	298
2021	3	73	0	12	0	1	2	0	1	9	3	4	1	2	0	0	4	0	24	27	1	167
2022	4	7	0	1	2	0	3	1	0	1	4	0	0	0	0	0	0	2	18	17	0	60
2023	4	3	0	0	0	1	5	0	3	4	0	0	0	3	0	0	1	0	14	7	0	45
2024	1	1	1	1	7	0	0	0	0	0	2	0	2	0	0	0	0	0	12	0	0	27
2025	6	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	6	0	0	13
2026	0	0	0	0	4	0	0	0	0	0	0	0	0	0	0	0	0	0	7	0	0	11
2027	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3	0	0	3
2028	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2030	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	9	0	0	9
2031	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2032	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2033	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2034	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2035	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2036	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2037	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2038	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2039	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2040	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5	0	0	5
Total	88	730	92	147	37	201	12	79	58	188	151	29	16	36	0	22	85	13	245	292	1	2,522

Table 12-41 shows the latest cost estimate of supplemental projects by expected in service year for each transmission zone. The average latest cost of supplemental projects in each expected in service year increased by 1,711.0 percent, from $64.5 million for years 1998 through 2007 (pre Order 890) to $1,167.8 million for years 2008 through 2019 (post Order 890).

Table 12-41 Latest cost estimate by expected in service year and zone ($ millions): 1998 through 2040

Year	AECO	AEP	APS	ATSI	BGE	ComEd	DAY	DEOK	DLCO	Dominion	DPL	EKPC	JCPL	Met-Ed	OVEC	PECO	PENELEC	Pepco	PPL	PSEG	RECO	Total
1998	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$1.67	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$1.67
1999	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.78	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.78
2000	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$32.95	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$32.95
2001	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$6.79	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$6.79
2002	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$7.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$7.00
2003	$7.42	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$8.75	$0.00	$0.00	$0.00	$0.00	$0.00	$9.60	$0.00	$0.00	$0.00	$0.00	$25.77
2004	$4.44	$0.00	$9.99	$0.00	$0.00	$0.82	$0.00	$0.00	$0.00	$0.00	$7.32	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$22.58
2005	$4.06	$14.67	$10.11	$0.00	$0.00	$2.58	$0.00	$0.00	$0.00	$0.02	$10.97	$0.00	$0.00	$0.00	$0.00	$0.50	$0.00	$0.00	$0.00	$0.00	$0.00	$42.90
2006	$4.03	$309.70	$0.94	$0.00	$0.00	$48.93	$0.00	$0.00	$0.00	$0.00	$11.63	$0.00	$6.00	$0.00	$0.00	$0.00	$1.50	$0.00	$4.63	$18.80	$0.00	$406.15
2007	$0.56	$2.06	$9.85	$0.00	$37.61	$4.65	$0.00	$0.00	$31.75	$0.00	$9.71	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.34	$2.25	$0.00	$98.77
2008	$2.36	$0.00	$12.03	$0.00	$0.45	$7.61	$0.00	$0.00	$7.00	$14.01	$2.28	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$1.60	$0.00	$0.00	$47.33
2009	$0.77	$0.90	$12.22	$0.00	$5.00	$21.11	$0.00	$0.00	$19.60	$2.12	$7.36	$0.00	$0.00	$0.00	$0.00	$48.10	$2.73	$0.00	$0.16	$17.60	$0.00	$137.67
2010	$0.00	$34.36	$12.13	$0.00	$18.90	$1.38	$0.00	$0.00	$34.45	$14.98	$0.00	$0.00	$0.03	$4.58	$0.00	$31.80	$0.00	$0.00	$1.86	$17.72	$0.00	$172.19
2011	$0.00	$37.60	$9.30	$0.00	$0.00	$1.00	$0.00	$0.00	$16.72	$85.67	$0.00	$0.00	$1.16	$0.00	$0.00	$113.30	$0.00	$0.00	$11.87	$34.60	$0.00	$311.22
2012	$0.00	$46.00	$5.12	$0.35	$2.20	$12.60	$0.00	$26.06	$11.60	$165.74	$0.99	$0.00	$6.61	$0.00	$0.00	$12.60	$0.00	$0.00	$19.66	$223.01	$0.00	$532.54
2013	$3.15	$134.93	$1.10	$33.68	$0.00	$59.25	$0.00	$9.93	$81.98	$25.03	$0.99	$0.00	$0.05	$4.10	$0.00	$22.50	$0.00	$2.40	$76.70	$503.72	$0.00	$959.51
2014	$8.03	$387.00	$5.97	$58.70	$21.20	$60.37	$0.00	$2.43	$14.90	$88.61	$5.96	$0.38	$5.60	$0.00	$0.00	$13.30	$1.30	$0.00	$33.47	$309.70	$0.00	$1,016.92
2015	$3.73	$237.45	$3.80	$21.90	$2.00	$376.00	$0.00	$14.12	$4.53	$113.53	$13.06	$1.56	$0.30	$0.00	$0.00	$33.80	$0.00	$42.50	$50.17	$743.91	$0.00	$1,662.36
2016	$73.54	$79.98	$18.40	$182.70	$0.00	$308.15	$0.00	$15.13	$26.95	$40.68	$26.60	$0.25	$0.00	$2.37	$0.00	$86.40	$0.40	$7.80	$58.76	$744.18	$0.00	$1,672.29
2017	$66.28	$642.74	$8.60	$164.45	$0.09	$145.97	$0.00	$65.01	$3.62	$105.45	$92.29	$2.21	$0.00	$14.70	$0.00	$0.00	$8.30	$12.00	$261.74	$988.92	$0.00	$2,582.37
2018	$66.55	$776.74	$14.80	$42.12	$4.08	$80.94	$0.00	$70.15	$4.98	$168.14	$68.94	$10.87	$0.00	$0.00	$0.00	$47.60	$0.00	$156.00	$186.64	$635.70	$0.00	$2,334.25
2019	$48.50	$1,013.62	$6.37	$235.27	$71.01	$95.59	$7.81	$134.74	$5.30	$46.08	$40.40	$16.69	$0.00	$12.80	$0.00	$2.00	$103.00	$70.00	$257.30	$418.38	$0.00	$2,584.86
2020	$91.82	$1,204.83	$0.00	$149.35	$62.50	$110.10	$0.00	$52.30	$18.10	$29.68	$36.02	$22.55	$0.00	$49.80	$0.00	$0.00	$191.00	$0.00	$456.17	$1,947.53	$0.00	$4,421.75
2021	$24.26	$1,127.33	$0.00	$239.80	$0.00	$1.00	$14.00	$0.00	$26.20	$69.12	$34.01	$21.21	$16.00	$40.10	$0.00	$0.00	$5.30	$0.00	$310.93	$888.77	$17.00	$2,835.03
2022	$81.90	$51.50	$0.00	$27.90	$263.00	$0.00	$10.25	$21.30	$0.00	$0.93	$35.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$527.00	$393.10	$951.47	$0.00	$2,363.35
2023	$45.04	$52.60	$0.00	$0.00	$0.00	$1.00	$32.85	$0.00	$135.40	$38.30	$0.00	$0.00	$0.00	$16.30	$0.00	$0.00	$200.00	$0.00	$179.60	$177.00	$0.00	$878.09
2024	$11.40	$8.50	$3.60	$170.00	$223.00	$0.00	$0.00	$0.00	$0.00	$0.00	$29.72	$0.00	$30.50	$0.00	$0.00	$0.00	$0.00	$0.00	$254.33	$0.00	$0.00	$731.05
2025	$82.99	$0.00	$0.00	$0.00	$7.50	$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	$150.80	$0.00	$0.00	$241.29
2026	$0.00	$0.00	$0.00	$0.00	$45.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$131.05	$0.00	$0.00	$176.05
2027	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$54.30	$0.00	$0.00	$54.30
2028	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2029	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2030	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$220.49	$0.00	$0.00	$220.49
2031	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2032	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2033	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2034	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2035	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2036	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2037	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2038	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2039	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2040	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$13.03	$0.00	$0.00	$13.03
Total	$630.83	$6,162.51	$144.33	$1,326.22	$763.54	$1,339.04	$64.91	$411.17	$443.08	$1,008.09	$491.16	$75.72	$66.25	$144.75	$0.00	$411.90	$523.13	$817.70	$3,128.69	$8,623.26	$17.00	$26,593.28

The MMU recommends, to increase the role of competition, that the exemption of supplemental from the Order No. 1000 competitive process be terminated.

End of Life Transmission Projects

An end of life transmission project is a project submitted for the purpose of replacing existing infrastructure that has, or is approaching, the end of its useful life.[49] Some Transmission Owners include end of life transmission projects in their Transmission Owner Form 715 Planning Criteria. These projects were exempt from the competitive planning process.[50] On August 30, 2019, the Commission issued an Order on Remand, which rejected the 2015 PJM Transmission Owner Tariff Revisions that "allocate 100 percent of costs for projects that are included in the PJM Regional Transmission Expansion Plan (RTEP) solely to address individual transmission owner Form No. 715 local planning criteria to the transmission zone of the transmission owner whose Form No. 715 local planning criteria underlie each project."[51] The Order directed PJM to regionally allocate cost responsibility to Transmission Owner Form 715 Planning Criteria projects. Additionally, this order removed the proposal window exemption for Form No. 715 Planning Criteria.[52]

The Commission stated that "the transmission planning reforms that the Commission adopted in Order No. 890 were intended to address concerns regarding undue discrimination in grid expansion."[53] The Commission has further clarified that even if certain end of life supplemental projects increase transmission capacity they are exempt from the competitive planning process. The Commission stated that "we find that this type of incidental increase in transmission capacity that is a function of advancements in technology of the replaced equipment, and is not reasonably severable from the asset management project or activity, would not render the asset management project or activity in question a transmission expansion that is subject to the transmission planning requirements of Order No. 890."[54] The Commission did not address end of life projects that are not incidental. In PJM's October 7, 2019, compliance filing to the August 30, 2019 Order on Remand, PJM sought additional clarification on the treatment of asset management activities that are included in some Transmission Owner's Form No. 715 Planning Criteria.[55]

The MMU recommends, to increase the role of competition, that the exemption of end of life projects from the Order No. 1000 competitive process be terminated and that end of life transmission projects should be included in the RTEP process and should be subject to a transparent, robust and clearly defined mechanism to permit competition to build such projects.

Competitive Planning Process Exclusions

There are several project types that are currently exempt from the competitive planning process. These project types include:

- **Immediate Need Exclusion:** Due to the immediate need of the violation (3 years or less), the timing required for an RTEP proposal window is defined to be infeasible and such projects are excluded from competition. As a result, the local Transmission Owner is the Designated Entity.[56]
- **Below 200kV:** Due to the lower voltage level of the identified violation(s), the driver(s) for this project are excluded from competition. As a result, the local Transmission Owner is the Designated Entity.[57]

49 The useful life of a transmission investment typically exceeds its depreciable life.
50 See PJM. Operating Agreement Schedule 6 § 1.5.8(o).
51 Docket No. ER15-1387 (March 26, 2015).
52 168 FERC ¶ 61,133 (August 30, 2019).
53 164 FERC ¶ 61,160 at P 31 (Aug. 31, 2018) (Docket Nos. ER18-370 and ED18-12).
54 164 FERC ¶ 61,160 at P 33 (Aug. 31, 2018) (Docket Nos. ER18-370 and ED18-12).
55 See PJM Interconnection, L.L.C. (October 7, 2019) (Docket Nos. EL19-61 and ER20-45).
56 See PJM Operating Agreement Schedule 6 § 1.5.8(m).
57 See PJM Operating Agreement Schedule 6 § 1.5.8(n).

- **FERC 715 (Transmission Owner (TO) Criteria):** Such projects are excluded from competition. As a result, the local Transmission Owner is the Designated Entity.[58] Effective August 30, 2019, FERC 715 Criteria are no longer exempt from the competitive planning process.[59]
- **Substation Equipment:** Due to identification of the limiting element(s) as substation equipment, such project are excluded from competition. As a result, the local Transmission Owner is the Designated Entity.[60]

While the PJM Operating Agreement defines who will be the Designated Entity for projects that are excluded from the competitive planning process, neither the PJM Operating Agreement nor the various commission orders on transmission competition prohibit PJM from permitting competition to provide financing for such projects. 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. In addition, the criteria for and need for all exclusions from the competitive process should be reviewed. There does not appear to be any market reason to exclude transmission projects from competition for any of these exclusion categories.

Cost Capping

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. On May 24, 2018, the PJM Markets and Reliability Committee (MRC) approved a motion that required PJM, with input from the MMU, to develop a comparative framework to evaluate the quality and effectiveness of binding cost containment proposals versus proposals without cost containment provisions.

Board Authorized Transmission Upgrades

The Transmission Expansion Advisory Committee (TEAC) regularly reviews internal and external proposals to improve transmission reliability throughout PJM. These proposals, which include reliability baseline, network, market efficiency and targeted market efficiency projects, are periodically presented to the PJM Board of Managers for authorization.[61]

An RTEP project can be approved by the PJM Board if the project ensures compliance with NERC, regional and local transmission owner planning criteria or to address market efficiency congestion relief. These projects are considered Baseline Projects. PJM Board approved RTEP projects that are necessary to allow new generation to interconnect reliably are considered Network Projects.

In the first nine months of 2019, the PJM Board approved $845.8 million in transmission upgrades. As of September 30, 2019, the PJM Board had approved $39.1 billion in transmission system enhancements since 1999. On February 12, 2019, the PJM Board of Managers authorized an additional $271.9 million in transmission upgrades and additions. On July 29, 2019, the PJM Board of Managers authorized an additional $327.8 million in transmission upgrades and additions. On September 30, 2019, the PJM Board of Managers authorized an additional $246.1 million in transmission upgrades and additions.

Qualifying Transmission Upgrades (QTU)

A Qualifying Transmission Upgrade (QTU) is an upgrade to the transmission system that increases the Capacity Emergency Transfer Limit (CETL) into an LDA and can be offered into capacity auctions as capacity. Once a QTU is in service, the upgrade is eligible to continue to offer the approved incremental import capability into future RPM Auctions. As of September 30, 2019, no QTUs have cleared a BRA.

If a QTU that was cleared in a BRA is not completed by the start of the Delivery Year, the submitting party is required to provide replacement capacity. Once a QTU is in service, the upgrade is eligible to continue to offer the approved incremental import capability into future RPM Auctions. As of September 30, 2019, no QTUs have cleared a BRA.

58 See PJM Operating Agreement Schedule 6 § 1.5.8(o).
59 168 FERC ¶ 61,133 (August 30, 2019).
60 See PJM Operating Agreement Schedule 6 § 1.5.8(p).
61 Supplemental Projects, including the end of life subset of supplemental projects, do not require PJM Board of Managers authorization.

Cost Allocation

In response to complaints against PJM RTEP Baseline Upgrade Filings in 2014 that included cost allocations for $1.5 billion in baseline transmission enhancements and expansions, on November 24, 2015, FERC issued an order directing investigation of "whether there is a definable category of reliability projects within PJM for which the solution-based DFAX cost allocation method may not be just and reasonable, such as projects addressing reliability violations that are not related to flow on the planned transmission facility, and whether an alternative just and reasonable *ex ante* cost allocation method could be established for any such category of projects."[62] FERC convened a technical conference on January 12, 2016, to address the complaints in multiple proceedings and to address these two core issues.[63]

The issues identified in the complaints and at the technical conference included: whether the solutions based allocation method is appropriate for upgrades not related to transmission overload issues; whether the solutions based allocation method correctly identifies all the beneficiaries of the upgrades; whether it is reasonable to allocate a level of costs to a merchant transmission project that could force bankruptcy; and whether the significant shifts in allocation that result from use of the 0.01 distribution factor cutoff are appropriate.

It is clear that the allocation issues are difficult. Nonetheless, the allocation methods affect the efficiency of the markets and the incentives for merchant transmission owners to compete to build new transmission. The use of the arbitrary 0.01 distribution factor cutoff can result in large and inappropriate shifts in cost allocation. If the intent of the use of the 0.01 cutoff is to help eliminate small, arbitrary cost allocations to geographically distant areas, this could be achieved by adding a threshold for a minimum usage impact on the line. The MMU recommends consideration of changing the minimum distribution factor in the allocation from 0.01 to 0.00 and adding a threshold minimum impact on the load on the line based on a complete analysis of the intent of the allocation and the impacts of the allocation.

62 153 FERC ¶ 61,245 at P 35 (Nov. 24, 2015) (Docket Nos. ER15-2562 and ER15-2563.).
63 See Docket Nos. EL15-18-000 (ConEd), EL15-67-000 (Linden), and EL15-95-000 (Artificial Island).

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.[64] When a reportable transmission facility needs to be taken out of service, the transmission owner is required to submit an outage request as early as possible.[65] The specific timeline is shown in Table 12-43.[66]

Transmission outages have significant impacts on PJM markets, including impacts on FTR auctions, on congestion, and on expected market outcomes in the day-ahead and real-time markets. The efficient functioning of the markets depends on clear, enforceable rules governing transmission outages.

The outage data for the FTR market are for outages scheduled to occur in the 2018/2019 planning period and the first four months of the 2019/2020 planning period, regardless of when they were initially submitted.[67] The outage data for the day-ahead market are for outages scheduled to occur from January 2015 through September 2019.

Transmission outages are categorized by duration: greater than 30 calendar days; less than or equal to 30 calendar days; greater than five calendar days; less than or equal to five calendar days.[68] Table 12-42 shows that 73.3 percent of requested outages were planned for less than or equal to five days and 12.5 percent of requested outages were planned for greater than 30 days in the first four months of 2019/2020 planning period. Table 12-42 also shows that 77.0 percent of the requested outages were planned for less than or equal to five days and 7.8 percent of requested outages were planned for greater than 30 days in the 2018/2019 planning period.

64 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 3: Transmission Operations, Rev. 55 (May 31, 2019).
65 See PJM, "Manual 3: Transmission Operations," Rev. 55A (Oct. 31, 2019).
66 See PJM, "Manual 3: Transmission Operations," Rev. 55A (Oct. 31, 2019).
67 The hotline tickets, EMS tripping tickets or test outage tickets were excluded. The analysis includes only the transmission outage tickets submitted by PJM companies which are currently active.
68 Id. at 70.

Table 12-42 Transmission facility outage request summary by planned duration: June 2018 through September, 2019

	2018/2019 (12 months)		2019/2020 (4 months)	
Planned Duration (Days)	Outage Requests	Percent of Total	Outage Requests	Percent of Total
<=5	17,003	77.0%	4,841	73.3%
>5 & <=30	3,376	15.3%	932	14.1%
>30	1,713	7.8%	828	12.5%
Total	22,092	100.0%	6,601	100.0%

After receiving a transmission facility outage request from a TO, PJM assigns a received status to the request based on its submission date and outage planned duration. The received status can be On Time or Late, as defined in Table 12-43.[69]

The purpose of the rules defined in Table 12-43 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 PJM can accurately model market conditions.[70]

Table 12-43 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

69 See PJM, "Manual 3: Transmission Operations," Rev. 55A (Oct. 31, 2019).
70 See "Report of PJM Interconnection, L.L.C. on Transmission Oversight Procedures," Docket No. EL01-122-000 (November 2, 2001).

Table 12-44 shows a summary of requests by received status. In the first four months of the 2019/2020 planning period, 50.9 percent of outage requests received were late. In the 2018/2019 planning period, 47.3 percent of outage requests received were late.

Table 12-44 Transmission facility outage request summary by received status: June 2018 through September 2019

	2018/2019 (12 months)				2019/2020 (4 months)			
Planned Duration (Days)	On Time	Late	Total	Percent Late	On Time	Late	Total	Percent Late
<=5	9,306	7,697	17,003	45.3%	2,444	2,397	4,841	49.5%
>5 & <=30	1,633	1,743	3,376	51.6%	453	479	932	51.4%
>30	700	1,013	1,713	59.1%	346	482	828	58.2%
Total	11,639	10,453	22,092	47.3%	3,243	3,358	6,601	50.9%

Once received, PJM processes outage requests in priority order: emergency transmission outage request; transmission outage request submitted on time; and transmission outage request submitted late. Transmission outage requests that are submitted late may be approved if the outage does not affect the reliability of PJM or cause congestion in the system.[71]

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.[72] Table 12-45 is a summary of outage requests by emergency status. Of all outage requests scheduled to occur in the first four months of 2019/2020 planning period, 15.6 percent were for emergency outages. Of all outage requests scheduled to occur in the 2018/2019 planning period, 12.5 percent were for emergency outages.

71 See PJM, "Manual 3: Transmission Operations," Rev. 55A (Oct 31, 2019). The following language was removed from Manual 3 Rev. 50: PJM retains the right to deny all jobs submitted after 8 a.m. three days prior to the requested start date unless the request is an emergency job or an exception request (i.e. a generator tripped and the Transmission Owner is taking advantage of a situation that was not available before the unit trip).
72 PJM, "Manual 3: Transmission Operations," Rev. 55A (Oct. 31, 2019).

Table 12-45 Transmission facility outage request summary by emergency: June 2018 through September 2019

	2018/2019 (12 months)				2019/2020 (4 months)			
Planned Duration (Days)	Emergency	Non Emergency	Total	Percent Emergency	Emergency	Non Emergency	Total	Percent Emergency
<=5	2,024	14,979	17,003	11.9%	757	4,084	4,841	15.6%
>5 & <=30	469	2,907	3,376	13.9%	146	786	932	15.7%
>30	263	1,450	1,713	15.4%	129	699	828	15.6%
Total	2,756	19,336	22,092	12.5%	1,032	5,569	6,601	15.6%

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."[73]

After PJM determines that a late request may cause congestion, PJM informs the transmission owner of solutions available to eliminate the congestion. For example, if a generator planned or maintenance outage request is contributing to the congestion, PJM can request that the generation owner defer the outage. If no solutions are available, PJM may require the transmission owner to reschedule or cancel the outage.

Table 12-46 is a summary of outage requests by congestion status. Of all outage requests submitted to occur in the first four months of the 2019/2020 planning period, 8.2 percent were expected to cause congestion. Of all the outage requests that were expected to cause congestion, 3.9 percent (21 out of 543) were denied by PJM in the first four months of the 2019/2020 planning period and 19.3 percent (105 out of 543) were cancelled (Table 12-48). Of all outage requests submitted to occur in the 2018/2019 planning period, 7.1 percent were expected to cause congestion. Of all the outage requests that were expected to cause congestion, 4.2 percent (66 out of 1,566) were denied by PJM in the 2018/2019 planning period and 21.9 percent (343 out of 1,566) were cancelled (Table 12-48).

73 PJM added this definition to Manual 38 in February 2017. PJM, "Manual 38: Operations Planning," Rev. 12 (Feb. 1, 2019).

Table 12-46 Transmission facility outage request summary by congestion: June 2018 through September 2019

	2018/2019 (12 months)				2019/2020 (4 months)			
Planned Duration (Days)	Congestion Expected	No Congestion Expected	Total	Percent Congestion Expected	Congestion Expected	No Congestion Expected	Total	Percent Congestion Expected
<=5	1,138	15,865	17,003	6.7%	377	4,464	4,841	7.8%
>5 & <=30	270	3,106	3,376	8.0%	88	844	932	9.4%
>30	158	1,555	1,713	9.2%	78	750	828	9.4%
Total	1,566	20,526	22,092	7.1%	543	6,058	6,601	8.2%

Table 12-47 shows the outage requests summary by received status, congestion status and emergency status. In the first four months of the 2019/2020 planning period, 35.4 percent of requests were submitted late and were nonemergency while 1.7 percent of requests (112 out of 6,601) were late, nonemergency, and expected to cause congestion. In the 2018/2019 planning period, 34.9 percent of request were submitted late and were nonemergency while 1.1 percent of requests (250 out of 22,092) were late, nonemergency, and expected to cause congestion.

Table 12-47 Transmission facility outage request summary by received status, emergency and congestion: June 2018 through September 2019

Received Status		2018/2019 (12 months) Congestion Expected	No Congestion Expected	Total	Percent of Total	2019/2020 (4 months) Congestion Expected	No Congestion Expected	Total	Percent of Total
Late	Emergency	72	2,663	2,735	12.4%	30	990	1,020	15.5%
	Non Emergency	250	7,468	7,718	34.9%	112	2,226	2,338	35.4%
On Time	Emergency	3	18	21	0.1%	3	9	12	0.2%
	Non Emergency	1,241	10,377	11,618	52.6%	398	2,833	3,231	48.9%
Total		1,566	20,526	22,092	100.0%	543	6,058	6,601	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.[74] Table 12-48 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 12-48. Table 12-48 shows that of all the outage requests that were expected to cause congestion, 3.9 percent (21 out of 543) were denied by PJM in the first four months of the 2019/2020 planning period, 56.4 percent were complete and 19.3 percent (105 out of 543) were cancelled. Of all the outage requests that were expected to cause congestion, 4.2 percent (66 out of 1,566) were denied by PJM in the 2018/2019 planning period, 67.9 percent were complete and 21.9 percent (343 out of 1,566) were cancelled.

Table 12-48 Transmission facility outage requests that might cause congestion status summary: June 2018 through September 2019

Received Status		2018/2019 (12 months) Cancelled	Complete	In Process	Denied	Congestion Expected	Percent Complete	2019/2020 (4 months) Cancelled	Complete	In Process	Denied	Congestion Expected	Percent Complete
Late	Emergency	7	64	0	0	72	88.9%	2	28	0	0	30	93.3%
	Non Emergency	47	170	10	20	250	68.0%	24	63	21	3	112	56.3%
On Time	Emergency	0	3	0	0	3	100.0%	1	2	0	0	3	66.7%
	Non Emergency	289	827	72	46	1,241	66.6%	78	213	86	18	398	53.5%
Total		343	1,064	82	66	1,566	67.9%	105	306	107	21	543	56.4%

There are clear rules defined for assigning On Time or Late status for submitted outage requests in both the PJM Tariff and PJM Manuals.[75] However, the On Time or Late status only affects the priority that PJM assigns for processing the outage request. Table 12-48 shows that in the 2018/2019 planning period, 250 nonemergency outage requests were submitted late and expected to cause congestion. 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 12-49 is a summary of all the outage requests planned for the 2018/2019 planning period and the first four months of the 2019/2020 planning period which were approved and then cancelled or rescheduled by TOs at least once. If an outage request was submitted, approved and subsequently rescheduled at least once, the outage request will be counted as Approved and Rescheduled. If an outage request was submitted, approved and subsequently cancelled at least once, the outage request will be counted as Approved and Cancelled. In the first four months of the 2019/2020 planning period, 28.3 percent of transmission outage requests were approved by PJM and then rescheduled by the TOs, and 11.2 percent of the transmission outages were approved by PJM

74 See PJM Markets & Operations, PJM Tools "Outage Information," <http://www.pjm.com/markets-and-operations/etools/oasis/system-information/outage-info.aspx> (2019).

75 PJM Operating Agreement Schedule 1 § 1.9.2.

and subsequently cancelled by the TOs. In the 2018/2019 planning period, 32.5 percent of transmission outage requests were approved by PJM and then rescheduled by the TO, and 12.2 percent of the transmission outages were approved by PJM and subsequently cancelled by the TO.

Table 12-49 Rescheduled and cancelled transmission outage request summary: June 2018 through September 2019

	2018/2019 (12 months)					2019/2020 (4 months)				
Planned Duration (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	17,003	4,019	23.6%	2,425	14.3%	4,841	1,102	22.8%	655	13.5%
>5 & <=30	3,376	2,050	60.7%	215	6.4%	932	451	48.4%	59	6.3%
>30	1,713	1,105	64.5%	57	3.3%	828	313	37.8%	25	3.0%
Total	22,092	7,174	32.5%	2,697	12.2%	6,601	1,866	28.3%	739	11.2%

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.[76] This rule allows a TO to reschedule within the same month with very little notice.

A transmission outage ticket with a duration exceeding five days with an On Time status can retain its On Time status if the outage is rescheduled to a future month, and the revision is submitted by the first of the month prior to the revised month in which the outage will occur.[77] This rescheduling rule is much less strict than the rule that applies to the first submission of outage requests with similar duration. When first submitted, the outage request with a duration exceeding five days needs to be submitted before the first of the month six months prior to the month in which the outage was expected to occur. The rescheduling rule allows TOs to avoid the timing requirements associated with outages exceeding five days.

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 12-43) 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.

More than one outage request can be submitted for the same transmission equipment. In order to accurately present the results, Table 12-50 shows equipment outages by the equipment instead of by outage request.

Table 12-50 shows that there were 5,208 transmission equipment planned outages in the first four months of the 2019/2020 planning period, of which 785 were longer than 30 days, and of which 20 or 0.4 percent were scheduled longer than 30 days when the duration of all the outage requests are combined for the same equipment.

76 PJM, "Manual 3: Transmission Operations," Rev. 55A (Oct. 31, 2019).
77 Id.

Table 12-50 Transmission outage summary: June 2018 through September 2019

		2018/2019 (12 months)		2019/2020 (4 months)	
Planned Duration (Days)	Divided into Shorter Periods	Count of Equipment with Planned Outages	Percent of Total	Count of Equipment with Planned Outages	Percent of Total
> 30	No	1,475	11.3%	765	14.7%
	Yes	246	1.9%	20	0.4%
<= 30		11,380	86.9%	4,423	84.9%
Total		13,101	100.0%	5,208	100.0%

Table 12-51 shows the details of long duration (> 30 days) outages when combining the duration of the outage requests for the same equipment. The actual duration of scheduled outages would be longer than 30 days if the duration of the outage requests were appropriately combined for the same equipment. An effective duration was calculated for each piece of equipment by subtracting the start date of the earliest outage request from the end date of the latest outage request of the equipment. In the first four months of the 2019/2020 planning period, within effective duration greater than a month and shorter than two months, there were 7 outages with a combined duration longer than 30 days.

Table 12-51 Equipment outages: June 2018 through September 2019

	2018/2019 (12 months)		2019/2020 (4 months)	
Effective Duration of Outage	Count of Equipment with Planned Outages	Percent of Total	Count of Equipment with Planned Outages	Percent of Total
<=31	3	1.2%	3	15.0%
>31 & <=62	26	10.6%	7	35.0%
>62 & <=93	22	8.9%	3	15.0%
>93	195	79.3%	7	35.0%
Total	246	100.0%	20	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 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 weeks as an initial list. Then PJM may exercise significant discretion in selecting outages to be modeled in the final model. PJM posts the final FTR outage list to the FTR web page usually at least one week before the auction bidding opening day.[78]

In the first four months of the 2019/2020 planning period, 138 outage requests were included in the annual FTR market outage list and 6,463 outage requests were not included.[79] In the 2018/2019 planning period, 239 outage requests were included in the annual FTR market outage list and 21,853 outage requests were not included. Table 12-52, Table 12-53, Table 12-54 and Table 12-55 show the summary information on the modeled outage requests and Table 12-56 and Table 12-57 show the summary information on outages that were not included in the Annual FTR Market.

Table 12-52 shows that 2.9 percent of the outage requests modeled in the Annual FTR Market for the first four months of the 2019/2020 planning period had a planned duration of less than two weeks and that 21.7 percent of the outage requests (30 out of 138) modeled in the Annual FTR Market for the planning period were submitted late according to outage submission rules. It also shows that 9.2 percent of the outage requests modeled in the Annual FTR Market for the 2018/2019 planning period had a planned duration of less

78 PJM Financial Transmission Rights, "Annual ARR Allocation and FTR Auction Transmission Outage Modeling," <https://www.pjm.com/-/media/markets-ops/ftr/annual-ftr-auction/2018-2019/2018-2019-annual-outage-modeling.ashx?la=en> (April 5, 2018). There is no documentation on the deadline for when modeling outages should be posted on the PJM website.

79 PJM's treatment of transmission outages in the FTR models is discussed in the 2019 Quarterly *State of the Market Report for PJM: January through September*, Section 13: FTRs and ARRs: Supply and Demand.

than two weeks and that 16.7 percent of the outage requests (40 out of 239) modeled in the Annual FTR Market for the planning period were submitted late according to outage submission rules.

Table 12-52 Annual FTR market modeled transmission facility outage requests by received status: June 2018 through September 2019

	2018/2019 (12 months)				2019/2020 (4 months)			
Planned Duration	On Time	Late	Total	Percent of Total	On Time	Late	Total	Percent of Total
<2 weeks	19	3	22	9.2%	3	1	4	2.9%
>=2 weeks & <2 months	65	9	74	31.0%	31	4	35	25.4%
>=2 months	115	28	143	59.8%	74	25	99	71.7%
Total	199	40	239	100.0%	108	30	138	100.0%

Table 12-53 shows the annual FTR market modeled outage requests summary by emergency status and received status. Two of the annual FTR market modeled outages expected to occur in the first four months of the 2019/2020 planning period were emergency outages. One of the modeled outages expected to occur in the 2018/2019 planning period was an emergency outage.

Table 12-53 Annual FTR market modeled transmission facility outage requests by emergency and received status: June 2018 through September 2019

		2018/2019 (12 months)				2019/2020 (4 months)			
Received Status	Planned Duration	Emergency	Non Emergency	Total	Percent Non Emergency	Emergency	Non Emergency	Total	Percent Non Emergency
On Time	<2 weeks	0	19	19	100.0%	0	3	3	100.0%
	>=2 weeks & <2 months	0	65	65	100.0%	0	31	31	100.0%
	>=2 months	0	115	115	100.0%	0	74	74	100.0%
	Total	0	199	199	100.0%	0	108	108	100.0%
Late	<2 weeks	0	3	3	100.0%	0	1	1	100.0%
	>=2 weeks & <2 months	0	9	9	100.0%	0	4	4	100.0%
	>=2 months	1	27	28	96.4%	2	23	25	92.0%
	Total	1	39	40	97.5%	2	28	30	93.3%

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 12-54 shows a summary of requests by expected congestion and received status. Of all the annual FTR market modeled outages expected to occur in the first four months of the 2019/2020 planning period and submitted late, 10.0 percent (3 out of 30) were expected to cause congestion Overall, none of all the annual FTR market modeled outages expected to occur in the 2018/2019 planning period and submitted late were expected to cause congestion.

Table 12-54 Annual FTR market modeled transmission facility outage requests by congestion and received status: June 2018 through September 2019

		2018/2019 (12 months)				2019/2020 (4 months)			
Received Status	Planned Duration	Congestion Expected	No Congestion Expected	Total	Percent Congestion Expected	Congestion Expected	No Congestion Expected	Total	Percent Congestion Expected
On Time	<2 weeks	10	9	19	52.6%	2	1	3	66.7%
	>=2 weeks & <2 months	17	48	65	26.2%	14	17	31	45.2%
	>=2 months	29	86	115	25.2%	16	58	74	21.6%
	Total	56	143	199	28.1%	32	76	108	29.6%
Late	<2 weeks	0	3	3	0.0%	1	0	1	100.0%
	>=2 weeks & <2 months	0	9	9	0.0%	1	3	4	25.0%
	>=2 months	0	28	28	0.0%	1	24	25	4.0%
	Total	0	40	40	0.0%	3	27	30	10.0%

Table 12-55 shows that 28.6 percent of outage requests modeled in the annual FTR market for the first four months of the 2019/2020 planning period and with a duration of two weeks or longer but shorter than two months were cancelled after the FTR auction was open, compared to 25.7 percent for the 2018/2019 planning period. Table 12-55 also shows that 18.2 percent of outages requests modeled in the Annual FTR Market for the first four months of the 2019/2020 planning period and with a duration of two months or longer were cancelled, compared to 23.1 percent for the 2018/2019 planning period.

Table 12-55 Annual FTR market modeled transmission facility outage requests by processed status: June 2018 through September 2019

		2018/2019 (12 months)		2019/2020 (4 months)	
Planned Duration	Processed Status	Outage Requests	Percent	Outage Requests	Percent
<2 weeks	In Progress	2	9.1%	0	0.0%
	Denied	0	0.0%	0	0.0%
	Approved	1	4.5%	0	0.0%
	Cancelled	4	18.2%	0	0.0%
	Active	0	0.0%	1	25.0%
	Completed	15	68.2%	3	75.0%
	Total	22	100.0%	4	100.0%
>=2 weeks & <2 months	In Progress	7	9.5%	8	22.9%
	Denied	0	0.0%	0	0.0%
	Approved	0	0.0%	1	2.9%
	Cancelled	19	25.7%	10	28.6%
	Active	0	0.0%	9	25.7%
	Completed	48	64.9%	7	20.0%
	Total	74	100.0%	35	100.0%
>=2 months	In Progress	20	14.0%	22	22.2%
	Denied	1	0.7%	0	0.0%
	Approved	1	0.7%	0	0.0%
	Cancelled	33	23.1%	18	18.2%
	Active	6	4.2%	47	47.5%
	Completed	82	57.3%	12	12.1%
	Total	143	100.0%	99	100.0%

More outage requests were not modeled in the Annual FTR Market than were modeled in the Annual FTR Market. In the first four months of the 2019/2020 planning period, 138 outage requests were modeled and 6,463 outage requests were not modeled in the Annual FTR Market. In the 2018/2019 planning period, 239 outage requests were modeled and 21,853 outage requests were not modeled in the Annual FTR Market.

Table 12-56 shows that 2.8 percent of outage requests not modeled in the Annual FTR Auction with duration longer than or equal to two months, labeled On Time according to the rules, were submitted after the Annual FTR Auction bidding opening date for the first four months of the 2019/2020 planning period compared to 13.5 percent in the 2018/2019 planning period.

Table 12-56 Transmission facility outage requests not modeled in Annual FTR Auction: June 2018 through September 2019

	2018/2019 (12 months)						2019/2020 (4 months)					
	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	1,717	8,457	83.1%	219	8,556	97.5%	951	1,718	64.4%	139	2,525	94.8%
>=2 weeks & <2 months	644	370	36.5%	163	907	84.8%	294	28	8.7%	101	255	71.6%
>=2 months	218	34	13.5%	204	364	64.1%	140	4	2.8%	196	112	36.4%
Total	2,579	8,861	77.5%	586	9,827	94.4%	1,385	1,750	55.8%	436	2,892	86.9%

Table 12-57 shows that 31.3 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 first four months of the 2019/2020 planning period. It also shows that 75.8 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 2018/2019 planning period.

Table 12-57 Late transmission facility outage requests not modeled in Annual FTR Auction and submitted after annual bidding opening date: June 2018 through September 2019

	2018/2019 (12 months)			2019/2020 (4 months)		
Planned Duration	Completed Outages	Total	Percent Complete	Completed Outages	Total	Percent Complete
<2 weeks	7,078	8,556	82.7%	2,100	2,525	83.2%
>=2 weeks & <2 months	784	907	86.4%	153	255	60.0%
>=2 months	276	364	75.8%	35	112	31.3%
Total	8,138	9,827	82.8%	2,288	2,892	79.1%

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 those 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 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 less than or equal to five days. PJM exercises 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.[80] Table 12-58 and Table 12-59 show the summary information on outage requests modeled in the Monthly Balance of Planning Period FTR Auction and Table 12-60 and Table 12-61 show the summary information on outage requests not modeled in the Monthly Balance of Planning Period FTR Auction.

Table 12-58 shows that on average, 40.0 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 first four months of the 2019/2020 planning period. On average, 29.8 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 2018/2019 planning period.

Table 12-58 Monthly Balance of Planning Period FTR Auction modeled transmission facility outage requests by received status: June 2018 through September 2019

	2018/2019				2019/2020			
Month	On Time	Late	Total	Percent Late	On Time	Late	Total	Percent Late
Jun	208	106	314	33.8%	162	115	277	41.5%
Jul	136	71	207	34.3%	92	96	188	51.1%
Aug	137	78	215	36.3%	131	86	217	39.6%
Sep	465	136	601	22.6%	379	147	526	27.9%
Oct	536	191	727	26.3%				
Nov	391	129	520	24.8%				
Dec	363	129	492	26.2%				
Jan	199	90	289	31.1%				
Feb	213	109	322	33.9%				
Mar	389	146	535	27.3%				
Apr	427	159	586	27.1%				
May	362	181	543	33.3%				
Average	319	127	446	29.8%	191	111	302	40.0%

Table 12-59 shows that on average, 18.9 percent of outage requests modeled in the Monthly Balance of Planning Period FTR Auction were cancelled in the first four months of the 2019/2020 planning period. On average, 20.0 percent of outage requests modeled in the Monthly Balance of Planning Period FTR Auction were cancelled in the 2018/2019 planning period.

80 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).

Table 12-59 Monthly Balance of Planning Period FTR Auction modeled transmission facility outage requests by processed status: June 2018 through September 2019

Planning Year	Month	In Process	Denied	Approved	Cancelled	Revised	Active	Complete	Total	Percent Cancelled
2018/2019	Jun	22	11	10	57	0	60	154	314	18.2%
	Jul	11	4	6	38	0	60	88	207	18.4%
	Aug	19	3	2	38	1	65	87	215	17.7%
	Sep	77	11	22	143	1	163	184	601	23.8%
	Oct	66	7	19	140	0	196	299	727	19.3%
	Nov	39	2	8	119	1	166	185	520	22.9%
	Dec	42	5	5	112	0	96	232	492	22.8%
	Jan	35	3	11	43	1	100	96	289	14.9%
	Feb	36	1	2	67	1	112	103	322	20.8%
	Mar	48	5	14	103	0	155	210	535	19.3%
	Apr	51	0	13	89	0	170	263	586	15.2%
	May	38	4	8	119	0	137	237	543	21.9%
	Avg	40	5	10	89	0	123	178	446	20.0%
2019/2020	Jun	17	2	2	47	0	82	127	277	17.0%
	Jul	13	4	0	45	0	72	54	188	23.9%
	Aug	14	5	0	37	0	79	82	217	17.1%
	Sep	58	2	25	93	0	178	170	526	17.7%
	Avg	26	3	7	56	0	103	108	302	18.9%

Table 12-60 shows that on average, 10.2 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 first four months of the 2019/2020 planning period, compared to 10.8 percent in the 2018/2019 planning period. On average, 69.0 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 first four months of the 2019/2020 planning period, compared to 68.6 percent in the 2018/2019 planning period.

Table 12-60 Transmission facility outage requests that are not modeled in Monthly Balance of Planning Period FTR Auction: June 2018 through September 2019

	2018/2019						2019/2020					
	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	757	120	13.7%	400	819	67.2%	683	76	10.0%	337	704	67.6%
Jul	393	64	14.0%	272	642	70.2%	394	61	13.4%	268	729	73.1%
Aug	483	68	12.3%	259	715	73.4%	364	37	9.2%	302	638	67.9%
Sep	819	145	15.0%	283	712	71.6%	936	82	8.1%	319	660	67.4%
Oct	1,232	116	8.6%	329	945	74.2%						
Nov	869	77	8.1%	406	860	67.9%						
Dec	663	44	6.2%	321	672	67.7%						
Jan	554	75	11.9%	369	726	66.3%						
Feb	641	101	13.6%	330	738	69.1%						
Mar	1,087	117	9.7%	380	772	67.0%						
Apr	1,399	102	6.8%	439	748	63.0%						
May	1,246	128	9.3%	446	852	65.6%						
Avg	845	96	10.8%	353	767	68.6%	594	64	10.2%	307	683	69.0%

Table 12-61 shows that on average, 72.4 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 first four months of 2019/2020 planning period, compared to 68.6 percent in the 2018/2019 planning period.

Table 12-61 Late transmission facility outage requests that are not modeled in Monthly Balance of Planning Period FTR Auction and submitted after monthly bidding opening date: June 2018 through September 2019

	2018/2019			2019/2020		
	Completed Outages	Total	Percent Complete	Completed Outages	Total	Percent Complete
Jun	625	819	76.3%	534	704	75.9%
Jul	449	642	69.9%	489	729	67.1%
Aug	506	715	70.8%	500	638	78.4%
Sep	480	712	67.4%	455	660	68.9%
Oct	614	945	65.0%			
Nov	570	860	66.3%			
Dec	468	672	69.6%			
Jan	471	726	64.9%			
Feb	470	738	63.7%			
Mar	568	772	73.6%			
Apr	504	748	67.4%			
May	586	852	68.8%			
Avg	526	767	68.6%	495	683	72.4%

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 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. [81]

There are three relevant time periods for the analysis of the impact of transmission outages on the energy market: 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 available to market participants. The day-ahead market model uses outages included in the day-ahead market save cases as an input. The 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 negative impact on markets. For example, if the list of outages before the day-ahead market was closed was different from the list of outages that included in the day-ahead market save cases, the day-ahead market participant would have inconsistent outage information as what day-ahead market model used.

For example for the operating day of May 5, 2018, Figure 12-4 shows that: there were 443 approved or active outages seen by market participants before the day-ahead market was closed; there were 329 outage requests included in the day-ahead market model; there were 315 outage requests included in both sets of outage; there were 128 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 14 outage requests included in day-ahead market model but not available to market participants prior to the day-ahead market.

81 PJM, "Manual 3: Transmission Operations," Rev. 55A (Oct. 31, 2019).

Figure 12-4 Illustration of day-ahead market analysis: May 5, 2018

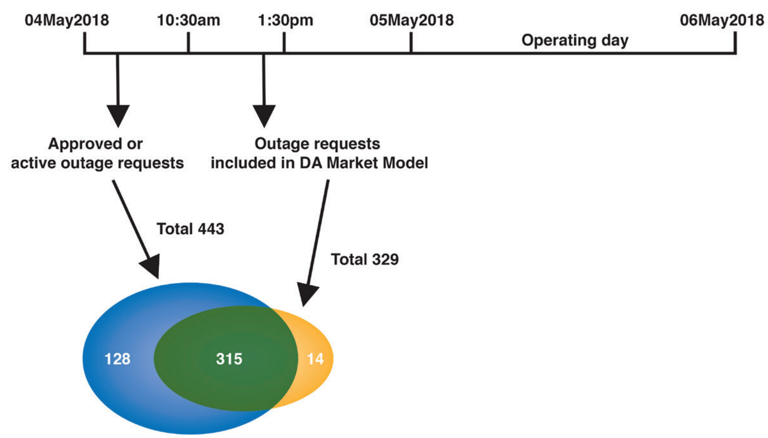


Figure 12-5 compares the weekly average number of active or approved outages available to market participants prior to the close of the day-ahead market with the outages included as inputs to the day-ahead market by PJM.

Figure 12-5 Approved or active outage requests: January 2015 through September 2019

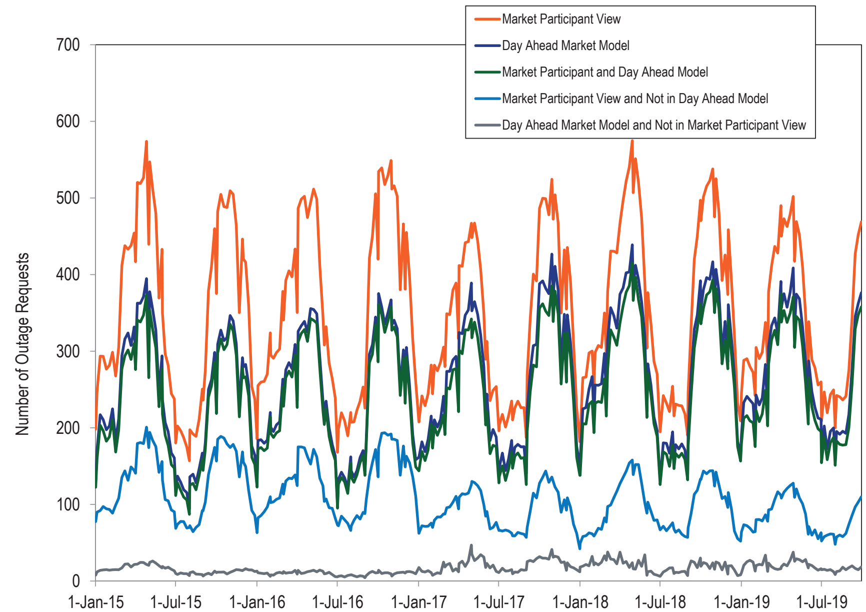


Figure 12-6 compares the weekly average number of outages included as inputs to the day-ahead market by PJM with the outages that actually occurred during the operating day.

Figure 12-6 Day-ahead market model outages: January 2015 through September 2019

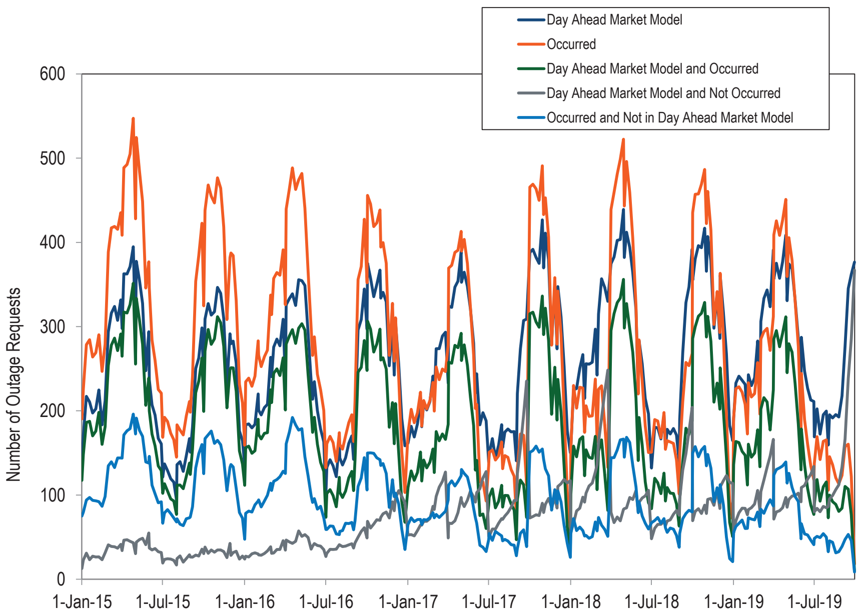


Figure 12-7 compares the weekly average number of active or approved outages available to market participants prior to the close of the day-ahead market with the outages that actually occurred during the operating day.

Figure 12-7 Approved or active outage requests: January 2015 through September 2019

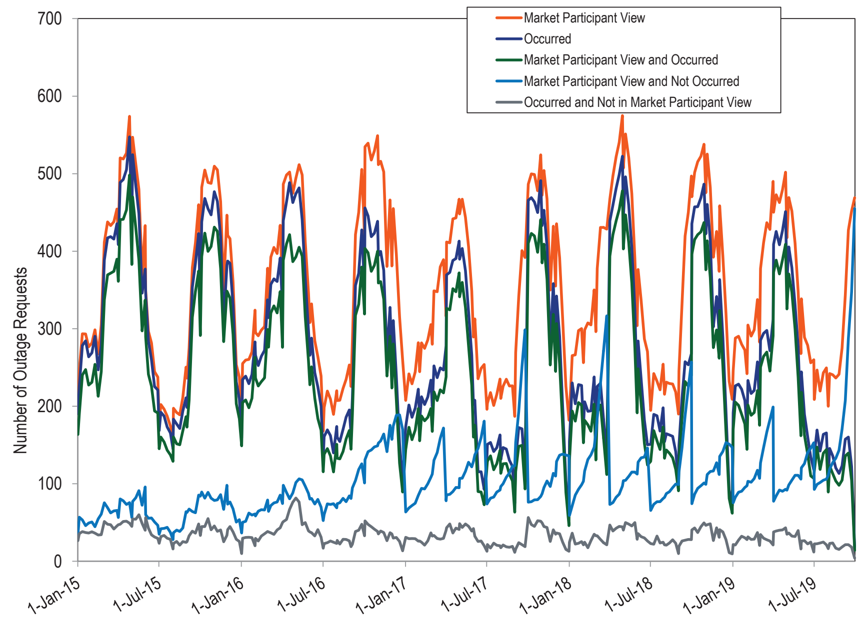


Figure 12-5, Figure 12-6, and Figure 12-7 show that on a weekly average basis, the active or approved outages available to day-ahead market participants, the outages included as inputs in the day-ahead market model and the outages that actually occurred in real time are not consistent. The active or 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, the delivery of low cost generation to load was based both on zonal generation and zonal transmission under cost of service rates, and on contracts with specific remote generation outside the local zone and on associated point to point transmission contracts. In both cases, customers paid for the physical rights associated with the transmission system used to provide for the delivery of low cost generation to load. Firm transmission customers who paid for the transmission system through cost of service rates or through bilateral contracts received the low cost generation.

After the introduction of LMP markets, financial transmission rights (FTRs) were introduced, effective April 1, 1999, for the real-time market and June 1, 2000, for the day-ahead and balancing markets, to permit the loads which pay for the transmission system to continue to receive the benefits of access to either local or remote low cost generation in the form of FTR revenues which offset congestion.[1] FTRs and the associated congestion revenues were directly provided to load in recognition of the fact that, as a result of LMP, load pays more for low cost generation than is paid to low cost generation. Under LMP, load pays and generation is paid locational prices which result in load payments in excess of generation revenues. The excess payments are congestion. The origin of FTRs was the recognition that the way to hold load harmless from making these excess payments created by the LMP system was to return the excess payments to load through the mechanism of FTRs. The rights to congestion belong to load.

1 See 81 FERC ¶ 61,257 at 62,241 (1997).

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 offset the congestion costs that load pays in an LMP market. Congestion revenues are the source of the funds to pay FTRs. Congestion revenues are assigned to the load that paid them through FTRs.[2] 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.

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, and 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 only 74.5 percent of total congestion costs including congestion in the Day-Ahead Energy Market and the balancing energy market, for the 2011/2012 planning period through the 2016/2017 planning period, before the FERC decision to allocate balancing congestion and M2M payments to load.[3] For the 2017/2018 planning

2 See *id.* at 62, 259–62,260 & n. 123.

3 On September 15, 2016, FERC ordered PJM to allocate balancing congestion to load, rather than to FTRs, to modify PJM's Stage 1A ARR allocation process and to continue to use portfolio netting. 153 FERC ¶ 61,180.

period, after the implementation of the FERC decision to reallocate balancing congestion and M2M payments to load, ARR and self scheduled FTR revenue offset 50.0 percent of total congestion.

On May 31, 2018, a rule change was implemented to offset the more egregious effects of the allocation of balancing congestion to load.[4] Effective for the 2018/2019 planning period, surplus day-ahead congestion and surplus FTR auction revenue were allocated to ARR holders.[5]

Surplus congestion revenue should be allocated to ARR holders because surplus day-ahead congestion and surplus auction revenue are associated with unallocated ARR capacity. This residual capacity is unallocated as a result of PJM's conservative modeling designed to improve FTR funding. Had this surplus allocation been implemented in the 2017/2018 planning period, the percent of congestion offset by ARRs and FTRs would have increased from 50.0 percent to 74.3 percent. For the first four months of the 2019/2020 planning period, over 100 percent of total congestion was offset by ARR credit allocations to ARR holders including FTR auction revenues, self scheduled FTR revenue, surplus from the FTR auction, and day-ahead congestion in excess of target allocations.

The ARR/FTR design does not serve as an efficient mechanism for returning congestion to load as a result of an FTR design that was flawed from its introduction and as a result of various distortions added to the design since its introduction. The distortions include the definition of target allocations based on day-ahead congestion only, the failure to assign all FTR auction revenues to ARR holders, differences between modeled and actual system capability and numerous cross subsidies among participants. One of the key flaws in the original design was the link between congestion revenues and specific generation to load transmission paths. This link retained the contract path based view of congestion rooted in physical transmission rights and inconsistent with the role of FTRs in a nodal, network system with locational marginal pricing.

If the original PJM FTR approach had been designed to return congestion revenues to load without use of the generation to load paths, and if the distortions subsequently introduced into the FTR design not been added, 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.

To address the issues with the current path based ARR/FTR market construct, the MMU is proposing that the current construct be replaced with a network construct in which the rights to actual congestion are assigned directly to load by node. The allocated right is to the actual congestion collected, both day ahead and balancing, between the load at a bus and the generation used to serve that load. The load can retain the right to the network congestion or sell the right through auctions with the desired frequency.

The network allocation of actual congestion has a number of advantages over the current path based approach. There are no cross subsidies among rights holder and no over or under allocation of rights relative to actual network market solutions. There are no revenue shortfalls as congestion payments equal congestion collected. There is no risk of prevailing flow FTRs flipping in value because congestion is always positive or zero and the full amount of congestion is always allocated. The risk of default is isolated to the buyer and seller of the right, and any default is not socialized to other right holders. In the case of a defaulting buyer, the rights to the congestion revenues revert to the load.

The *2019 Quarterly State of the Market Report for PJM: January through September* focuses on the 2019/2022 Long Term FTR Auction, the 2019/2020 Annual FTR Auction and the 2018/2019 Monthly Balance of Planning Period FTR Auctions, specifically covering January 1, 2019, through September 30, 2019. A caveat that applies to the 2018/2019 planning period is that the

4 On May 31, 2018, FERC issued an order accepting PJM's proposal to allocate surplus day-ahead congestion charges and surplus FTR auction revenue that remain at the end of the Planning Period to ARR holders, rather than to FTR holders. 163 FERC ¶ 61,165.

5 163 FERC ¶61,165 (2018).

results may change depending on the final FERC actions in the GreenHat Energy, LLC matter.[6]

Table 13-1 The FTR auction markets results were competitive

Market Element	Evaluation	Market Design
Market Structure	Partially Competitive	
Participant Behavior	Partially Competitive	
Market Performance	Competitive	Flawed

- Market structure was evaluated as partially competitive because while purchasing FTRs in the FTR Auction is voluntary, issues have been identified with the under assignment of system capability to ARRs and the accuracy of modeling in the Long Term FTR Auctions.
- Participant behavior was evaluated as partially competitive based on the behavior of GreenHat Energy, LLC.
- Market performance was evaluated as competitive because it reflected the interaction between participant demand behavior and the expected system capability that PJM made available for sale as FTRs. It is not clear, in a competitive market, why FTR purchases by financial entities remain persistently profitable. The fact that load is not able to define its willingness to sell FTRs or the prices at which it is willing to sell FTRs also raises questions about the market structure, the market performance and the market design.
- 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. The path based assignment of congestion rights is inadequate and incorrect. ARR holders cannot determine the price at which they are willing to sell rights to congestion revenue. Ongoing PJM subjective intervention in the FTR market that affects market fundamentals is also an issue.

6 See 166 FERC ¶ 61,072, *reh'g pending*; see also 163 FERC ¶ 61,157 (establishing settlement judge proceedings).

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 four months of the 2019/2020 planning period, PJM allocated a total of 11,162.7 MW of residual ARRs, down from 11,961.8 MW in the 2018/2019 planning period, with a total target allocation of $2.7 million for the 2019/2020 planning period, down from $4.1 million for the 2018/2019 planning period.

- **ARR Reassignment for Retail Load Switching.** There were 18,913 MW of ARRs associated with $223,800 of revenue that were reassigned in the 2019/2020 planning period. There were 35,571 MW of ARRs associated with $423,100 of revenue that were reassigned for the 2018/2019 planning period.

Market Performance

- **Revenue Adequacy.** For the first four months of the 2019/2020 planning period, the ARR target allocations, which are based on the nodal price differences from the Annual FTR Auction, were $246.9 million, while PJM collected $956.9 million from the combined Long Term, Annual and Monthly Balance of Planning Period FTR Auctions, making ARRs revenue adequate. The new allocation of surplus congestion revenue provides for revenue adequacy for FTRs first, and any remaining revenues at the end of the planning period are allocated to ARR holders. For the 2018/2019 planning period, the ARR target allocations were $726.8 million while PJM collected $907.6 million from the combined Annual and Monthly Balance of Planning Period FTR Auctions.

- **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 2016/2017 planning period, under the previous allocation of balancing congestion. In 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 50.0 percent of total congestion costs. Under the new rules for surplus congestion revenue allocation beginning in the 2018/2019 planning periods, for the first four months of the 2019/2020 planning period, over 100 percent of total congestion was offset by ARR credit allocations to ARR holders including FTR auction revenues, self scheduled FTR revenue, surplus from the FTR auction, and day-ahead congestion in excess of target allocations. 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.** In a given auction, market participants can sell FTRs that they have acquired in preceding auctions or preceding rounds of auctions. In the Monthly Balance of Planning Period FTR Auctions for the first four months of the 2019/2020 planning period, total participant FTR sell offers were 3,881,264 MW, up from 3,320,461 MW for the same period during the 2018/2019 planning period.
- **Demand.** The total FTR buy bids from the Monthly Balance of Planning Period FTR Auctions for the first four months of the 2019/2020 planning period increased 1.2 percent from 9,443,085 MW for the same time period of the prior planning period, to 9,555,146 MW.
- **Patterns of Ownership.** For the Monthly Balance of Planning Period Auctions, financial entities purchased 79.9 percent of prevailing flow and 71.7 percent of counter flow FTRs for January through September of 2019. Financial entities owned 68.9 percent of all prevailing and counter flow FTRs, including 62.0 percent of all prevailing flow FTRs and 79.1 percent of all counter flow FTRs during the period from January through September 2019.

Market Behavior

- **FTR Forfeitures.** For the period January 19, 2017, through September 30, 2019, total FTR forfeitures were $24.6 million.
- **Credit.** There were no collateral defaults in the first nine months of 2019. There were 58 payment defaults in the first nine months of 2019 not involving GreenHat Energy, LLC for a total of $59,933. GreenHat Energy continued to accrue payment defaults of $53.6 million in the first nine months of 2019, for a total of $130.6 million in defaults to date, which will continue to accrue through May 2021, including the auction liquidation costs.

Market Performance

- **Volume.** In the first four months of the 2019/2020 planning period Monthly Balance of Planning Period FTR Auctions cleared 1,588,345 MW (16.6 percent) of FTR buy bids and 832,832 MW (21.5 percent) of FTR sell offers.
- **Price.** The weighted average buy bid cleared FTR price in the Monthly Balance of Planning Period FTR Auctions for the first four months of the 2019/2020 planning period was $0.17, up from $0.12 per MW for the same period in the 2018/2019 planning period.
- **Revenue.** The Monthly Balance of Planning Period FTR Auctions generated $27.9 million in net revenue for all FTRs of the first four months of the

2019/2020 planning period, down from $33.5 million for the same time period in the 2018/2019 planning period.

- **Revenue Adequacy.** FTRs were paid at 100.0 percent of the target allocation level for the first four months of the 2019/2020 planning period, assuming the distribution of the current (as of September) existing surplus revenue. This level of FTR funding 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 four months of the 2019/2020 planning period, physical entities made -$22.6 million in profits on FTRs purchased directly (not self scheduled), while receiving $39.5 million in returned congestion from self scheduled FTRs, and financial entities made -$3.1 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
2020/2023 Long Term	6/3/2019	12/11/2019
2018/2019 ARR	3/4/2019	4/5/2019
2018/2019 Annual	4/9/2019	5/6/2019

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 the Long Term FTR product be eliminated. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that, if the Long Term FTR product is not eliminated, the Long Term FTR Market be modified so that the supply of prevailing flow FTRs in the Long Term FTR Market is based solely on counter flow offers in the Long Term FTR Market. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends that, under the current FTR design, the full capability of the transmission system be allocated as ARRs prior to sale as FTRs. Reductions for outages and increased system capability should be reserved for ARRs rather than sold in the Long Term FTR Auction. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends that all FTR auction revenue be distributed to ARR holders monthly, regardless of FTR funding levels. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that, under the current FTR design, all congestion revenue in excess of FTR target allocations be distributed to ARR holders on a monthly basis. (Priority: High. First reported 2018. 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.[7] (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: Partially 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. Rejected by FERC.)
- The MMU recommends that PJM eliminate subsidies to counter flow FTRs by applying the payout ratio to counter flow FTRs in the same way the payout ratio is applied to prevailing flow FTRs. (Priority: High. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM eliminate geographic cross subsidies. (Priority: High. First reported 2013. Status: Not adopted.)

7 See "PJM Manual 6: Financial Transmission Rights," Rev. 23 (Sep. 1, 2019).

- 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 and its members continue to review the management of a defaulted member's FTR portfolio, including options other than immediate liquidation. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM continue to evaluate the bilateral indemnification rules and any asymmetries they may create. (Priority: Low. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM examine the source and sink node combinations available in the FTR market and eliminate generation to generation paths and all other paths that do not represent the delivery of power to load. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that the forfeiture amount from the FTR forfeiture rule be based on the correct hourly cost of an FTR, rather than a simple daily price divided by 24. (Priority: High. First reported 2018. Status: Pending at FERC.)
- The MMU recommends that the direct customer request approach for creating and allocating IARRs be eliminated from PJM's tariff. (Priority: Low. First reported 2018. Status: Not adopted.)

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 inconsistent with the network based delivery of power and the actual way congestion is generated in security constrained 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 load paying congestion revenues, in an LMP market.

Revenue adequacy is misunderstood and generally incorrectly defined. Revenue adequacy has received a lot of attention in the PJM FTR Market and conclusions based on the incorrect definition have led to significant changes in the design of the ARR/FTR market that have distorted the function and purpose of ARRs and FTRs as a means of allocating congestion and congestion rights. Correctly defined, revenue adequacy for ARRs means that ARRs have the rights to 100 percent of congestion revenue. FTR holders, with the creation of ARRs, do not have a right to receive revenues equal to CLMP differentials on individual FTR paths.

The current ARR/FTR design does not serve as an efficient way to ensure that load receives the rights to all the congestion revenues and has the ability to receive the auction revenues associated with all the potential congestion revenues. Total ARR and self scheduled FTR revenue offset only 65.3, 90.3, 103.6, 50.0 and 92.1 percent of total congestion costs including congestion in the Day-Ahead Energy Market and the balancing energy market for the 2014/2015, 2015/2016, 2016/2017, 2017/2018, 2018/2019 planning periods. Within the planning period, surplus monthly revenue can be distributed to achieve revenue adequacy for the planning year to date, but at the end of the planning period any remaining surplus revenue left after paying FTR target allocations is assigned to ARR holders. Distributing surplus to FTR holders first does not preserve ARR's rights to congestion revenue. If the surplus revenue available through September 2019 were distributed to ARR holders, total ARR and self scheduled FTR revenue would offset 116.2 percent, and 94.3 percent without distribution of surplus revenue, of total congestion costs for the first four months of the 2019/2020 planning period.

PJM has persistently and subjectively intervened in the FTR market in order to affect the payments to FTR holders. These interventions are not appropriate. For example, in the 2014/2015, 2015/2016 and 2016/2017 planning periods, PJM significantly reduced the allocation of ARR capacity, and FTRs, in order to guarantee full FTR funding. PJM reduced system capability in the FTR auction model by including more outages, reducing line limits and including additional constraints. PJM's modeling changes resulted in significant reductions in Stage 1B and Stage 2 ARR allocations, a corresponding reduction in the available quantity of FTRs, a reduction in congestion revenues assigned to ARRs, and an associated 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. Starting in the 2017/2018 planning period, with the allocation of balancing congestion and M2M payments to load rather than FTRs, PJM increased system capability allocated to Stage 1B and Stage 2 ARRs, but continued to conservatively select outages to manage FTR funding levels.

PJM has intervened aggressively in the FTR market since its inception in order to meet various subjective objectives. PJM should not intervene in the FTR market to subjectively manage FTR funding. PJM should fix the FTR/ARR design and then should let the market work to return congestion to load and to let FTR values reflect actual congestion.

Load should never be required to subsidize payments to FTR holders, regardless of the reason. Such subsidies have been suggested repeatedly.[8] The FERC order of September 15, 2016, introduced a subsidy to FTR holders at the expense of ARR holders.[9] The order requires PJM to ignore balancing congestion when calculating total congestion dollars available to fund FTRs. 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. The Commission's order shifts substantial revenue from load to the holders of FTRs and reduces the ability of load to offset congestion. 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 pays for the physical transmission system, pays in excess of generator revenues and pays negative balancing congestion again. The result is that load gets back less than total congestion. Based on a recent rule change, balancing congestion is allocated to load on a load ratio share, rather than on the basis of location or source of the balancing congestion. This rule creates inappropriate cross subsidies among loads.

These changes were made in order to increase the payout to holders of FTRs who are not loads. 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. Increasing the payout to FTR holders at the expense of the load is not a supportable market objective. Under the current FTR design, FTR holders should receive actual congestion on the relevant FTR paths and paths should be limited to actual physical source and sink points to align congestion rights with the paths that generate congestion and to limit cross subsidies. But PJM should implement an FTR design that calculates and assigns congestion rights to load rather than continuing to modify the current design.

Load was made 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 revenues were significantly reduced for the 2017/2018 FTR Auction, the first auction under the new rules. ARRs and self scheduled FTRs offset 50.0 percent of total congestion costs for the 2017/2018 planning period rather than the 60.5 percent offset that would have occurred under the prior rules, a difference of $125.8 million. There was a significant amount of congestion in January 2018 which adversely affected the congestion offset value of ARRs. ARR revenue is fixed at annual auction prices, but congestion revenue varies with market conditions. If these allocation rules had been in place beginning with the 2011/2012 planning period, ARR holders would have received a total

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

9 See 156 FERC ¶ 61,180 (2016), *reh'g denied*, 156 FERC ¶ 61,093 (2017).

of $1,160.0 million less in congestion offsets from the 2011/2012 through the 2017/2018 planning period. The total overpayment to FTR holders for the 2011/2012 through 2018/2019 planning period would have been $1,427.4 million.

The actual underpayment to load and the overpayment to FTR holders was a result of several rules, all of which mean the transfer of revenues to FTR holders and the shifting of costs to load. Load is not assigned rights to all congestion as a result of using generation to load paths. Load is 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. Surplus revenues from the FTR auction are not assigned to ARR holders, but are used by PJM to clear counter flow FTRs in the Monthly FTR Auctions in order to make it possible to sell more prevailing flow FTRs and to insure revenue adequacy for FTRs before distribution to ARR holders. Under the prior rules, surplus revenues in the day-ahead market were assigned directly to FTR holders along with surplus auction revenues.

A rule change was implemented by PJM that offset the more egregious effects of the allocation of balancing congestion to load. Beginning with the 2018/2019 planning period, surplus revenues in the day-ahead market and surplus auction revenue are assigned to FTR holders only up to revenue adequacy, and then distributed to ARR holders. This is consistent with a recognition that PJM's modeling does not assign the full capacity of the system to ARR holders.[10]

All congestion revenue belongs to ARR holders, and PJM's new surplus congestion allocation rule is consistent with that goal. However, under the rules, ARR holders will only be allocated this surplus after full funding of FTRs is accomplished. The new rules do not fully recognize ARR holders' primary rights to surplus congestion revenue. If this rule had been in effect for the 2018/2019 planning period, ARRs and FTRs would have offset 92.1 percent of total congestion rather than 78.1 percent.

10 163 FERC ¶61,165 (2018).

The overallocation of Stage 1A ARRs results in FTR overallocations on the same facilities. While Stage 1A overallocation has been reduced, 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 many of the over allocations are due to outages in the FTR model, or are not actual system limitations. Capacity issues do not persist if the modeled outages are removed, so there is no need to expand the transmission system to support them. 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. The MMU recommends that the transmission modeling in the FTR auction and persistent FTR path overallocation 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 participation in the Long Term FTR Auction continues to be very low for the second and third year long term product. 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. Recent changes to improve the modeling of the next year's auction model and include an offline ARR allocation model are steps in the right direction, but do not do enough to guarantee ARR holders' rights to the congestion being auctioned in the Long Term FTR Auction.

Another issue with the current market design is that there is no effective way for the market to result in price discovery in the long term and annual auctions because the sellers of congestion rights, ARR holders, cannot set a reserve price or otherwise actually participate in what is called the FTR market. ARR holders cannot claim all of the network that serves their load, cannot choose how much of the system they want to sell and cannot set a reserve price on what is made available in the market. PJM, as the system administrator, chooses what is available to sell, including system capability that cannot be claimed by load, and then offers that market model capability as a price taker in the FTR auction. Due to this design, FTR prices are consistently below the value of congestion. When FTR prices begin to converge towards expected congestion levels in near term monthly auctions it is the result of the active participation as sellers by entities who have purchased FTRs in the long term and annual auctions, who set explicit reserve prices reflecting the expected value of congestion.

The MMU recommends that the Long Term FTR product be eliminated. If the Long Term FTR product is not eliminated, the MMU recommends that Long Term FTR Market be modified so that the supply of prevailing flow FTRs in the Long Term FTR Market is based solely on counter flow offers in the Long Term FTR Market. This would ensure ARR holders' rights to congestion while maintaining the ability for participants to purchase congestion offsets for future planning periods.

Auction Revenue Rights

ARR revenues result from the sale of congestion rights that belong to ARR holders. ARRs are the financial instruments through which the proceeds from FTR Auctions are allocated to load. ARR values are based on nodal price differences, established by cleared FTR bids in the Annual FTR Auction, between the ARR source and sink points in the FTR Auction.[11] ARR revenues are a function of FTR auction participants' expectations of congestion, risk, competition and available system capability. PJM has significant discretion over that level of system capability. The appropriate goals of that discretion need to be significantly limited and defined clearly in the tariff.

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's value, which is established from the Annual FTR Auction, can be a benefit or liability depending on the price difference between sink and source, and represents the fixed stream of revenue that an ARR holder would receive if the ARR is retained. 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, otherwise, available revenue is proportionally allocated among all ARR holders. If there are auction revenues greater than the ARR target allocations, the revenue is first used to fully fund ARRs in previous months, then fully fund FTRs, and then provided to ARR holders at the end of the planning period.

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. If ARR holders have rights to all congestion revenue and the FTR auction is the way in which ARR holders exchange rights to congestion for fixed payments, then 100 percent of the FTR auction revenue should be assigned to ARR 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

11 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.

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.

On December 1, 2018, PJM integrated the Ohio Valley Electric Cooperative (OVEC) as a PJM zone. In anticipation of OVEC joining PJM earlier, PJM included the OVEC Zone integration into their 2018/2019 Annual ARR Allocation, so that Kyger Creek and Clifty Creek were valid source points, and the OVEC residual aggregate was added as a biddable node in the ARR model. From June 1, 2018, to December 1, 2018, any ARRs or self scheduled FTRs source at Kyger Creek and Clifty Creek resources were remapped back to the historical OVEC Interface. Effective December 1, 2018, any ARRs and self scheduled FTRs which were allocated in the Annual ARR Allocation to the OVEC interface were remapped back to Clifty Creek or Kyger Creek.

Incremental Auction Revenue Rights (IARRs) are ARRs made available by physical transmission system upgrades from customer funded transmission projects or from merchant transmission or generation interconnection requests. In order for a transmission project to generate IARRs, the project must create simultaneously feasible incremental market flow capability in PJM's ARR market model, over and above all system capability being used by existing allocated ARRs and/or would be used by granting any prorated outstanding ARR requests, in the ARR market model.[12]

There are three approaches to the creation and assigning of IARRs: IARRs can be requested by customers, which requires the customer to build sufficient transmission to support the request; IARRs can be the granted as a result of customer transmission projects such as merchant transmission or generation interconnection projects; and IARRs can be the result of RTEP upgrades. In each case, the customer(s) paying for the upgrades are allocated the IARR that are created.

The direct customer request approach for creating and allocating IARR should be eliminated from PJM's tariff. Given the current allocation of existing ARRs relative to system capability, the upgrades needed to produce any quantity of IARR under this approach are prohibitively expensive and impractical. The PJM process is not sufficiently transparent for a potential customer to make a rational decision about a potential IARR project. Much of the information required to determine whether a particular IARR project is economically viable is confidential and proprietary to incumbent transmission companies including the nature and cost of any required upgrades. In addition, PJM's process for using IARR requests to compensate competitive transmission projects is fundamentally flawed and cannot be made consistent with the requirements of Order No. 681 which established IARRs.[13] The problem is inherent to guaranteeing the IARRs created by the process. Order No. 681 requires that long-term firm transmission rights made feasible by transmission upgrades or expansions must be available upon request to the party that pays for such upgrades or expansions.[14] However, Order No. 681 also requires that the rights granted by upgrades/expansions cannot come at the expense of transmission rights held by others. Any and all IARRs awarded by the process are treated as Stage 1A rights in any subsequent annual allocation of ARRs. Granting Stage 1A status to IARRs represents preferential treatment of IARR rights relative to the set of ARR rights belonging to load. Only a subset of the ARR rights paid for by load and allocated to load are treated as Stage 1A rights. Stage 1A rights are given first and absolute priority in PJM's annual allocation process, over and above later stage requests to claim existing system congestion rights by PJM load. This means that if the annual market model used to allocate existing ARR rights in a given year cannot simultaneously support Stage 1A ARR requests (e.g., expected outages), the system model is modified so as to make the Stage 1A ARR requests feasible. When this occurs, the result is a model that will, absent any other adjustments, result in an over allocation of congestion rights relative to expected congestion. To avoid having FTR target allocations exceed expected congestion, PJM reduces annual market model system capability available to non-Stage 1A rights through selective line outages and line rating reductions.

12 See PJM Incremental Auction Revenue Rights Model Development and Analysis, PJM June 12, 2017. <https://www.pjm.com/~/media/markets-ops/ftr/pjm-iarr-model-development-and-analysis.ashx>.

13 See November 7, 2019 Comments on TranSource, LLC v. PJM, 168 FERC ¶ 61,119 (2019) ("Opinion No. 566").

14 Long-Term Firm Transmission Rights in Organized Electricity Markets, Order No. 681, 116 FERC ¶61,077 (2006) ("Order No. 681"), order on reh'g, Order No. 618-A, 117 FERC ¶ 61,201 (2006), order on reh'g, Order No. 681-A, 126 FERC ¶ 61,254 (2009).

The resulting market model artificially supports all the Stage 1A ARR requests and artificially reduces the amount of remaining later tier ARR requests from other rights holders. This means that the Stage 1A ARRs, including IARRs, are sustained at the expense of other preexisting congestion rights, and for IARRs in violation of Order No. 681.

IARRs are appropriately 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.[15] 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.[16] 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 additional congestion revenues returned to them in the planning period over their Stage 1A allocation, but may be prorated. ARR holders can self schedule ARRs as FTRs during the Annual FTR Auction.[17]

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

15 "PJM Manual 6: Financial Transmission Rights," Rev. 23 (Sep. 1, 2019); "IARRs for RTEP Upgrades Allocated for 2016/2017 Planning Period," <http://www.pjm.com/~/media/markets-ops/ftr/annual-arr-allocation/2018-2019/2018-2019-iarrs-for-rtep-upgrades-allocated.ashx>.

16 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.

17 OATT Attachment K 7.1.1.(b).

1A ARRs are found to be infeasible, transmission system upgrades must be undertaken to maintain feasibility.[18]

- **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.[19] 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.[20]

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 modeled transmission system can support the approved set of ARRs. In making simultaneous feasibility determinations, PJM uses a power flow model of security constrained dispatch based on assumptions about generation and transmission outages.[21] If the requested set of ARRs is not simultaneously feasible, customers are allocated prorated shares in direct proportion to their requested MW and in inverse proportion to their impact on binding constraints, except Stage 1A ARRs:

Equation 13-1 Calculation of prorated ARRs[22]

$$MW = Constraint\ Capability\ x\ \left(\frac{Individual\ Requested\ MW}{Total\ Requested\ MW}\right) x \left(\frac{1}{MW\ impact\ on\ line}\right)$$

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.[23] PJM replaced retired units with operating generators, termed qualified replacement resources (QRRs).[24]

18 See "PJM Manual 6: Financial Transmission Rights," Rev. 23 (Sep. 1, 2019).
19 Id. at 21.
20 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>.
21 "PJM Manual 6: Financial Transmission Rights," Rev. 23 (Sep. 1, 2019.
22 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>.
23 156 FERC ¶ 61,180 (2016).
24 See FERC Docket No. EL16-6-003.

The method PJM implemented continues to rely on a contract path based approach. 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. Generation to load paths, even from active generators, are based on a contract path model rather than a network model. Generation to load paths should not be used as a basis for assigning ARR capability. Contract paths are not an accurate representation of the reasons that congestion is created or that load is served in a network and will, by definition, not accurately measure the exposure of load to congestion, resulting in modeling inaccuracies and revenue inadequacy.

Market Performance

Revenue

ARRs are allocated to qualifying customers rather than sold, so ARR revenue (target allocation) is different from the revenue that results from the FTR auctions which generally exceeds the sum of the ARR target allocations.

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.[25] 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.

25 See "PJM Manual 6: Financial Transmission Rights," Rev. 23 (Sep. 1, 2019).

There were 35,571 MW of ARRs associated with $423,100 of revenue that were reassigned for the 2018/2019 planning period. There were 18,913 MW of ARRs associated with $223,800 of revenue that were reassigned in the first four months of the 2019/2020 planning period.

Table 13-3 summarizes ARR MW and associated revenue reassigned for network load in each control zone where changes occurred between June 2018 and September 2019.

Table 13-3 ARRs and ARR revenue automatically reassigned for network load changes by control zone: June 2018 through September 2019

	ARRs Reassigned (MW-day)		ARR Revenue Reassigned [Dollars (Thousands) per MW-day]	
Control Zone	2018/2019 (12 months)	2019/2020 (4 months)	2018/2019 (12 months)	2019/2020 (4 months)
AECO	392	166	$2.1	$1.2
AEP	2,730	4,089	$35.0	$66.9
APS	945	634	$17.6	$11.4
ATSI	4,923	2,244	$49.9	$18.2
BGE	1,732	884	$46.1	$21.7
ComEd	3,261	977	$43.9	$7.2
DAY	718	438	$3.7	$5.1
DEOK	2,442	693	$60.3	$13.4
DLCO	4,576	2,729	$44.6	$16.2
DPL	1,932	422	$43.3	$9.1
Dominion	70	108	$0.6	$1.0
EKPC	0	0	$0.0	$0.0
JCPL	1,172	500	$1.6	$1.6
Met-Ed	604	170	$4.7	$1.1
OVEC	NA	0	NA	$0.0
PECO	2,997	1,780	$20.9	$12.5
PENELEC	716	202	$8.4	$2.3
PPL	3,643	1,410	$8.0	$18.6
PSEG	1,195	699	$14.2	$8.5
Pepco	1,477	755	$18.1	$7.9
RECO	46	12	$0.0	$0.0
Total	35,571	18,913	$423.1	$223.8

Residual ARRs

Introduced August 1, 2012, Residual ARRs are available for eligible ARR holders when a transmission outage was modeled in the Annual ARR Allocation, but the transmission facility returns to service during the planning period. Residual ARRs are effective for single 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. 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. Beginning with the June 2017 monthly auction, Residual ARRs that would have cleared with a negative target allocation are not assigned to participants.[26]

Table 13-4 shows the Residual ARRs (cleared volume) allocated to participants, along with the target allocations (bid and requested) from the effective month. In the 2019/2020 planning period, PJM allocated a total of 8,148.3 MW of Residual ARRs with a target allocation of $2.7 million. In the same time period for the 2018/2019 planning period, PJM allocated a total of 8,829.6 MW of residual ARRs with a target allocation of $4.1 million. In the 2017/2018 planning period, PJM allocated a total of 39,597.4 MW of residual ARRs, up from 35,034.9 MW for the 2016/2017 planning period. Residual ARRs had a total target allocation of $17.5 million for the 2017/2018 planning period, up from $7.0 million for the 2016/2017 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.

26 See FERC Letter Order, Docket No. ER17-1057 (April 5, 2017).

Table 13-4 Residual ARR allocation volume and target allocation: January through September 2019

Month	Available Volume (MW)	Cleared Volume (MW)	Cleared Volume	Target Allocation
Jan-19	3,964.1	2,796.7	70.6%	$2,764,132
Feb-19	3,399.5	2,455.6	72.2%	$1,380,364
Mar-19	2,737.7	2,109.3	77.0%	$850,832
Apr-19	6,180.9	2,022.1	32.7%	$467,726
May-19	7,105.6	2,488.6	35.0%	$676,447
Jun-19	2,016.0	1,633.8	81.0%	$795,709
Jul-19	3,232.0	2,251.9	69.7%	$750,500
Aug-19	3,040.8	2,271.3	74.7%	$780,765
Sep-19	2,873.9	1,991.3	69.3%	$367,478
Total	34,550.5	20,020.6	57.9%	$8,833,953

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. 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. Negative target allocations require the FTR holder to pay into the FTR market, helping fund positively valued FTRs. With the reallocation of balancing congestion and M2M payments to load, available revenue to pay FTR holders in a given month is based on the amount of day-ahead congestion, payments by holders of negatively valued FTRs, additional auction revenues available at the end of a month over ARR target allocations, any charges made to day-ahead operating reserves and any surplus revenue from preceding months in these categories. At the end of the planning period, any surplus revenue from these categories is distributed proportionally to ARR holders.

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 because if the FTR market is revenue inadequate for the planning period, each participant is charged an FTR uplift proportional to their FTR target allocations. 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.

Auction market participants are free to request FTRs between any eligible pricing nodes on the system. For the Long Term FTR Auction there is a more restricted set of available hubs, control zones, aggregates, generator buses and interface pricing points 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 any single calendar month following that auction may include any bus for which an LMP is calculated in the FTR model used. 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.

On December 1, 2018, PJM integrated the Ohio Valley Electric Cooperative (OVEC) joined PJM as a zone. Any FTRs mapped to the previous OVEC Interface were remapped to the OVEC zonal aggregate, which is the same definition as the current OVEC Interface. The OVEC Interface was only available for sell offers beginning in the December 2018 Monthly FTR Auction and is no longer biddable.

Market Structure

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 the choice by an ARR holder to be paid based on actual day-ahead congestion revenue rather than the fixed ARR value determined in the annual FTR auction.

There are two types of FTR products: obligations and options. An obligation provides a credit, positive or negative, equal to the product of the FTR MW and the congestion price difference between FTR sink (destination) and source (origin) that occurs in the Day-Ahead Energy Market. An option provides only positive credits and options are available for only a subset of the possible FTR transmission paths.

There are three classes of FTR products: 24 hour, on peak and off peak. The 24 hour products are effective 24 hours a day, seven days a week, while the on peak products are effective during on peak periods defined as the hours ending 0800 through 2300, Eastern Prevailing Time (EPT) Mondays through Fridays, excluding North American Electric Reliability Council (NERC) holidays. The off peak products are effective during hours ending 2400 through 0700, EPT, Mondays through Fridays, and during all hours on Saturdays, Sundays and NERC holidays.

PJM operates three types of auction for FTRs. The objective function of all FTR auctions is to maximize the bid based value of FTRs awarded in each auction. PJM conducts an Annual FTR Auction, Monthly Balance of Planning Period FTR Auctions for the remaining months of the planning period and a Long Term FTR Auction for the following three consecutive planning years.[27] FTR options are not available in the Long Term FTR Auction.

A self scheduled FTR must have the same source and sink points as the ARR and be a 24 hour obligation product. Self scheduled FTRs may not designate a price bid; rather their price is determined by the clearing price in the annual

27 See "PJM Manual 6: Financial Transmission Rights," Rev. 23 (Sep. 1, 2019).

FTR auction. From a settlements perspective, the self scheduling participant is paid their ARR target allocation, which is then immediately used to pay their FTR's buy price. The participant then receives the hourly congestion LMP difference of their source and sink points as any other FTR would.

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. FTR self scheduled bids by ARR holders are available only as obligations for the 24 hour product and only in the Annual FTR Auction.

Supply and Demand

Total FTR supply is limited by the capability of the transmission system, in each auction, included in the PJM FTR market model as modified, for example, by PJM assumptions about outages. PJM may also limit available capability through subjective judgment exercised without any clear guidelines. PJM outage assumptions are a key factor in determining the supply of ARRs and the related supply of FTRs in the Annual FTR Auction. Long Term FTR Auction capability is determined by removing all outages and running an offline model of the previous Annual FTR Auction model with all ARR bids. Any ARR MW that clear are reserved for ARR holders in their effective planning periods, and are removed from the Long Term FTR Auction capability. This does not, and cannot, preserve all possible capacity for ARR holders before a long term auction due to changes in system topology and outage selection between planning periods. Total Monthly FTR Auction capacity is based on the residual capacity available after the Long Term and Annual FTR auctions are conducted and adjustments are made to outages to reflect anticipated system conditions for the time periods auctioned.

The MMU recommends that the full transmission capacity of the system be allocated as ARRs prior to sale as FTRs.

Depending on assumptions used in the auction transmission model, the total FTR supply can be greater than or less than system capability in aggregate and/or on a path basis. FTR supply greater than system capability contributes to FTR revenue inadequacy relative to target allocations. FTR supply less than system capability contributes to FTR revenue surplus relative to target allocations.

PJM can also make further subjective adjustments to the auction model to manage FTR revenues. PJM can assume arbitrarily 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.

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.[28] 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 recommends 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).[29] 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

28 See the 2018 State of the Market Report for PJM, Volume 2, Section 12: Transmission Facility Outages: Transmission Facility Outages Analysis for the FTR Market.
29 116 FERC ¶ 61,077 (2006).

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. PJM expands the available transmission capacity for the Long Term FTR Auction by removing all the transmission outages included in the model when allocating ARRs.

Beginning with Round 2 of the 2019/2022 Long Term FTR Auction, PJM has implemented revisions to the determination of residual system capability made available in the Long Term FTR Auctions, and eliminated the YRALL product, consistent with the MMU's recommendation. The PJM proposal revises the determination of ARR rights that are reserved for ARR holders. Rather than simply preserving the ARR cleared capacity from the previous annual allocation, PJM would rerun the simultaneous feasibility test for the ARR/FTR market model, without outages, using the previous year's ARR requests, prorated when necessary, and use the resulting ARRs as the basis for reserving capability for ARR holders in the Long Term FTR Auction. The resulting difference between the revised set of ARRs and ARR/FTR market models' system capability, without outages, would determine the residual capability offered in the Long Term FTR Auction. This method will provide ARR holders with a more accurate representation of capacity that will carry into the Annual FTR Auction than is currently preserved for ARR holders. Capacity awarded in the Long Term FTR Auction is modeled as a fixed injection/withdrawal in the Annual FTR Auction, and is therefore unavailable in preceding auctions. While the new rules will improve the allocation of congestion rights to ARR holders, a proportion of congestion revenues will still be assigned to the Long Term FTR Auction without ever having been made available to ARR holders. Due to the duration of long term FTRs and the inconstant nature of the ARR/FTR model's outage selections and system topology, reserving the previous year's ARR bids does not fully capture all of the capability that should be available to ARR holders. Any capability that is auctioned in the Long Term FTR Auction and that should otherwise be available to ARR holders results in lost revenue to ARR holders. That outcome is inconsistent with the basic logic of ARRs and inconsistent with the stated intent of the market design.

The 2009/2012 and 2010/2013 Long Term FTR Auctions consisted of two rounds.[30] 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 have terms of any one of the next three. 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.

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, as well as any outages of a shorter duration that PJM determines would cause FTR revenue inadequacy if not modeled, are included in the determination of the simultaneous feasibility for the Annual FTR Auction.[31] While the full list of outages selected is publicly posted, PJM exercises significant subjective judgment in selecting outages to accomplish FTR revenue adequacy goals and the process by which these outages are selected is not clear and is not documented. ARR holders who wish to self schedule must inform PJM prior to round one of the annual 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

30 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).

31 See "PJM Manual 6: Financial Transmission Rights," Rev. 23 (Sep. 1, 2019).

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 effective. By not properly reserving all ARR capacity in the Long Term FTR Auction, it is possible that a SFT violation may occur between a long term FTR and a self scheduled ARR, resulting in revenue adequacy issues.

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.[32] Beginning with the 2018/2019 planning period, to address performance issues in solving the Monthly Balance of Planning Period Auctions, participants may no longer place bids that overlap three available monthly periods.[33] For example, participants cannot place a bid for Quarter 1 in the June auction because that quarter overlaps three individual month periods.

32 "PJM Manual 6: Financial Transmission Rights," Rev. 23 (Sep. 1, 2019).
33 "PJM Manual 6: Financial Transmission Rights," Rev. 23 (Sep. 1, 2019).

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, or the terms and risks 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 more restrictive start and end times, meaning that 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.

The HHI is commonly used to measure market concentration with a HHI of 10000 indicating a monopoly. 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.[34]

Table 13-5 presents the monthly balance of planning period FTR auction cleared FTRs for 2019 by trade type, organization type and FTR direction. Financial entities purchased 71.7 percent of prevailing flow FTRs, down 0.6 percentage points, and 79.9 percent of counter flow FTRs, down 0.6 percentage points, for the year, with the result that financial entities purchased 75.3 percent, down 0.7 percentage points, of all prevailing and counter flow FTR buy bids in the monthly balance of planning period FTR auction cleared FTRs for the first nine months of 2019.

Table 13-5 Monthly Balance of Planning Period FTR Auction patterns of ownership by FTR direction: January through September, 2019

		FTR Direction		
Trade Type	Organization Type	Prevailing Flow	Counter Flow	All
Buy Bids	Physical	28.3%	20.1%	24.7%
	Financial	71.7%	79.9%	75.3%
	Total	100.0%	100.0%	100.0%
Sell Offers	Physical	13.0%	13.6%	13.2%
	Financial	87.0%	86.4%	86.8%
	Total	100.0%	100.0%	100.0%

Table 13-6 shows the HHI values for cleared MW for the 2019/2020 planning period monthly auctions by period. Cleared obligation buy bids are Unconcentrated or Moderately Concentrated. Cleared option buy bids range from Unconcentrated to Highly Concentrated.

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

Table 13-6 Monthly Balance of Planning Period FTR Auction HHIs by period

Auction	Hedge Type	Prompt Month	Prompt Month+1	Prompt Month+2	Q2	Q3	Q4
Jun-19	Obligation	254	386	411	552	525	552
	Option	1948	3973	3848	1728	3044	2224
Jul-19	Obligation	205	297	526	395	407	445
	Option	1962	2594	2837	2202	3114	3479
Aug-19	Obligation	256	558	689	708	443	552
	Option	1245	2415	2850	4100	2450	3418
Sep-19	Obligation	237	436	454		455	528
	Option	1070	2287	2085		2033	2770

Table 13-7 shows the average daily net position ownership for all FTRs for the first nine months of 2019, by FTR direction.

Table 13-7 Daily FTR net position ownership by FTR direction: January through September, 2019

	FTR Direction		
Organization Type	Prevailing Flow	Counter Flow	All
Physical	38.0%	20.9%	31.1%
Financial	62.0%	79.1%	68.9%
Total	100.0%	100.0%	100.0%

Market Performance

Volume

PJM regularly intervenes in the FTR market based on subjective judgment which is not based on clear or documented guidelines. Such intervention in the FTR, or any market, is not appropriate and not consistent with the operation of competitive markets. In an apparent effort to manage FTR revenues, PJM may adjust normal transmission limits (rather than the inflated limits used in Stage 1A) in the FTR auction model. If, in PJM's judgment, the normal capability limit is not consistent with revenue adequacy goals and simultaneous feasibility, 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.[35] PJM may also remove or reduce infeasibilities caused by transmission outages by clearing counter flow

35 See "PJM Manual 6: Financial Transmission Rights," Rev. 23 (Sep. 1, 2019).

bids without being required to clear the corresponding prevailing flow bids.[36] The use of both of these procedures is contingent on PJM actions not affecting the revenue adequacy of allocated ARRs, all requested self scheduled FTRs clear and net FTR auction revenue is positive.

Monthly Balance of Planning Period Auctions

Table 13-8 provides the monthly balance of planning period FTR auction market volume for the entire 2018/2019 and 2019/2020 planning periods. There were 8,289,126 MW of FTR obligation buy bids and 3,172,186 MW of FTR obligation sell offers for all bidding periods in the first four months of the 2019/2020 planning period. The monthly balance of planning period FTR auction cleared 1,507,609 (18.2 percent) of FTR obligation buy bids and 656,454 MW (20.7 percent) of FTR obligation sell offers.

There were 1,266,020 MW of FTR option buy bids and 709,078 MW of FTR option sell offers for all bidding periods in the Monthly Balance of Planning Period FTR Auctions for the first four months of the 2019/2020 planning period. The monthly auctions cleared 80,736 MW (6.4 percent) of FTR option buy bids, and 176,378 MW (24.9 percent) of FTR option sell offers.

36 See *id*.

Table 13-8 Monthly Balance of Planning Period FTR Auction market volume: January through September, 2019

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-19	Obligations	Buy bids	345,894	1,161,069	217,303	18.7%	943,766	81.3%
		Sell offers	223,686	499,331	79,704	16.0%	419,627	84.0%
	Options	Buy bids	6,069	89,470	9,046	10.1%	80,424	89.9%
		Sell offers	14,752	110,725	36,445	32.9%	74,280	67.1%
Feb-19	Obligations	Buy bids	397,644	1,299,918	263,448	20.3%	1,036,470	79.7%
		Sell offers	187,553	428,231	72,378	16.9%	355,852	83.1%
	Options	Buy bids	5,250	89,017	8,297	9.3%	80,720	90.7%
		Sell offers	12,207	101,025	33,532	33.2%	67,492	66.8%
Mar-19	Obligations	Buy bids	385,192	1,189,201	247,546	20.8%	941,655	79.2%
		Sell offers	316,967	647,968	111,174	17.2%	536,794	82.8%
	Options	Buy bids	4,146	103,905	13,701	13.2%	90,204	86.8%
		Sell offers	13,355	128,952	37,054	28.7%	91,899	71.3%
Apr-19	Obligations	Buy bids	303,663	999,335	198,854	19.9%	800,481	80.1%
		Sell offers	205,875	419,577	67,870	16.2%	351,707	83.8%
	Options	Buy bids	2,672	66,021	9,844	14.9%	56,177	85.1%
		Sell offers	9,430	94,794	25,509	26.9%	69,285	73.1%
May-19	Obligations	Buy bids	200,388	701,681	145,331	20.7%	556,350	79.3%
		Sell offers	94,152	219,427	40,052	18.3%	179,375	81.7%
	Options	Buy bids	1,350	23,096	5,218	22.6%	17,878	77.4%
		Sell offers	4,672	54,636	18,704	34.2%	35,932	65.8%
Jun-19	Obligations	Buy bids	635,410	2,302,609	394,147	17.1%	1,908,462	82.9%
		Sell offers	422,022	830,772	185,375	22.3%	645,398	77.7%
	Options	Buy bids	9,380	284,551	24,668	8.7%	259,884	91.3%
		Sell offers	25,151	223,507	54,050	24.2%	169,457	75.8%
Jul-19	Obligations	Buy bids	605,057	2,136,249	381,949	17.9%	1,754,300	82.1%
		Sell offers	352,515	836,464	174,950	20.9%	661,514	79.1%
	Options	Buy bids	9,554	324,252	22,045	6.8%	302,207	93.2%
		Sell offers	20,076	169,920	43,618	25.7%	126,301	74.3%
Aug-19	Obligations	Buy bids	585,448	2,012,663	376,474	18.7%	1,636,190	81.3%
		Sell offers	279,599	636,860	135,214	21.2%	501,646	78.8%
	Options	Buy bids	9,925	344,278	19,052	5.5%	325,226	94.5%
		Sell offers	16,727	150,565	39,922	26.5%	110,643	73.5%
Sep-19	Obligations	Buy bids	522,797	1,837,604	355,039	19.3%	1,482,565	80.7%
		Sell offers	323,752	868,089	160,915	18.5%	707,174	81.5%
	Options	Buy bids	8,974	312,938	14,972	4.8%	297,967	95.2%
		Sell offers	18,993	165,087	38,788	23.5%	126,299	76.5%
2018/2019*	Obligations	Buy bids	4,329,182	15,659,008	2,966,810	18.9%	12,692,199	81.1%
		Sell offers	2,843,624	6,774,436	1,237,274	18.3%	5,537,162	81.7%
	Options	Buy bids	84,129	4,168,186	191,043	4.6%	3,977,143	95.4%
		Sell offers	195,333	1,708,827	466,274	27.3%	1,242,553	72.7%
2019/2020**	Obligations	Buy bids	2,348,712	8,289,126	1,507,609	18.2%	6,781,517	81.8%
		Sell offers	1,377,888	3,172,186	656,454	20.7%	2,515,732	79.3%
	Options	Buy bids	37,833	1,266,020	80,736	6.4%	1,185,284	93.6%
		Sell offers	80,947	709,078	176,378	24.9%	532,700	75.1%

* Shows 12 months for 2018/2019 ** Shows 4 months for 2019/2020

Table 13-9 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 2019 was 300,770 MW. The average monthly cleared volume for 2018 was 226,127.6 MW.

Table 13-9 Monthly Balance of Planning Period FTR Auction buy bid, bid and cleared volume (MW per period): 2019

Monthly Auction	MW Type	Prompt Month	Second Month	Third Month	Q1	Q2	Q3	Q4	Total
Jan-19	Bid	631,086	244,214	179,770				195,470	1,250,540
	Cleared	140,962	43,731	14,753				26,903	226,349
Feb-19	Bid	752,082	233,401	192,921				210,531	1,388,935
	Cleared	171,787	42,077	28,958				28,924	271,745
Mar-19	Bid	742,020	286,529	264,556					1,293,106
	Cleared	154,347	61,658	45,242					261,246
Apr-19	Bid	774,909	290,447						1,065,356
	Cleared	160,482	48,215						208,698
May-19	Bid	724,776							724,776
	Cleared	150,549							150,549
Jun-19	Bid	843,374	385,114	365,163		351,566	326,152	315,791	2,587,161
	Cleared	183,826	59,047	49,645		44,839	46,480	34,979	418,815
Jul-19	Bid	847,147	353,308	288,710		301,876	349,742	319,718	2,460,501
	Cleared	182,798	60,318	28,151		41,353	51,397	39,976	403,994
Aug-19	Bid	965,511	308,880	251,834		218,194	312,893	299,629	2,356,942
	Cleared	195,400	51,907	37,063		21,687	46,598	42,871	395,526
Sep-19	Bid	891,140	327,419	305,269			316,330	310,384	2,150,542
	Cleared	184,552	59,711	41,150			45,205	39,393	370,011

Secondary Bilateral Market

Table 13-10 provides the PJM registered secondary bilateral FTR market volume for the entire 2018/2019 and the first four months of the 2019/2020 planning periods. Bilateral FTR transactions are not required to be registered through PJM.

Table 13-10 Secondary bilateral FTR market volume: 2018/2019 and 2019/2020[37]

Planning Period	Type	Class Type	Volume (MW)
2018/2019	Obligation	24-Hour	296.3
		On Peak	2,582.8
		Off Peak	1,899.3
		Total	4,778.4
	Option	24-Hour	0.0
		On Peak	0.0
		Off Peak	40.0
		Total	40.0
2019/2020	Obligation	24-Hour	1,139.6
		On Peak	1,620.0
		Off Peak	1,459.1
		Total	4,218.7
	Option	24-Hour	0.0
		On Peak	0.0
		Off Peak	0.0
		Total	0.0

Figure 13-1 shows the FTR bid, cleared and net bid volume from June 2003 through September 2019 for Long Term, Annual and Monthly Balance of Planning Period Auctions. Cleared volume includes 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. Volume in August 2018 was negative due to the liquidation of the GreenHat FTR portfolio, which resulted in a large quantity of FTRs selling in the monthly auction.

37 The 2018/2019 planning period covers bilateral FTRs that are effective for any time between June 1, 2017 through May 31, 2018, which originally had been purchased in a Long Term FTR Auction, Annual FTR Auction or Monthly Balance of Planning Period FTR Auction.

Figure 13-1 Long Term, Annual and Monthly FTR Auction bid and cleared volume: June 2003 through September 2019

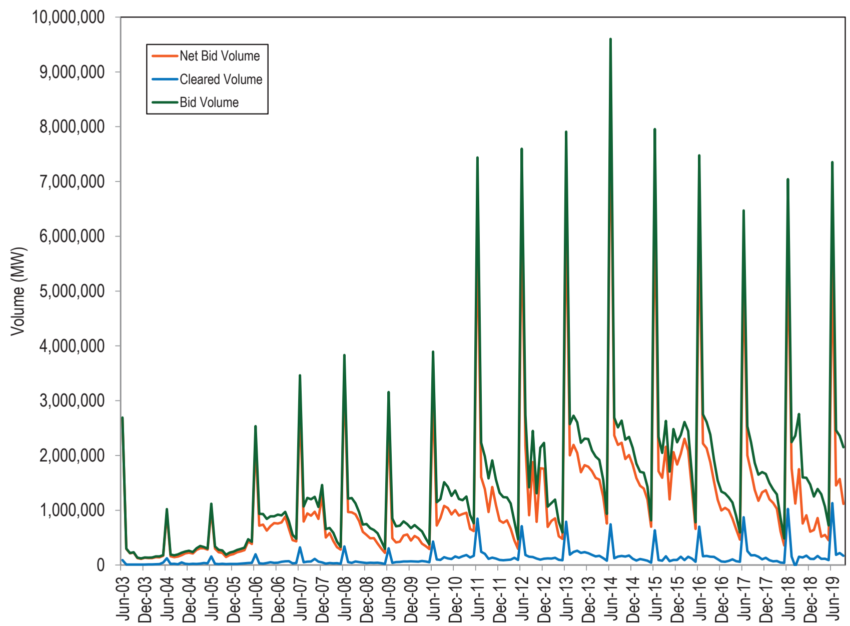


Figure 13-2 Cleared auction volume (MW) as a percent of total FTR cleared volume by calendar month: June 2004 through September 2019

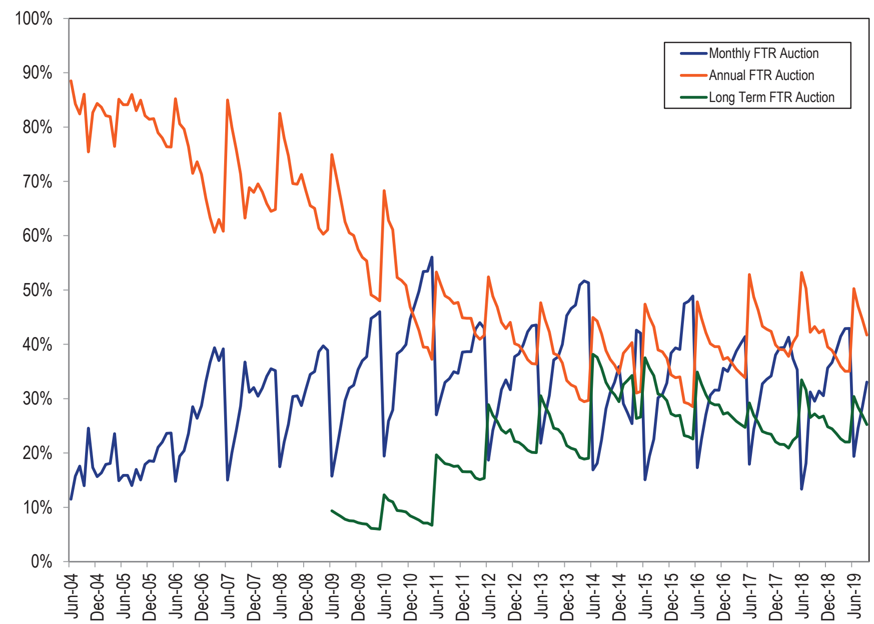


Figure 13-2 shows cleared auction volumes by auction type as a percent of the total FTR cleared volume by calendar months for June 2004 through September 2019, by type of auction. FTR volumes are included in the calendar month they are effective, with long term and annual FTR auction volume spread equally 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 any planning period an increasing number of Monthly Balance of Planning Period FTRs are purchased, making them a greater percent of total 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.

Price

Table 13-11 shows the weighted average cleared buy bid price in the Monthly Balance of Planning Period FTR Auctions by bidding period for January through September 2019. 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 September 2019 was $0.17 per MW, down from $0.20 per MW for the same period last year, a 15.0 percent decrease in FTR prices. The cleared weighted-average price for the first four months of the current planning period was $0.17 per MW, up 30.8 percent from $0.13 per MW for the same period last year.

Table 13-11 Monthly Balance of Planning Period FTR Auction cleared, weighted-average, buy bid price per period (Dollars per MW): 2019

Monthly Auction	Prompt Month	Second Month	Third Month	Q1	Q2	Q3	Q4	Total
Jan-19	$0.22	$0.35	$0.16				$0.20	$0.23
Feb-19	$0.22	$0.27	$0.15				$0.15	$0.20
Mar-19	$0.16	$0.22	$0.24				$0.00	$0.19
Apr-19	$0.10	$0.17						$0.12
May-19	$0.09							$0.09
Jun-19	$0.11	$0.19	$0.20		$0.25	$0.31	$0.18	$0.20
Jul-19	$0.10	$0.18	$0.13		$0.25	$0.24	$0.18	$0.18
Aug-19	$0.07	$0.17	$0.21		$0.18	$0.17	$0.17	$0.14
Sep-19	$0.09	$0.16	$0.16			$0.23	$0.13	$0.15

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 and are trading rights to congestion revenues for a fixed payment.

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 surplus congestion revenue, 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 13-14). 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 13-12 lists FTR profits by organization type and FTR direction for the first four months of the 2019/2020 planning period. Some participants classified as physical, such as a company that owns only generation, are not eligible for ARRs but do have a physical presence on the PJM system are classified in the physical 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 that FTR, not including self scheduled FTRs. Self scheduled FTRs represent a return of congestion revenue to ARR holders, and are not profits. ARR holders who self scheduled FTRs received $39.5 million in congestion revenues. Revenues from self scheduled FTRs are a return of congestion to the load that paid the congestion rather than profits.

Table 13-12 FTR profits and revenues by organization type and FTR direction: 2019/2020

	FTR Direction				
Organization Type	Prevailing Flow Profit	Self Scheduled Prevailing Flow Revenue Returned	Counter Flow Profit	Self Scheduled Counter Flow Revenue Returned	All
Financial	($74,239,531)	$0	$71,120,644	$0	($3,118,887)
Physical	($36,935,023)	$39,196,945	$14,351,494	$287,957	$16,901,373
Total	($111,174,554)	$39,196,945	$85,472,138	$287,957	$13,782,486

Table 13-13 lists the monthly FTR profits for the 2018/2019 and the first four months of the 2019/2020 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 13-13 Monthly FTR profits by organization type: 2018/2019 and 2019/2020

	Organization Type		
Month	Physical	Financial	Total
Jun-18	$8,959,001	$16,374,714	$25,333,715
Jul-18	($7,329,905)	$8,826,482	$1,496,576
Aug-18	($2,093,482)	$6,880,524	$4,787,043
Sep-18	$19,875,921	$16,799,058	$36,674,979
Oct-18	$9,065,717	$20,328,429	$29,394,146
Nov-18	$7,892,354	$8,051,851	$15,944,205
Dec-18	($4,074,003)	$16,403,516	$12,329,514
Jan-19	($55,670)	$41,735,751	$41,680,080
Feb-19	($26,059,909)	($621,454)	($26,681,363)
Mar-19	($17,165,099)	$210,844	($16,954,255)
Apr-19	($25,737,657)	($12,160,549)	($37,898,206)
May-19	($15,606,225)	($6,333,907)	($21,940,132)
Summary for Planning Period 2018/2019			
Total	($52,328,957)	$116,495,260	$64,166,303
Jun-19	($15,129,405)	($10,759,060)	($25,888,465)
Jul-19	($1,457,786)	$9,027,150	$7,569,365
Aug-19	($12,477,247)	($13,051,378)	($25,528,625)
Sep-19	$6,480,908	$11,664,401	$18,145,309
Summary for Planning Period 2019/2020			
Total	($22,583,529)	($3,118,887)	($25,702,416)

Table 13-14 FTR profits by organization type: 2012/2013 through 2019/2020

		2012/2013	2013/2014	2014/2015	2015/2016	2016/2017	2017/2018	2018/2019	2019/2020
Financial	Profit	$63,457,511	$557,583,317	$236,692,290	$41,264,165	($13,519,824)	$246,317,915	$116,495,260	($3,118,887)
	Surplus	($80,450,357)	($256,820,253)	$44,410,625	$11,897,525	$20,968,663	$147,413,287		
	Total	($16,992,846)	$300,763,064	$281,102,915	$53,161,690	$7,448,839	$393,731,202	$116,495,260	($3,118,887)
Physical	Profit	($65,702,875)	$401,144,350	$160,694,399	$22,585,629	($112,955,478)	$88,426,464	($52,328,957)	($22,583,529)
	Surplus	($83,332,665)	($104,947,376)	$14,485,066	$5,072,985	$10,533,444	$67,512,070		
	Total	($149,035,540)	$296,196,975	$175,179,465	$27,658,614	($102,422,034)	$155,938,535	($52,328,957)	($22,583,529)
Total		($166,028,386)	$596,960,039	$456,282,380	$80,820,304	($94,973,195)	$549,669,736	$64,166,303	($25,702,416)

* Four months of the 2019/2020 planning period

Table 13-14 lists the historical profits by calendar year by organization type beginning in the 2012/2013 planning period, excluding revenue to self scheduled FTRs for physical participants. The profits include any end of planning period surplus distribution or uplift, where applicable, that affects profitability. The surplus or uplift was distributed prorata based on FTR positive target allocations through the 2017/2018 planning period. Beginning with the 2018/2019 planning period, surplus congestion revenue was distributed to ARR holders instead of FTR holders if there was a net surplus at the end of the planning year after ensuring monthly payments to FTR holders equal to target allocations. The surplus row indicates the surplus congestion revenue collected from the FTR market for the entire planning period. When positive, it is a payout to FTRs distributed prorata, which includes surplus ARR auction revenue and surplus day-ahead congestion revenue. When negative, it is a payment made to FTRs, pro-rata, by all FTR holders to meet revenue adequacy.

Revenue

Monthly Balance of Planning Period FTR Auction Revenue

Table 13-15 shows monthly balance of planning period FTR auction revenue by trade type, type and class type for January through September 2019. The Monthly Balance of Planning Period FTR Auctions for the first four months of the 2019/2020 planning period netted $27.9 million in revenue, the difference between buyers paying $162.9 million and sellers receiving $135.0 million. For the entire 2018/2019 planning period, the Monthly Balance of Planning Period FTR Auctions netted $59.7 million in revenue with buyers paying $324.9 million and sellers receiving $265.2 million.

Table 13-15 Monthly Balance of Planning Period FTR Auction revenue: 2019

Monthly Auction	Type	Trade Type	Class Type 24-Hour	On Peak	Off Peak	All
Jan-19	Obligations	Buy bids	$7,429,663	$9,608,687	$4,887,280	$21,925,630
		Sell offers	$987,205	$6,540,062	$4,065,408	$11,592,675
	Options	Buy bids	$1,240,922	$1,030,156	$736,432	$3,007,510
		Sell offers	$14,822	$6,069,106	$3,845,740	$9,929,668
Feb-19	Obligations	Buy bids	$8,986,453	$8,637,432	$5,482,321	$23,106,206
		Sell offers	$48,475	$7,523,942	$6,034,319	$13,606,736
	Options	Buy bids	$838,173	$771,411	$729,381	$2,338,964
		Sell offers	$32,186	$5,356,597	$3,251,805	$8,640,588
Mar-19	Obligations	Buy bids	$5,815,450	$7,982,901	$3,873,158	$17,671,509
		Sell offers	$1,666,791	$5,726,644	$2,935,930	$10,329,364
	Options	Buy bids	$111,401	$903,499	$528,783	$1,543,682
		Sell offers	$11,372	$3,178,368	$1,908,681	$5,098,421
Apr-19	Obligations	Buy bids	$1,001,882	$4,982,173	$2,271,137	$8,255,192
		Sell offers	$242,252	$3,444,912	$1,632,619	$5,319,784
	Options	Buy bids	$37,128	$704,332	$362,419	$1,103,879
		Sell offers	$4,980	$1,645,001	$898,043	$2,548,024
May-19	Obligations	Buy bids	($504,881)	$3,675,925	$1,696,524	$4,867,568
		Sell offers	$449,130	$1,607,559	$672,541	$2,729,231
	Options	Buy bids	$40,292	$250,657	$130,412	$421,361
		Sell offers	$3,022	$1,417,317	$660,872	$2,081,211
Jun-19	Obligations	Buy bids	$18,794,860	$21,532,330	$7,902,040	$48,229,231
		Sell offers	$1,543,921	$19,847,506	$9,338,719	$30,730,145
	Options	Buy bids	$20,873	$2,431,176	$1,191,402	$3,643,451
		Sell offers	$207,836	$7,053,424	$4,166,792	$11,428,052
Jul-19	Obligations	Buy bids	$16,096,332	$19,769,258	$7,121,940	$42,987,529
		Sell offers	$678,798	$20,795,090	$10,601,466	$32,075,354
	Options	Buy bids	$39,338	$2,227,193	$1,436,853	$3,703,383
		Sell offers	$88,775	$4,761,883	$2,649,983	$7,500,641
Aug-19	Obligations	Buy bids	$11,315,365	$13,413,111	$6,104,555	$30,833,032
		Sell offers	$623,419	$13,147,202	$7,070,769	$20,841,391
	Options	Buy bids	$64,870	$1,655,836	$1,085,370	$2,806,076
		Sell offers	$109,056	$3,986,008	$2,537,970	$6,633,034
Sep-19	Obligations	Buy bids	$12,042,726	$12,337,035	$3,909,227	$28,288,988
		Sell offers	$373,684	$12,963,176	$6,034,595	$19,371,455
	Options	Buy bids	$94,223	$1,512,002	$757,673	$2,363,898
		Sell offers	$94,624	$4,104,817	$2,197,651	$6,397,092
2018/2019*	Obligations	Buy bids	$93,669,208	$132,488,450	$61,989,515	$288,147,173
		Sell offers	$11,150,630	$104,938,558	$61,964,081	$178,053,269
	Options	Buy bids	$4,501,727	$18,020,791	$14,189,999	$36,712,518
		Sell offers	$1,042,372	$54,821,585	$31,237,878	$87,101,835
	Net Total		$85,977,934	($9,250,902)	($17,022,444)	$59,704,587
2019/2020**	Obligations	Buy bids	$58,249,284	$67,051,734	$25,037,762	$150,338,780
		Sell offers	$3,219,823	$66,752,974	$33,045,549	$103,018,345
	Options	Buy bids	$219,304	$7,826,207	$4,471,297	$12,516,809
		Sell offers	$500,292	$19,906,131	$11,552,396	$31,958,819
	Net Total		$54,748,474	($11,781,164)	($15,088,885)	$27,878,425

* Shows Twelve Months for 2018/2019 **Shows four months for 2019/2020

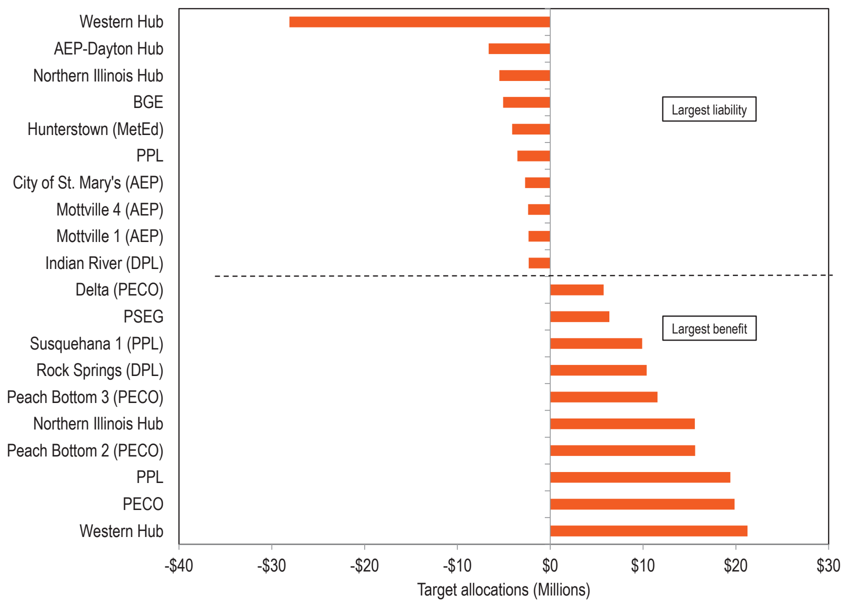
FTR Target Allocations

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. Figure 13-3 shows the 10 largest positive and negative FTR target allocations, summed by sink, for the 2019/2020 planning period. The top 10 sinks that produced financial benefit accounted for 29.7 percent of total positive target allocations with the Western Hub accounting for 9.8 percent of all positive target allocations. The top 10 sinks that created liability accounted for 19.7 percent of total negative target allocations with PSEG Zone accounting for 3.9 percent of all negative target allocations.

Figure 13-3 Ten largest positive and negative FTR target allocations summed by sink: 2019/2020

Figure 13-4 shows the 10 largest positive and negative FTR target allocations, summed by source, for the 2019/2020 planning period. The top 10 sources with a positive target allocation accounted for 26.4 percent of total positive target allocations with the Western Hub accounting for 4.1 percent of total positive target allocations. The top 10 sources with a negative target allocation accounted for 24.5 percent of all negative target allocations, with the Western Hub accounting for 11.0 percent.

Figure 13-4 Ten largest positive and negative FTR target allocations summed by source: 2019/2020



Revenue Adequacy

FTR revenue adequacy is not equivalent to 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.

Under the current, incorrect, market rules, FTR revenues are primarily comprised of hourly congestion revenue, from the day-ahead market, but also include payments by holders of negative FTR target allocations.[38] Total day-ahead congestion revenues in excess of FTR payments are carried forward from prior months and distributed back from later months within each planning year. For example, in June 2014, $2.9 million in excess congestion revenues were carried forward to fund months later in the planning period with a revenue shortfall. At the end of a planning period, if some months remain not fully funded, an uplift charge is collected at the end of the planning period 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 FTR position for the planning year. Before the 2018/2019 planning period, at the end of the planning period, surplus congestion revenue, after paying any monthly shortfalls, was distributed to FTR participants in the same manner that the FTR uplift is applied. From the 2018/2019 planning period onward, at the end of the planning period, surplus congestion revenue is distributed to ARR holders prorata based on their target allocations, after making FTRs revenue adequate, and the FTR uplift continues to be applied to FTR holders. This distribution is an effort to return the congestion to load that is not available to them throughout the planning period. This method does not go far enough in that the long term auction continues to remove capacity that should be available to ARR holders, and that the terms of this distribution do not ensure ARR holders receive all of the surplus revenue.

38 When hourly congestion revenues are negative, it is defined as a net negative congestion hour.

FTR Revenue Adequacy and Stage 1B/Stage 2 ARR Allocations

A high level of revenue adequacy was primarily a result of PJM's subjective decision to reduce available system capability in FTR auctions for the 2014/2015 through 2016/2017 planning periods. PJM's decision to reduce available system capability was intended to guarantee that FTR target allocations were, on an annual basis, less than congestion. As congestion revenues are unrelated to PJM's decisions about the FTR auction model, the fewer FTRs sold, the higher the probability that congestion would exceed the sum of the FTR target allocations. PJM's decisions 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 arbitrary decision to increase outages in the ARR allocation and in the Annual FTR Auction reduced FTR revenue inadequacy, it did not address the Stage 1A ARR over allocation issue directly because Stage 1A ARR allocations cannot be prorated. PJM's actions for the 2014/2015 through 2016/2017 planning periods resulted in decreased Stage 1B ARR allocations, decreased Stage 2 ARR allocations and decreased FTR capability. Following the assignment of balancing congestion and M2M payments to load beginning in the 2017/2018 planning period, PJM reduced the number of outages taken in the ARR allocation and in the Annual FTR Auction, increasing ARR allocations and FTR availability. The direct assignment of negative balancing congestion to load increased the congestion revenue available to pay FTR holders.

Surplus Congestion Revenue

Beginning in the 2018/2019 planning period, surplus congestion revenue, including surplus FTR auction revenue, is distributed to ARR holders in proportion to their ARR target allocations.[39] Surplus FTR auction revenue is the difference between ARR target allocations and the sum of FTR auction revenues. PJM initiated this change to surplus congestion revenue to recognize that any surplus revenue is a result of unallocated system capability that belongs to ARR holders, not FTR holders, who had received this surplus revenue after the creation of ARRs.

Under the new allocation process, at the end of the planning period, any surplus congestion revenue will first go to ARR holders until they are revenue adequate relative to their target allocations if they are not already. The remaining surplus congestion revenue is then applied to cover FTR target allocations, if they are not already. Then at the end of the planning period, any remaining surplus congestion revenue after funding ARRs and FTRs to 100 percent, will go to ARR holders in proportion to their target allocations. While the new allocation process returns the value of some of the unallocated rights to ARR holders, it does not fully recognize that ARR holders own the rights to all congestion revenues.

Figure 13-5 shows the total monthly ARR auction revenue surplus, and its distribution to ARR and FTR holders within a month. Surplus auction revenue is first paid to FTR holders, to meet revenue adequacy for the month. In any month that is not revenue adequate from day-ahead congestion, the surplus auction revenue is used to meet revenue adequacy for FTRs. In months that are revenue inadequate even after the allocation of surplus auction revenue of that month, any remaining inadequacy is funded from surplus revenue from previous or future months within the planning period. At the end of the planning period, any remaining surplus auction revenue is distributed, prorata, to ARR holders along with other surplus transmission congestion charges.

The market rules should recognize that ARR holders have the right to all auction revenue, not just the surplus after funding FTRs. The MMU recommends that all FTR auction revenue be distributed directly to ARR holders on a monthly basis. In Figure 13-5 this would mean that the full bars would be assigned to ARR holders in every month.

39 163 FERC ¶61,165 (2018).

Figure 13-5 Monthly surplus ARR revenue to ARR and FTR holders: 2017/2018 through 2019/2020

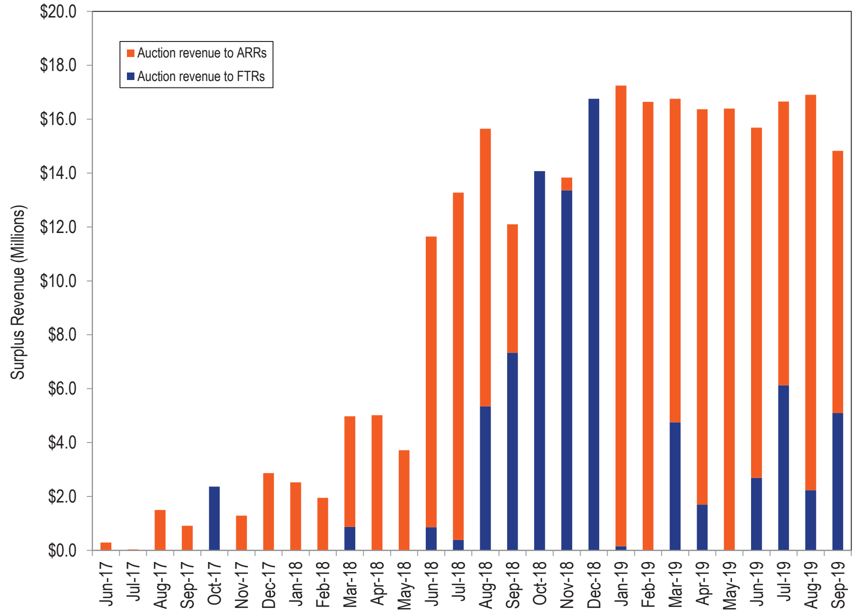
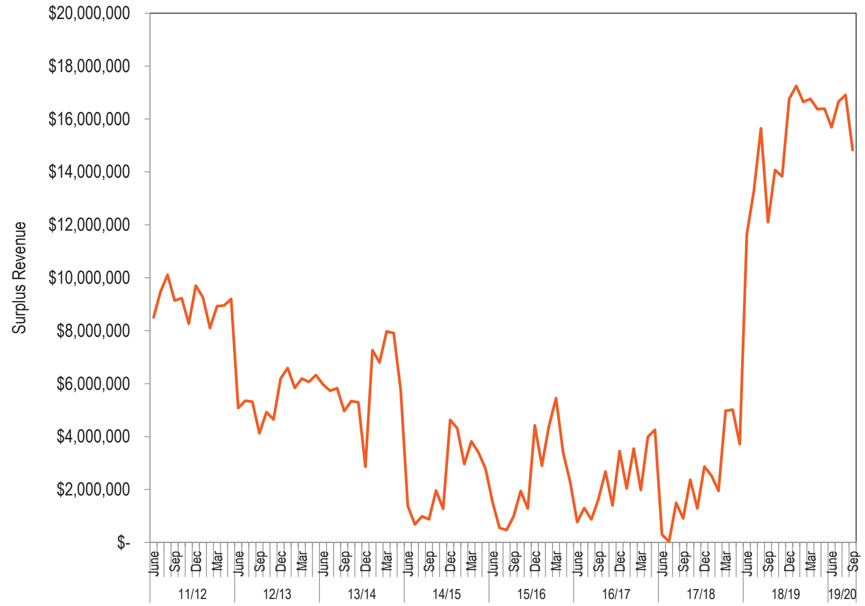


Figure 13-6 shows the monthly auction revenue collected each month from FTR auctions above ARR target allocations from the 2011/2012 planning period through the first four months of the 2019/2020 planning period.

Beginning with the 2014/2015 planning period, market rules allow PJM to decrease prevailing flow target allocations by clearing counter flow FTRs using FTR auction revenue, without making the opposite prevailing flow FTR available, as long as ARRs remain revenue adequate.[40] The result has been to increase FTR funding, but to decrease ARR revenue.

FTR auction revenue is the value that FTR buyers assign to congestion rights that ARR holders are selling. There is no logical or market based reason to assign any part of that auction revenue back to the FTR buyers. It is an unsupported wealth transfer. Auction revenue for the sale of FTRs should be distributed directly and completely to ARR holders. The MMU recommends that all FTR auction revenue be distributed to ARR holders on a monthly basis.

Figure 13-6 Monthly surplus ARR revenue: 2011/2012 through 2019/2020



40 See "PJM Manual 6: Financial Transmission Rights," Rev. 23 (Sep. 1, 2019).

Table 13-16 shows the auction revenue over ARR target allocations, by planning period, for planning periods 2010/2011 through the first four months of 2019/2020.

Table 13-16 Additional Auction Revenue: 2010/2011 through 2019/2020

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	$27,419,061
2018/2019	$180,757,676
2019/2020**	$64,077,920
Total	$635,749,676

*Start of counter flow "buy back"

**First four months

ARR and FTR 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 and less relevant 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. ARRs can be revenue adequate at the same time that ARRs return only half of congestion to load.

Total net FTR auction revenue for the 2017/2018 planning period, before accounting for self scheduling, load shifts or residual ARRs, was $573.8 million. The FTR auction revenue collected pays ARR holders' credits. During the 2018/2019 planning period, total net FTR auction revenue was $907.6 million.

Table 13-17 lists projected ARR target allocations from the Annual ARR Allocation and net revenue sources from the Long Term, Annual and Monthly Balance of Planning Period FTR Auctions for the 2017/2018 planning period and 2018/2019 planning periods. 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 FTR revenue adequacy beginning in the 2014/2015 planning period was primarily a result of subjective interventions by PJM to address prior low levels of revenue adequacy.

Table 13-17 presents the PJM FTR revenue detail for the 2018/2019 planning period and the first four months of the 2019/2020 planning period. In this table, under the new balancing congestion and M2M payment rules, any negative congestion is from day-ahead congestion and does not include balancing congestion.

Table 13-17 Total annual PJM ARR and FTR revenue detail (Dollars (Millions)): 2018/2019 and 2019/2020

Accounting Element	2018/2019	2019/2020
ARR information		
ARR target allocations	$726.8	$246.9
ARR credits	$726.8	$246.9
FTR auction revenue	$907.6	$956.9
Annual FTR Auction net revenue	$822.6	$844.6
Long Term FTR Auction net revenue	$25.2	$84.5
Monthly Balance of Planning Period FTR Auction net revenue	$59.7	$27.9
Surplus auction revenue		
ARR excess	$180.8	$64.1
ARR payout ratio	100%	100%
FTR targets		
Positive target allocations	$1,137.6	$305.0
Negative target allocations	($234.2)	($66.2)
FTR target allocations	$903.3	$238.8
Adjustments:		
Adjustments to FTR target allocations	($2.1)	($2.4)
Total FTR targets	$901.2	$236.4
FTR payout ratio	100%	100%
FTR revenues		
ARR excess	$180.8	$64.1
Congestion		
Net Negative Congestion (enter as negative)	$0.0	$0.0
Hourly congestion revenue	$832.7	$220.2
Midwest ISO M2M (credit to PJM minus credit to Midwest ISO)	$0.0	$0.0
Adjustments:		
Excess revenues carried forward into future months	$6.5	$0.0
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	$6.5	$0.0
Net Negative Congestion charged to DA Operating Reserves	$0.0	$0.0
Total FTR congestion credits	$1,020.0	$284.3
Total congestion credits on bill (includes CEPSW and end-of-year distribution)	$914.3	$284.3
Remaining deficiency	($112.3)	($47.9)

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 the day-ahead CLMP difference on those paths. FTR credits are paid to FTR holders and, depending on market conditions, can be less than the target allocations. Table 13-18 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 13-18 is not the sum of each of the monthly rows because the monthly rows may include excess revenues carried forward from prior months and excess revenues distributed back from later months. October and December 2018 had revenue shortfalls totaling $6.5 million, but were fully funded using excess revenue from previous months.

Table 13-18 Monthly FTR accounting summary (Dollars (Millions)): 2018/2019 and 2019/2020

Period	FTR Revenues (with adjustments)	FTR Target Allocations	FTR Payout Ratio (original)	FTR Credits (with adjustments)	FTR Payout Ratio (with adjustments)	Monthly Credits Surplus/Deficiency (with adjustments)
Jun-18	$106.8	$96.0	100.0%	$106.8	100.0%	($10.8)
Jul-18	$84.1	$71.3	100.0%	$84.1	100.0%	($12.9)
Aug-18	$84.8	$74.6	100.0%	$84.8	100.0%	($10.3)
Sep-18	$107.3	$102.8	100.0%	$107.3	100.0%	($4.8)
Oct-18	$109.1	$113.8	95.9%	$113.8	100.0%	$4.7
Nov-18	$83.0	$82.5	100.0%	$83.0	100.0%	($0.5)
Dec-18	$79.8	$81.9	97.5%	$81.9	100.0%	$1.8
Jan-19	$138.0	$120.9	100.0%	$138.0	100.0%	($17.1)
Feb-19	$53.1	$34.8	100.0%	$53.1	100.0%	($18.3)
Mar-19	$61.8	$49.8	100.0%	$61.8	100.0%	($12.3)
Apr-19	$41.8	$27.1	100.0%	$41.8	100.0%	($14.8)
May-19	$63.9	$47.0	100.0%	$63.9	100.0%	($17.0)
Summary for Planning Period 2018/2019						
Total	$1,013.5	$902.5		$1,020.2		($112.3)
Jun-19	$52.1	$39.4	100.0%	$52.1	100.0%	($13.0)
Jul-19	$91.7	$82.0	100.0%	$91.7	100.0%	($10.5)
Aug-19	$57.1	$42.8	100.0%	$57.1	100.0%	($14.7)
Sep-19	$83.4	$74.6	100.0%	$93.4	100.0%	($9.7)
Summary for Planning Period 2019/2020						
Total	$284.3	$238.8		$294.3		($47.9)

Figure 13-7 shows the original PJM reported FTR payout ratio by month, excluding excess revenue distribution, for January 2004 through September 2019. The months with payout ratios above 100 percent have congestion revenue greater than the target allocations and the months with payout ratios under 100 percent have congestion revenue that is less than the target allocations. Figure 13-7 also shows the payout ratio after distributing surplus congestion revenue across months within the planning period. If there are surplus congestion revenues in a given month, the surplus 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 surplus congestion 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 surplus from previous months to bring the payout ratio to 100 percent. Congestion in December 2017 and January 2018 was high relative to other months in the planning period, resulting in an extremely high payout ratio.

Figure 13-7 FTR payout ratio by month, excluding and including excess revenue distribution: January 2004 through September 2019

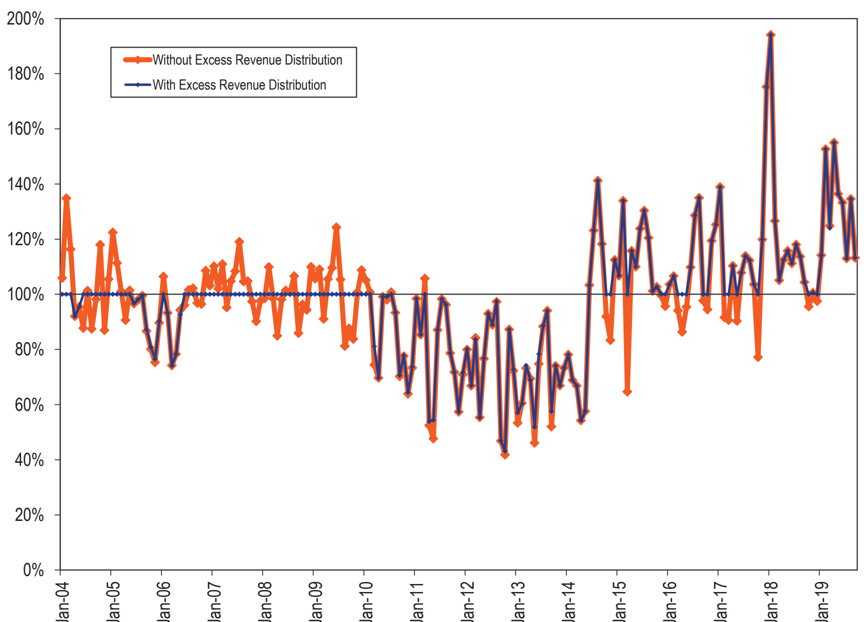


Table 13-19 shows the FTR payout ratio by planning period from the 2003/2004 planning period forward. Planning period 2013/2014 includes the additional revenue from unallocated congestion charges from Balancing Operating Reserves. For the 2014/2015, 2015/2016 and 2016/2017 planning periods, there was surplus 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 13-19 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%
2018/2019	100.0%
2019/2020	100.0%

FTR Uplift Charge

At the end of the planning period, an uplift charge may be assigned to FTR holders. This charge is to cover the net of the monthly deficiencies, if any, in the target allocations calculated for individual participants. An individual participant's uplift charge is a ratio of their share of net positive target allocations to the total net positive target allocations.

Revenue Adequacy Issues and Solutions

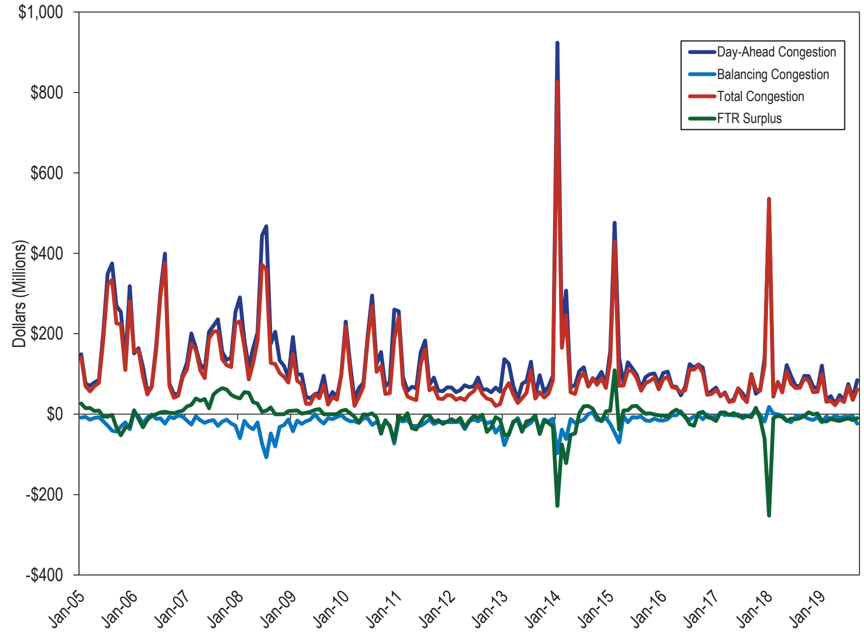
The current ARR/FTR design does not serve as an efficient way to ensure that load receives all the congestion revenues or has the ability to receive the auction revenues associated with all the potential congestion revenues. There are several reasons for the disconnect between congestion revenues and ARR/FTR revenues. The reasons include unavoidable modeling differences, such as emergency outages, 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 surplus congestion revenue, which contains excess day-ahead congestion revenue and additional FTR auction revenue, to FTR holders solely, increased revenue to FTRs and reduced payments to load. Under the new rules, effective for the 2018/2019 planning period, ARR holders receive the surplus congestion revenue, but must still pay balancing congestion to help FTR holders' revenue adequacy. 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.[41]

Figure 13-8 shows the FTR surplus, collected day-ahead, balancing and total congestion payments from January 2005 through September 2019. May 2016 had positive total balancing congestion of $7.5 million. March 2015 had balancing congestion of -$70.0 million.

41 2018 State of the Market Report for PJM, Vol. 2, Section 13: FTRs and ARRs.

Figure 13-8 FTR surplus and the collected day-ahead, balancing and total congestion: January 2005 through September 2019



ARRs as an Offset to Congestion for Load

Load pays for the transmission system and pays congestion revenues. FTRs and later ARRs were intended to return congestion revenues to load. With the implementation of the current FTR/ARR design, the purpose of FTRs has been subverted.

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.[42] The MMU

42 See 156 FERC ¶ 61,180 (2016), reh'g denied, 156 FERC ¶ 61,093 (2017).

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. The case was consolidated with appeals filed by others. The consolidated appeals were denied in an unpublished opinion issued June 12, 2018.[43]

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, total balancing congestion and M2M payments were $1,607.4 million, so load would have been responsible for an additional $1,103.3 million in balancing congestion and M2M charges if the new rules had been place for that period.

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.

Before the 2018/2019 planning period, the reallocation of balancing congestion and M2M payments from FTR holders to load, and the allocation of additional FTR auction revenues to FTR holders required ARRs to subsidize FTRs.

Beginning with the 2018/2019 planning period, surplus congestion revenue, which is defined as day-ahead congestion revenue and surplus auction revenue remaining after funding FTRs, will be allocated to ARRs prorata based on ARR target allocations.[44]

43 NJBPU v. FERC, No. 17-1106 et al., attached memorandum at 3 ("After a thorough review of the record, we conclude that none of petitioners' challenges can overcome the deference we owe FERC. As FERC's order make clear, the Commission adequately considered and reasonably rejected each of the arguments that petitioners advance before the court.")

44 163 FERC ¶61,165 (2018).

This surplus revenue is generated by a failure of the current ARR/FTR construct to make all congestion revenue rights available to load in the form of ARRs. All congestion revenue belongs to ARR holders and PJM's new surplus congestion allocation rule is an attempt to get closer to that goal. However, under the current rules, ARR holders will only have access to this surplus after full funding of FTRs is accomplished, which does not fully recognize ARR holders' primary rights to this surplus congestion revenue. If this rule had been in effect for the 2017/2018 planning period, ARRs and FTRs would have offset 74.3 percent of total congestion rather than 50.0 percent.

Table 13-20 shows the ARR and FTR revenue paid to load, the congestion offset available to load with and without allocating balancing congestion to load and the congestion offset when surplus congestion revenue is allocated to load. Offsets highlighted are the actual offsets based on the effective rules in that planning period. The pre 2017/2018 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 103.6 percent payout ratio in the 2016/2017 planning period, which was the last planning period before balancing congestion was assigned to load, is likely due to PJM selecting an overly conservative ARR/FTR model to improve FTR revenue adequacy. The 2017/2018 offset is the sum of the ARR credits, adjusted FTR credits and the load share of balancing congestion and M2M payments. The post 2017/2018 offset is calculated identically to the 2017/2018 offset, but includes any surplus congestion revenue remaining in the planning period. FTRs are fully funded before ARR holders have access to the surplus, so in planning periods with revenue inadequacy there is no difference between 2017/2018 and post 2017/2018. In planning periods that are fully funded, the surplus goes to load, and provides an increased congestion offset.

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 $1,305.1 million less in congestion offsets from the 2011/2012 through the 2018/2019 planning period. The total overpayment to FTR holders for the 2011/2012 through 2018/2019 planning period would have been $1,427.4 million.

If the surplus revenue available through September 2019 were distributed to ARR holders, total ARR and self scheduled FTR revenue would offset 116.2 percent, and 94.3 percent without distribution of surplus revenue, of total congestion costs for the first four months of the 2019/2020 planning period.

Table 13-20 ARR and FTR total congestion offset (in millions) for ARR holders: 2011/2012 through 2019/2020

	Revenue				Pre 2017/2018 (Without Balancing)		2017/2018 (With Balancing)		Post 2017/2018 (With Surplus)	
Planning Period	ARR Credits	FTR Credits	Total Congestion	Surplus Revenue	Total ARR/ FTR Offset	Percent Offset	Current Revenue Received	Percent Offset	New Revenue Received	New Offset
2011/2012	$512.2	$249.8	$749.7	($192.5)	$762.0	101.6%	$598.6	79.8%	$563.0	79.8%
2012/2013	$349.5	$181.9	$524.8	($292.3)	$531.4	101.3%	$275.9	52.6%	$257.5	52.6%
2013/2014	$337.7	$456.4	$1,870.6	($678.7)	$794.0	42.4%	$574.1	30.7%	$623.1	30.7%
2014/2015	$482.4	$404.4	$1,357.6	$139.6	$886.8	65.3%	$686.6	50.6%	$715.0	52.7%
2015/2016	$635.3	$223.4	$951.1	$42.5	$858.8	90.3%	$744.8	78.3%	$745.2	78.4%
2016/2017	$640.0	$169.1	$780.8	$72.6	$809.1	103.6%	$727.7	93.2%	$763.8	97.8%
2017/2018	$427.3	$294.2	$1,192.6	$371.2	$721.5	60.5%	$595.7	50.0%	$886.5	74.3%
2018/2019	$529.1	$130.1	$680.0	$112.3	$675.93	99.4%	$530.8	78.1%	$626.3	92.1%
2019/2020*	$179.8	$35.9	$185.5	$47.9	$222.93	120.2%	$174.9	94.3%	$215.5	116.2%
Total	$4,093.3	$2,145.0	$8,292.8	($377.4)	$6,262.4	75.5%	$4,909.3	59.2%	$5,396.1	65.1%

* Four months of 2019/2020 planning period

Table 13-20 demonstrates the inadequacies of the ARR/FTR design. The goal of the design should be to return 100 percent of the congestion revenues to the load. The actual results continue to fall well short of that goal.

Zonal ARR Congestion Offset

ARRs are allocated to zonal load based on historical generation to load transmission paths, in many cases based on pre 1999 paths. ARRs are allocated within zones based on zonal base load (Stage 1A) and zonal peak loads (other Stages). ARR revenue is the result of the prices that result from the sale of FTRs through the FTR auctions. ARR revenue for each zone is the revenue for the ARRs that sink in each zone.

Congestion paid by load in a zone is the total difference between what the zonal load pays in congestion charges net of payments to the generation that serves the zonal load.

Table 13-21 shows the congestion offsets paid to load: the allocation of FTR auction revenue to ARRs; self scheduled FTR revenue; and the allocation of end of planning year surplus. The offset for the 2019/2020 planning period assigns the current surplus revenue at the end of September 2019 to ARR holders. Table 13-21 also shows payments by load: the allocation of balancing congestion; the allocation of M2M payments. The total offset available to load, which is the revenue load receives to offset their congestion charges, is the sum of all of those credits and charges.

Table 13-21 shows day-ahead congestion and balancing congestion paid by load in each zone, plus the allocation of M2M charges.[45]

The zonal offset percentage shown in Table 13-21 is the sum of the congestion related revenues (offset) paid to load in each zone divided by the total congestion payment made by load in each zone, including M2M payments.

45 See 2018 State of the Market Report for PJM, Volume 2, Section 11: Congestion and Marginal Losses

Table 13-21 Zonal ARR and FTR total congestion offset (in millions) for ARR holders: 2019/2020 planning period

Zone	ARR Credits	FTR Credits	Balancing+ M2M Charge	Surplus Allocation	Total Offset	Day Ahead Congestion	Balancing Congestion	M2M Payments	Total Congestion	Offset
AECO	$2.6	$0.0	($0.7)	$0.5	$2.4	$2.3	($0.5)	($0.1)	$1.6	147.6%
AEP	$22.4	$14.3	($7.5)	$10.6	$39.8	$45.3	($7.0)	($1.4)	$37.0	107.7%
APS	$13.9	$3.5	($2.8)	$4.0	$18.5	$13.7	($2.3)	($0.5)	$10.9	170.1%
ATSI	$11.7	$0.0	($4.0)	$2.2	$10.0	$18.1	($3.3)	($0.7)	$14.1	70.8%
BGE	$21.3	$1.4	($2.0)	$4.3	$24.9	$9.4	($1.7)	($0.4)	$7.3	343.2%
ComEd	$18.0	$2.1	($6.0)	$4.1	$18.2	$33.9	($4.6)	($1.1)	$28.2	64.4%
DAY	$3.7	$0.2	($1.1)	$0.7	$3.5	$5.4	($1.0)	($0.2)	$4.2	84.8%
DEOK	$11.4	$2.3	($1.7)	$2.8	$14.7	$9.0	($1.6)	($0.3)	$7.1	208.4%
DLCO	$1.8	$0.0	($0.9)	$0.3	$1.3	$2.9	($0.7)	($0.2)	$2.0	65.2%
Dominion	$1.4	$8.7	($6.3)	$4.1	$7.9	$29.1	($5.3)	($0.2)	$23.6	33.4%
DPL	$16.6	$0.8	($1.2)	$3.3	$19.5	$14.7	($0.9)	($1.2)	$12.7	153.8%
EKPC	$0.8	$0.0	($0.7)	$0.1	$0.2	$4.0	($0.7)	($0.1)	$3.2	5.9%
EXT	$0.8	$0.0	$0.0	$0.2	$1.0	$0.1	($1.6)	$0.0	($1.6)	(62.8%)
JCPL	$1.9	$0.0	($1.5)	$0.4	$0.8	$5.0	($1.2)	($0.3)	$3.5	23.1%
Met-Ed	$2.3	$0.1	($0.9)	$0.5	$2.0	$4.2	($0.8)	($0.2)	$3.2	62.4%
OVEC	$0.0	$0.0	$0.0	$0.0	$0.0	$0.2	$0.1	$0.0	$0.2	0.0%
PECO	$7.9	$0.1	($2.5)	$1.5	$7.0	$7.3	($2.0)	($0.5)	$4.8	144.0%
Penelec	$4.6	$1.2	($1.0)	$1.1	$6.0	$4.2	($0.7)	($0.2)	$3.3	179.6%
Pepco	$9.2	$0.9	($1.9)	$1.9	$10.1	$8.2	($1.6)	($0.3)	$6.3	161.6%
PPL	$11.9	$0.3	($2.3)	$2.4	$12.1	$9.1	($1.8)	($0.4)	$6.9	176.0%
PSEG	$15.3	$0.0	($2.8)	$2.9	$15.4	$10.0	($2.2)	($0.5)	$7.3	210.1%
RECO	$0.2	$0.0	($0.1)	$0.0	$0.2	$0.4	($0.1)	($0.0)	$0.3	61.6%
Total	$179.8	$35.9	($48.1)	$47.9	$215.5	$236.3	($41.5)	($8.8)	$186.0	115.8%

The total congestion offset paid to loads in the first four months of the 2019/2020 planning period would be 115.8 percent of congestion costs if the surplus revenue available were distributed to ARR holders.[46] The results vary significantly by zone. Loads in some zones, like BGE, receive substantially more in offsets than their total congestion payments. Loads in other zones, like JCPL, receive substantially less in offsets than their total congestion payments. The offsets are a function of the assignment of ARRs and the valuation of ARRs in the FTR auctions. Loads in some zones, like EKPC, receive negative offsets as a result of balancing and M2M charges. The EXT zone is a set of external interfaces (MISO, DUKEXP and CPLEEXP) that are allocated ARRs (the allocated ARRs sink at the external interface) based on agreements with PJM. There is no PJM billable load associated with these ARR positions. EXT is paid ARR credits based on ARR assignments, but the offsets are less than the negative balancing congestion allocated to EXT.

The results shown in Table 13-21 further illustrate the fundamental issues with the FTR/ARR construct in PJM. If ARRs were assigned correctly, based on actual zonal congestion, and if balancing congestion were appropriately included in total congestion, the zonal offsets to load should equal zonal congestion payments by load.

Credit

There were no collateral defaults in the first nine months of 2019. There were 58 payment defaults in 2019 not involving GreenHat Energy, LLC for a total of $59,933. GreenHat Energy continued to accrue payment defaults of $53.6 million in the first nine months of 2019 for a total of $130.6 million in defaults to date, which will continue to accrue through May 2021, including the auction liquidation costs.[47]

FTR Forfeitures

Hourly FTR Cost

Only the profit is forfeited when an FTR triggers the FTR forfeiture rule. The profit is calculated as the hourly FTR target allocation minus the FTR's hourly cost. Under the current rules, the hourly cost is calculated incorrectly. Currently, the daily cost of an FTR is calculated for its effective period, and then divided by 24 hours. However, this does not accurately represent the

46 The 116.2 percent offset result is not identical to the 115.8 percent offset included in this section as a result of rounding.

47 See 2019 Quarterly State of the Market Report for PJM: January through June for a more complete explanation of credit issues that occurred in 2019.

hourly cost of on and off peak FTRs. The correct way to calculate the hourly cost of an FTR is to calculate its cost for the effective period only for hours in which it is effective. On June 24, 2019, PJM filed with FERC to amend their tariff to properly account for the hourly cost of an FTR.[48]

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.[49] 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 and ordered that counter flow FTRs be included in FTR forfeiture calculations.

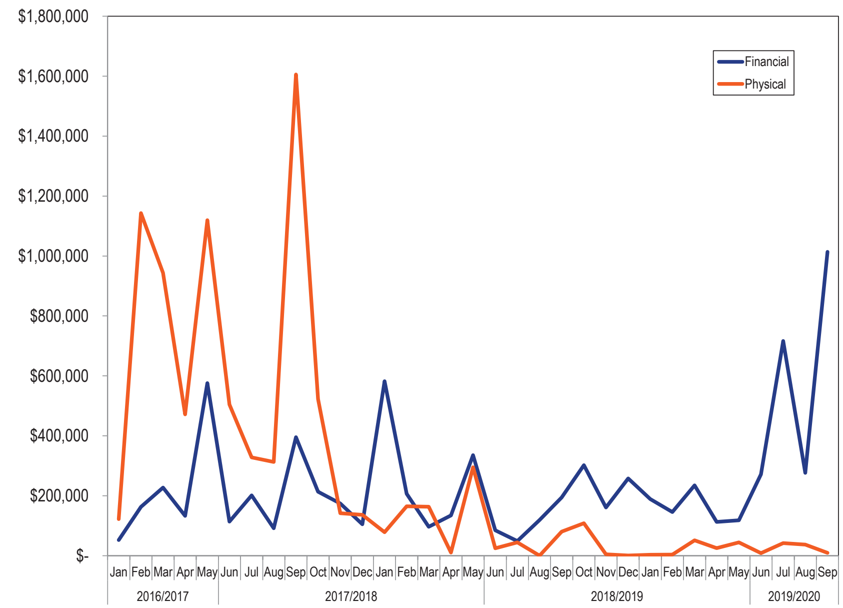
FERC ordered a retroactive effective date meaning that participants would be retroactively billed their FTR forfeiture amounts based on the new FTR forfeiture rule once it was in place.

Until January 19, 2017, an FTR holder was subject to forfeiture of any profits from an FTR if it met the criteria defined in Section 5.2.1(b) of Schedule 1 of the OA. 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 were subject to the new FTR forfeiture rule. 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.

Figure 13-9 shows the monthly FTR forfeitures under the newly established FTR forfeiture rule from January 19, 2017, through September 30, 2019. PJM began retroactively billing FTR forfeitures with the September 2017 bill. In the interim period from January 2017 through September 2017 participants did not know what behaviors were causing FTR forfeitures, so they had no way to modify their bidding behavior to avoid FTR forfeitures. After September 2017, FTR forfeitures were down significantly, and stabilized, as participants could now see the effect of their activities on FTR forfeitures. Beginning with the September 2019 bill, PJM began billing using the correct hourly cost calculation. For the period of January 19, 2017, through September 30, 2019, total FTR forfeitures were $24.6 million.

Figure 13-9 Monthly FTR forfeitures for physical and financial participants



48 See "Minor modification to Tariff Language for FTR Forfeiture Rule," Docket No. ER19-2240 (June 24, 2019).
49 See 158 FERC ¶ 61,038.