Q2

State of the Market Report for PJM

January through June

Monitoring Analytics, LLC

Independent
Market Monitor
for PJM

8.8.2019

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 June*.[3]

1 PJM Open Access Transmission Tariff (OATT) Attachment M (PJM Market Monitoring Plan) § VI.A. Capitalized terms used herein and not otherwise defined have the meaning provided in the OATT, PJM Operating Agreement, PJM Reliability Assurance Agreement or other 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 June*.

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Introduction

2019 Q2 in Review

The goal of competition 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 six 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 half of 2019 than in the first half 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. 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. 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.

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.

But there is another way to address the capacity market issues raised so starkly in the Commission's order. 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.

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 current technologies, 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

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>.

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 six months of 2019 compared to the first six months of 2018. The load-weighted, average real-time LMP was 35.2 percent lower in the first six months of 2019 than in the first six months of 2018, $27.49 per MWh versus $42.44 per MWh. Of the $14.95 per MWh decrease, 31 percent was a result of lower fuel costs. The balance of the decrease was a result of decreased load and lower markups.

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 six months of 2019 as a result of lower energy prices. For example, in the first six months of 2019, average energy market net revenues decreased by 65 percent for a new combustion turbine, 44 percent for a new combined cycle, 87 percent for a new coal plant, 34 percent for a new nuclear plant, and 30 percent for a new on shore wind installation compared to the first six months of 2018.

Lower real-time energy market prices were reflected in significant reductions in forward energy market prices which reduced the expected profitability of nuclear plants in PJM. Prior forward analysis showed that three nuclear plants would not cover their annual avoidable costs for each of the three forward years. The current analysis shows different results by year for some plants. The same three plants, Davis Besse, Perry, and Three Mile Island, show higher shortfalls, with an average annual shortfall of $11.57 per MWh. The three plants are single unit sites which have higher operating costs per MWh than multiple unit plants. In May 2017, TMI requested deactivation in 2019. In March 2018, Davis Besse and Perry requested deactivation in 2021 but reversed the decision based on new subsidies in Ohio. Although the Cook and Susquehanna plants show an average annual shortfall of $1.90 per MWh based on average NEI cost data, Susquehanna has reduced its operating costs and Cook is designated FRR, receives cost of service revenues and is not subject to PJM market revenues. In addition, four nuclear plants would not cover avoidable costs in two of the three forward years with an average annual shortfall of $0.73 per MWh during shortfall years, given current forward prices: Braidwood; Byron; LaSalle; and Quad Cities.

Net revenues for nuclear power plants increased significantly in 2018 and decreased in the first six months of 2019. There are some 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 suggests 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 15,000 ICAP MW on June 1, 2020, based on current positions. There are currently 125,757.4 MW in the PJM generator interconnection queues. Based on historical completion rates, 33,654.7 MW of new generation in the queue are expected to go into service.

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 June, 2018 and 2019[2]

	Jan - Jun, 2018	Jan - Jun, 2019	Percent Change
Average Hourly Load (MW)	88,847	86,297	(2.9%)
Average Hourly Generation (MW)	91,631	91,613	(0.0%)
Peak Load (MW)	145,367	134,060	(7.8%)
Installed Capacity at June 30 (MW)	183,489	187,458	2.2%
Load Weighted Average Real Time LMP ($/MWh)	$42.44	$27.49	(35.2%)
Total Congestion Costs ($ Million)	$896.60	$254.11	(71.7%)
Total Uplift Charges ($ Million)	$139.56	$36.90	(73.6%)
Total PJM Billing ($ Billion)	$25.78	$20.07	(22.1%)

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."

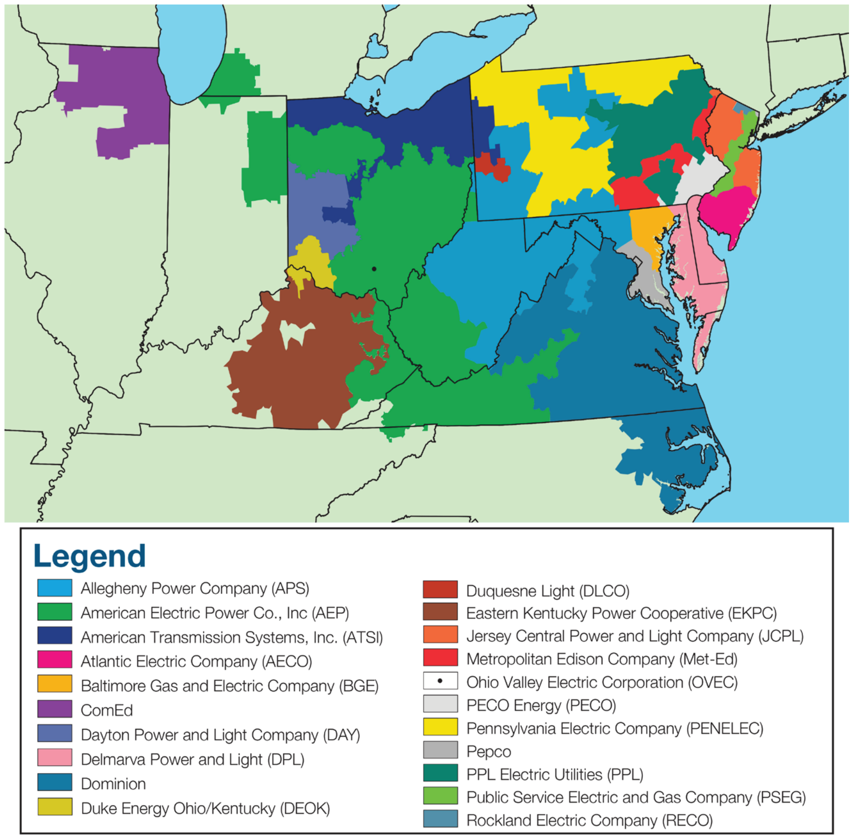
PJM Market Background

The PJM Interconnection, L.L.C. (PJM) operates a centrally dispatched, competitive wholesale electric power market that, as of June 30, 2019, had installed generating capacity of 187,458 megawatts (MW) and 1,029 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.

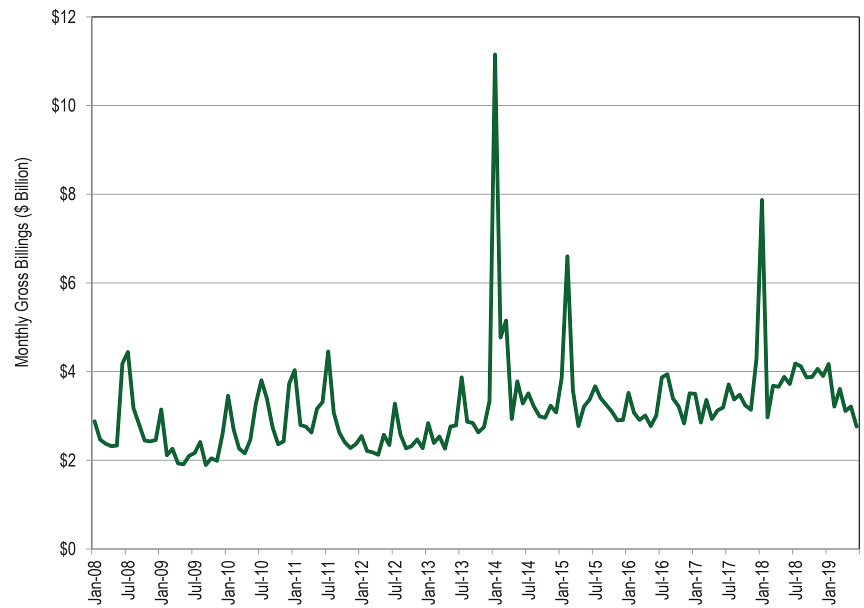
3 See PJM. "Member List," which can be accessed at: <http://pjm.com/about-pjm/member-services/member-list.aspx>.
4 See PJM. "Who We Are," which can be accessed at: <http://pjm.com/about-pjm/who-we-are.aspx>.
5 See the *2018 State of the Market Report for PJM*, Volume II, Appendix A:"PJM Geography" for 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 six months of 2019, PJM had total billings of $20.07 billion, a decrease of 22.1 percent from $25.78 billion in the first six months of 2018 (Figure 1-2).[6] The monthly billing for June 2019, $2.76 billion, was the lowest monthly billing reported by PJM since November 2013.

Figure 1-2 PJM reported monthly billings ($ Billion): 2008 through June 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 six 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 six 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 six months of 2019 was unconcentrated by FERC HHI standards in 97.5 percent of market hours and moderately concentrated in 2.5 percent of market hours. Average HHI was 792 with a minimum of 599 and a maximum of 1098 in the first six months of 2019. The PJM energy market peaking segment of supply was 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 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.
- 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

9 OATT Attachment M (PJM Market Monitoring Plan).

competitive and thus where market design alone cannot mitigate market power. In the PJM energy market, this occurs primarily in the case of local market power. When a transmission constraint creates the potential for local market power, PJM applies a structural test to determine if the local market is competitive, applies a behavioral test to determine if generator offers exceed competitive levels and applies a market performance test to determine if such generator offers would affect the market price.[10] There are, however, identified issues with the application of market power mitigation to resources whose owners fail the TPS test that can result in the exercise of local market power even when market power mitigation rules are applied. These issues need to be addressed. There are issues related to the definition of gas costs includable in energy offers that need to be addressed. There are issues related to the level of variable operating and maintenance expense includable in energy offers that need to be addressed. There are currently no market power mitigation rules in place that limit the ability to exercise market power when aggregate market conditions are tight and there are pivotal suppliers in the aggregate market. Aggregate market power needs to be addressed. Now that generators are allowed to modify offers hourly, market design must reflect appropriate incentives for competitive behavior, the application of local market power mitigation needs to be fixed, the definition of a competitive offer needs to be fixed, and aggregate market power mitigation rules need to be developed. The importance of these issues is amplified by the new rules permitting cost-based offers in excess of $1,000 per MWh.

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 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.

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.

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.

- 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, the PJM DASR Market, and the PJM Regulation Market for the first six 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

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 4.9 percent of cleared hours in the first six 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 208 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

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 87.5 percent of the hours in the first six months of 2019.
- Participant behavior in the PJM Regulation Market was evaluated as competitive for the first six 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

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

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

Reporting

The MMU performs its reporting function primarily by issuing and filing annual and quarterly state of the market reports; regular reports on market 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 the FERC.[17] The MMU may also refer matters to the attention of state commissions.[18]

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

21 OATT § I.1.

22 The MMU has no prosecutorial or enforcement authority. The MMU notifies the FERC when it identifies a significant market problem or market violation. OATT Attachment M § IV.I.1. If the problem or violation involves a market participant, the MMU discusses the matter with the participant(s) involved and analyzes relevant market data. If that investigation produces sufficient credible evidence of a violation, the MMU prepares a formal referral and thereafter undertakes additional investigation of the specific matter only at the direction of FERC staff. *Id.* If the problem involves an existing or proposed law, rule or practice that exposes PJM markets to the risk that market power or market manipulation could compromise the integrity of the markets, the MMU explains the issue, as appropriate, to the FERC, state regulators, stakeholders or other authorities. The MMU may also participate as a party or provide information or testimony in regulatory or other proceedings.

23 OATT Attachment M § IV.C.

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 the FERC or other regulatory authorities. The FERC and other regulators have enforcement and regulatory authority that they may exercise with respect to offers submitted by market participants. PJM also reviews offers, but it does so in order to determine whether offers comply with the PJM tariff and manuals. PJM, in its role as the market operator, may reject an offer that fails to comply with the market rules. The respective reviews performed by the MMU and PJM are separate and non-sequential.

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 June*, the MMU includes three new recommendations.[38]

New Recommendation from Section 6, Demand Response

- 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. New recommendation. Status: Not adopted.)

New Recommendation from Section 8, Environmental and Renewable Energy Regulations

- The MMU recommends that load and generation located at separate nodes be treated as separate resources. (Priority: High. New recommendation. Status: Not adopted.)

New Recommendation from Section 9, Interchange Transactions

- 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. 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 six 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.[39]
- The Energy Uplift (Operating Reserves) component is the average price per MWh of day-ahead and balancing operating reserves and synchronous condensing charges.[40]

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 June.*

39 OATT §§ 13.7, 14.5, 27A & 34.

40 OA Schedules 1 §§ 3.2.3 & 3.3.3.

- The Reactive component is the average cost per MWh of reactive supply and voltage control from generation and other sources.[41]
- The Regulation component is the average cost per MWh of regulation procured through the PJM Regulation Market.[42]
- 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.[43]
- 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.[44]
- The Emergency Load Response component is the average cost per MWh of the PJM Emergency Load Response Program.[45]
- 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.[46]
- 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.[47]
- The Synchronized Reserve component is the average cost per MWh of synchronized reserve procured through the Synchronized Reserve Market.[48]
- The Black Start component is the average cost per MWh of black start service.[49]
- The RTO Startup and Expansion component is the average cost per MWh of charges to recover AEP, ComEd and DAY's integration expenses.[50]
- The NERC/RFC component is the average cost per MWh of NERC and RFC charges, plus any reconciliation charges.[51]
- The Economic Load Response component is the average cost per MWh of day ahead and real time economic load response program charges to LSEs.[52]
- The Transmission Facility Charges component is the average cost per MWh of Ramapo Phase Angle Regulators charges allocated to PJM Mid-Atlantic transmission owners.[53]
- The nonsynchronized reserve component is the average cost per MWh of non-synchronized reserve procured through the Non-Synchronized Reserve Market.[54]
- The Emergency Energy component is the average cost per MWh of emergency energy.[55]

41 OATT Schedule 2 and OA Schedule 1 § 3.2.3B. The line item in Table 1-8 includes all reactive services charges.
42 OA Schedules 1 §§ 3.2.2, 3.2.2A, 3.3.2, & 3.3.2A; OATT Schedule 3.
43 OATT Schedule 12.
44 RAA Schedule 8.1.
45 OATT PJM Emergency Load Response Program.
46 OA Schedules 1 §§ 3.2.3A.01 & OATT Schedule 6.
47 OATT Schedule 1A.
48 OA Schedule 1 § 3.2.3A.01; PJM OATT Schedule 6.
49 OATT Schedule 6A. The line item in Table 1-8 includes all Energy Uplift (Operating Reserves) charges for Black Start.
50 OATT Attachments H-13, H-14 and H-15 and Schedule 13.
51 OATT Schedule 10-NERC and OATT Schedule 10-RFC.
52 OA Schedule 1 § 3.6.
53 OA Schedule 1 § 5.3b.
54 OA Schedule 1 § 3.2.3A.001.
55 OA Schedule 1 § 3.2.6.

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 97.6 percent of the total price per MWh in the first six months of 2019.

Table 1-8 Total price per MWh by category: January through June, 2018 and 2019[56] [57]

Category	Jan-Jun 2018 $/MWh	Jan-Jun 2018 ($ Millions)	Jan-Jun 2018 Percent of Total	Jan-Jun 2019 $/MWh	Jan-Jun 2019 ($ Millions)	Jan-Jun 2019 Percent of Total	Percent Change
Load Weighted Energy	$42.44	$16,376	64.4%	$27.49	$10,302	51.7%	(35.2%)
Capacity	$12.15	$4,687	18.4%	$13.81	$5,175	26.0%	13.7%
Capacity	$12.10	$4,668	18.4%	$13.78	$5,164	25.9%	13.9%
Capacity (FRR)	$0.00	$0	0.0%	$0.00	$0	0.0%	0.0%
Capacity (RMR)	$0.05	$18	0.1%	$0.03	$11	0.1%	(37.8%)
Transmission	$9.54	$3,682	14.5%	$10.57	$3,963	19.9%	10.8%
Transmission Service Charges	$8.84	$3,409	13.4%	$9.92	$3,717	18.6%	12.2%
Transmission Enhancement Cost Recovery	$0.61	$237	0.9%	$0.57	$213	1.1%	(7.3%)
Transmission Owner (Schedule 1A)	$0.09	$36	0.1%	$0.09	$33	0.2%	(4.9%)
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	$0.91	$350	1.4%	$0.71	$268	1.3%	(21.4%)
Reactive	$0.44	$170	0.7%	$0.47	$175	0.9%	6.2%
Regulation	$0.24	$92	0.4%	$0.11	$40	0.2%	(55.8%)
Black Start	$0.09	$33	0.1%	$0.09	$32	0.2%	(1.0%)
Synchronized Reserves	$0.08	$29	0.1%	$0.04	$14	0.1%	(51.0%)
Non-Synchronized Reserves	$0.03	$10	0.0%	$0.01	$5	0.0%	(49.8%)
Day Ahead Scheduling Reserve (DASR)	$0.04	$15	0.1%	$0.00	$2	0.0%	(87.8%)
Administration	$0.52	$200	0.8%	$0.51	$192	1.0%	(1.2%)
PJM Administrative Fees	$0.48	$187	0.7%	$0.48	$179	0.9%	(1.8%)
NERC/RFC	$0.03	$11	0.0%	$0.03	$12	0.1%	7.4%
RTO Startup and Expansion	$0.00	$1	0.0%	$0.00	$1	0.0%	3.3%
Energy Uplift (Operating Reserves)	$0.33	$129	0.5%	$0.10	$36	0.2%	(71.0%)
Demand Response	$0.00	$2	0.0%	$0.00	$1	0.0%	(46.9%)
Load Response	$0.00	$2	0.0%	$0.00	$1	0.0%	(46.9%)
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	$65.89	$25,426	100.0%	$53.19	$19,936	100.0%	(19.3%)
Total Load (GWh)	385,864			374,789			(2.9%)
Total Billing ($ Billions)	$25.43			$19.94			(21.6%)

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

57 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 June, 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).[58]

Table 1-9 Inflation adjusted total price per MWh by category: January through June, 2018 and 2019[59]

Category	Jan-Jun 2018 $/MWh	Jan-Jun 2018 ($ Millions)	Jan-Jun 2018 Percent of Total	Jan-Jun 2019 $/MWh	Jan-Jun 2019 ($ Millions)	Jan-Jun 2019 Percent of Total	Percent Change
Load Weighted Energy	$27.48	$10,603	64.5%	$17.48	$6,551	51.7%	(36.4%)
Capacity	$7.85	$3,028	18.4%	$8.77	$3,288	25.9%	11.8%
Capacity	$7.82	$3,016	18.3%	$8.76	$3,281	25.9%	12.0%
Capacity (FRR)	$0.00	$0	0.0%	$0.00	$0	0.0%	0.0%
Capacity (RMR)	$0.03	$12	0.1%	$0.02	$7	0.1%	(38.5%)
Transmission	$6.17	$2,379	14.5%	$6.72	$2,517	19.9%	8.9%
Transmission Service Charges	$5.71	$2,203	13.4%	$6.30	$2,361	18.6%	10.3%
Transmission Enhancement Cost Recovery	$0.40	$153	0.9%	$0.36	$135	1.1%	(8.9%)
Transmission Owner (Schedule 1A)	$0.06	$23	0.1%	$0.06	$21	0.2%	(6.6%)
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	$0.59	$227	1.4%	$0.45	$170	1.3%	(22.8%)
Reactive	$0.28	$110	0.7%	$0.30	$111	0.9%	4.4%
Regulation	$0.15	$60	0.4%	$0.07	$25	0.2%	(56.6%)
Black Start	$0.06	$22	0.1%	$0.05	$20	0.2%	(2.7%)
Synchronized Reserves	$0.05	$19	0.1%	$0.02	$9	0.1%	(51.9%)
Non-Synchronized Reserves	$0.02	$7	0.0%	$0.01	$3	0.0%	(50.6%)
Day Ahead Scheduling Reserve (DASR)	$0.03	$10	0.1%	$0.00	$1	0.0%	(88.0%)
Administration	$0.33	$129	0.8%	$0.33	$122	1.0%	(2.9%)
PJM Administrative Fees	$0.31	$121	0.7%	$0.30	$113	0.9%	(3.4%)
NERC/RFC	$0.02	$7	0.0%	$0.02	$8	0.1%	5.7%
RTO Startup and Expansion	$0.00	$1	0.0%	$0.00	$1	0.0%	0.0%
Energy Uplift (Operating Reserves)	$0.22	$84	0.5%	$0.06	$23	0.2%	(71.5%)
Demand Response	$0.00	$1	0.0%	$0.00	$1	0.0%	(46.9%)
Load Response	$0.00	$1	0.0%	$0.00	$1	0.0%	(46.9%)
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	$42.63	$16,451	100.0%	$33.81	$12,673	100.0%	(20.7%)
Total Load (GWh)	385,864			374,789			(2.9%)
Total Billing ($ Billions)	$16.45			$12.67			(23.0%)

58 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> (July 11, 2019).

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

Table 1-10 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[60]

Category	1999 $/MWh	2000 $/MWh	2001 $/MWh	2002 $/MWh	2003 $/MWh	2004 $/MWh	2005 $/MWh	2006 $/MWh	2007 $/MWh	2008 $/MWh	2009 $/MWh	2010 $/MWh	2011 $/MWh	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	$0.43
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	$62.30
Total Load (GWh)	259,623	264,510	265,398	2,899	327,533	438,874	684,592	696,165	715,524	698,459	666,069	697,391	723,101	764,300	773,790	780,505	776,093	778,269	758,775	791,093
Total Billing ($ 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

60 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.[61]

Table 1-11 Inflation adjusted total price per MWh by category: 1999 through 2018[62]

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	$0.28
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	$40.13
Total Load (GWh)	259,623	264,510	265,398	312,899	327,533	438,874	684,592	696,165	715,524	698,459	666,069	697,391	723,101	764,300	773,790	780,505	776,093	778,269	758,775	791,093
Total Billing ($ 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

61 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> (July 11, 2019).

62 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[63]

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%

63 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 June 2019[64]

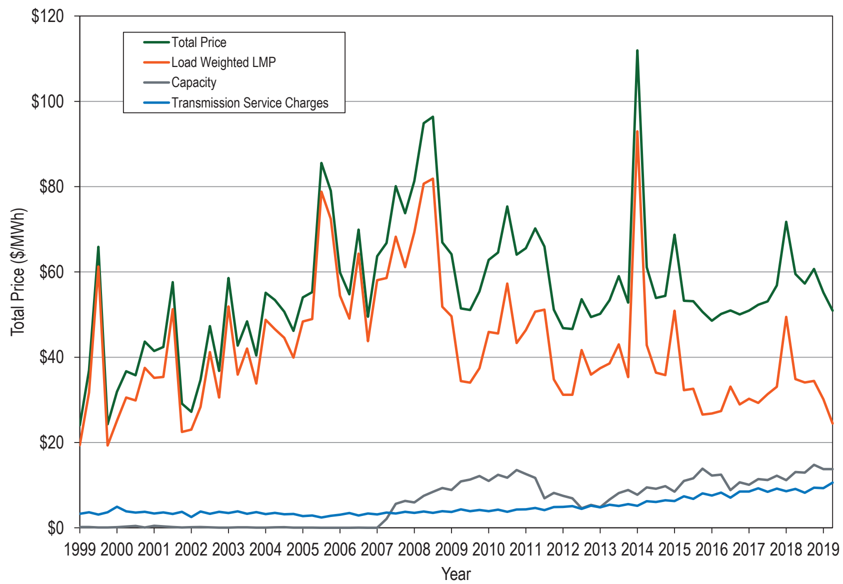
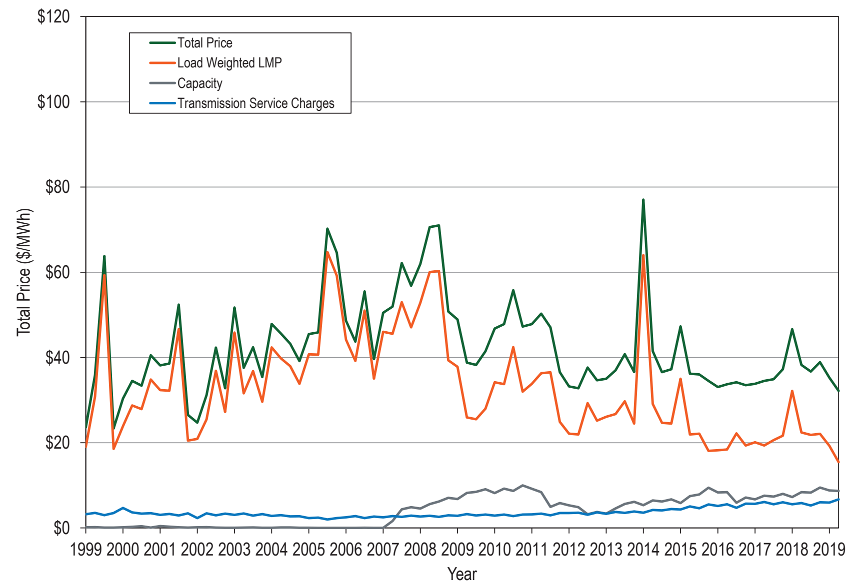


Figure 1-4 shows the inflation adjusted contributions of load-weighted energy, capacity and transmission service charges to the total price of wholesale power for each quarter since 1999.[65]

Figure 1-4 Inflation adjusted top three components of quarterly total price ($/MWh): January 1999 through June 2019[66]



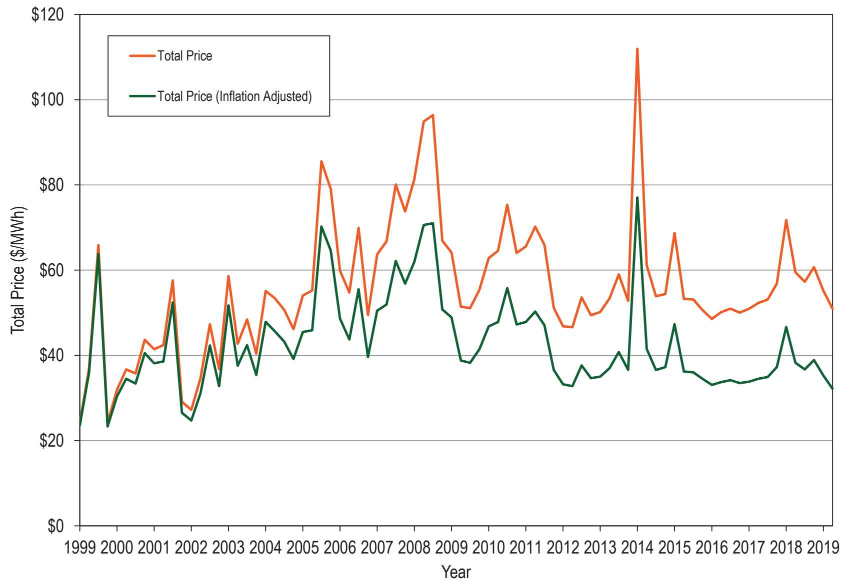
64 Note: The totals presented in this figure include after the fact billing adjustments and may not match totals presented in past reports.

65 US Consumer Price Index for all items, Urban Consumers (base period: January 1998), published by *Bureau of Labor Statistics*. <http://download.bls.gov/pub/time.series/cu/cu.data.1.AllItems> (July 11, 2019)

66 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.[67]

Figure 1-5 Quarterly total price and quarterly inflation adjusted total price ($/MWh): January 1999 through June 2019[68 69]



67 US Consumer Price Index for all items, Urban Consumers (base period: January 1998), published by *Bureau of Labor Statistics*. <http://download.bls.gov/pub/time.series/cu/cu.data.1.AllItems> (July 11, 2019)
68 Note: The totals presented in this figure include after the fact billing adjustments and may not match totals presented in past reports.
69 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> (July 11, 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 123,039 MW for spring of 2018 and 128,183 MW for spring of 2019. In the first six months of 2019, 587.7 MW of new resources were added and 3,265.8 MW were retired.

  PJM average real-time cleared generation in the first six months of 2019 decreased 18 MWh from the first six months of 2018, from 91,631 MWh to 91,613 MWh.

  PJM average day-ahead cleared supply in the first six months of 2019, including INCs and up to congestion transactions, increased by 2.2 percent from the first six months of 2018, from 113,028 MWh to 115,511 MWh.

- **Demand.** Demand includes physical load and exports and virtual transactions. The PJM accounting peak load in the first six months of 2019 was 134,060 MWh in the HE 0800 on January 31, 2019 which was 11,307 MWh, 7.8 percent, lower than the PJM peak load for the first six months of 2018, which was 145,367 MWh in the HE 1700 on June 18, 2018.

  PJM average real-time demand in the first six months of 2019 decreased by 2.9 percent from the first six months of 2018, from 88,847 MWh to 86,297 MWh. PJM average day-ahead demand in the first six months of 2019, including DECs and up to congestion transactions, increased by 1.8 percent from the first six months of 2018, from 108,950 MWh to 110,890 MWh.

Market Behavior

- **Supply and Demand: Load and Spot Market.** Companies that serve load in PJM do so using a combination of self-supply, bilateral market purchases and spot market purchases. For the first six months of 2019, 14.8 percent of real-time load was supplied by bilateral contracts, 28.0 percent by spot market purchases and 58.3 percent by self-supply. Compared to the first six months of 2018, reliance on bilateral contracts increased by 2.3 percentage points, reliance on spot market purchases decreased by 1.9 percentage points and reliance on self-supply decreased by 0.3 percentage points.

- **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 six months of 2019, 26.4 percent were offered as available for economic dispatch, 30.5 percent were offered at their economic minimum, 4.3 percent were offered as emergency dispatch, 14.9 percent were offered as self scheduled, and 23.9 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 six months of 2019, the average hourly increment offers submitted and cleared MW increased by 6.5 percent and 8.0 percent, from 5,851 MW and 2,757 MW in the first six months of 2018 to 6,234 MW and 2,976 MW in the first six months of 2019. The hourly average submitted decrement MW decreased by 2.6 percent and cleared decrement MW increased by 36.4 percent, from 6,936 MW and 2,736 MW in the first six months of 2018 to 6,755 MW and 3,732 MW in the first six months of 2019. The average hourly up to congestion submitted decreased by 0.8 percent and cleared MW increased by 15.4 percent, from 64,236 MW and 17,983 MW in the first six months of 2018 to 63,738 MW and 20,748 MW in the first six months of 2019.

Market Performance

- **Generation Fuel Mix.** In the first six months of 2019, coal units provided 24.8 percent, nuclear units 34.4 percent and natural gas units 33.5 percent of total generation. Compared to the first six months of 2018, generation from coal units decreased 16.7 percent, generations from natural gas units increased 18.4 percent and generation from nuclear units decreased 2.8 percent.
- **Fuel Diversity.** In the first six months of 2019, the fuel diversity of energy generation, measured by the fuel diversity index for energy (FDI_e), decreased 0.3 percent over the FDI_e for the first six months of 2018.
- **Marginal Resources.** In the PJM Real-Time Energy Market, in the first six months of 2019, coal units were 27.3 percent and natural gas units were 69.6 percent of marginal resources. In the first six months of 2018, coal units were 29.6 percent and natural gas units were 60.9 percent of marginal resources. Among the natural gas units that were marginal in the first six months of 2019, nearly 93 percent were combined cycle units.

  In the PJM Day-Ahead Energy Market, in the first six months of 2019, up to congestion transactions were 57.8 percent, INCs were 13.3 percent, DECs were 18.2 percent, and generation resources were 10.5 percent of marginal resources. In the first six months of 2018, up to congestion transactions were 66.9 percent, INCs were 8.4 percent, DECs were 14.7 percent, and generation resources were 9.9 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 six months of 2019 compared to the first six months of 2018. The load-weighted, average real-time LMP was 35.2 percent lower in the first six months of 2019 than in the first six months of 2018, $27.49 per MWh versus $42.44 per MWh.

PJM day-ahead energy market prices decreased in the first six months of 2019 compared to the first six months of 2018. The load-weighted, average day-ahead LMP was 31.7 percent lower in the first six months of 2019 than in the first six months of 2018, $27.97 per MWh versus $40.96 per MWh.

- **Components of LMP.** In the PJM Real-Time Energy Market, in the first six months of 2019, 26.6 percent of the load-weighted LMP was the result of coal costs, 45.3 percent was the result of gas costs and 0.80 percent was the result of the cost of emission allowances.

  In the PJM Day-Ahead Energy Market, in the first six months of 2019, 23.4 percent of the load-weighted LMP was the result of coal costs, 20.8 percent was the result of gas costs, 20.5 percent was the result of INC offers, 20.4 percent was the result of DEC bids, and 2.1 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 $0.93 per MWh in the first six months of 2018 and -$0.45 per MWh in the first six 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 twenty intervals with five minute shortage pricing on eleven days in the first six months of 2019. In all twenty intervals, shortage pricing was triggered due to synchronized reserves being short of the extended synchronized reserve requirement in the RTO and MAD reserve zones. This included two intervals when synchronized reserves were short of the synchronized reserve requirement. There were no intervals with primary reserve shortage in the first six months of 2019.

- There were 1,482 five minute intervals, or 2.8 percent of all five minute intervals in the first six months of 2019 for which at least one solved SCED case showed a shortage of reserves, and 692 five minute intervals, or 1.3 percent of all five minute intervals in the first six months of 2019 for which more than one solved SCED case showed a shortage of reserves. PJM operators used only twenty RT SCED cases that showed a shortage of reserves in LPC to calculate real-time LMPs and ancillary service prices.

- In the first six 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 six months of 2018 to 0.5 percent in the first six months of 2019. In the Real-Time Energy Market, for units committed to provide energy for local constraint relief, offer-capped unit hours decreased from 1.3 percent in the first six months of 2018 to 0.8 percent in the first six 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 six months of 2019, 10 control zones experienced congestion resulting from one or more constraints binding for 50 or more hours. The analysis of the application of the TPS test to local markets demonstrates that it is working successfully to 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 six months of 2018 to 0.0 percent in the first six months of 2019. In the Real-Time Energy Market, for units committed for reliability reasons, offer-capped unit hours decreased from 0.2 percent in the first six months of 2018 to 0.0 percent in the first six months of 2019.

- **Markup Index.** The markup index is a summary measure of participant offer behavior for individual marginal units. In the first six months of 2019, in the PJM Real-Time Energy Market, 97.4 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 ($0.53 per MWh) when using unadjusted cost-based offers. The average dollar markup of units with offer prices between $25 and $50 was positive ($2.10 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 six months of 2019 was more than $300 per MWh while the highest markup in the first six 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 six months of 2019, in the PJM Day-Ahead Energy Market, 98.5 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 ($0.71 per MWh) when using unadjusted cost-based offers. The average dollar markup of units with offer prices between $25 and $50 was positive ($1.57 per MWh) when using unadjusted cost-based offers. Using the unadjusted cost-based offers, the highest markup for any marginal unit in the first six months of 2019 was about $90 per MWh, while the highest markup in the first six 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 three 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 since December 2014.

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 six months of 2019, the unadjusted markup component of LMP was $1.90 per MWh or 6.9 percent of the PJM load-weighted, average LMP. February had the highest unadjusted peak markup component, $3.05 per MWh, or 10.3 percent of the real-time, off peak hour load-weighted, average LMP. There were 27 hours in the first six months of 2019 where the positive markup contribution to the PJM system wide, load-weighted, average LMP exceeded $32.14 per MWh.

In the PJM Day-Ahead Energy Market, INCs, DECs and UTCs have zero markups. In the first six months of 2019, the unadjusted markup component of LMP resulting from generation resources was $0.48 per MWh or 1.7 percent of the PJM day-ahead load-weighted average LMP. January had the highest unadjusted peak markup component, $1.68 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 Day-Ahead Energy Market be competitive, where competitive is defined to be the short run marginal cost of the units. The short run marginal cost should reflect opportunity cost when and where appropriate. The MMU recommends that the level of incremental costs includable in cost-based offers not exceed the short run marginal cost of the unit. (Priority: Medium. First reported 2009. Status: Not adopted.)
- The MMU recommends that PJM require 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 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.[70] (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 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.)

70 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 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 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.[71] [72] (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.)

71 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.

72 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 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.)

Transparency

- The MMU recommends that PJM market rules require the fuel type be identified for every price and cost schedule 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.)

Section 3 Conclusion

The MMU analyzed key elements of PJM energy market structure, participant conduct and market performance in the first six 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, loads and prices.

PJM average real-time cleared generation decreased by 18 MWh, and peak load decreased by 11,307 MWh, 7.8 percent, in the first six months of 2019 compared to the first six 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.[73] However, there are some issues with the application of market power mitigation in the Day-Ahead Energy Market and the Real-Time Energy Market when market sellers fail the TPS test. These issues can be resolved by simple rule changes.

The enforcement of market power mitigation rules is undermined if the definition of a competitive offer is not correct. A competitive offer is equal to short run marginal costs. The significance of competition metrics like markup is also undermined if the definition of a competitive offer is not correct. The definition of a competitive offer, as interpreted by PJM, is not currently correct. Some unit owners include costs that are not short run marginal costs in offers, including maintenance costs. This issue can be resolved by simple rule changes to incorporate a clear and accurate definition of short run marginal costs.

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

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 six 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. 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. 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 does indicate a shortage of reserves, it should be used in calculating real-time prices. 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 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.

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 six months of 2019 or prior years. 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 six months of 2019.

Overview: Section 4, Energy Uplift

Energy Uplift Credits

- **Types of credits.** In the first six months of 2019, energy uplift credits were \$37.1 million, including \$8.2 million in day-ahead generator credits, \$21.4 million in balancing generator credits, \$4.0 million in lost opportunity cost credits, and \$2.7 million in local constraint control credits.
- **Types of units.** Coal units received 90.1 percent of all day-ahead generator credits. Combustion turbines received 82.7 percent of all balancing generator credits and 90.2 percent of lost opportunity cost credits.
- **Economic and Noneconomic Generation.** In the first six months of 2019, 81.3 percent of the day-ahead generation eligible for operating reserve credits was economic and 66.6 percent of the real-time generation eligible for operating reserve credits was economic.

- **Day-Ahead Unit Commitment for Reliability.** In the first six months of 2019, 0.2 percent of the total day-ahead generation MWh was scheduled as must run by PJM, of which 52.8 percent received energy uplift payments.
- **Concentration of Energy Uplift Credits.** The top 10 units receiving energy uplift credits received 29.3 percent of all credits. The top 10 organizations received 77.3 percent of all credits. The HHI for day-ahead operating reserves was 8523, the HHI for balancing operating reserves was 3867 and the HHI for lost opportunity cost was 6532, all of which are classified as highly concentrated.
- **Lost Opportunity Cost Credits.** Lost opportunity cost credits decreased by $37.5 million or 90.3 percent, in the first six months of 2019 compared to the first six months of 2018, from $41.5 million to $4.0 million. Generation from combustion turbines and diesels scheduled day-ahead but not requested in real time, receiving lost opportunity cost credits decreased by 527 GWh or 78.1 percent in the first six months of 2019, compared to the first six months of 2018, from 674.9 GWh to 148 GWh.

Energy Uplift Charges

- **Energy Uplift Charges.** Total energy uplift charges decreased by $102.9 million, or 73.6 percent, in the first six months of 2019 compared to the first six months of 2018, from $139.8 million to $36.9 million.
- **Energy Uplift Charges Categories.** The decrease of $102.9 million in the first six months of 2019 is comprised of a $19.4 million decrease in day-ahead operating reserve charges, a $73.2 million decrease in balancing operating reserve charges, and a $10.3 million decrease in reactive services charges.
- **Average Effective Operating Reserve Rates in the Eastern Region.** Day-ahead load paid $0.021 per MWh, real-time load paid $0.028 per MWh, a DEC paid $0.230 per MWh and an INC and any load, generation or interchange transaction deviation paid $0.209 per MWh.
- **Average Effective Operating Reserve Rates in the Western Region.** Day-ahead load paid $0.021 per MWh, real-time load paid $0.025 per MWh, a DEC paid $0.210 per MWh and an INC and any load, generation or interchange transaction deviation paid $0.189 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 $0.016 per MWh, DPL had a rate of $0.011 per MWh, and Dominion had a rate of $0.004 per MWh.

Geography of Charges and Credits

- In the first six months of 2019, 91.0 percent of all uplift charges allocated regionally (day-ahead operating reserves and balancing operating reserves) were paid by transactions at control zones, 2.3 percent by transactions at hubs and aggregates, and 6.7 percent by transactions at interchange interfaces.
- Generators in the Eastern Region received 52.8 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.
- Generators in the Western Region received 446.5 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.
- External generators received 1.6 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.

Section 4 Recommendations

- The MMU 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.[74])

74 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 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.)
- 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.[75])
- 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 4 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

75 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.

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.

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.[76]

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.[77]

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

76 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.

77 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.

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.[78]

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.[79] 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.[80] 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.[81]

The 2019/2020 RPM Third Incremental Auction was conducted in the first six 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.[82] 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.[83]

On June 9, 2015, FERC accepted changes to the PJM capacity market rules proposed in PJM's Capacity Performance (CP) filing.[84] 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.[85] 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.[86] Existing generation capable of qualifying as a capacity resource must be offered into RPM auctions, except for resources owned by entities

78 The terms *PJM Region*, *RTO Region* and *RTO* are synonymous in this report and include all capacity within the PJM footprint.
79 See 126 FERC ¶ 61,275 at P 86 (2009).
80 See Letter Order, FERC Docket No. ER10-366-000 (January 22, 2010).
81 See 126 FERC ¶ 61,275 at P 88 (2009).
82 See 164 FERC ¶ 61,153 (2018).
83 See 168 FERC ¶ 61,051 (2019).
84 See 151 FERC ¶ 61,208 (2015).
85 See "PJM Manual 18: PJM Capacity Market," Rev. 41 (Jan. 1, 2019) § 1.5, at p 19.
86 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.

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.

Market Structure

- **RPM Installed Capacity.** During the first six months of 2019, RPM installed capacity decreased 910.9 MW or 0.5 percent, from 186,496.1 MW on January 1 to 185,585.2 MW on June 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 June 30, 2019, 41.9 percent was gas; 31.0 percent was coal; 17.7 percent was nuclear; 4.7 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 2019/2020 RPM Third Incremental Auction all participants in the total PJM market as well as the LDA RPM markets failed the three pivotal supplier (TPS) test.[87] 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.[88] [89] [90]
- **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

- **2019/2020 RPM Third Incremental Auction.** Of the 137 generation resources that submitted Base Capacity offers, the MMU calculated offer caps for one generation resource (0.7 percent), of which one (0.7 percent) was a unit-specific offer cap. Of the 454 generation resources that submitted Capacity Performance offers, the MMU calculated unit specific offer caps for four generation resources (0.9 percent).

Market Performance

- The 2019/2020 RPM Third Incremental Auction was conducted in the first six months of 2019.[91] 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 $112.63 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.

87 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).

88 See OATT Attachment DD § 6.5.

89 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).

90 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).

91 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).

- 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 six months of 2019 was 6.5 percent, a decrease from 8.3 percent for the first six months of 2018.[92]
- **Generator Performance Factors.** The PJM aggregate equivalent availability factor for the first six months of 2019 was 82.5 percent, an increase from 82.0 percent for the first six months of 2018.

Section 5 Recommendations[93]

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.[94]

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.[95] [96] (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.[97] [98] 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

92 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 July 24, 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.

93 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.

94 151 FERC ¶ 61,208 (2015).

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

96 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).

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

98 See the *2017 State of the Market Report for PJM*, Volume 2, Section 7: Net Revenue.

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.[99] (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.[100] (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

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

100 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).

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.)

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.

The 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 six 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.[101] [102] [103] [104] [105] [106] 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 15,000 ICAP MW on June 1, 2020, based on current positions.[107] A majority of capacity investments in PJM were financed by market sources. Of the 39,451.7 MW of additional capacity that cleared in RPM auctions for the 2007/2008 through 2018/2019 delivery years, 29,923.8 MW (75.8 percent) were based on market funding. Of the 8,340.9 MW of additional capacity that cleared in RPM auctions for the 2019/2020 through 2021/2022 delivery years, 6,367.4 MW (76.3 percent) are based on market funding. Those investments were made based on the

101 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).
102 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).
103 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).
104 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).
105 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2016," <http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Analysis_of_Replacement_Capacity_for_RPM_Commitments_06012007_to_06012016_20161227.pdf> (December 27, 2016).
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 The calculated reserve margin for June 1, 2020, does not account for cleared buy bids that have not been used in replacement capacity transactions.

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, emerged more fully in 2017 and 2018 and the first six months of 2019. 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). 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 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.[108] Demand response resources

108 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.

participate in the Synchronized Reserve Market. Demand response resources participate in the Regulation Market.

In the first six months of 2019, total demand response revenue increased by $25.6 million, 9.4 percent, from $271.9 million in the first six months of 2018 to $297.5 million in the first six months of 2019. Emergency demand response revenue accounted for 99.0 percent of all demand response revenue, economic demand response for 0.2 percent, demand response in the Synchronized Reserve Market for 0.4 percent and demand response in the regulation market for 0.4 percent.

Total emergency demand response revenue increased by $29.1 million, 10.9 percent, from $265.5 million in the first six months of 2018 to $294.6 million in the first six months of 2019. This increase consisted entirely of capacity market revenue.[109]

Economic demand response revenue decreased by $1.0 million, 66.7 percent, from $1.6 million in the first six months of 2018 to $0.5 million in the first six months of 2019.[110] Demand response revenue in the Synchronized Reserve Market decreased by $2.0 million, 62.3 percent, from $3.2 million in the first six months of 2018 to $1.2 million in the first six months of 2019. Demand response revenue in the regulation market decreased by $0.5 million, 62.3 percent, from $1.6 million in the first six months of 2018 to $1.2 million in the first six 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.[111]

- **Demand Response Market Concentration.** The ownership of economic demand response resources was highly concentrated in 2018 and the first six months of 2019. The HHI for economic resource reductions increased by 373 points from 7541 in 2018 to 7914 in the first six months of 2019. The ownership of emergency demand response resources was moderately concentrated in the first six 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 June 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,

109 The total credits and MWh numbers for demand resources were calculated as of July 23, 2019 and may change as a result of continued PJM billing updates.
110 Economic credits are synonymous with revenue received for reductions under the economic load response program.
111 "PJM Manual 28: Operating Agreement Accounting," § 11.2.2, Rev. 82 (July 25, 2019).

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.[112] (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.)

112 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 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.[113] (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.)

113 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 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.[114])
- 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.)

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

- 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. New recommendation. 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.[115] The MMU proposal was based on the BGE load forecasting program and Pennsylvania Act 129 Utility Program.[116] [117] 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.[118] PJM's proposal includes only a THI curtailment trigger and not an overall load curtailment trigger.

115 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>.
116 *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).
117 *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).
118 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).

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

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

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

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

- This approach would work under the CP design in the capacity market. This approach is entirely consistent with the Supreme Court decision in *EPSA* as it does not depend on whether FERC has jurisdiction over the demand side. This approach will allow FERC to more fully realize its overriding policy objective to create competitive and efficient wholesale energy markets. The decision of the Supreme Court addressed jurisdictional issues and did not address the merits of FERC's approach. The Supreme Court's decision has removed the uncertainty surrounding the jurisdictional issues and created the opportunity for FERC to revisit its approach to demand side.

Overview: Section 7, Net Revenue

Net Revenue

- Energy net revenues are significantly affected by energy prices and fuel prices. Energy prices were significantly lower in the first six months of 2019 than in the first six months of 2018 as a result of lower gas prices. Coal prices were slightly higher.
- In the first six months of 2019, average energy market net revenues decreased by 65 percent for a new CT, 44 percent for a new CC, 87 percent for a new CP, 34 percent for a new nuclear plant, 87 percent for a new DS, 30 percent for a new on shore wind installation, 30 percent for a new off shore wind installation and 23 percent for a new solar installation compared to the first six months of 2018.
- The relative prices of fuel varied during the first six months of 2019. As a result, the marginal cost of the new CC was consistently below that of the new CP in 2018, 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.[119]

Historical New Entrant CT and CC Revenue Adequacy

Total unit net revenues include energy and capacity revenues. Analysis of the total unit revenues of theoretical new entrant CTs and CCs for three representative locations shows that CT and CC units that entered the PJM markets in 2007 have not covered their total costs, including the return on and of capital, on a cumulative basis. The analysis also shows that theoretical new entrant CTs that entered the PJM markets in 2012 have covered their total costs on a cumulative basis in the eastern PSEG and BGE zones but have not covered total costs in the western ComEd Zone. 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 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.

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. CT and CC units that entered the PJM markets in 2007

119 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.

have not covered 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 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

- **EPA Mercury and Air Toxics Standards Rule.** The U.S. Environmental Protection Agency's (EPA) Mercury and Air Toxics Standards rule (MATS) applies the Clean Air Act (CAA) maximum achievable control technology (MACT) requirement to new or modified sources of emissions of mercury and arsenic, acid gas, nickel, selenium and cyanide.[120] 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.[121]
- **National Emission Standards for Reciprocating Internal Combustion Engines.** The national emissions standards uniformly apply to RICE.[122] RICE are allowed to operate during emergencies, including declared Energy Emergency Alert Level 2 or five percent voltage/frequency deviations.[123]
- **Greenhouse Gas Emissions Rule.** On June 19, 2019, the EPA repealed the prior administration's Clean Power Plan[124] and replaced it with the Affordable Clean Energy (ACE) rule, which establishes emission guidelines for states to develop plans to address greenhouse gas emissions from existing coal-fired power plants.[125]
- **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.[126]

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 in the process of resuming participation.[127] Virginia is making preparations to join.[128] The auction price in the June 5, 2019, auction for the 2018/2020 compliance period was \$5.62 per ton. The clearing price is equivalent to a price of \$6.19 per metric tonne, the unit used in other carbon markets. The price increased by \$0.35 per ton, 6.6 percent, from \$5.27 per ton from March 13, 2019, to \$5.62 per ton for June 5, 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).

120 *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).
121 CAA § 110(a)(2)(D)(i)(I).
122 EPA, Memorandum, Peter Tsirigotis Guidance on Vacatur of RICE NESHAP and NSPS Provisions for Emergency Engines (April 15, 2016).
123 See 40 CFR § 63.6640(f).
124 *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.
125 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).
126 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).
127 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>.
128 See Regulation for Emissions Trading, 9 VAC 5-140. The Virginia Air Pollution Control Board is developing the regulation and considering public comments.

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 June 30, 2019, Delaware, Illinois, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, and Washington DC had renewable portfolio standards. Virginia and Indiana had voluntary renewable portfolio standards. Kentucky, 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.[129]

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 June 30, 2019, 93.8 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 94.5 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 3.4 percent of total generation in PJM for the first six months of 2019. Tier I generation was 5.7 percent of total generation in PJM and Tier II generation was 2.3 percent of total generation in PJM for the first six 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. New recommendation. Status: Not adopted.)

129 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.

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.[130] 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, DC to $31.78 per tonne in Pennsylvania. The price of carbon implied by SREC prices ranges from $44.50 per tonne in Pennsylvania to $768.99 per tonne in Washington, DC. The effective prices for carbon compare to the RGGI clearing price in June 2019 of $6.19 per tonne and to the social cost of carbon which is estimated in the range of $50 per tonne.[131] The impact on the cost of generation from a new combined cycle unit of a $700 per tonne carbon price would be $233.89 per MWh. 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.

130 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.").

131 "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>.

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.[132] The RPS compliance cost for the most recent year for which there was complete data 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 $2.2 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 $1.3 billion. The costs of a carbon price are the impact on energy market prices, net of the revenue returned to states/customers.

132 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.

Overview: Section 9, Interchange Transactions

Interchange Transaction Activity

- **Aggregate Imports and Exports in the Real-Time Energy Market.** In the first six months of 2019, PJM was a monthly net exporter of energy in the Real-Time Energy Market in all months.[133] In the first six months of 2019, the real-time net interchange was -15,767.1 GWh. The real-time net interchange in the first six months of 2018 was -4,537.3 GWh.
- **Aggregate Imports and Exports in the Day-Ahead Energy Market.** In the first six months of 2019, PJM was a monthly net exporter of energy in the Day-Ahead Energy Market in February and June, and a net importer of energy in the remaining months. In the first six months of 2019, the total day-ahead net interchange was -218.3 GWh. The day-ahead net interchange in the first six months of 2018 was -516.8.
- **Aggregate Imports and Exports in the Day-Ahead and the Real-Time Energy Market.** In the first six months of 2019, gross imports in the Day-Ahead Energy Market were 128.0 percent of gross imports in the Real-Time Energy Market (187.7 percent in the first six months of 2018). In the first six months of 2019, gross exports in the Day-Ahead Energy Market were 472.6 percent of the gross exports in the Real-Time Energy Market (134.7 percent in the first six months of 2018).
- **Interface Imports and Exports in the Real-Time Energy Market.** In the first six 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 six months of 2019, there were net scheduled exports at 9 of PJM's 17 interface pricing points eligible for real-time transactions in the Real-Time Energy Market.[134]

133 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.
134 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 six 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 six 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 six 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 six months of 2019, net scheduled interchange was -15,767 GWh and net actual interchange was -15,770 GWh, a difference of 3 GWh. In the first six months of 2018, the difference was 35 GWh. This difference is inadvertent interchange.
- **Loop Flows.** In the first six 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 -5,658 GWh of net actual interchange, a difference of 5,643 GWh. In the first six months of 2019, the SouthIMP interface pricing point had the largest loop flows of any interface pricing point with 3,203 GWh of net scheduled interchange and 13,858 GWh of net actual interchange, a difference of 10,654 GWh.

Interactions with Bordering Areas

PJM Interface Pricing with Organized Markets

- **PJM and MISO Interface Prices.** In the first six 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 62.2 percent of the hours.
- **PJM and New York ISO Interface Prices.** In the first six 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 59.8 percent of the hours.
- **Neptune Underwater Transmission Line to Long Island, New York.** In the first six 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 72.9 percent of the hours.
- **Linden Variable Frequency Transformer (VFT) Facility.** In the first six 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 67.9 percent of the hours.
- **Hudson DC Line.** In the first six 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 65.6 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 six months of 2019, compared to four such TLR issued in the first six months of 2018.
- **Up To Congestion.** 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.[135] As a result, market participants reduced up to congestion trading effective February 22, 2018. The average number of up to congestion bids submitted in the Day-Ahead Energy Market decreased by 37.0 percent, from 76,114 bids per day in the first six months of 2018 to 47,989 bids per day in the first six months of 2019. The average cleared volume of up to congestion bids submitted in the Day-Ahead Energy Market increased by 15.4 percent, from 431,553 MWh per day in the first six months of 2018, to 497,987 MWh per day in the first six months of 2019.
- **45 Minute Schedule Duration Rule.** Effective May 19, 2014, PJM removed the 45 minute scheduling duration rule in response to FERC

135 162 FERC ¶ 61,139 (2018).

Order No. 764.[136] [137] 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.[138]

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.)

136 Order No. 764, 139 FERC ¶ 61,246 (2012), *order on reh'g*, Order No. 764-A, 141 FERC ¶ 61231 (2012).
137 *See* Letter Order, Docket No. ER14-381-000 (June 30, 2014).
138 *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 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. New recommendation. Status: Not adopted.)

Section 9 Conclusion

Transactions between PJM and multiple balancing authorities in the Eastern Interconnection are part of a single energy market. While some of these balancing authorities are termed market areas and some are termed 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.[139]

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 six months of 2019, the average

139 See PJM. "Manual 10: Pre-Scheduling Operations," § 3.1.1 Day-ahead Scheduling (Operating Reserve, Rev. 37 (Dec. 10, 2018).

primary reserve requirement was 2,445.7 MW in the RTO Zone and 2,418.3 MW in the MAD Subzone.

Tier 1 Synchronized Reserve

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

Tier 1 synchronized reserve is 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 six months of 2019, there was an average hourly supply of 2,108.7 MW of tier 1 available in the RTO Zone. In the first six months of 2019, there was an average hourly supply of 1,552.9 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.[140] This is the Synchronized Energy Premium Price.

  There were no spinning events 10 minutes or longer in the first six months of 2019.

- **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 $1,094,766 in the first six 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, that have an obligation to respond, that have penalties for failure to respond, and that must be dispatched in order to satisfy the synchronized reserve requirement.

When the synchronized reserve requirement cannot be met with tier 1 synchronized reserve, PJM uses a market to satisfy the balance of the requirement with tier 2 synchronized reserve. The Tier 2 Synchronized Reserve Market includes the PJM RTO Reserve Zone and a subzone, the Mid-Atlantic Dominion Reserve Subzone (MAD).

Market Structure

- **Supply.** In the first six months 2019, the supply of offered and eligible tier 2 synchronized reserve was 29,234.4 MW in the RTO Zone of which 5,427.5 MW was located in the MAD Subzone.
- **Demand.** The average hourly synchronized reserve requirement was 1,694.4 MW in the RTO Reserve Zone and 1,676.5 MW for the Mid-Atlantic Dominion Reserve Subzone. The hourly average cleared tier 2

140 See PJM. "Manual 11: Energy & Ancillary Services Market Operations,"§ 4.2.10 Settlements, Rev. 106 (May 30, 2019).

synchronized reserve was 264.1 MW in the MAD Subzone and 534.0 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 six months 2019.

  The average HHI for tier 2 synchronized reserve in the RTO Zone was 5622 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 six months of 2019 was $2.58 per MW, a decrease of $3.48 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 $2.64 per MW in the first six months of 2019, a decrease of $3.76 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 six months of 2019, the average hourly supply of eligible nonsynchronized reserve was 3,879.1 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.[141] 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 1,770.4 MW of nonsynchronized reserve in the first six months of 2019.
- **Market Concentration.** The MMU calculates that the three pivotal supplier test would have been failed in 59.8 percent of hours in the first six 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

141 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," § $b.2.2 Non-Synchronized Reserve Zones and Levels, Rev. 106 (May 30, 2019). "Because Synchronized Reserve may be utilized to meet the Primary Reserve requirement, there is no explicit requirement for non-synchronized reserves."

$0.13 per MW in the first six months of 2019. The price cleared above $0.00 in 0.8 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.[142] 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 six months of 2019, the average available hourly DASR was 44,532.7 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 six months of 2019 was 5,115.5 MW. This is a reduction from the 5,534.0 hourly MW in 2018.
- **Concentration.** In the first six months of 2019, the DASR Market did not fail the three pivotal supplier test in any hour.

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 six months of 2019, a daily average of 39.6 percent of units offered above $0.00. A daily average of 16.5 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 six months of 2019.

Market Performance

- **Price.** In the first six months of 2019, the weighted average DASR price for all hours when the DASRMCP was above $0.00 was $1.14.

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 function (MBF). Correctly implemented, the MBF would be the marginal rate of technical substitution (MRTS) between RegA and RegD, holding the level of regulation service constant. The current market design is critically flawed as it has not properly implemented the MBF as an MRTS between RegA and RegD resource MW and the MBF has not been consistently applied in the optimization, clearing and settlement of the Regulation Market.

Market Structure

- **Supply.** In the first six months of 2019, the average hourly eligible supply of regulation for nonramp hours was 1,096.2 performance adjusted MW (821.9 effective MW). This was an increase of 7.6 performance adjusted

142 See PJM, "Manual 11: Energy & Ancillary Services Market Operations," § 11.2.7 Day-Ahead Scheduling Reserve Performance, Rev. 106 (May 30, 2019).

MW (a decrease of 28.8 effective MW) from the first six months of 2018, when the average hourly eligible supply of regulation was 1,088.7 performance adjusted MW (850.7 effective MW). In the first six months of 2019, the average hourly eligible supply of regulation for ramp hours was 1,384.8 performance adjusted MW (1,137.1 effective MW). This was an increase of 5.5 performance adjusted MW (a decrease of 30.9 effective MW) from the first six months of 2018, when the average hourly eligible supply of regulation was 1,379.2 performance adjusted MW (1,168.0 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 470.3 hourly average performance adjusted actual MW in the first six months of 2019. This is a decrease of 16.1 performance adjusted actual MW from the first six months of 2018, when the average hourly total regulation cleared performance adjusted actual MW for nonramp hours were 486.4 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 717.0 hourly average performance adjusted actual MW in the first six months of 2019. This is an increase of 29.5 performance adjusted actual MW from the first six months of 2018, where the average hourly regulation cleared MW for ramp hours were 746.6 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 1.93 in the first six months of 2019. This is an increase of 4.5 percent from the first six months of 2018, when the ratio was 1.85. The ratio of the average hourly eligible supply of regulation to average hourly regulation demand (performance adjusted cleared MW) for nonramp hours was 2.33 in the first six months of 2019. This is an increase of 4.0 percent from the first six months of 2018, when the ratio was 2.24.

- **Market Concentration.** In the first six months of 2019, the three pivotal supplier test was failed in 87.5 percent of hours. In the first six months of 2019, the effective MW weighted average HHI of RegA resources was 2475 which is highly concentrated and the weighted average HHI of RegD resources was 1300 which is moderately concentrated.[143] The weighted average HHI of all resources was 1024, 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.[144] In the first six months of 2019, there were 187 resources following the RegA signal and 58 resources following the RegD signal.

Market Performance

- **Price and Cost.** The weighted average clearing price for regulation was $13.85 per MW of regulation in the first six months of 2019. This is a decrease of $19.11 per MW, or 58.0 percent, from the weighted average clearing price of $32.97 per MW in the first six months of 2018. The weighted average cost of regulation in the first six months of 2019 was $18.12 per MW of regulation. This is a decrease of $22.64 per MW, or 55.6 percent, from the weighted average cost of $40.76 per MW in the first six 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

143 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.

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

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 Function.** The marginal benefit factor (MBF) is intended to measure the operational substitutability of RegD resources for RegA resources. The marginal benefit factor function is incorrectly defined and applied in the PJM market clearing. Correctly defined, the MBF function represents the Marginal Rate of Technical Substitution (MRTS) between RegA and RegD. Correctly implemented, the MBF would be consistently applied in the Regulation Market clearing and settlement. The current incorrect and inconsistent implementation of the MBF function has resulted in the PJM Regulation Market over procuring RegD relative to RegA in most hours and in a consistently inefficient market signal to participants regarding the value of RegD to the market in every hour. This over procurement 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.[145] The MMU and PJM filed requests for rehearing.[146]

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).[147]

145 162 FERC ¶ 61,295.
146 FERC Docket No. ER18-87-002.
147 OATT Schedule 1 § 1.3BB.

In the first six months of 2019, total black start charges were $32.21 million, including $32.10 million in revenue requirement charges and $0.114 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 six months of 2019 ranged from $0.04 per MW-day in the DLCO Zone (total charges were $22,609) to $4.07 per MW-day in the PENELEC Zone (total charges were $2,206,364).

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 revenue requirements are based on FERC approved filings that permit recovery based on a cost of service approach.[148] 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 six months of 2019, total reactive charges were $175.00 million, a 2.9 percent increase from $170.04 million in the first six months of 2018. Reactive capability revenue requirement charges increased from $159.32 million in the first six months of 2018 to $174.55 million in the first six months of 2019 and reactive service charges decreased from $10.72 million in the first six months of 2018 to $0.45 million in 2019. Total reactive service charges in the first six months of 2019 ranged from $0 in the RECO and OVEC Zones, which have no generating units, to $24.10 million in the AEP Zone.

148 OATT Schedule 2.

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.[149] PJM filed revisions in compliance with Order No. 842 that substantively incorporated the pro forma agreements into its market rules.[150]

Section 10 Recommendations

- The MMU recommends that the Regulation Market be modified to incorporate a consistent application of the marginal benefit factor (MBF) throughout the optimization, assignment and settlement process. The MBF should be defined as the Marginal Rate of Technical Substitution (MRTS) between RegA and RegD. (Priority: High. First reported 2012. Status: Not adopted. FERC rejected, pending rehearing request before FERC.[151])
- 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.[152] FERC rejected, pending rehearing request before FERC.[153])
- 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.[154])
- 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.[155])
- 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.[156])
- 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.)

149 See 157 FERC ¶ 61,122 (2016).
150 See 164 FERC ¶ 61,224 (2018).
151 FERC Docket No. ER18-87.
152 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.
153 FERC Docket No. ER18-87.
154 *Id.*
155 *Id.*
156 *Id.*

- 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.)

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.[157]

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.[158] 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.[159] The MMU and PJM separately filed requests for rehearing.[160]

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 were no spinning events 10 minutes or longer in the first six months of 2019. 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 $1.1 million in the first six 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.

157 Order No. 755, 137 FERC ¶ 61,064 at PP 197–200 (2011).
158 18 CFR § 385,211 (2017).
159 162 FERC ¶ 61,295 (2018).
160 The MMU filed its request for rehearing on April 27, 2018, and PJM filed its request for rehearing on April 30, 2018.

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 $642.5 million or 71.7 percent, from $896.6 million in the first six months of 2018 to $254.1 million in the first six months of 2019.
- **Day-Ahead Congestion.** Day-ahead congestion costs decreased by $605.0 million or 66.0 percent, from $916.5 million in the first six months of 2018 to $311.5 million in the first six months of 2019.
- **Balancing Congestion.** Negative balancing congestion costs increased by $37.5 million or 188.6 percent, from -$19.9 million in the first six months of 2018 to -$57.4 million in the first six months of 2019. Balancing explicit costs decreased by $40.9 million or 364.9 percent, from $11.2 million in the first six months of 2018 to -$29.7 million in the first six months of 2019.
- **Real-Time Congestion.** Real-time congestion costs decreased by $749.1 million or 71.8 percent, from $1,042.9 million in the first six months of 2018 to $293.8 million in the first six months of 2019.
- **Monthly Congestion.** Monthly total congestion costs in the first six 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 Siegfried Transformer, the AP South Interface, the East Interface, and the CPL - DOM 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 six 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 36.5 percent from 81,854 congestion event hours in the first six months of 2018 to 51,990 congestion event hours in the first six months of 2019. The majority (94.2 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.[161]

  Real-time congestion frequency decreased by 35.6 percent from 12,867 congestion event hours in the first six months of 2018 to 8,287 congestion event hours in the first six 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 six months of 2019. With $40.7 million in total congestion costs, it accounted for 16.0 percent of the total PJM congestion costs in the first six 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 six months of 2019 and -$2.6 million of balancing congestion in the first six months of 2019. None of the closed loop interfaces was binding in the first six months of 2019 or 2018.
- **Zonal Congestion.** AEP had the largest zonal congestion costs among all control zones in the first six months of 2019. AEP had $38.8 million in zonal congestion costs, comprised of $48.0 million in zonal day-ahead congestion costs and -$9.2 million in zonal balancing congestion costs.

161 162 FERC ¶ 61,139.

The Conastone - Peach Bottom Line, the AP South Interface, the East Interface, the Hazard Transformer, and the Conastone - Northwest Line contributed $13.7 million, or 35.2 percent of the AEP zonal congestion costs.

Marginal Loss Cost

- **Total Marginal Loss Costs.** Total marginal loss costs decreased by $198.3 million or 38.0 percent, from $521.4 million in the first six months of 2018 to $323.1 million in the first six months of 2019. The loss MWh in PJM decreased by 230.1 GWh or 3.0 percent, from 7,657.9 GWh in the first six months of 2018 to 7,427.8 GWh in the first six months of 2019. The loss component of real-time LMP in the first six months of 2019 was $0.02, compared to $0.02 in the first six months of 2018.
- **Monthly Total Marginal Loss Costs.** Monthly total marginal loss costs in the first six 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 $184.6 million or 34.5 percent, from $534.4 million in the first six months of 2018 to $349.7 million in the first six months of 2019.
- **Balancing Marginal Loss Costs.** Negative balancing marginal loss costs increased by $13.7 million or 105.9 percent, from -$12.9 million in the first six months of 2018 to -$26.6 million in the first six months of 2019.
- **Total Marginal Loss Surplus.** The total marginal loss surplus decreased in the first six months of 2019 by $71.4 million or 40.7 percent, from $175.6 million in the first six months of 2018, to $104.2 million in the first six months of 2019.

Energy Cost

- **Total Energy Costs.** Total energy costs increased by $126.2 million or 36.6 percent, from -$345.2 million in the first six months of 2018 to -$218.9 million in the first six months of 2019.
- **Day-Ahead Energy Costs.** Day-ahead energy costs increased by $112.4 million or 29.6 percent, from -$380.4 million in the first six months of 2018 to -$268.0 million in the first six months of 2019.
- **Balancing Energy Costs.** Balancing energy costs increased by $17.4 million or 57.2 percent, from $30.3 million in the first six months of 2018 to $47.7 million in the first six months of 2019.
- **Monthly Total Energy Costs.** Monthly total energy costs in the first six months of 2019 ranged from -$59.3 million in January to -$25.7 million in April.

Section 11 Conclusion

Congestion is defined to be the total congestion payments by load in excess of the total congestion credits received by generation. The level and distribution of congestion reflects the underlying characteristics of the power system, including the nature and capability of transmission facilities, the offers and geographic distribution of generation facilities, the level and geographic distribution of incremental bids and offers and the geographic and temporal distribution of load.

Total congestion in the first six months of 2019 decreased significantly from the first six 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.[162] 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, following the FERC decision to allocate some of the surplus to load, the offset was 92.1 percent.

Overview: Section 12, Planning

Generation Interconnection Planning

Existing Generation Mix

- As of June 30, 2019, PJM had a total installed capacity of 198,599.2 MW, of which 55,952.4 MW (28.2 percent) are coal fired steam units, 47,591.6 MW (24.0 percent) are combined cycle units and 34,257.6 MW (17.2 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 198,599.2 MW of PJM total installed capacity, 31,643.0 MW (15.9 percent) are in the AEP Zone, of which 14,727.8 MW (46.5 percent) are coal fired steam units, 6,990.0 MW (22.1 percent) are combined cycle units and 2,071.0 MW (6.5 percent) are nuclear units.
- Pennsylvania has the most total installed capacity of any PJM state. Of the 198,599.2 MW of installed capacity, 46,077.5 MW (23.2 percent) are in Pennsylvania, of which 9,415.7 MW (20.4 percent) are coal fired steam units, 15,021.5 MW (32.6 percent) are combined cycle units and 9,648.8 MW (20.9 percent) are nuclear units.
- Of the 198,599.2 MW of installed capacity, 74,483.0 MW (37.5 percent) are from units older than 40 years, of which 39,667.2 MW (53.3 percent) are coal fired steam units, 532 MW (0.7 percent) are combined cycle units and 16,044.9 MW (21.5 percent) are nuclear units.

Generation Retirements[163]

- There are 46,448.9 MW of generation that have been, or are planned to be, retired between 2011 and 2022, of which 32,486.2 MW (69.9 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 six months of 2019, 3,225.8 MW of generation retired. The largest generators that retired in the first six 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 3,225.8 MW of generation that retired, 1,660.0 MW (51.5 percent) were located in the ATSI Zone.
- As of June 30 2019, there are 11,852.0 MW of generation that have requested retirement after June 30, 2019, of which 5,131.0 MW (43.3 percent) are located in the ATSI Zone. Of the ATSI generation requesting retirement, 2,960.0 MW (57.7 percent) are coal fired steam units and 2,134.0 MW (41.6 percent) are nuclear units.

Generation Queue[164]

- 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 six months of 2019, the AE2 queue window closed, and the AF1 queue window opened. Combined, these queue windows added 32,555.1 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 June 30, 2019, there were

162 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.

163 See PJM. Planning. "Generator Deactivations," at <http://www.pjm.com/planning/services-requests/gen-deactivations.aspx>.

164 See PJM. Planning. "New Services Queue," at <https://www.pjm.com/planning/services-requests/interconnection-queues.aspx>.

125,757.4 total MW in generation queues, in the status of active, under construction or suspended, an increase of 10,803.7 MW (9.4 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 June 30, 2019, there were 45,732.1 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).[165] As of June 30, 2019, there were only 133.0 MW of coal fired steam capacity active, suspended or under construction in PJM queues.
- As of June 30, 2019, 4,500 projects, representing 560,874.6 MW, have entered the queue process since its inception in 1998. Of those, 854 projects, representing 66,918.4 MW, went into service. Of the projects that entered the queue process, 2,530 projects, representing 368,198.8 MW (65.6 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 June 30, 2019, 125,757.4 MW of capacity were in generation request queues in the status of active, under construction or suspended. Of the total 125,757.4 MW in the queue, 56,685.8 MW (45.1 percent) have reached at least the system impact study (SIS) milestone and 69,071.6 MW (54.9 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), 33,654.7 MW of new generation in the queue are expected to go into service.

165 The unit type RICE refers to Reciprocating Internal Combustion Engines.

Regional Transmission Expansion Plan (RTEP)

Backbone Facilities

- There are currently six backbone projects under development, the Surry-Skiffes Creek 500kV Line, the Loudoun-Brambleton 500kV Line, the conversion of the Marion-Bayonne and Bayway-Linden lines from 138 kV to 345 kV, the conversion of the Robinson Park-Sorenson lines to double circuit 345kV and the Meadow Lake-Reynolds 345kV Line rebuild.[166]

Market Efficiency Process

- PJM's first market efficiency analysis was performed in 2013, prior to Order 1000. This analysis evaluated the reasons for congestion on 25 flowgates.[167] The proposal window was open from August 12, 2013, through September 26, 2013. PJM received 38 proposals from six entities. One project was approved by the PJM Board.
- Through June 30, 2019, PJM has completed two market efficiency cycles under Order No. 1000. In the first cycle, PJM received 93 proposals for 57 identified sources of congestion. In the second cycle, PJM received 96 proposals for four identified sources of congestion. The proposal window for 2018/2019 opened on November 1, 2018, and closed on February 28, 2019. PJM received 22 proposals for one identified source of congestion.
- 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, using PJM's flawed approach.
- 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.

166 See PJM. "*2017 RTEP Process Scope and Input Assumptions White Paper,*" at 25. <https://www.pjm.com/-/media/library/reports-notices/2017-rtep/20170731-rtep-input-assumptions-and-scope-whitepaper.ashx?la=en>.
167 Historical congestion drivers are identified using the historical congestion tables presented in the *2018 State of the Market Report for PJM*, Section 11: Congestion and Marginal Losses, historical analysis of real-time constraints, the NERC Book of Flowgates and PROMOD simulations.

PJM MISO Interregional Targeted Market Efficiency Process (TMEP)

- The first Targeted Market Efficiency Process (TMEP) analysis occurred in 2017 and included the investigation of congestion on 50 market to market flowgates. The study resulted in the evaluation of 13 potential upgrades, resulting in the recommendation of five TMEP projects. The five projects address $59.0 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.[168]
- The 2018 TMEP analysis included the investigation of congestion on 61 market to market flowgates. The study resulted in the evaluation of 19 potential upgrades, resulting in the recommendation of 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.[169]

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."[170] Supplemental projects are exempt from the competitive planning process.
- The average number of supplemental projects in each expected in service year increased by 615.0 percent, from 20 for years 1998 through 2007 (pre Order No. 890) to 143 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. End of life transmission projects fall under the Transmission Owner Form 715 Planning Criteria, and are currently exempt from the competitive planning process.[171] End of life transmission projects are already included in the supplemental projects totals or, if included in the transmission owners' reliability plan, will be included in the baseline project list as a reliability criteria project.
- 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.[172] On February 12, 2019, the PJM Board of Managers authorized an additional $272.0 million in transmission upgrades and additions. As of June 30, 2019, the PJM Board has approved $38.5 billion in system enhancements since 1999.

168 See PJM. "MISO PJM IPSAC," (January 12, 2018) <http://www.pjm.com/-/media/committees-groups/stakeholder-meetings/ipsac/20180112/20180112-ipsac-presentation.ashx>.
169 See PJM. "MISO PJM IPSAC," (January 18, 2019) <https://www.pjm.com/-/media/committees-groups/stakeholder-meetings/ipsac/20190118/20190118-ipsac-presentation.ashx>.
170 See PJM. "Transmission Construction Status," (Accessed on June 30, 2019) <http://www.pjm.com/planning/rtep-upgrades-status/construct-status.aspx>.
171 See PJM. Operating Agreement Schedule 6 § 1.5.8(o).
172 Supplemental Projects, including the end of life subset of supplemental projects, do not require PJM Board of Managers authorization.

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 cost effective 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 binding cost containment proposals versus proposals 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 into an LDA and can be offered into capacity auctions as capacity.
- QTU projects are submitted and tracked through the PJM queue.[173] A total of 51 QTU projects have entered the queue since 2007. Of the 51 submitted QTU projects, 38 projects (74.5 percent) have been withdrawn, six (11.8 percent) are in service and seven (13.7 percent) are currently in active development.

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.[174]
- There were 22,091 transmission outage requests submitted in the 2018/2019 planning period. Of the requested outages, 77.0 percent of the requested outages were planned for less than or equal to five days and 7.7 percent of requested outages were planned for greater than 30 days. Of the requested outages, 47.3 percent were late according to the rules in PJM's Manual 3.

Section 12 Recommendations

The MMU recommends improvements to the planning process:

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.[175] (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

173 See PJM. Planning. "New Services Queue," at <https://www.pjm.com/planning/services-requests/interconnection-queues.aspx>.
174 See PJM. "PJM Manual 03: Transmission Operations," Rev. 55 (May 31, 2019).
175 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>.

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 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. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that 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.[176] (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.)

176 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.

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.

The inclusion of market efficiency transmission projects in the transmission planning process, in addition to reliability projects, effectively results in direct competition between generation and transmission to address congestion issues in the wholesale power market, including congestion in the energy and capacity markets but with a bias towards the transmission option. The role of the market efficiency process and its impact on competition should be more thoroughly evaluated. But PJM fails to explicitly address this fact in the design of the market efficiency process. While the market efficiency process and metrics require modification, for example to ensure that all congestion is measured, the role of the market efficiency process and its impact on competition should also be more thoroughly evaluated. Building transmission under cost of service regulation already provides a significant competitive advantage to transmission over generation which is built entirely based on market prices and for which investors take the risks. The risks of cost increases for transmission projects should also be incorporated in the cost benefit analysis.

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.

The current rules governing the benefit/cost analysis evaluate competing projects with different in service dates on an asymmetric basis. Under the current rules, projects are evaluated on a present value, benefit/cost basis over a 15 year service horizon, starting with the in service date of the project. A better approach would be to establish a common end date for all evaluated competing projects so that the minimum included years for any evaluated project is 15 years. This means that if there were an RTEP year zero project and a RTEP year +2 project competing, the benefit/cost ratio analysis would include the benefits and costs for both projects for every year from RTEP year zero to RTEP+16. Under this approach all projects would be evaluated over an identical term rather than an artificially truncated term and all projects would be evaluated on a present value basis at year zero.[177]

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 2018/2019 planning period, PJM allocated a total of 27,335.6 MW of residual ARRs, down from 39,597.4 MW in the 2017/2018 planning period, with a total target allocation of $11.8 million for the 2018/2019 planning period, down from $17.5 million for the 2017/2018 planning period.

- **ARR Reassignment for Retail Load Switching.** There were 35,571 MW of ARRs associated with $423,100 of revenue that were reassigned in the 2018/2019 planning period. There were 44,823 MW of ARRs associated with $339,500 of revenue that were reassigned for the 2017/2018 planning period.

Market Performance

- **Revenue Adequacy.** For the 2018/2019 planning period, the ARR target allocations, which are based on the nodal price differences from the Annual FTR Auction, were $726.8 million, while PJM collected $907.6 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 2017/2018 planning period, the ARR target allocations were $573.8 million while PJM collected $601.2 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, ARRs, self scheduled FTRs and surplus congestion revenue offset 92.1 percent of total congestion costs. The goal of the FTR market design should be to ensure that load has the rights to 100 percent of the congestion revenues.

177 See "Comments of the Independent Market Monitor for PJM," (January 11, 2019) <http://www.monitoringanalytics.com/Filings/2019/IMM_Comments_Docket_No_ER19-80_20190111.pdf>.

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 2019/2022 Long Term FTR Auction, total participant FTR sell offers were 318,022 MW. In the 2019/2020 Annual FTR Auction, total participant FTR sell offers were 375,582 MW. In the Monthly Balance of Planning Period FTR Auctions for the 2018/2019 planning period, total participant FTR sell offers were 8,483,263 MW, up from 4,401,873 MW for the same period during the 2017/2018 planning period.
- **Demand.** In the 2019/2022 Long Term FTR auction, total FTR buy bids were 1,949,546 MW, down 5.0 percent from 2,052,820 MW the previous long term auction. There were 2,816,861 MW of buy and self scheduled bids in the 2019/2020 Annual FTR Auction, down 3.1 percent from 2,907,583 MW the previous planning period. The total FTR buy bids from the Monthly Balance of Planning Period FTR Auctions for the 2018/2019 planning period increased 3.6 percent from 19,138,752 MW for the same time period of the prior planning period, to 19,827,194 MW.
- **Patterns of Ownership.** For the 2019/2022 Long Term FTR Auction, financial entities purchased 68.1 percent of prevailing flow FTRs and 70.4 percent of counter flow FTRs. For the 2019/2020 Annual FTR Auction, financial participants purchased 64.8 percent of all prevailing flow FTRs and 79.5 percent of all counter flow FTRs. For the Monthly Balance of Planning Period Auctions, financial entities purchased 72.3 percent of prevailing flow and 81.5 percent of counter flow FTRs for January through June of 2019. Financial entities owned 71.2 percent of all prevailing and counter flow FTRs, including 63.9 percent of all prevailing flow FTRs and 81.7 percent of all counter flow FTRs during the period from January through June 2019.

Market Behavior

- **FTR Forfeitures.** For the period January 19, 2017, through June 30, 2019, total FTR forfeitures were $14.5 million.
- **Credit.** There were no collateral defaults in the first six 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 $39.1 million in the first six months of 2019, for a total of $116.1 million in defaults for the company, including the auction liquidation costs.

Market Performance

- **Volume.** The 2019/2022 Long Term FTR Auction cleared 408,237 MW (20.9 percent) of FTR buy bids, up 18.2 percent from 345,506 MW (16.8 percent) in the 2018/2021 Long Term FTR Auction. The Long Term FTR Auction also cleared 35,412 MW (11.1 percent) of FTR sell offers, compared to 42,555 (17.8 percent), a 16.9 percent decrease.

  In the Annual FTR Auction for the 2019/2020 planning period 641,023 MW (22.8 percent) of buy and self schedule bids cleared, up 4.2 percent from 615,254 MW (21.2 percent) for the previous planning period. In the 2018/2019 planning period Monthly Balance of Planning Period FTR Auctions cleared 3,157,852 MW (15.9 percent) of FTR buy bids and 1,703,548 MW (20.1 percent) of FTR sell offers.
- **Price.** The weighted average buy bid FTR price in the 2019/2020 Long Term FTR Auction was $0.10 per MW, up from $0.03 per MW for the 2018/2021 planning period. The weighted average buy bid FTR price in the Annual FTR Auction for the 2019/2020 planning period was $0.66 per MW, up from $0.59 per MW in the 2018/2019 planning period. The weighted average buy bid cleared FTR price in the Monthly Balance of Planning Period FTR Auctions for the 2018/2019 planning period was $0.20, up from $0.13 per MW for the same period in the 2017/2018 planning period.
- **Revenue.** The 2019/2022 Long Term FTR Auction generated $161.7 million of net revenue for all FTRs, up from $29.6 million for the 2018/2021 Long Term FTR Auction. The 2018/2019 Annual FTR Auction generated $822.6 million in net revenue, up from $542.2 million for the 2017/2018 Annual FTR Auction. The Monthly Balance of Planning Period FTR Auctions generated $59.7 million in net revenue for all FTRs of the 2018/2019

planning period, up from $40.3 million for the same time period in the 2017/2018 planning period.

- **Revenue Adequacy.** FTRs were paid at 100 percent of the target allocation level for the 2018/2019 planning period. 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 2018/2019 planning period, physical entities made -$52.3 million in profits on FTRs purchased directly (not self scheduled), while receiving $129.9 million in returned congestion from self scheduled FTRs, and financial entities made $116.5 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.[178] (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

178 See "PJM Manual 6: Financial Transmission Rights," Rev. 22 (June 27, 2019).

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 should 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 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, 100.0, 50.0 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 planning years. With surplus through May 2019 distributed, total ARR and self scheduled FTR revenue offset 92.1 percent of total congestion costs for the 2018/2019 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.[179] The FERC order of September 15, 2016, introduced a subsidy to FTR holders at the expense of ARR holders.[180] 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.

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

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 2017/2018 planning period would have been $1,315.1 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.[181]

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 2017/2018 planning period, ARRs and FTRs would have offset 74.3 percent of total congestion rather than 50.0 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.

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.

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.

181 163 FERC ¶61,165 (2018).

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 June*, the MMU includes three 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 June.*

New Recommendation from Section 6, Demand Response

- 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. New recommendation. Status: Not adopted.)

New Recommendation from Section 8, Environmental and Renewable Energy Regulations

- The MMU recommends that load and generation located at separate nodes be treated as separate resources. (Priority: High. New recommendation. Status: Not adopted.)

New Recommendation from Section 9, Interchange Transactions

- 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. 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 Day-Ahead Energy Market be competitive, where competitive is defined to be the short run marginal cost of the units. The short run marginal cost should reflect opportunity cost when and where appropriate. The MMU recommends that the level of incremental costs includable in cost-based offers not exceed the short run marginal cost of the unit. (Priority: Medium. First reported 2009. Status: Not adopted.)
- The MMU recommends that PJM require 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 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.[8] (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

8 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).

determine capacity performance assessment or uplift payments. (Priority: Medium. First reported 2015. Status: Partially 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 document how LMPs are calculated when demand response is marginal. (Priority: Low. First reported 2014. Status: Not 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.[9] [10] (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.)

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

10 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 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.)

Transparency

- The MMU recommends that PJM market rules require the fuel type be identified for every price and cost schedule 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.)

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.[11])
- 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.)
- 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

11 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.

in the PJM region. (Priority: High. First reported 2013. Status: Partially adopted.[12])

- 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.[13]

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.[14 15] (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.[16 17] 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.)

12 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.
13 151 FERC ¶ 61,208 (2015).
14 See also Comments of the Independent Market Monitor for PJM, Docket No. ER14-503-000 (December 20, 2013).
15 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).
16 See PJM Interconnection, L.L.C., Docket No. ER12-513-000 (December 1, 2011) ("Triennial Review").
17 See the *2017 State of the Market Report for PJM*, Volume 2, Section 7: Net Revenue.

- 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.[18] (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.[19] (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.)

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

19 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 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 June 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.[20] (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.[21] (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.)

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

21 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 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.[22])
- 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.)

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

- 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. New recommendation. 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. New recommendation. 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. New recommendation. Status: Not adopted.)

Section 10, Ancillary Services

- The MMU recommends that the Regulation Market be modified to incorporate a consistent application of the marginal benefit factor (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.[23])
- 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.[24] FERC rejected, pending rehearing request before FERC.[25])
- 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.[26])
- 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.[27])
- 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.[28])
- 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

23 FERC Docket No. ER18-87.

24 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.

25 FERC Docket No. ER18-87.

26 *Id.*

27 *Id.*

28 *Id.*

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.)

Section 11, Congestion and Marginal Losses

There are no recommendations in this section.

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.[29] (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 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. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that 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.)

29 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>.

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.[30] (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.)

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

- 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.)

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.[31] (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

31 See "PJM Manual 6: Financial Transmission Rights," Rev. 22 (June 27, 2019).

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 should 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 six 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 six months of 2019 was unconcentrated by FERC HHI standards in 97.5 percent of market hours and moderately concentrated in 2.5 percent of market hours. Average HHI was 792 with a minimum of 599 and a maximum of 1098 in the first six months of 2019. The PJM energy market peaking segment of supply was 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 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.

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."

- Market design was evaluated as effective because the analysis shows that the PJM energy market resulted in competitive market outcomes. In general, PJM's energy market design provides incentives for competitive behavior and results in competitive outcomes. In local markets, where market power is an issue, the market design identifies market power and causes the market to provide competitive market outcomes in most cases although issues with the implementation of market power mitigation and development of cost-based offers remain. The role of UTCs in the Day-Ahead Energy Market continues to cause concerns.

PJM markets are designed to promote competitive outcomes derived from the interaction of supply and demand in each of the PJM markets. Market design itself is the primary means of achieving and promoting competitive outcomes in PJM markets. One of the MMU's primary goals is to identify actual or potential market design flaws.[2] The approach to market power mitigation in PJM has focused on market designs that promote competition (a structural basis for competitive outcomes) and on limiting market power mitigation to instances where the market structure is not competitive and thus where market design alone cannot mitigate market power. In the PJM energy market, this occurs primarily in the case of local market power. When a transmission constraint creates the potential for local market power, PJM applies a structural test to determine if the local market is competitive, applies a behavioral test to determine if generator offers exceed competitive levels and applies a market performance test to determine if such generator offers would affect the market price.[3] There are, however, identified issues with the application of market power mitigation to resources whose owners fail the TPS test that can result in the exercise of local market power even when market power mitigation rules are applied. These issues need to be addressed. There are issues related to the definition of gas costs includable in energy offers that need to be addressed. There are issues related to the level of variable operating and maintenance expense includable in energy offers that need to be addressed. There are currently no market power mitigation rules in place that limit the ability to exercise market power when aggregate market conditions are tight and there are pivotal suppliers in the aggregate market. Aggregate market power needs to be addressed. Now that generators are allowed to modify offers hourly, market design must reflect appropriate incentives for competitive behavior, the application of local market power mitigation needs to be fixed, the definition of a competitive offer needs to be fixed, and aggregate market power mitigation rules need to be developed. The importance of these issues is amplified by the new rules permitting cost-based offers in excess of $1,000 per MWh.

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 123,039 MWh for spring of 2018 and 128,183 MWh for spring of 2019. In the first six months of 2019, 587.7 MW of new resources were added and 3265.8 MW were retired.

  PJM average real-time cleared generation in the first six months of 2019 decreased 18 MWh from the first six months of 2018, from 91,631 MWh to 91,613 MWh.

  PJM average day-ahead cleared supply in the first six months of 2019, including INCs and up to congestion transactions, increased by 2.2 percent from the first six months of 2018, from 113,028 MWh to 115,511 MWh.

- **Demand.** Demand includes physical load and exports and virtual transactions. The PJM accounting peak load in the first six months of 2019 was 134,060 MWh in the HE 0800 on January 31, 2019 which was 11,307 MWh, 7.8 percent, lower than the PJM peak load for the first six months of 2018, which was 145,367 MWh in the HE 1700 on June 18, 2018.

  PJM average real-time demand in the first six months of 2019 decreased by 2.9 percent from the first six months of 2018, from 88,847 MWh to 86,297 MWh. PJM average day-ahead demand in the first six months of

2019, including DECs and up to congestion transactions, increased by 1.8 percent from the first six months of 2018, from 108,950 MWh to 110,890 MWh.

Market Behavior

- **Supply and Demand: Load and Spot Market.** Companies that serve load in PJM do so using a combination of self-supply, bilateral market purchases and spot market purchases. For the first six months of 2019, 14.8 percent of real-time load was supplied by bilateral contracts, 28.0 percent by spot market purchases and 58.3 percent by self-supply. Compared to the first six months of 2018, reliance on bilateral contracts increased by 2.3 percentage points, reliance on spot market purchases decreased by 1.9 percentage points and reliance on self-supply decreased by 0.3 percentage points.
- **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 six months of 2019, 26.4 percent were offered as available for economic dispatch, 30.5 percent were offered at their economic minimum, 4.3 percent were offered as emergency dispatch, 14.9 percent were offered as self scheduled, and 23.9 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 six months of 2019, the average hourly increment offers submitted and cleared MW increased by 6.5 percent and 8.0 percent, from 5,851 MW and 2,757 MW in the first six months of 2018 to 6,234 MW and 2,976 MW in the first six months of 2019. The hourly average submitted decrement MW decreased by 2.6 percent and cleared decrement MW increased by 36.4 percent, from 6,936 MW and 2,736 MW in the first six months of 2018 to 6,755 MW and 3,732 MW in the first six months of 2019. The average hourly up to congestion submitted decreased by 0.8 percent and cleared MW increased by 15.4 percent, from 64,236 MW and 17,983 MW in the first six months of 2018 to 63,738 MW and 20,748 MW in the first six months of 2019.

Market Performance

- **Generation Fuel Mix.** In the first six months of 2019, coal units provided 24.8 percent, nuclear units 34.4 percent and natural gas units 33.5 percent of total generation. Compared to the first six months of 2018, generation from coal units decreased 16.7 percent, generations from natural gas units increased 18.4 percent and generation from nuclear units decreased 2.8 percent.
- **Fuel Diversity.** In the first six months of 2019, the fuel diversity of energy generation, measured by the fuel diversity index for energy (FDI_e), decreased 0.3 percent over the FDI_e for the first six months of 2018.
- **Marginal Resources.** In the PJM Real-Time Energy Market, in the first six months of 2019, coal units were 27.3 percent and natural gas units were 69.6 percent of marginal resources. In the first six months of 2018, coal units were 29.6 percent and natural gas units were 60.9 percent of marginal resources. Among the natural gas units that were marginal in the first six months of 2019, nearly 93 percent were combined cycle units.

  In the PJM Day-Ahead Energy Market, in the first six months of 2019, up to congestion transactions were 57.8 percent, INCs were 13.3 percent, DECs were 18.2 percent, and generation resources were 10.5 percent of marginal resources. In the first six months of 2018, up to congestion transactions were 66.9 percent, INCs were 8.4 percent, DECs were 14.7 percent, and generation resources were 9.9 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 six months of 2019 compared to the first six months of 2018. The load-weighted, average real-time LMP was 35.2 percent lower in the first six months of 2019 than in the first six months of 2018, $27.49 per MWh versus $42.44 per MWh.

PJM day-ahead energy market prices decreased in the first six months of 2019 compared to the first six months of 2018. The load-weighted, average day-ahead LMP was 31.7 percent lower in the first six months of 2019 than in the first six months of 2018, $27.97 per MWh versus $40.96 per MWh.

- **Components of LMP.** In the PJM Real-Time Energy Market, in the first six months of 2019, 26.6 percent of the load-weighted LMP was the result of coal costs, 45.3 percent was the result of gas costs and 0.80 percent was the result of the cost of emission allowances.

  In the PJM Day-Ahead Energy Market, in the first six months of 2019, 23.4 percent of the load-weighted LMP was the result of coal costs, 20.8 percent was the result of gas costs, 20.5 percent was the result of INC offers, 20.4 percent was the result of DEC bids, and 2.1 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 $0.93 per MWh in the first six months of 2018 and -$0.45 per MWh in the first six 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 twenty intervals with five minute shortage pricing on eleven days in the first six months of 2019. In all twenty intervals, shortage pricing was triggered due to synchronized reserves being short of the extended synchronized reserve requirement in the RTO and MAD reserve zones. This included two intervals when synchronized reserves were short of the synchronized reserve requirement. There were no intervals with primary reserve shortage in the first six months of 2019.
- There were 1,482 five minute intervals, or 2.8 percent of all five minute intervals in the first six months of 2019 for which at least one solved SCED case showed a shortage of reserves, and 692 five minute intervals, or 1.3 percent of all five minute intervals in the first six months of 2019 for which more than one solved SCED case showed a shortage of reserves. PJM operators used only twenty RT SCED cases that showed a shortage of reserves in LPC to calculate real-time LMPs and ancillary service prices.
- In the first six 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 six months of 2018 to 0.5 percent in the first six months of 2019. In the Real-Time Energy Market, for units committed to provide energy for local constraint relief, offer-capped unit hours decreased from 1.3 percent in the first six months of 2018 to 0.8 percent in the first six 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 six months of 2019, 10 control zones experienced congestion resulting from one or more constraints binding for 50 or more hours. The analysis of the application of the TPS test to local markets demonstrates that it is working successfully to 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 six months of 2018 to 0.0 percent in the first six months of 2019. In the Real-Time Energy Market, for units committed for reliability reasons, offer-capped unit hours decreased from 0.2 percent in the first six months of 2018 to 0.0 percent in the first six months of 2019.

- **Markup Index.** The markup index is a summary measure of participant offer behavior for individual marginal units. In the first six months of 2019, in the PJM Real-Time Energy Market, 97.4 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 ($0.53 per MWh) when using unadjusted cost-based offers. The average dollar markup of units with offer prices between $25 and $50 was positive ($2.10 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 six months of 2019 was more than $300 per MWh while the highest markup in the first six 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 six months of 2019, in the PJM Day-Ahead Energy Market, 98.5 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 ($0.71 per MWh) when using unadjusted cost-based offers. The average dollar markup of units with offer prices between $25 and $50 was positive ($1.57 per MWh) when using unadjusted cost-based offers. Using the unadjusted cost-based offers, the highest markup for any marginal unit in the first six months of 2019 was about $90 per MWh, while the highest markup in the first six 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 three 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 since December 2014.

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 six months of 2019, the unadjusted markup component of LMP was $1.90 per MWh or 6.9 percent of the PJM load-weighted, average LMP. February had the highest unadjusted peak markup component, $3.05 per MWh, or 10.3 percent of the real-time, off peak hour load-weighted, average LMP. There were 27 hours in the first six months of 2019 where the positive markup contribution to the PJM system wide, load-weighted, average LMP exceeded $32.14 per MWh.

  In the PJM Day-Ahead Energy Market, INCs, DECs and UTCs have zero markups. In the first six months of 2019, the unadjusted markup component of LMP resulting from generation resources was $0.48 per MWh or 1.7 percent of the PJM day-ahead load-weighted average LMP. January had the highest unadjusted peak markup component, $1.68 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 Day-Ahead Energy Market be competitive, where competitive is defined to be the short run marginal cost of the units. The short run marginal cost should reflect opportunity cost when and where appropriate. The MMU recommends that the level of incremental costs includable in cost-based offers not exceed the short run marginal cost of the unit. (Priority: Medium. First reported 2009. Status: Not adopted.)
- The MMU recommends that PJM require 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 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.)

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).

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 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 document how LMPs are calculated when demand response is marginal. (Priority: Low. First reported 2014. Status: Not 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.)
- 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 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.)

Transparency

- The MMU recommends that PJM market rules require the fuel type be identified for every price and cost schedule 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.)

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 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.)

Conclusion

The MMU analyzed key elements of PJM energy market structure, participant conduct and market performance in the first six 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, loads and prices.

PJM average real-time cleared generation decreased by 18 MWh, and peak load decreased by 11,307 MWh, 7.8 percent, in the first six months of 2019 compared to the first six 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, as interpreted by PJM, is not currently correct. Some unit owners include costs that are not short run marginal costs in offers, including maintenance costs. This issue can be resolved by simple rule changes to incorporate a clear and accurate definition of short run marginal costs.

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

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

Prices in PJM are not too low. There is no evidence to support the need for a significant change to the calculation of LMP. The underlying problem that fast start pricing and PJM's 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. 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 does indicate a shortage of reserves, it should be used in calculating real-time prices. 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 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.

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 six months of 2019 or prior years. 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 six months of 2019.

Supply and Demand

Market Structure

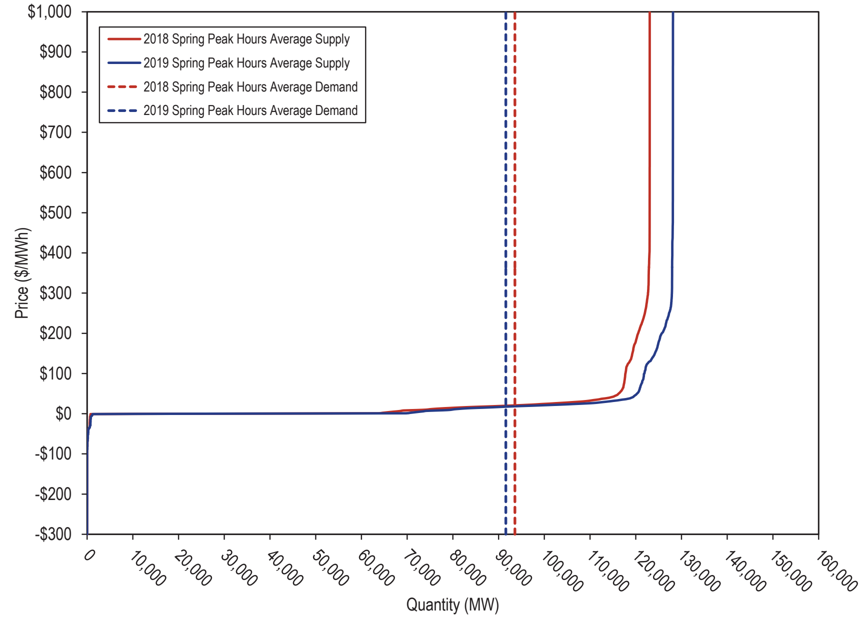
Supply

Supply includes physical generation, imports and virtual transactions.

In the first six months of 2019, 587.7 MW of new resources were added and 3,265.8 MW were retired.

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

Figure 3-1 Average hourly spring 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 spring supply curve period is from March 1, to May 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 spring real-time supply curves

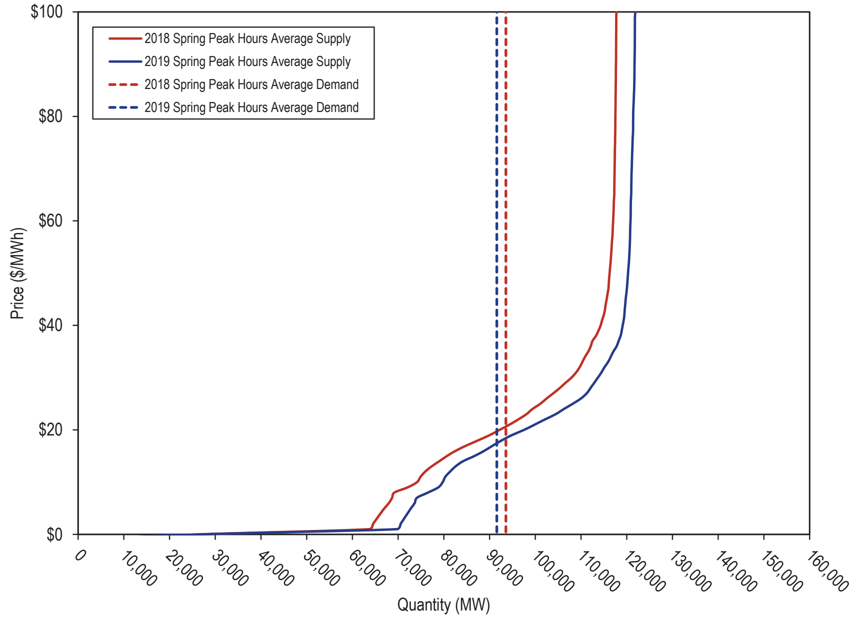


Table 3-2 shows the price elasticity of supply for the on peak hours of spring of 2018 and 2019. The price elasticity of supply is the measure of the responsiveness of the quantity supplied of supply (MWh) to a change in price.

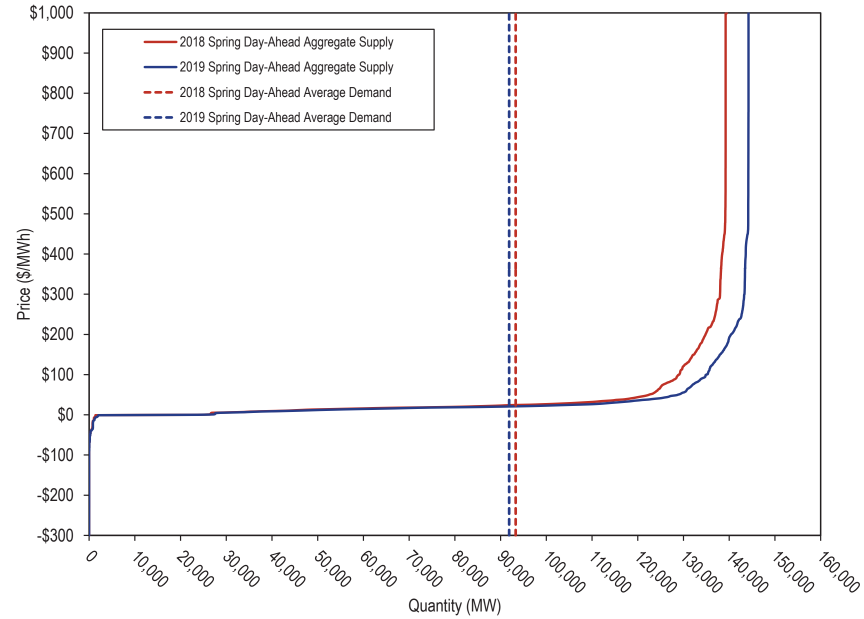
Elasticity of Supply = Percent change in quantity / Percent change in price.

Table 3-2 Price Elasticity of Supply

	Elasticity of Supply					
Price Range	$ 01-20	$ 20-40	$ 40-60	$ 60-80	$ 80-100	> $100
Mar 2018 - May 2018	0.025	0.247	0.049	0.013	0.008	0.017
Mar 2019 - May 2019	0.021	0.224	0.029	0.015	0.016	0.018

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

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



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 hour offered real-time supply was 123,039 MWh for the spring of 2018, and 128,183 MWh for the spring of 2019. Real-time supply at a defined time is restricted by unit ramp limits and start times. Therefore, the available supply in real-time is less than the total capacity of the PJM system.

PJM average real-time cleared generation in the first six months of 2019 decreased by 18 MWh from the first six months of 2018, from 91,631 MWh to 91,613 MWh.[12]

PJM average, real-time cleared supply, including imports in the first six months of 2019 decreased by 1.2 percent from the first six months of 2018, from 94,091 MWh to 92,947 MWh.

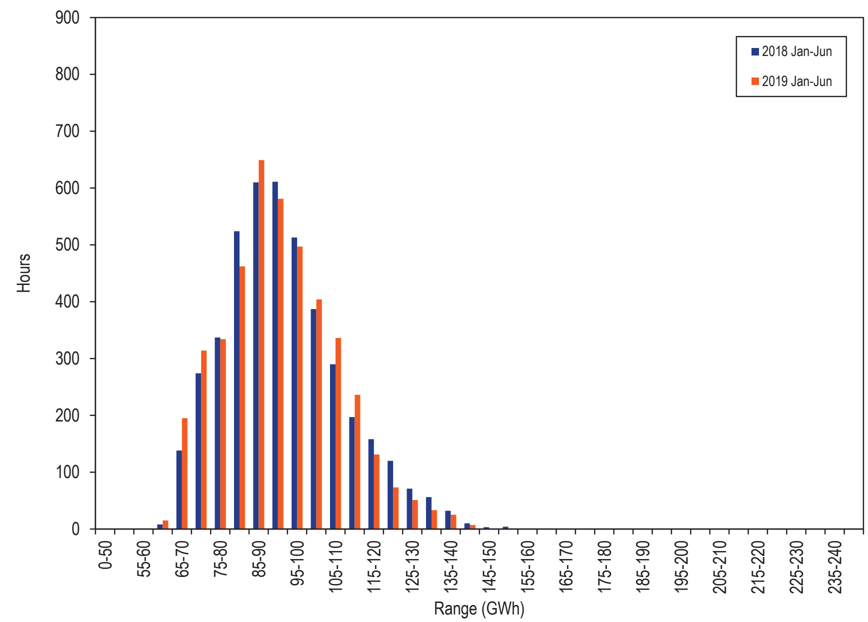
In the PJM Real-Time Energy Market, there are three types of supply offers:

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

PJM Real-Time Supply Frequency

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

Figure 3-4 Distribution of real-time generation plus imports: January through June, 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 summary average real-time hourly supply statistics for each year for the first six months of the 19 year period from 2001 through 2019.

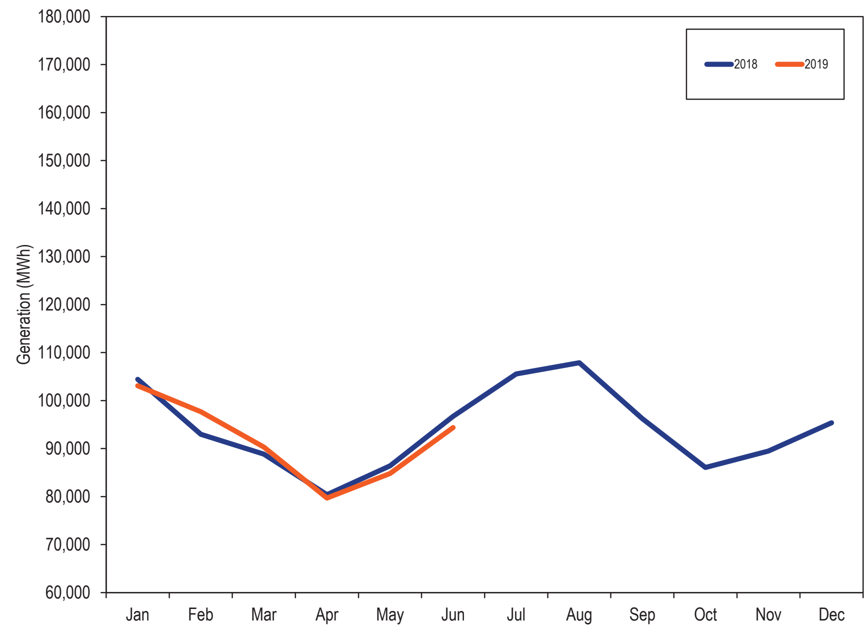
Table 3-3 Average hourly real-time generation and real-time generation plus imports: January through June, 2001 through 2019

	PJM Real-Time Supply (MWh)				Year-to-Year Change			
	Generation		Generation Plus Imports		Generation		Generation Plus Imports	
Jan-Jun	Generation	Standard Deviation	Supply	Standard Deviation	Generation	Standard Deviation	Supply	Standard Deviation
2001	29,428	4,679	32,412	4,813	NA	NA	NA	NA
2002	30,967	5,770	34,730	6,238	5.2%	23.3%	7.2%	29.6%
2003	36,034	6,008	39,644	6,021	16.4%	4.1%	14.1%	(3.5%)
2004	41,430	9,435	45,597	9,699	15.0%	57.0%	15.0%	61.1%
2005	74,365	12,661	79,693	13,242	79.5%	34.2%	74.8%	36.5%
2006	80,249	11,011	84,819	11,574	7.9%	(13.0%)	6.4%	(12.6%)
2007	83,478	12,105	88,150	13,192	4.0%	9.9%	3.9%	14.0%
2008	83,294	12,458	88,824	12,778	(0.2%)	2.9%	0.8%	(3.1%)
2009	77,508	12,961	82,928	13,580	(6.9%)	4.0%	(6.6%)	6.3%
2010	80,702	13,968	85,575	14,455	4.1%	7.8%	3.2%	6.4%
2011	81,483	13,677	86,268	14,428	1.0%	(2.1%)	0.8%	(0.2%)
2012	86,310	13,695	91,526	14,279	5.9%	0.1%	6.1%	(1.0%)
2013	87,974	13,528	93,166	14,277	1.9%	(1.2%)	1.8%	(0.0%)
2014	92,458	15,722	98,186	16,710	5.1%	16.2%	5.4%	17.0%
2015	90,097	16,028	96,626	17,168	(2.6%)	1.9%	(1.6%)	2.7%
2016	86,335	14,576	91,218	15,231	(4.2%)	(9.1%)	(5.6%)	(11.3%)
2017	88,669	13,528	91,108	14,029	2.7%	(7.2%)	(0.1%)	(7.9%)
2018	91,631	14,828	94,091	15,312	3.3%	9.6%	3.3%	9.1%
2019	91,613	14,403	92,947	14,735	(0.0%)	(2.9%)	(1.2%)	(3.8%)

PJM Real-Time, Monthly Average Generation

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

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



Day-Ahead Supply

PJM average, day-ahead cleared supply in the first six months of 2019, including INCs and up to congestion transactions, increased by 2.2 percent from the first six months of 2018, from 113,028 MWh to 115,511 MWh.

PJM average, day-ahead cleared supply in the first six months of 2019, including INCs, up to congestion transactions, and imports, increased by 2.1 percent from the first six months of 2018, from 113,493 MWh to 115,896 MWh.

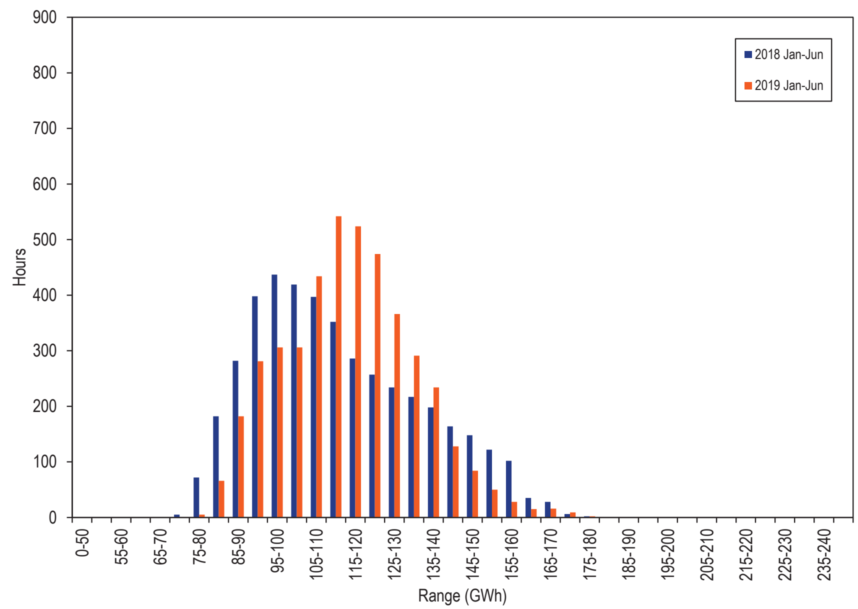
In the PJM Day-Ahead Energy Market, there are five types of financially binding supply offers:

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

PJM Day-Ahead Supply Duration

Figure 3-6 shows the hourly distribution of PJM day-ahead supply, including increment offers, up to congestion transactions, and imports for first six months of 2018 and 2019.

Figure 3-6 Distribution of day-ahead supply plus imports: January through June, 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 summary average day-ahead hourly supply statistics for the first six months of the 19-year period from 2001 through 2019.

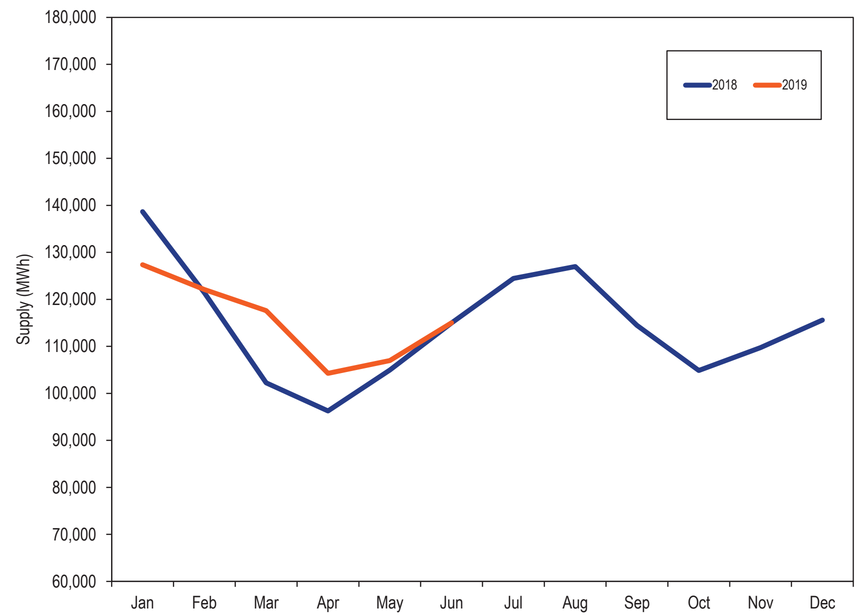
Table 3-4 Average hourly day-ahead supply and day-ahead supply plus imports: January through June, 2001 through 2019

	PJM Day-Ahead Supply (MWh)				Year-to-Year Change			
	Supply		Supply Plus Imports		Supply		Supply Plus Imports	
Jan-Jun	Supply	Standard Deviation	Supply	Standard Deviation	Supply	Standard Deviation	Supply	Standard Deviation
2001	26,796	4,305	27,540	4,382	NA	NA	NA	NA
2002	25,840	10,011	26,398	10,021	(3.6%)	132.5%	(4.1%)	128.7%
2003	36,420	7,000	36,994	7,023	40.9%	(30.1%)	40.1%	(29.9%)
2004	50,089	10,108	50,836	10,171	37.5%	44.4%	37.4%	44.8%
2005	87,855	14,365	89,382	14,395	75.4%	42.1%	75.8%	41.5%
2006	95,562	12,620	97,796	12,615	8.8%	(12.1%)	9.4%	(12.4%)
2007	106,470	14,522	108,815	14,772	11.4%	15.1%	11.3%	17.1%
2008	104,705	14,124	107,169	14,190	(1.7%)	(2.7%)	(1.5%)	(3.9%)
2009	97,607	16,283	100,076	16,342	(6.8%)	15.3%	(6.6%)	15.2%
2010	102,626	18,206	105,463	18,378	5.1%	11.8%	5.4%	12.5%
2011	108,143	16,666	110,656	16,926	5.4%	(8.5%)	4.9%	(7.9%)
2012	132,326	15,710	134,747	15,841	22.4%	(5.7%)	21.8%	(6.4%)
2013	148,381	15,606	150,554	15,830	12.1%	(0.7%)	11.7%	(0.1%)
2014	165,620	13,930	167,939	14,119	11.6%	(10.7%)	11.5%	(10.8%)
2015	115,150	18,851	117,613	18,996	(30.5%)	35.3%	(30.0%)	34.5%
2016	127,715	20,380	129,798	20,518	10.9%	8.1%	10.4%	8.0%
2017	133,601	19,109	134,433	19,293	4.6%	(6.2%)	3.6%	(6.0%)
2018	113,028	21,246	113,493	21,258	(15.4%)	11.2%	(15.6%)	10.2%
2019	115,511	16,792	115,896	16,811	2.2%	(21.0%)	2.1%	(20.9%)

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 six months of 2019.

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



Real-Time and Day-Ahead Supply

Table 3-5 presents summary statistics for the first six 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 six months of 2019, up to congestion transactions were 17.9 percent of the total day-ahead supply compared to 15.8 percent in the first six months of 2018.

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

		Day-Ahead					Real-Time		Day-Ahead Less Real-Time	
	Jan-Jun	Generation	INC Offers	Up to Congestion	Imports	Total Supply	Generation	Total Supply	Total Supply	Total Generation
Average	2018	92,270	2,772	17,986	464	113,493	91,631	94,091	19,402	639
	2019	91,791	2,977	20,744	385	115,896	91,613	92,947	22,949	178
Median	2018	90,972	2,666	14,468	440	109,681	90,156	92,395	17,286	816
	2019	90,724	2,852	20,543	337	115,388	90,442	91,752	23,636	282
Standard Deviation	2018	15,276	1,028	9,669	242	21,258	14,828	15,312	5,945	448
	2019	15,132	984	4,227	242	16,811	14,403	14,735	2,076	729
Peak Average	2018	99,759	3,338	18,952	451	122,500	98,632	101,276	21,224	1,127
	2019	99,802	3,456	21,918	342	125,518	98,954	100,338	25,180	848
Peak Median	2018	98,060	3,257	14,946	429	117,744	96,532	98,829	18,916	1,528
	2019	97,990	3,399	21,578	281	123,629	96,880	98,330	25,299	1,110
Peak Standard Deviation	2018	12,558	1,012	10,246	266	19,014	12,460	12,817	6,197	99
	2019	12,609	928	4,032	243	13,717	12,299	12,660	1,057	310
Off-Peak Average	2018	85,588	2,268	17,123	476	105,454	85,384	87,679	17,775	203
	2019	84,747	2,555	19,712	423	107,436	85,158	86,448	20,988	(411)
Off-Peak Median	2018	82,945	2,220	14,159	460	99,113	82,881	84,848	14,265	64
	2019	83,078	2,432	19,532	380	106,336	83,171	84,258	22,078	(93)
Off-Peak Standard Deviation	2018	14,360	739	9,039	217	19,891	13,959	14,491	5,400	401
	2019	13,583	827	4,125	236	14,585	12,955	13,300	1,285	629

Figure 3-8 shows the average hourly cleared volumes of day-ahead supply and real-time supply for the first six 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 June, 2019

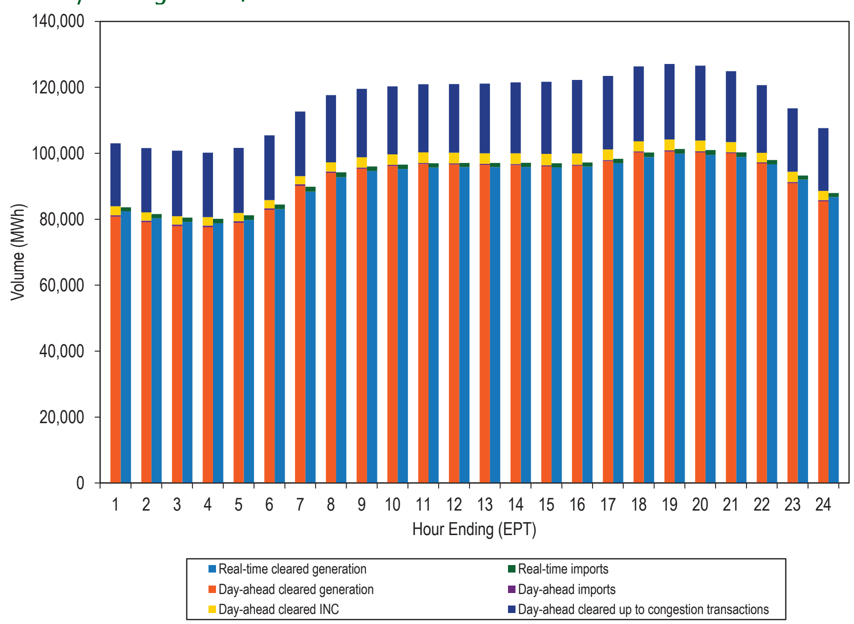
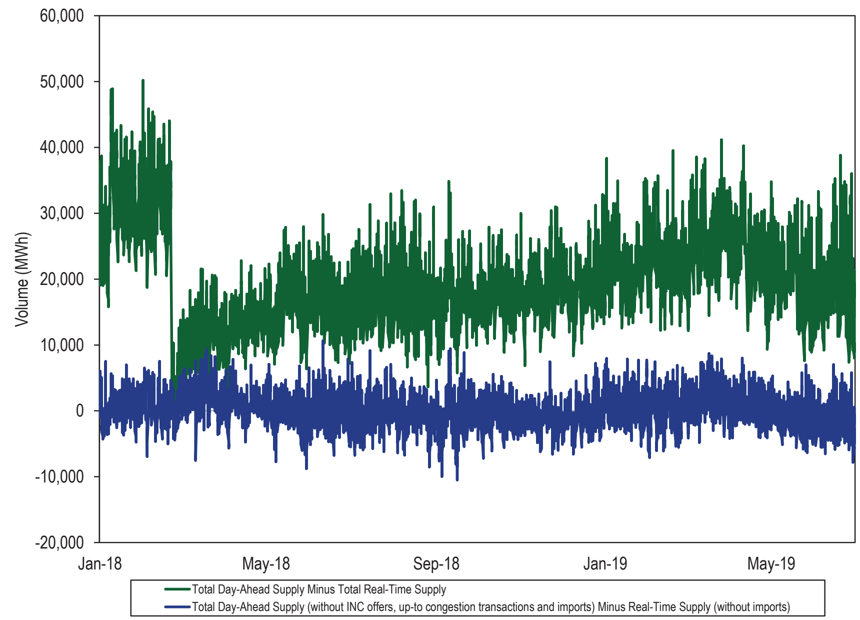


Figure 3-9 shows the difference between the day-ahead and real-time average daily supply for 2018 and the first six months of 2019.

Figure 3-9 Difference between day-ahead and real-time supply (Average daily volumes): January 2018 through June 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 peak load in the first six months of 2019 was 134,060 MWh in the HE 0800 on January 31, 2019, which was 11,307 MWh, or 7.8 percent, less than the peak load in the first six months of 2018, which was 145,367 MWh in the HE 1700 on June 18, 2018.

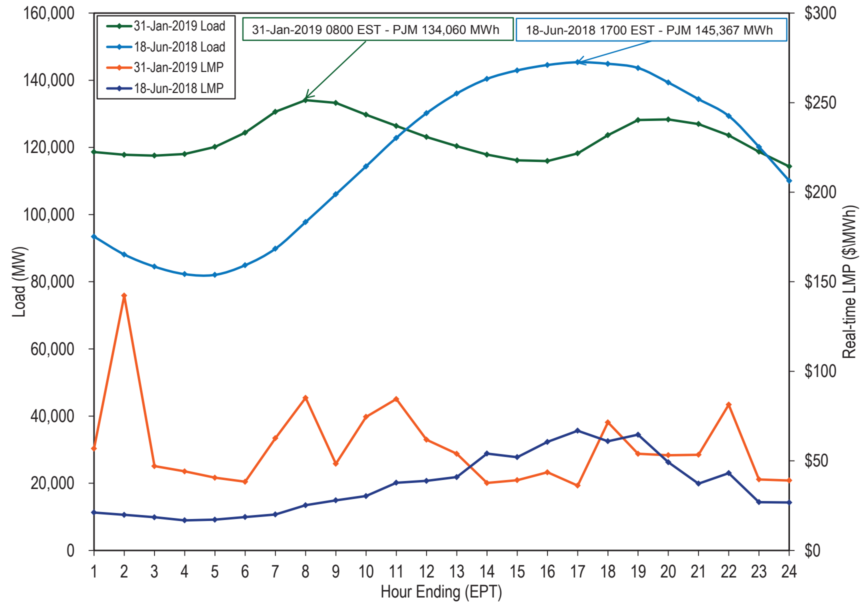
Table 3-6 shows the peak loads for the first six months of 2009 through 2019.

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

(Jan - Jun)	Date	Hour Ending (EPT)	PJM Load (MWh)	Annual Change (MWh)	Annual Change (%)
2009	Fri, January 16	19	114,765	NA	NA
2010	Wed, June 23	17	123,490	8,726	7.6%
2011	Wed, June 08	17	141,074	17,583	14.2%
2012	Wed, June 20	18	144,361	3,287	2.3%
2013	Tue, June 25	16	136,674	(7,687)	(5.3%)
2014	Tue, June 17	17	138,448	1,774	1.3%
2015	Fri, February 20	8	139,647	1,199	0.9%
2016	Mon, June 20	17	132,042	(7,606)	(5.4%)
2017	Mon, June 12	18	137,834	5,793	4.4%
2018	Mon, June 18	17	145,367	7,532	5.5%
2019	Thu, January 31	8	134,060	(11,307)	(7.8%)

Figure 3-10 compares the peak load days during the first six months of 2018 and 2019. The average real-time LMP for the January 31, 2019 peak load hour was $85.21 and for the June 18, 2018 peak load hour was $66.85.

Figure 3-10 Peak-load comparison: Monday, June 18, 2018 and Thursday, January 31, 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 real-time demand in the first six months of 2019 decreased by 2.9 percent from the first six months of 2018, from 88,847 MWh to 86,297 MWh.[18]

PJM average real-time demand including exports in the first six months of 2019 decreased by 1.2 percent from the first six months of 2018, from 92,352 MWh to 91,262 MWh.

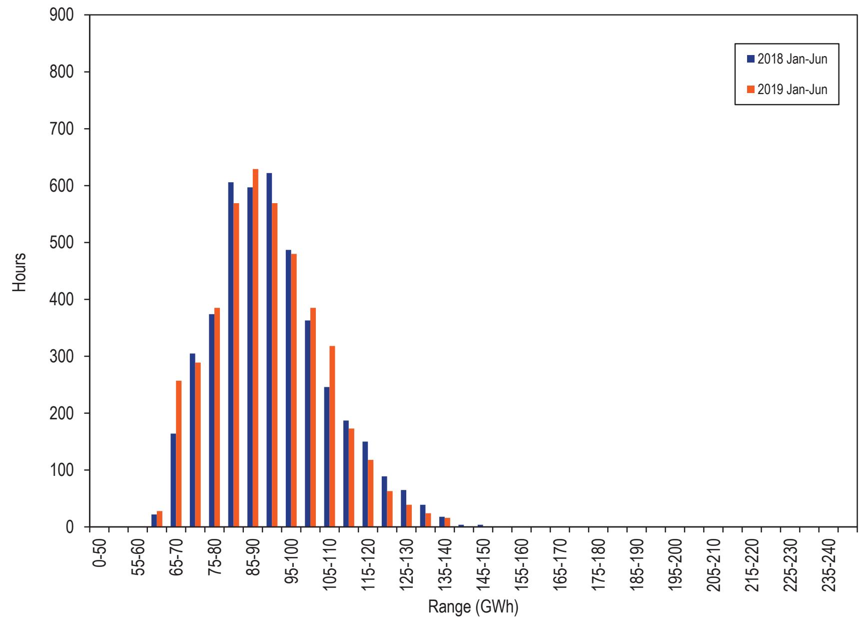
In the PJM Real-Time Energy Market, there are two types of demand:

- **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 six months of 2018 and 2019.[19]

Figure 3-11 Distribution of real-time accounting load plus exports: January through June, 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 summary average real-time hourly demand statistics for the first six 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 June, 2001 through 2019

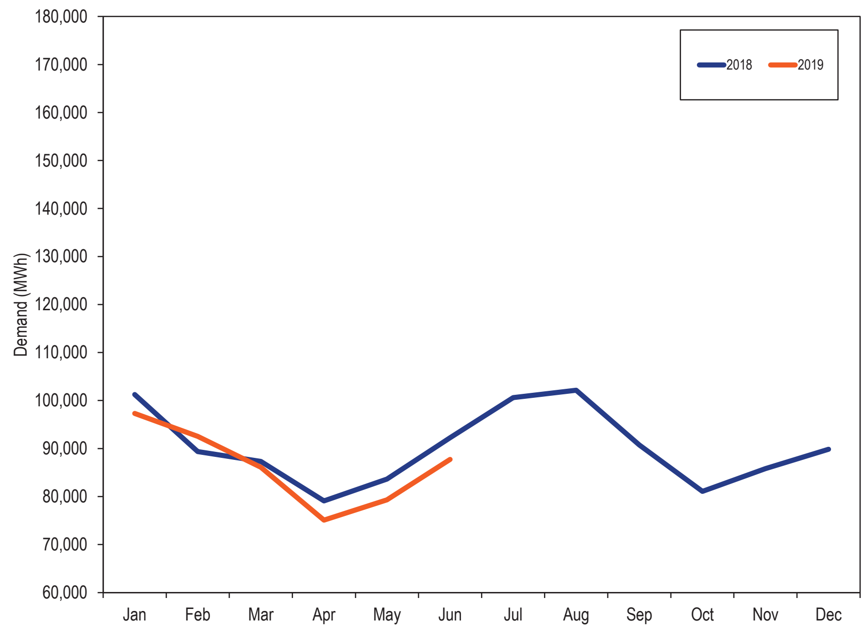
	PJM Real-Time Demand (MWh)				Year-to-Year Change			
	Load		Load Plus Exports		Load		Load Plus Exports	
Jan-Jun	Load	Standard Deviation	Demand	Standard Deviation	Load	Standard Deviation	Demand	Standard Deviation
2001	30,180	5,274	32,041	5,103	NA	NA	NA	NA
2002	32,678	6,457	33,969	6,557	8.3%	22.4%	6.0%	28.5%
2003	36,727	6,428	38,775	6,554	12.4%	(0.4%)	14.1%	(0.0%)
2004	41,787	8,999	44,808	10,033	13.8%	40.0%	15.6%	53.1%
2005	71,939	13,603	78,745	13,798	72.2%	51.2%	75.7%	37.5%
2006	77,232	12,003	83,606	12,377	7.4%	(11.8%)	6.2%	(10.3%)
2007	81,110	13,499	86,557	13,819	5.0%	12.5%	3.5%	11.6%
2008	78,685	12,819	85,819	13,242	(3.0%)	(5.0%)	(0.9%)	(4.2%)
2009	75,991	12,899	81,062	13,253	(3.4%)	0.6%	(5.5%)	0.1%
2010	78,106	13,643	83,758	14,227	2.8%	5.8%	3.3%	7.3%
2011	78,823	13,931	84,288	14,046	0.9%	2.1%	0.6%	(1.3%)
2012	84,946	13,941	89,638	13,848	7.8%	0.1%	6.3%	(1.4%)
2013	86,897	13,871	91,199	13,848	2.3%	(0.5%)	1.7%	0.0%
2014	90,529	16,266	96,189	16,147	4.2%	17.3%	5.5%	16.6%
2015	90,586	16,192	94,782	16,589	0.1%	(0.5%)	(1.5%)	2.7%
2016	85,800	14,517	89,746	14,798	(5.3%)	(10.3%)	(5.3%)	(10.8%)
2017	84,569	13,670	89,477	13,638	(1.4%)	(5.8%)	(0.3%)	(7.8%)
2018	88,847	14,683	92,352	14,818	5.1%	7.4%	3.2%	8.7%
2019	86,297	14,038	91,262	14,303	(2.9%)	(4.4%)	(1.2%)	(3.5%)

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 six months of 2019.

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



PJM real-time load is significantly affected by temperature. Table 3-8 compares the PJM monthly heating and cooling degree days in 2018 and the first six months of 2019.[22] Heating degree days decreased 6.4 percent, and cooling degree days decreased 22.2 percent from 2018 to the first six months of 2019.

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 June 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				
Aug	0	363				
Sep	0	213				
Oct	207	65				
Nov	566	0				
Dec	675	0				
Jan-Jun	2,532	385	2,372	299	(6.4%)	(22.2%)

Day-Ahead Demand

PJM average day-ahead demand in the first six months of 2019, including DECs and up to congestion transactions, increased by 1.8 percent from the first six months of 2018, from 108,950 MWh to 110,890 MWh.

PJM average day-ahead demand in the first six months of 2019, including DECs, up to congestion transactions, and exports, increased by 2.1 percent from of the first six months of 2018, from 111,451 MWh to 113,738 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.
- **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.

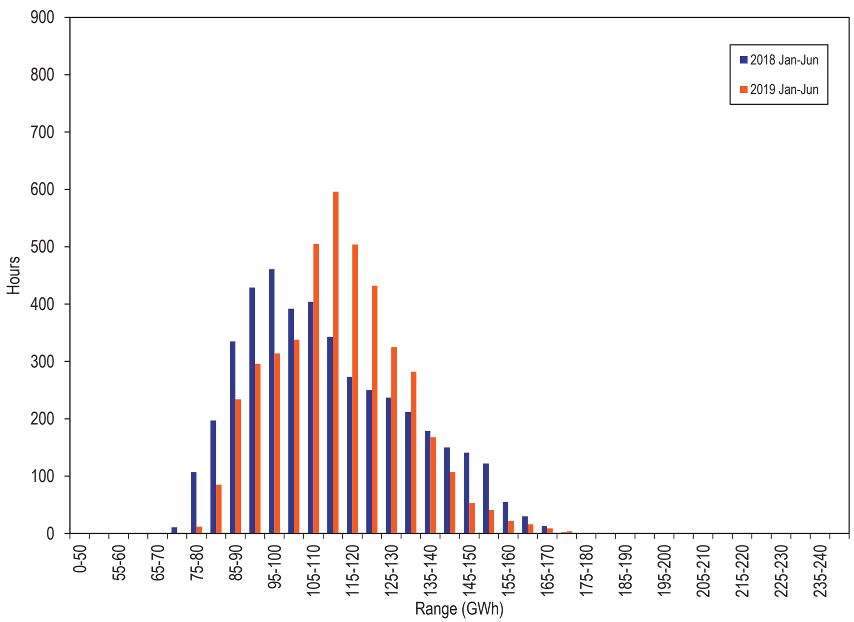
PJM day-ahead demand is the hourly total of the five types of cleared demand bids.

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.

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 six months of 2018 and 2019.

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



PJM Day-Ahead, Average Demand

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

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

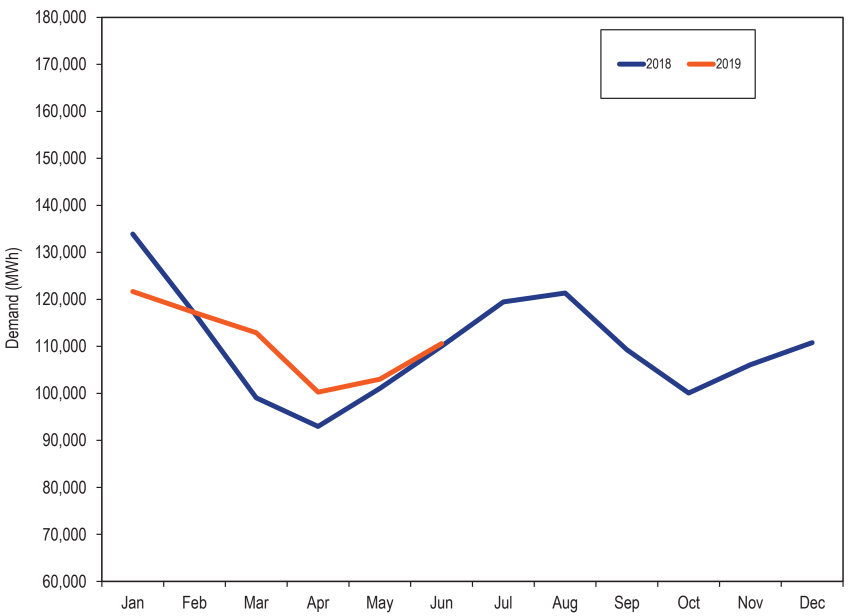
	PJM Day-Ahead Demand (MWh)				Year-to-Year Change			
	Demand		Demand Plus Exports		Demand		Demand Plus Exports	
Jan-Jun	Demand	Standard Deviation	Demand	Standard Deviation	Demand	Standard Deviation	Demand	Standard Deviation
2001	32,425	6,014	33,075	5,857	NA	NA	NA	NA
2002	37,561	8,293	37,607	8,311	15.8%	37.9%	13.7%	41.9%
2003	44,391	7,717	44,503	7,704	18.2%	(6.9%)	18.3%	(7.3%)
2004	50,161	10,304	50,596	10,557	13.0%	33.5%	13.7%	37.0%
2005	86,890	14,677	89,388	14,827	73.2%	42.4%	76.7%	40.4%
2006	94,470	12,925	97,460	13,303	8.7%	(11.9%)	9.0%	(10.3%)
2007	104,737	15,019	107,647	15,269	10.9%	16.2%	10.5%	14.8%
2008	100,948	14,255	104,499	14,461	(3.6%)	(5.1%)	(2.9%)	(5.3%)
2009	95,130	15,878	98,001	15,972	(5.8%)	11.4%	(6.2%)	10.4%
2010	99,691	18,097	103,573	18,366	4.8%	14.0%	5.7%	15.0%
2011	105,071	16,452	108,756	16,578	5.4%	(9.1%)	5.0%	(9.7%)
2012	129,881	15,268	133,046	15,436	23.6%	(7.2%)	22.3%	(6.9%)
2013	145,280	15,552	148,414	15,588	11.9%	1.9%	11.6%	1.0%
2014	160,805	13,872	164,740	13,800	10.7%	(10.8%)	11.0%	(11.5%)
2015	111,750	18,076	115,117	18,477	(30.5%)	30.3%	(30.1%)	33.9%
2016	124,542	19,750	127,461	19,991	11.4%	9.3%	10.7%	8.2%
2017	128,690	18,440	131,976	18,746	3.3%	(6.6%)	3.5%	(6.2%)
2018	108,950	20,548	111,451	20,718	(15.3%)	11.4%	(15.6%)	10.5%
2019	110,890	15,994	113,738	16,323	1.8%	(22.2%)	2.1%	(21.2%)

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 six months of 2019.

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



Real-Time and Day-Ahead Demand

Table 3-10 presents summary statistics for the first six months of 2018 and 2019 day-ahead and real-time demand. All data are cleared MW. 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 June, 2018 and 2019

		Day-Ahead						Real-Time		Day-Ahead Less Real-Time	
Jan-Jun	Year	Fixed Demand	Price Sensitive	DEC Bids	Up-to Congestion	Exports	Total Demand	Load	Total Demand	Total Demand	Total Load
Average	2018	85,670	2,543	2,751	17,986	2,501	111,451	88,847	92,352	19,100	(634)
	2019	85,105	1,309	3,732	20,744	2,848	113,738	86,297	91,262	22,476	117
Median	2018	84,484	2,583	2,438	14,468	2,331	107,826	87,605	90,756	17,070	(538)
	2019	84,476	1,332	3,442	20,543	2,684	113,286	85,281	90,128	23,158	527
Standard Deviation	2018	13,913	472	1,348	9,669	838	20,718	14,683	14,818	5,900	(298)
	2019	13,536	248	1,486	4,227	828	16,323	14,038	14,303	2,019	(255)
Peak Average	2018	92,997	2,781	2,951	18,952	2,576	120,256	95,919	99,375	20,881	(141)
	2019	92,735	1,427	4,089	21,918	2,962	123,130	93,495	98,505	24,626	668
Peak Median	2018	91,340	2,906	2,690	14,946	2,382	115,646	93,539	97,079	18,568	707
	2019	91,389	1,449	3,845	21,578	2,837	121,290	91,582	96,586	24,705	1,256
Peak Standard Deviation	2018	11,032	433	1,273	10,246	851	18,523	12,039	12,384	6,139	(574)
	2019	10,950	242	1,528	4,032	859	13,305	11,852	12,257	1,048	(661)
Off-Peak Average	2018	79,132	2,330	2,574	17,123	2,435	103,594	82,537	86,085	17,510	(1,074)
	2019	78,396	1,205	3,418	19,712	2,749	105,480	79,969	84,894	20,586	(367)
Off-Peak Median	2018	77,313	2,399	2,197	14,159	2,268	97,391	80,155	83,350	14,041	(444)
	2019	77,303	1,219	3,176	19,532	2,585	104,374	78,225	82,839	21,534	297
Off-Peak Standard Deviation	2018	12,926	399	1,387	9,039	821	19,374	13,937	13,980	5,394	(612)
	2019	11,947	202	1,374	4,125	786	14,118	12,700	12,874	1,244	(550)

Figure 3-15 shows the average hourly cleared volumes of day-ahead demand and real-time demand for the first six 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 June, 2019

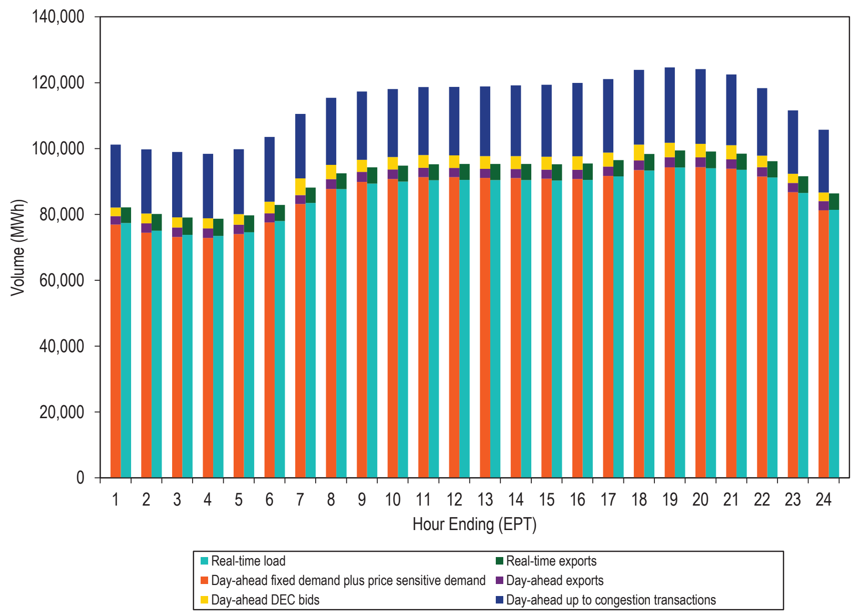
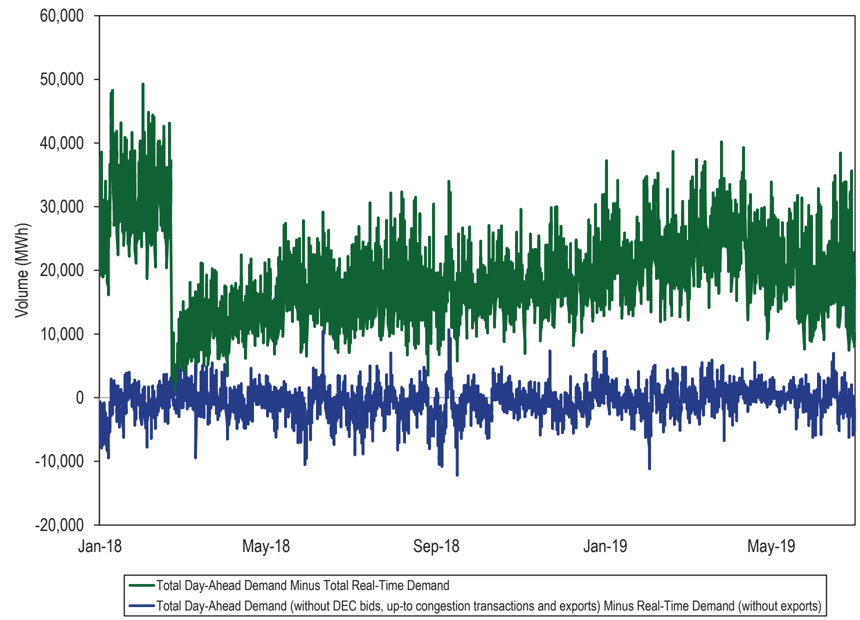


Figure 3-16 shows the difference between the day-ahead and real-time average daily demand for 2018 and the first six months of 2019.

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



Market Behavior

Supply and Demand: Load and Spot Market

Real-Time Load and Spot Market

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

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

The PJM system's reliance on self-supply, bilateral contracts and spot purchases to meet real-time load is calculated by summing across all the parent companies of PJM billing organizations that serve load in the Real-Time Energy Market for each hour. Table 3-11 shows the monthly average share of real-time load served by self-supply, bilateral contracts and spot purchase in the first six months of 2018 and 2019 based on parent company. In the first six months of 2019, 14.8 percent of real-time load was supplied by bilateral contracts, 28.0 percent by spot market purchase and 58.3 percent by self-supply. Compared with the first six months of 2018, reliance on bilateral contracts increased by 2.3 percentage points, reliance on spot supply decreased by 1.9 percentage points and reliance on self-supply decreased by 0.4 percentage points.

Table 3-11 Sources of real-time supply: January through June, 2018 and 2019[24]

	2018			2019			Difference in Percentage Points		
	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply
Jan	11.8%	29.8%	59.4%	14.3%	26.8%	59.9%	2.4%	(2.9%)	0.5%
Feb	13.5%	29.1%	58.5%	14.1%	28.1%	58.8%	0.6%	(1.0%)	0.4%
Mar	12.0%	31.8%	57.2%	14.7%	31.4%	55.0%	2.7%	(0.4%)	(2.2%)
Apr	13.1%	30.2%	57.7%	16.9%	27.9%	56.4%	3.8%	(2.3%)	(1.2%)
May	12.6%	29.8%	58.6%	15.7%	27.4%	58.1%	3.0%	(2.4%)	(0.5%)
Jun	12.6%	28.5%	60.0%	14.1%	26.6%	60.5%	1.5%	(1.9%)	0.5%
Jan-Jun	12.6%	29.9%	58.6%	14.8%	28.0%	58.3%	2.3%	(1.9%)	(0.3%)

Day-Ahead Load and Spot Market

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

The PJM system's reliance on self-supply, bilateral contracts, and spot purchases to meet day-ahead demand (cleared fixed-demand, price-sensitive

24 Table 3-22 and Table 3-23 were calculated as of July 19, 2019. The values may change slightly as billing values are updated by PJM.

load and decrement bids) is calculated by summing across all the parent companies of PJM billing organizations that serve demand in the Day-Ahead Energy Market for each hour. Table 3-12 shows the monthly average share of day-ahead demand served by self-supply, bilateral contracts and spot purchases in the first six months of 2018 and 2019, based on parent companies. In the first six months of 2019, 11.0 percent of day-ahead demand was supplied by bilateral contracts, 29.4 percent by spot market purchases and 59.6 percent by self-supply. Compared with the first six months of 2018, reliance on bilateral contracts increased by 1.5 percentage points, reliance on spot supply decreased by 2.2 percentage points, and reliance on self-supply increased by 0.6 percentage points.

Table 3-12 Sources of day-ahead supply: January through June, 2018 and 2019

	2018			2019			Difference in Percentage Points		
	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply
Jan	9.2%	31.9%	58.9%	11.4%	27.6%	61.0%	2.2%	(4.2%)	2.1%
Feb	10.2%	31.3%	58.5%	11.3%	28.9%	59.8%	1.1%	(2.4%)	1.2%
Mar	9.1%	32.8%	58.1%	10.7%	31.7%	57.6%	1.6%	(1.1%)	(0.5%)
Apr	9.9%	31.9%	58.2%	11.3%	30.3%	58.4%	1.4%	(1.6%)	0.1%
May	9.4%	31.5%	59.1%	10.7%	29.5%	59.8%	1.3%	(2.0%)	0.7%
Jun	9.4%	29.8%	60.8%	10.9%	28.6%	60.5%	1.4%	(1.2%)	(0.3%)
Jan-Jun	9.5%	31.5%	59.0%	11.0%	29.4%	59.6%	1.5%	(2.2%)	0.6%

Hourly Offers and Intraday Offer Updates

On November 1, 2017, PJM implemented hourly offers and intraday offer updates. Hourly offers means the ability to offer hourly differentiated offers (up to one offer per hour instead of one offer per day). Intraday offer updates means the ability to make changes to an offer after the rebid period. All participants are eligible to make hourly offers. Participants must opt in on a monthly basis to make intraday offer updates. Table 3-13 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 June 2019, a daily average of 335 natural gas fired units had opted in for intraday offer updates out of a daily average of 449 natural gas fired units. This is an increase of 0.5 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	336.0	37.0	373.0	447.9	358.6	806.5
Feb	300.0	32.0	332.0	444.0	395.7	839.7	336.0	37.0	373.0	447.3	355.7	803.0
Mar	302.0	32.0	334.0	444.5	394.6	839.0	336.0	37.0	373.0	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						
Aug	326.0	36.0	362.0	445.0	363.7	808.7						
Sep	326.0	36.0	362.0	445.2	360.1	805.3						
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	333.4	37.0	370.4	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 June 2019, an average of 320 units made hourly differentiated offers. This is an increase of 18.7 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			
Aug	259.6	16.6	276.2			
Sep	238.2	14.9	253.1			
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 June 2019, an average of 146 units made intraday offer updates. This is an increase of 20.4 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			
Aug	130.2	3.4	133.6			
Sep	124.3	4.3	128.6			
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. During the 2016/2017 and 2017/2018 delivery years, all cost-based offers, submitted by resources that are not capacity performance resources, are parameter limited in accordance with the Parameter Limited Schedule (PLS) matrix or with the level of an approved exception.[25] During the 2016/2017 and 2017/2018 delivery years, all cost-based offers, submitted by capacity performance resources, are parameter limited in accordance with predetermined unit specific parameter limits. During the 2016/2017 and 2017/2018 delivery years, there was no base capacity procured.

25 See PJM Operating Agreement Schedule 1 § 6.6.

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.

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.[26] 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 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

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

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.[27] 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 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.

27 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>.

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.[28]

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

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 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.[29] The Commission directed that capacity performance resources with parameters based on nonphysical constraints should receive uplift payments.[30] 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.[31]

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

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

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

The MMU recommends that 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.

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

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 submit 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.[32] Up to congestion transactions may be submitted between any two buses on a list of 49 buses, eligible for up to congestion transaction bidding.[33] Import and export transactions may be

32 162 FERC ¶ 61,139 (2018).

33 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>.

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

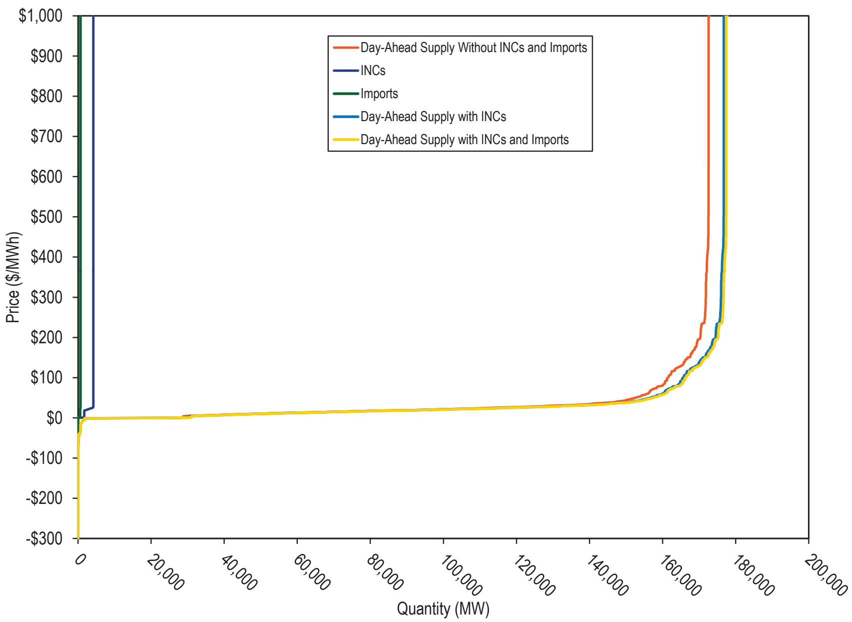


Figure 3-18 shows example PJM day-ahead aggregate supply curves for the typical dispatch price range.

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

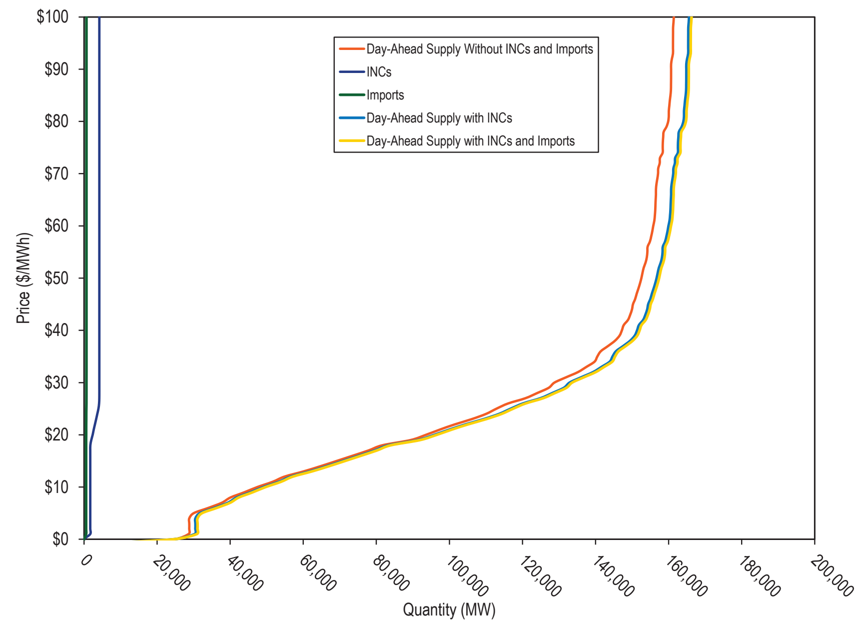


Table 3-17 shows the hourly average number of cleared and submitted increment offers and decrement bids by month in January 2018 through June 2019. The hourly average submitted and cleared increment MW increased by 6.5 percent and 8.0 percent, from 5,851 MW and 2,757 MW in the first six months of 2018 to 6,234 MW and 2,976 MW in the first six months of 2019. The hourly average submitted decrement MW decreased by 2.6 percent and cleared decrement MW increased by 36.4 percent, from 6,936 MW and 2,736 MW in the first six months of 2018 to 6,755 MW and 3,732 MW in the first six months of 2019.

Table 3-17 Average hourly number of cleared and submitted INCs and DECs by month: January 2018 through June 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	Jan-Jun	2,976	6,234	266	1,055	3,732	6,755	192	799

Table 3-18 shows the average hourly number of up to congestion transactions and the average hourly MW in January 2018 through June 2019. In the first six months of 2019, the average hourly up to congestion submitted decreased by 0.8 percent and cleared MW increased by 15.4 percent, compared to the first six months of 2018.

Table 3-18 Average hourly cleared and submitted up to congestion bids by month: January 2018 through June 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	Jan-Jun	20,748	63,738	1,005	1,999

Table 3-19 shows the average hourly number of import and export transactions and the average hourly MW in January 2018 through June 2019. In the first six months of 2019, the average hourly submitted and cleared import transaction MW increased by 12.3 and 9.4 percent, and the average hourly submitted and cleared export transaction MW increased by 26.2 and 26.8 percent, compared to the first six months of 2018.

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

Table 3-20 Type of day-ahead marginal resources: January 2018 through June 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%						
Aug	11.1%	0.2%	54.5%	22.5%	11.7%	0.0%						
Sep	15.1%	0.2%	50.7%	20.5%	13.5%	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%	10.5%	0.1%	57.8%	18.2%	13.3%	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 June 2019.

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

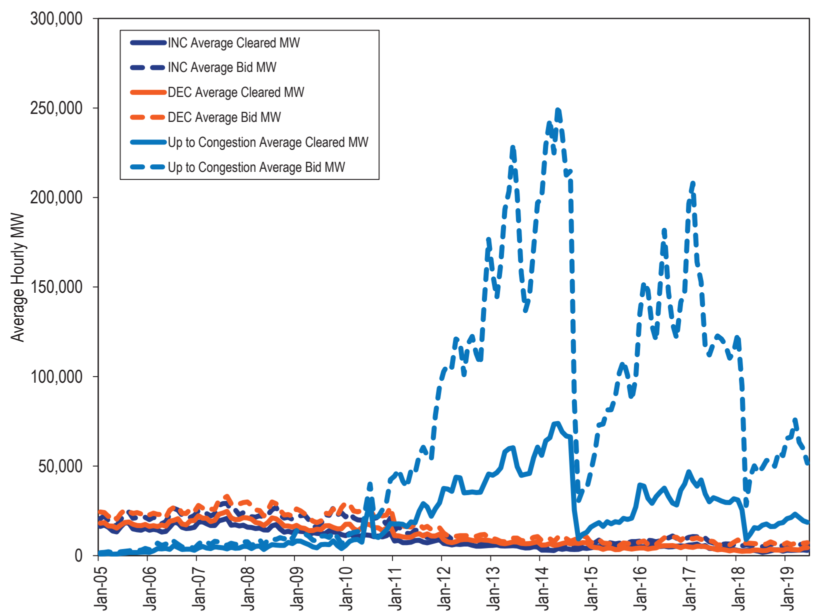
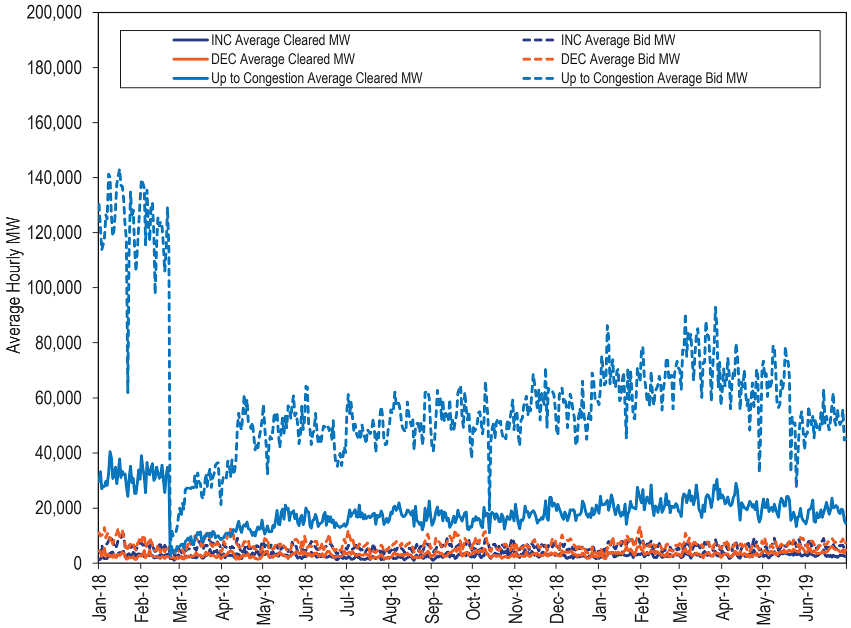


Figure 3-20 shows the daily volume of bid and cleared INC, DEC and up to congestion bids from January 1, 2018 through June 30, 2019.

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

	2018 (Jan-Jun)				2019 (Jan-Jun)			
Category	Total Virtual Bid MWh	Percent	Total Virtual Cleared MWh	Percent	Total Virtual Bid MWh	Percent	Total Virtual Cleared MWh	Percent
Financial	49,018,213	87.8%	19,652,647	81.9%	48,770,076	86.5%	24,358,945	83.6%
Physical	6,826,335	12.2%	4,337,437	18.1%	7,640,294	13.5%	4,775,626	16.4%
Total	55,844,548	100.0%	23,990,085	100.0%	56,410,370	100.0%	29,134,571	100.0%

Table 3-22 shows, in the first six 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 June, 2018 and 2019

	2018 (Jan-Jun)				2019 (Jan-Jun)			
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	275,239,147	98.6%	75,621,806	96.8%	272,585,372	98.5%	86,650,465	96.2%
Physical	3,772,044	1.4%	2,489,289	3.2%	4,227,216	1.5%	3,458,038	3.8%
Total	279,011,191	100.0%	78,111,095	100.0%	276,812,587	100.0%	90,108,504	100.0%

Table 3-23 shows, in the first six 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 June, 2018 and 2019

		2018 (Jan-Jun)		2019 (Jan-Jun)	
	Category	Total Import and Export MW	Percent	Total Import and Export MW	Percent
Day-Ahead	Financial	3,308,861	25.7%	3,001,675	25.4%
	Physical	9,572,016	74.3%	8,822,015	74.6%
	Total	12,880,877	100.0%	11,823,690	100.0%
Real-Time	Financial	5,115,768	19.7%	5,198,676	22.9%
	Physical	20,787,471	80.3%	17,525,109	77.1%
	Total	25,903,239	100.0%	22,723,785	100.0%

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

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

2018 (Jan-Jun)					2019 (Jan-Jun)				
Aggregate/Bus Name	Aggregate/Bus Type	INC MW	DEC MW	Total MW	Aggregate/Bus Name	Aggregate/Bus Type	INC MW	DEC MW	Total MW
WESTERN HUB	HUB	1,767,353	784,240	2,551,593	MISO	INTERFACE	74,384	3,216,498	3,290,882
SOUTHIMP	INTERFACE	1,397,745	0	1,397,745	WESTERN HUB	HUB	670,231	728,727	1,398,958
MISO	INTERFACE	124,433	836,789	961,222	LINDENVFT	INTERFACE	16,411	852,801	869,212
DOM_RESID_AGG	RESIDUAL_METERED_EDC	68,055	434,326	502,381	SOUTHIMP	INTERFACE	777,005	0	777,005
NYIS	INTERFACE	408,953	75,460	484,413	DOM_RESID_AGG	RESIDUAL_METERED_EDC	143,261	610,567	753,827
DOMINION HUB	HUB	72,023	393,000	465,022	DOMINION HUB	HUB	371,321	370,699	742,020
LINDENVFT	INTERFACE	14,564	441,209	455,773	AEP-DAYTON HUB	HUB	305,543	414,315	719,858
N ILLINOIS HUB	HUB	146,750	304,063	450,813	N ILLINOIS HUB	HUB	281,063	306,988	588,051
BGE_RESID_AGG	RESIDUAL_METERED_EDC	72,206	357,722	429,928	NYIS	INTERFACE	415,153	158,993	574,146
AEP-DAYTON HUB	HUB	169,207	255,011	424,219	NEW JERSEY HUB	HUB	388,117	118,779	506,896
Top ten total		4,241,289	3,881,820	8,123,109			3,442,489	6,778,366	10,220,856
PJM total		12,040,773	11,949,312	23,990,085			12,926,938	16,207,634	29,134,571
Top ten total as percent of PJM total		35.2%	32.5%	33.9%			26.6%	41.8%	35.1%

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 six months of 2018 and 2019.[34]

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

2018 (Jan-Jun)							
Imports							
Source	Source Type	Sink	Sink Type	MW	Source Profit	Sink Profit	UTC Profit
NORTHWEST	INTERFACE	N ILLINOIS HUB	HUB	1,419,133	($962,307)	$1,610,034	$647,727
NORTHWEST	INTERFACE	CHICAGO GEN HUB	HUB	1,126,204	($298,636)	$861,892	$563,257
MISO	INTERFACE	CHICAGO GEN HUB	HUB	594,774	$369,858	$510,620	$880,478
NORTHWEST	INTERFACE	COMED_RESID_AGG	AGGREGATE	545,870	$237,039	($128,064)	$108,975
OVEC	INTERFACE	AEP GEN HUB	HUB	526,484	$221,219	($291,166)	($69,947)
MISO	INTERFACE	CHICAGO HUB	HUB	515,073	$313,278	$167,475	$480,753
NORTHWEST	INTERFACE	CHICAGO HUB	HUB	438,321	($294,633)	$458,960	$164,327
OVEC	INTERFACE	DEOK_RESID_AGG	AGGREGATE	376,463	($127,836)	$554,114	$426,278
SOUTHIMP	INTERFACE	AEP GEN HUB	HUB	298,223	($650,721)	$674,048	$23,327
OVEC	INTERFACE	ATSI GEN HUB	HUB	285,106	$154,355	($160,635)	($6,280)
Top ten total				6,125,651	($1,038,382)	$4,257,278	$3,218,896
PJM total				14,488,463	($535,403)	$6,511,164	$5,975,762
Top ten total as percent of PJM total				42.3%	193.9%	65.4%	53.9%
2019 (Jan-Jun)							
Imports							
Source	Source Type	Sink	Sink Type	MW	Source Profit	Sink Profit	UTC Profit
NORTHWEST	INTERFACE	N ILLINOIS HUB	HUB	2,738,366	$901,526	($287,823)	$613,703
NORTHWEST	INTERFACE	CHICAGO GEN HUB	HUB	1,758,049	$681,317	($354,864)	$326,453
NORTHWEST	INTERFACE	COMED_RESID_AGG	AGGREGATE	1,615,387	$795,234	($378,123)	$417,111
NYIS	INTERFACE	RECO_RESID_AGG	AGGREGATE	981,191	($408,170)	$567,343	$159,173
SOUTHIMP	INTERFACE	AEP GEN HUB	HUB	735,826	$1,248,270	($769,591)	$478,680
NEPTUNE	INTERFACE	JCPL_RESID_AGG	AGGREGATE	717,623	$200,055	($135,340)	$64,715
NORTHWEST	INTERFACE	CHICAGO HUB	HUB	690,960	$372,014	($340,012)	$32,002
MISO	INTERFACE	AEPIM_RESID_AGG	AGGREGATE	661,045	$201,153	$51,623	$252,776
SOUTHIMP	INTERFACE	AEPAPCO_RESID_AGG	AGGREGATE	592,731	$396,471	($42,542)	$353,929
SOUTHIMP	INTERFACE	DOMINION HUB	HUB	429,275	$445,042	($406,103)	$38,938
Top ten total				10,920,454	$4,832,915	($2,095,434)	$2,737,481
PJM total				20,537,987	$11,876,242	($6,540,593)	$5,335,649
Top ten total as percent of PJM total				53.2%	40.7%	32.0%	51.3%

34 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 six months of 2018 and 2019.

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

2018 (Jan-Jun)							
Exports							
Source	Source Type	Sink	Sink Type	MW	Source Profit	Sink Profit	UTC Profit
CHICAGO GEN HUB	HUB	NIPSCO	INTERFACE	386,983	$596,098	$286,302	$882,400
N ILLINOIS HUB	HUB	NIPSCO	INTERFACE	385,691	$441,262	$297,753	$739,016
COMED_RESID_AGG	AGGREGATE	NIPSCO	INTERFACE	364,703	($25,408)	$1,043,662	$1,018,254
JCPL_RESID_AGG	AGGREGATE	HUDSONTP	INTERFACE	205,949	$45,659	($196,858)	($151,198)
CHICAGO HUB	HUB	NIPSCO	INTERFACE	119,254	($27,695)	$237,156	$209,461
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
JEFFERSON	EHVAGG	NIPSCO	INTERFACE	106,570	($171,872)	$412,287	$240,415
OHIO HUB	HUB	OVEC	INTERFACE	99,629	($1,023,460)	$859,941	($163,519)
AEP GEN HUB	HUB	OVEC	INTERFACE	94,696	($12,478)	($31,482)	($43,960)
Top ten total				1,988,381	$160,461	$2,922,557	$3,083,019
PJM total				6,981,030	($5,454,500)	$7,969,756	$2,515,256
Top ten total as percent of PJM total				28.5%	(2.9%)	36.7%	122.6%
2019 (Jan-Jun)							
Exports							
Source	Source Type	Sink	Sink Type	MW	Source Profit	Sink Profit	UTC Profit
N ILLINOIS HUB	HUB	NIPSCO	INTERFACE	1,073,902	$1,447,949	($943,687)	$504,262
COMED_RESID_AGG	AGGREGATE	NIPSCO	INTERFACE	951,722	$1,172,116	($491,872)	$680,244
CHICAGO HUB	HUB	NIPSCO	INTERFACE	847,905	$1,195,494	$133,543	$1,329,037
CHICAGO GEN HUB	HUB	NIPSCO	INTERFACE	796,735	$577,220	($45,838)	$531,382
CHICAGO HUB	HUB	MISO	INTERFACE	546,666	$321,666	($256,635)	$65,030
N ILLINOIS HUB	HUB	MISO	INTERFACE	393,987	$96,059	($138,381)	($42,322)
CHICAGO GEN HUB	HUB	MISO	INTERFACE	372,498	$129,807	($84,760)	$45,047
AEP GEN HUB	HUB	SOUTHEXP	INTERFACE	355,882	$238,525	$108,388	$346,913
CHICAGO GEN HUB	HUB	NORTHWEST	INTERFACE	335,566	($401,916)	$465,062	$63,146
AEP GEN HUB	HUB	NIPSCO	INTERFACE	216,228	($717,055)	$823,418	$106,363
Top ten total				5,891,090	$4,059,864	($430,762)	$3,629,101
PJM total				10,063,219	$4,867,436	$694,467	$5,561,903
Top ten total as percent of PJM total				58.5%	83.4%	(62.0%)	65.2%

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 six months of 2018 and 2019.

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

2018 (Jan-Jun)							
Wheels							
Source	Source Type	Sink	Sink Type	MW	Source Profit	Sink Profit	UTC Profit
MISO	INTERFACE	NIPSCO	INTERFACE	460,727	$915,144	$333,135	$1,248,278
MISO	INTERFACE	NORTHWEST	INTERFACE	401,863	$396,594	$213,567	$610,162
NORTHWEST	INTERFACE	MISO	INTERFACE	210,969	$145,287	$131,712	$276,998
SOUTHIMP	INTERFACE	OVEC	INTERFACE	158,924	($1,378,311)	$1,309,154	($69,156)
NORTHWEST	INTERFACE	NIPSCO	INTERFACE	152,090	($125,368)	$583,068	$457,700
SOUTHWEST	INTERFACE	SOUTHEXP	INTERFACE	143,660	$558,551	$31,300	$589,850
SOUTHIMP	INTERFACE	NIPSCO	INTERFACE	110,014	($221,378)	$384,639	$163,261
SOUTHIMP	INTERFACE	MISO	INTERFACE	102,305	($160,752)	$132,505	($28,246)
NYIS	INTERFACE	HUDSONTP	INTERFACE	97,430	$108,468	($102,310)	$6,158
OVEC	INTERFACE	NIPSCO	INTERFACE	80,503	($189,090)	$690	($188,400)
Top ten total				1,918,485	$49,145	$3,017,461	$3,066,606
PJM total				2,572,532	($122,168)	$3,122,110	$2,999,942
Top ten total as percent of PJM total				74.6%	(40.2%)	96.6%	102.2%
2019 (Jan-Jun)							
Wheels							
Source	Source Type	Sink	Sink Type	MW	Source Profit	Sink Profit	UTC Profit
MISO	INTERFACE	NIPSCO	INTERFACE	1,123,672	$987,100	($402,029)	$585,070
NORTHWEST	INTERFACE	NIPSCO	INTERFACE	1,031,505	$862,401	($350,040)	$512,361
NORTHWEST	INTERFACE	MISO	INTERFACE	677,564	$654,921	($415,352)	$239,569
MISO	INTERFACE	NORTHWEST	INTERFACE	441,855	$4,320	$242,083	$246,403
SOUTHIMP	INTERFACE	MISO	INTERFACE	312,890	$223,114	($15,575)	$207,538
MISO	INTERFACE	SOUTHEXP	INTERFACE	282,257	$55,190	$1,014,930	$1,070,120
SOUTHIMP	INTERFACE	NIPSCO	INTERFACE	267,332	$307,020	$475,509	$782,529
LINDENVFT	INTERFACE	HUDSONTP	INTERFACE	134,512	($2,973)	$50,625	$47,652
NYIS	INTERFACE	IMO	INTERFACE	76,366	($44,381)	$46,846	$2,465
IMO	INTERFACE	SOUTHEXP	INTERFACE	55,554	$59,353	$98,153	$157,506
Top ten total				4,403,508	$3,106,065	$745,149	$3,851,214
PJM total				5,171,240	$3,414,863	$382,252	$3,797,115
Top ten total as percent of PJM total				85.2%	91.0%	194.9%	101.4%

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 15.9 percent of the PJM total internal up to congestion transactions MW in the first six 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 six months of 2018 and 2019. The total internal UTC profits decreased by $15.9 million, from $15.0 million in the first six months of 2018 to -$0.3 million in the first six months of 2019. The total internal cleared MW increased by 0.3 million MW, or 0.5 percent, from 54.1 million MW in the first six months of 2018 to 54.3 million MW in the first six months of 2019.

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

2018 (Jan-Jun)							
Internal							
Source	Source Type	Sink	Sink Type	MW	Source Profit	Sink Profit	UTC Profit
SMECO_RESID_AGG	AGGREGATE	BGE_RESID_AGG	AGGREGATE	461,686	($267,030)	$388,031	$121,001
DUMONT	EHVAGG	COOK	EHVAGG	367,071	$608,188	($299,703)	$308,484
CHICAGO HUB	HUB	COMED_RESID_AGG	AGGREGATE	351,228	$331,331	($292,857)	$38,475
WESTERN HUB	HUB	AEP-DAYTON HUB	HUB	344,909	($154,777)	$567,290	$412,513
STUART 3	AGGREGATE	MICHFE	AGGREGATE	332,557	$286,697	($180,870)	$105,827
AECO_RESID_AGG	AGGREGATE	VINELAND_RESID_AGG	AGGREGATE	329,583	($177,157)	$102,581	($74,576)
PPL_RESID_AGG	AGGREGATE	METED_RESID_AGG	AGGREGATE	319,395	$920,581	($1,027,751)	($107,170)
MARION	AGGREGATE	HUDSON BC	AGGREGATE	312,289	$243,365	$267,591	$510,956
DOM_RESID_AGG	AGGREGATE	DOMINION HUB	HUB	304,208	$1,063,132	($836,217)	$226,915
JEFFERSON	EHVAGG	OHIO HUB	HUB	301,231	$264,543	($203,926)	$60,617
Top ten total				3,424,157	$3,118,872	($1,515,832)	$1,603,040
PJM total				54,069,070	($28,418,849)	$43,449,238	$15,030,389
Top ten total as percent of PJM total				6.3%	(11.0%)	(3.5%)	10.7%
2019 (Jan-Jun)							
Internal							
Source	Source Type	Sink	Sink Type	MW	Source Profit	Sink Profit	UTC Profit
OVEC_RESID_AGG	AGGREGATE	DEOK_RESID_AGG	AGGREGATE	1,446,145	$619,897	($861,884)	($241,988)
SMECO_RESID_AGG	AGGREGATE	BGE_RESID_AGG	AGGREGATE	1,105,106	$1,216,373	($846,207)	$370,166
AEP GEN HUB	HUB	AEPOHIO_RESID_AGG	AGGREGATE	1,018,437	$485,933	($353,899)	$132,034
OVEC_RESID_AGG	AGGREGATE	DAY_RESID_AGG	AGGREGATE	1,014,721	$494,126	($463,534)	$30,592
AEP GEN HUB	HUB	FEOHIO_RESID_AGG	AGGREGATE	883,731	$598,554	($797,514)	($198,960)
AEP GEN HUB	HUB	AEP-DAYTON HUB	HUB	797,331	$711,868	($714,031)	($2,163)
AEP GEN HUB	HUB	ATSI GEN HUB	HUB	636,785	$226,884	($415,550)	($188,667)
AECO_RESID_AGG	AGGREGATE	VINELAND_RESID_AGG	AGGREGATE	594,612	($298,038)	($5,854)	($303,892)
CHICAGO GEN HUB	HUB	AEPIM_RESID_AGG	AGGREGATE	570,382	$216,789	($132,373)	$84,416
OVEC_RESID_AGG	AGGREGATE	OHIO HUB	HUB	549,435	$324,534	($352,921)	($28,387)
Top ten total				8,616,684	$4,596,921	($4,943,768)	($346,847)
PJM total				54,336,058	$26,143,237	($26,998,983)	($855,747)
Top ten total as percent of PJM total				15.9%	17.6%	18.3%	40.5%

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

Table 3-29 Number of offered and cleared source and sink pairs: January 2018 through June 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	Jan-Jun	1,689	1,860	1,510	1,699

Table 3-30 and Figure 3-21 show total cleared up to congestion transactions by type in the first six months of 2018 and 2019. Total up to congestion transactions in the first six months of 2019 increased by 15.4 percent from 78.1 million MW in the first six months of 2018 to 90.1 million MW in the first six months of 2019. Internal up to congestion transactions in the first six months of 2019 were 60.3 percent of all up to congestion transactions compared to 69.2 percent in the first six months of 2018.

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

	2018 (Jan-Jun)				
	Cleared Up to Congestion Bids				
	Import	Export	Wheel	Internal	Total
Top ten total (MW)	6,125,651	1,988,381	1,918,485	3,424,157	13,456,673
PJM total (MW)	14,488,463	6,981,030	2,572,532	54,069,070	78,111,095
Top ten total as percent of PJM total	42.3%	28.5%	74.6%	6.3%	17.2%
PJM total as percent of all up to congestion transactions	18.5%	8.9%	3.3%	69.2%	100.0%
	2019 (Jan-Jun)				
	Cleared Up to Congestion Bids				
	Import	Export	Wheel	Internal	Total
Top ten total (MW)	10,920,454	5,891,090	4,403,508	8,616,684	29,831,737
PJM total (MW)	20,537,987	10,063,219	5,171,240	54,336,058	90,108,503
Top ten total as percent of PJM total	53.2%	58.5%	85.2%	15.9%	33.1%
PJM total as percent of all up to congestion transactions	22.8%	11.2%	5.7%	60.3%	100.0%

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.[35] 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.[36] 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.

35 *Id.*
36 162 FERC ¶ 61,139 (2018).

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

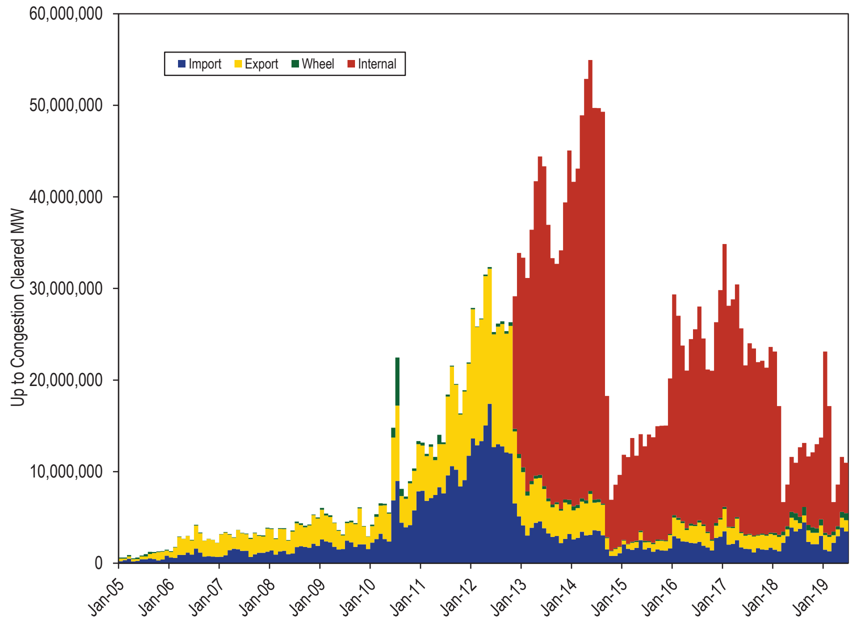
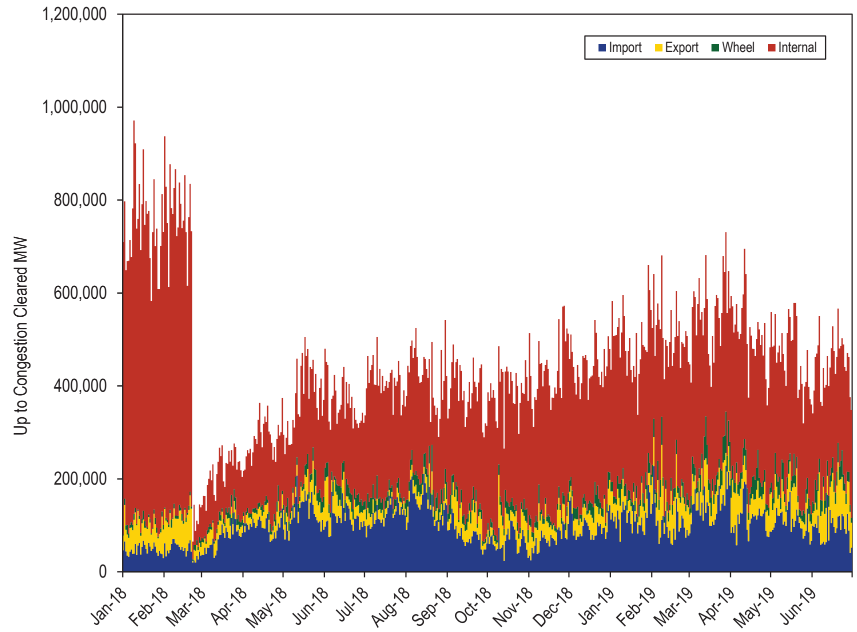


Figure 3-22 shows the daily cleared up to congestion MW by transaction type from January 1, 2018 through June 30, 2019.

Figure 3-22 Daily cleared up to congestion transaction by type (MW): January 2018 through June 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. With price formation in a competitive market, prices equal the value of the marginal unit of output and reflect the most efficient and least cost allocation of resources to meet demand.

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.

Real-time and day-ahead energy market load-weighted prices were 35.2 percent and 31.7 percent lower in the first six months of 2019 than in the first six months of 2018.

PJM real-time energy market prices decreased in the first six months of 2019 compared to the first six months of 2018. The average LMP was 32.0 percent lower in the first six months of 2019 than in the first six months of 2018, $26.41 per MWh versus $38.82 per MWh. The load-weighted average real-time LMP was 35.2 percent lower in the first six months of 2019 than in the first six months of 2018, $27.49 per MWh versus $42.44 per MWh.

The real-time load-weighted average LMP for the first six months of 2019 was 14.1 percent lower than the real-time fuel-cost adjusted, load-weighted, average LMP for the first six months of 2019. If fuel and emission costs in the first six months of 2019 had been the same as in the first six months of 2018, holding everything else constant, the load-weighted LMP would have been higher, $31.98 per MWh instead of the observed $27.49 per MWh.

PJM day-ahead energy market prices decreased in the first six months of 2019 compared to the first six months of 2018. The day-ahead average LMP was 29.1 percent lower in the first six months of 2019 than in the first six months of 2018, $26.86 per MWh versus $37.90 per MWh. The day-ahead load-weighted average LMP was 31.7 percent lower in the first six months of 2019 than in the first six months of 2018, $27.97 per MWh versus $40.96 per MWh.

Occasionally, in a constrained market, the LMPs at some pricing nodes can exceed the offer price of the highest cleared generator in the supply stack.[37] 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.[38]

37 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.

38 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).

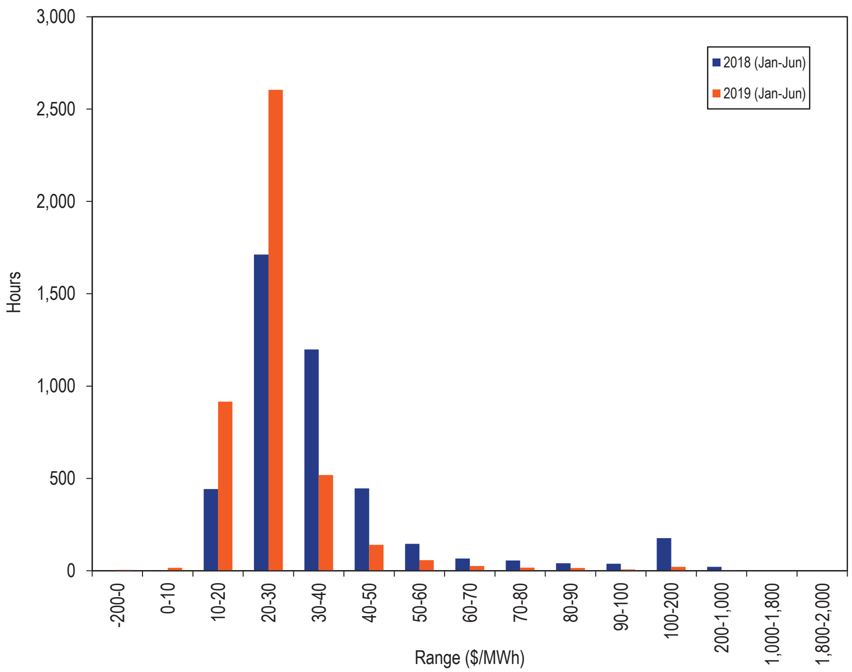
Real-Time Average LMP

Real-time average LMP is the hourly average LMP for the PJM Real-Time Energy Market.[39]

PJM Real-Time Average LMP Duration

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

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



PJM Real-Time, Average LMP

Table 3-31 shows the PJM real-time, average LMP for the first six months of 1998 through 2019.[40]

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

	Real-Time LMP			Year-to-Year Change		
(Jan-Jun)	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$20.13	$15.90	$15.59	NA	NA	NA
1999	$22.94	$17.84	$41.16	14.0%	12.2%	164.0%
2000	$25.38	$18.03	$25.65	10.6%	1.1%	(37.7%)
2001	$33.10	$25.69	$21.11	30.4%	42.5%	(17.7%)
2002	$24.10	$19.64	$13.21	(27.2%)	(23.6%)	(37.4%)
2003	$41.31	$33.74	$27.81	71.4%	71.8%	110.6%
2004	$44.99	$40.75	$22.97	8.9%	20.8%	(17.4%)
2005	$45.71	$39.80	$23.51	1.6%	(2.3%)	2.3%
2006	$49.36	$43.46	$25.26	8.0%	9.2%	7.5%
2007	$55.03	$48.05	$31.42	11.5%	10.6%	24.4%
2008	$70.19	$59.53	$41.77	27.6%	23.9%	33.0%
2009	$40.12	$35.42	$19.30	(42.8%)	(40.5%)	(53.8%)
2010	$43.27	$37.11	$22.20	7.9%	4.8%	15.0%
2011	$45.51	$37.40	$32.52	5.2%	0.8%	46.5%
2012	$29.74	$28.32	$16.10	(34.6%)	(24.3%)	(50.5%)
2013	$36.56	$32.79	$17.18	22.9%	15.8%	6.7%
2014	$62.14	$39.69	$88.87	69.9%	21.0%	417.4%
2015	$38.87	$29.04	$34.04	(37.4%)	(26.8%)	(61.7%)
2016	$25.84	$23.17	$13.61	(33.5%)	(20.2%)	(60.0%)
2017	$28.72	$25.76	$12.03	11.1%	11.2%	(11.6%)
2018	$38.82	$27.21	$38.76	35.2%	5.6%	222.3%
2019	$26.41	$23.81	$15.75	(32.0%)	(12.5%)	(59.4%)

Real-Time, Load-Weighted, Average LMP

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

39 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>.

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

PJM Real-Time, Load-Weighted, Average LMP

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

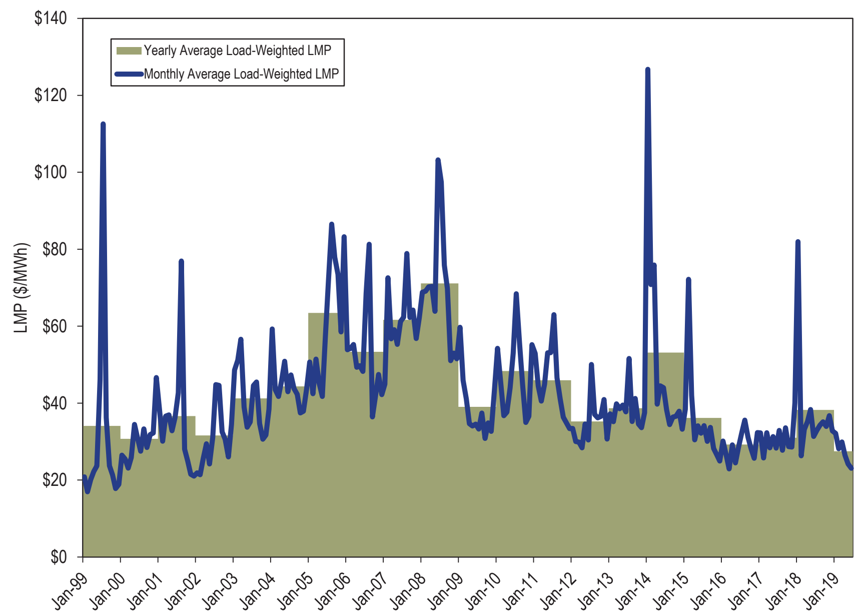
Table 3-32 Real-time, load-weighted, average LMP (Dollars per MWh): January through June, 1998 through 2019

	Real-Time, Load-Weighted, Average LMP			Year-to-Year Change		
(Jan-Jun)	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$21.66	$16.80	$18.39	NA	NA	NA
1999	$25.34	$18.59	$52.06	17.0%	10.7%	183.1%
2000	$27.76	$18.91	$29.69	9.5%	1.7%	(43.0%)
2001	$35.27	$27.88	$22.12	27.0%	47.4%	(25.5%)
2002	$25.93	$20.67	$14.62	(26.5%)	(25.9%)	(33.9%)
2003	$44.43	$37.98	$28.55	71.4%	83.8%	95.2%
2004	$47.62	$43.96	$23.30	7.2%	15.8%	(18.4%)
2005	$48.67	$42.30	$24.81	2.2%	(3.8%)	6.5%
2006	$51.83	$45.79	$26.54	6.5%	8.3%	7.0%
2007	$58.32	$52.52	$32.39	12.5%	14.7%	22.1%
2008	$74.77	$64.26	$44.25	28.2%	22.4%	36.6%
2009	$42.48	$36.95	$20.61	(43.2%)	(42.5%)	(53.4%)
2010	$45.75	$38.78	$23.60	7.7%	5.0%	14.5%
2011	$48.47	$38.63	$37.59	5.9%	(0.4%)	59.3%
2012	$31.21	$28.98	$17.69	(35.6%)	(25.0%)	(52.9%)
2013	$37.96	$33.58	$18.54	21.6%	15.9%	4.8%
2014	$69.92	$42.61	$103.35	84.2%	26.9%	457.6%
2015	$42.30	$30.34	$37.85	(39.5%)	(28.8%)	(63.4%)
2016	$27.09	$23.82	$14.49	(36.0%)	(21.5%)	(61.7%)
2017	$29.81	$26.47	$12.88	10.1%	11.1%	(11.1%)
2018	$42.44	$28.36	$43.68	42.4%	7.1%	239.1%
2019	$27.49	$24.40	$16.38	(35.2%)	(14.0%)	(62.5%)

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 June 2019.

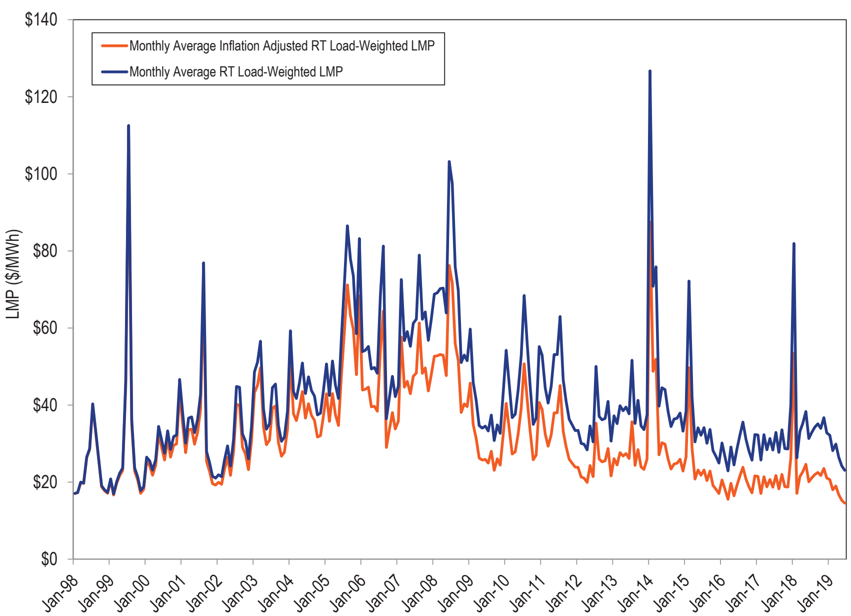
Figure 3-24 Real-time, monthly and annual, load-weighted, average LMP: January 1999 through June 2019



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 June 2019.[41] Table 3-33 shows the PJM real-time load-weighted average LMP and inflation adjusted first six months of 2019, load-weighted average LMP for the first six months of every year from 1998 through 2019. The PJM real-time inflation adjusted load-weighted average LMP for January through June, 2019 was the lowest six month value since PJM real-time markets started on April 1, 1999. The real-time inflation adjusted monthly load-weighted average LMP for June ($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 June 2019



41 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 July 1 2019)

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

	Load-Weighted, Average LMP	Inflation Adjusted Load-Weighted, Average LMP
1998	$21.66	$21.54
1999	$25.34	$24.74
2000	$27.76	$26.25
2001	$35.27	$32.27
2002	$25.93	$23.40
2003	$44.43	$39.18
2004	$47.62	$41.02
2005	$48.67	$40.71
2006	$51.83	$41.78
2007	$58.32	$45.83
2008	$74.77	$56.29
2009	$42.48	$32.26
2010	$45.75	$33.99
2011	$48.47	$35.04
2012	$31.21	$22.05
2013	$37.96	$26.40
2014	$69.92	$47.96
2015	$42.30	$28.98
2016	$27.09	$18.34
2017	$29.81	$19.74
2018	$42.44	$27.48
2019	$27.49	$17.48

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).[42] 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.

42 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Rev. 106 (May 30, 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.

Figure 3-26 shows, on a daily basis for the first six 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 six 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.

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

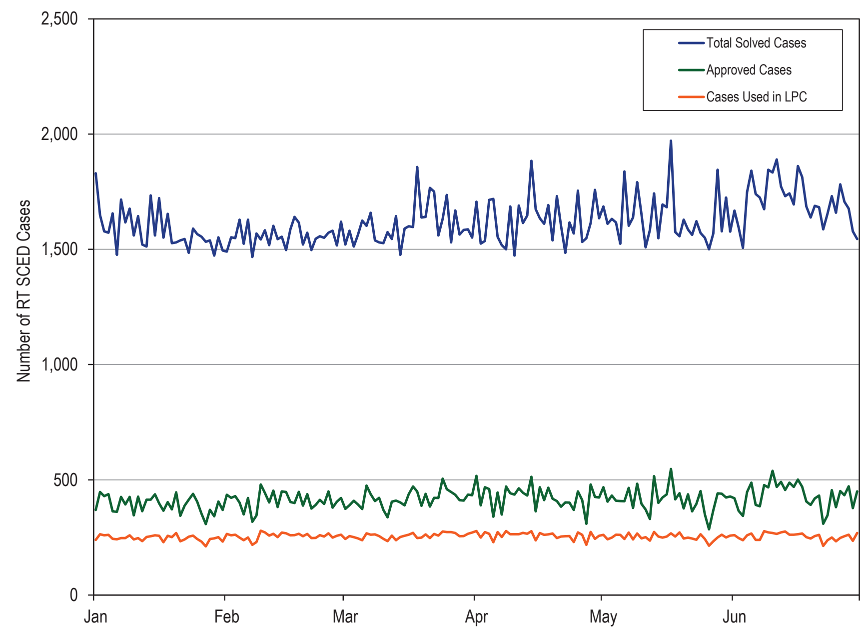


Table 3-34 RT SCED cases solved, approved and used in pricing: January through June, 2019

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%

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 six months of 2019. Table 3-35 shows that in the first six months of 2019, 67.6 percent of the five minute intervals have prices assigned for a target interval that is ten minutes prior to the dispatch target interval and 27.7 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 June, 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	27.7%
10	67.6%

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 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 six months of 2019, among 52,116 five minute intervals, PJM recalculated LMPs for 141 five minute intervals or 0.27 percent of the total five minute intervals in the first six months.

Table 3-36 Number of five minute interval real-time prices recalculated: January through June, 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
Total	52,116	141

Real-Time SCED Reserve Shortage

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 3-37 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 3-37 shows that, in the first six months of 2019, PJM dispatchers approved only 28 RT SCED cases that indicated a shortage of reserves, from a total of 2,718 solved RT SCED cases that indicated shortage. Among the 28 approved cases, only

43 OATT Attachment K § 1.10.8(e).

20 cases were used in LPC to calculate LMPs and reserve clearing prices. It is unclear what criteria PJM dispatchers use to approve the RT SCED cases to send dispatch signals to resources.

Table 3-37 RT SCED cases with reserve shortage: January through June, 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	7	1.6%	1.1%	0.9%
May	50,772	364	0	0	0.7%	0.0%	0.0%
Jun	51,299	377	0	0	0.7%	0.0%	0.0%
Total	293,375	2,718	28	20	0.9%	1.0%	0.7%

While there were 2,718 solved RT SCED cases that indicated shortage, the number of five minute intervals where RT SCED indicated shortage was only 1,482. This is because PJM solves multiple RT SCED cases for each five minute target interval.[44]

The MMU analyzed the intervals where one or more solved RT SCED cases indicated a shortage of one or more reserve products. Table 3-38 shows, for each month in the first six 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 3-38 shows that 1,482 intervals, or 2.8 percent of all five minute intervals in the first six months of 2019 had at least one solved SCED case showing a shortage of reserves, and 692 intervals, or 1.3 percent of all five minute intervals in the first six months of 2019 had more than one solved SCED case showing a shortage of reserves.

Table 3-38 Five minute intervals with shortage: January through June, 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%
Total	52,116	1,482	2.8%	692	1.3%	20	0.0%

44 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 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 twenty five minute intervals with shortage pricing that occurred on eleven days in the first six months of 2019, while there were 692 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.

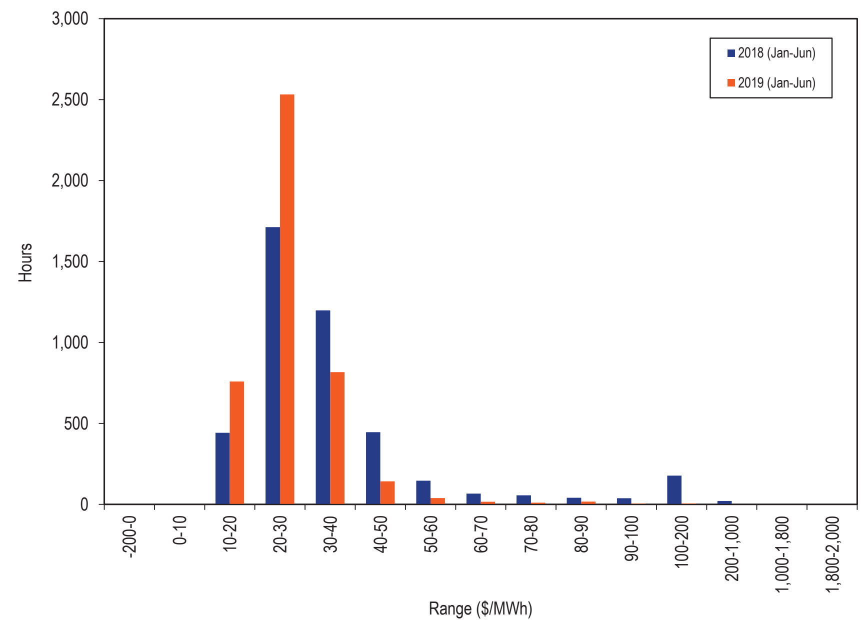
Day-Ahead Average LMP

Day-ahead average LMP is the hourly average LMP for the PJM Day-Ahead Energy Market.[45]

PJM Day-Ahead Average LMP Duration

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

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



45 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 3-39 shows the PJM day-ahead, average LMP in the first six months of 2000 through 2019.

Table 3-39 Day-ahead, average LMP (Dollars per MWh): January through June, 2000 through 2019

	Day-Ahead LMP			Year-to-Year Change		
(Jan-Jun)	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2000	$30.29	$22.72	$19.75	NA	NA	NA
2001	$35.02	$31.34	$17.43	15.6%	38.0%	(11.8%)
2002	$24.76	$21.28	$12.49	(29.3%)	(32.1%)	(28.4%)
2003	$42.83	$39.18	$23.52	73.0%	84.1%	88.3%
2004	$44.02	$43.14	$18.33	2.8%	10.1%	(22.0%)
2005	$45.63	$42.51	$18.35	3.7%	(1.5%)	0.1%
2006	$48.33	$47.07	$16.02	5.9%	10.7%	(12.7%)
2007	$53.03	$51.08	$22.91	9.7%	8.5%	43.0%
2008	$70.12	$66.09	$31.98	32.2%	29.4%	39.6%
2009	$40.01	$37.46	$15.38	(42.9%)	(43.3%)	(51.9%)
2010	$43.81	$40.64	$15.66	9.5%	8.5%	1.8%
2011	$44.75	$40.85	$19.53	2.1%	0.5%	24.8%
2012	$30.44	$29.64	$11.77	(32.0%)	(27.4%)	(39.8%)
2013	$37.11	$35.19	$10.42	21.9%	18.7%	(11.4%)
2014	$63.52	$44.42	$69.93	71.2%	26.2%	571.1%
2015	$39.98	$31.93	$28.76	(37.1%)	(28.1%)	(58.9%)
2016	$26.24	$24.95	$8.54	(34.4%)	(21.9%)	(70.3%)
2017	$29.03	$27.26	$8.87	10.6%	9.3%	3.9%
2018	$37.90	$30.08	$29.14	30.5%	10.3%	228.6%
2019	$26.86	$25.31	$9.56	(29.1%)	(15.8%)	(67.2%)

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 3-40 shows the PJM day-ahead, load-weighted, average LMP in the first six months of 2000 through 2019.

Table 3-40 Day-ahead, load-weighted, average LMP (Dollars per MWh): January through June, 2000 through 2019

	Day-Ahead, Load-Weighted, Average LMP			Year-to-Year Change		
(Jan-Jun)	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2000	NA	NA	NA	NA	NA	NA
2001	$37.08	$33.91	$18.11	NA	NA	NA
2002	$26.88	$23.00	$14.36	(27.5%)	(32.2%)	(20.7%)
2003	$45.62	$42.01	$23.96	69.7%	82.7%	66.8%
2004	$46.12	$45.45	$18.62	1.1%	8.2%	(22.3%)
2005	$48.12	$44.88	$19.24	4.3%	(1.3%)	3.3%
2006	$50.21	$48.67	$16.23	4.3%	8.5%	(15.7%)
2007	$55.70	$54.26	$23.47	10.9%	11.5%	44.7%
2008	$73.71	$69.33	$33.95	32.3%	27.8%	44.7%
2009	$42.21	$38.83	$16.16	(42.7%)	(44.0%)	(52.4%)
2010	$46.12	$42.50	$16.54	9.3%	9.5%	2.3%
2011	$47.12	$42.58	$22.34	2.2%	0.2%	35.1%
2012	$31.84	$30.35	$13.94	(32.4%)	(28.7%)	(37.6%)
2013	$38.23	$36.19	$11.03	20.1%	19.3%	(20.8%)
2014	$70.67	$47.04	$79.85	84.8%	30.0%	623.8%
2015	$43.26	$33.45	$32.23	(38.8%)	(28.9%)	(59.6%)
2016	$27.33	$25.92	$8.89	(36.8%)	(22.5%)	(72.4%)
2017	$30.02	$28.21	$9.38	9.8%	8.8%	5.6%
2018	$40.96	$31.44	$32.70	36.5%	11.4%	248.5%
2019	$27.97	$26.10	$10.59	(31.7%)	(17.0%)	(67.6%)

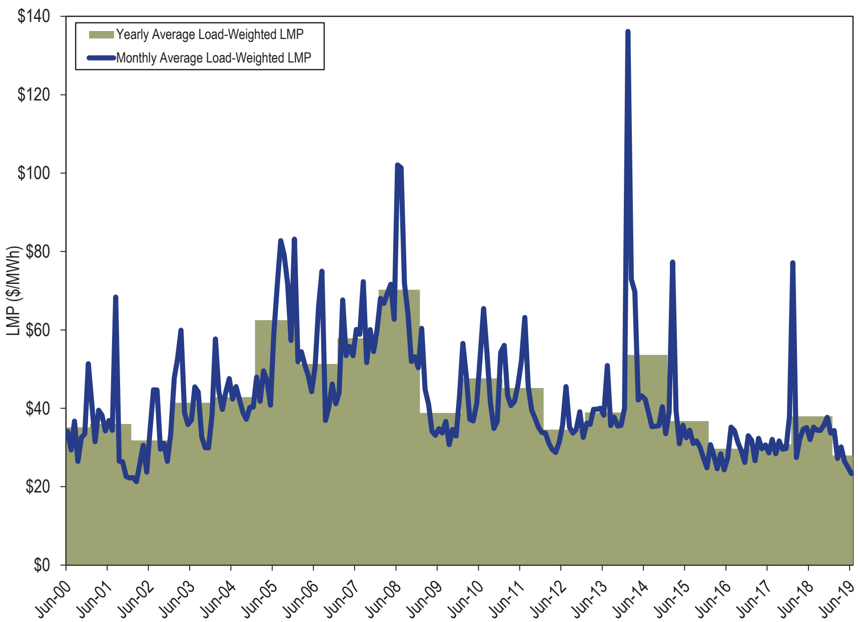
Table 3-50 shows zonal day-ahead, and day-ahead, load-weighted, average LMP in the first six months of 2018 and 2019.[46]

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

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 June 30, 2019.[47]

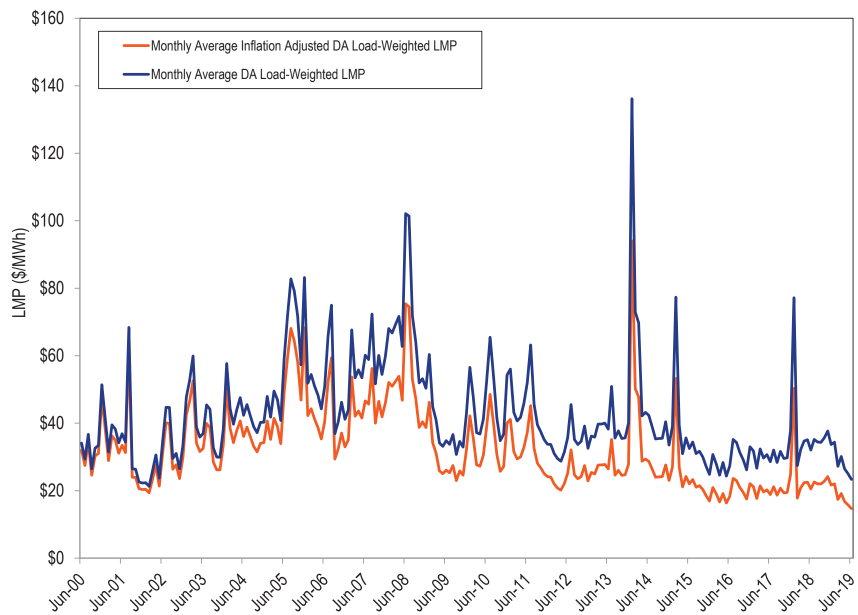
Figure 3-28 Day-ahead, monthly and annual, load-weighted, average LMP: June 2000 through June 2019



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

Figure 3-31 shows the PJM day-ahead monthly load-weighted average LMP and inflation adjusted monthly day-ahead load-weighted average LMP for June 2000 through June 2019.[48] Table 3-41 shows the PJM day-ahead first six month load-weighted average LMP and inflation adjusted load-weighted average LMP for every year from 2001 through 2019. The PJM day-ahead inflation adjusted load-weighted average LMP for January through June, 2019 was the third lowest six month value since PJM day-ahead markets started in 2000. The day-ahead inflation adjusted monthly load-weighted average LMP for June ($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 June 2019



47 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.

48 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 July 1, 2019).

Table 3-41 Day-ahead, yearly, load-weighted, average LMP unadjusted and inflation adjusted: January through June, 2000 through 2019

	Load-Weighted, Average LMP	Inflation Adjusted Load-Weighted, Average LMP
2000	$34.12	$31.98
2001	$37.08	$33.94
2002	$26.88	$24.25
2003	$45.62	$40.23
2004	$46.12	$39.73
2005	$48.12	$40.24
2006	$50.21	$40.47
2007	$55.70	$43.76
2008	$73.71	$55.49
2009	$42.21	$32.06
2010	$46.12	$34.28
2011	$47.12	$34.08
2012	$31.84	$22.49
2013	$38.23	$26.59
2014	$70.67	$48.48
2015	$43.26	$29.64
2016	$27.33	$18.51
2017	$30.02	$19.88
2018	$40.96	$26.52
2019	$27.97	$17.79

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 3-42 shows the number of cleared UTC transactions, the number of profitable cleared UTCs, the number of cleared UTCs that were profitable at their source point and the number of cleared UTCs that were profitable at their sink point in the first six months of 2018 and 2019. In the first six months of 2019, 47.2 percent of all cleared UTC transactions were net profitable. Of cleared UTC transactions, 68.6 percent were profitable on the source side and 31.4 were profitable on the sink side but only 5.8 percent were profitable on both the source and sink side.

Table 3-42 Cleared UTC profitability by source and sink point: January through June, 2018 and 2019[49]

(Jan-Jun)	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	5,302,730	2,643,427	3,428,122	1,910,222	304,610	49.9%	64.6%	36.0%	5.7%
2019	4,363,096	2,060,568	2,991,574	1,368,737	253,756	47.2%	68.6%	31.4%	5.8%

Table 3-43 shows the number of cleared INC and DEC transactions, the number of profitable cleared transactions in the first six months of 2018 and 2019. Of cleared INC and DEC transactions in the first six months of 2019, 69.2 percent of INCs were profitable and 33.9 percent of DECs were profitable.

Table 3-43 Cleared INC and DEC profitability: January through June, 2018 and 2019

(Jan-Jun)	Cleared INC	Profitable INC	Profitable INC Percent	Cleared DEC	Profitable DEC	Profitable DEC Percent
2018	1,180,928	773,830	65.5%	844,615	321,396	38.1%
2019	1,155,107	799,296	69.2%	831,940	281,642	33.9%

Figure 3-30 shows total UTC daily gross profits and losses and net profits and losses in the first six months of 2019.

Figure 3-30 UTC daily gross profits and losses and net profits: January through June, 2019[50]

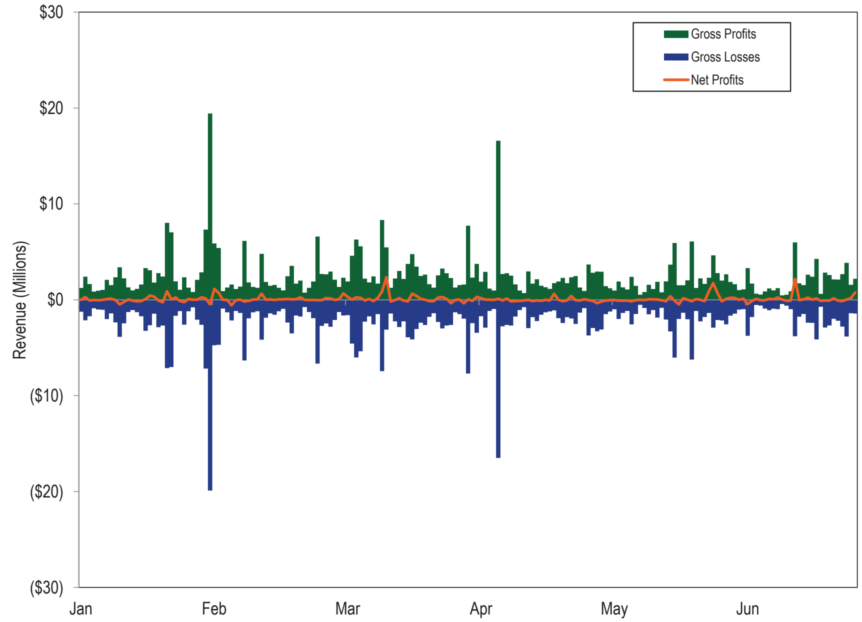


Figure 3-31 shows the cumulative UTC daily profits for January 1, 2013 through March 31, 2019. UTC profits during this period were primarily a result of significant unanticipated price differences between day-ahead and real-time LMPs. The large increases in cumulative daily UTC profits were due to PJM events that resulted in high real time LMPs. For example, the cumulative daily UTC profits in 2014 were greater than for the other three years as a result of profits from the significant and unanticipated day-ahead and real-time price differences that resulted from the polar vortex conditions in January 2014. The cumulative daily UTC profits increased during late February 2015 as a result of profits from the significant day-ahead and real-time prices

49 Calculations exclude PJM administrative charges.

50 Calculations exclude PJM administrative charges.

differences that resulted from cold weather conditions. The cumulative daily UTC profits increased during late September and December 2017 as a result of profits from the significant day-ahead and real-time price difference that resulted from the shortage event on September 21, 2017 and cold weather in late December. Cumulative daily UTC profits increased significantly during the cold weather in January 2018 as a result of large day-ahead and real-time price differences.

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

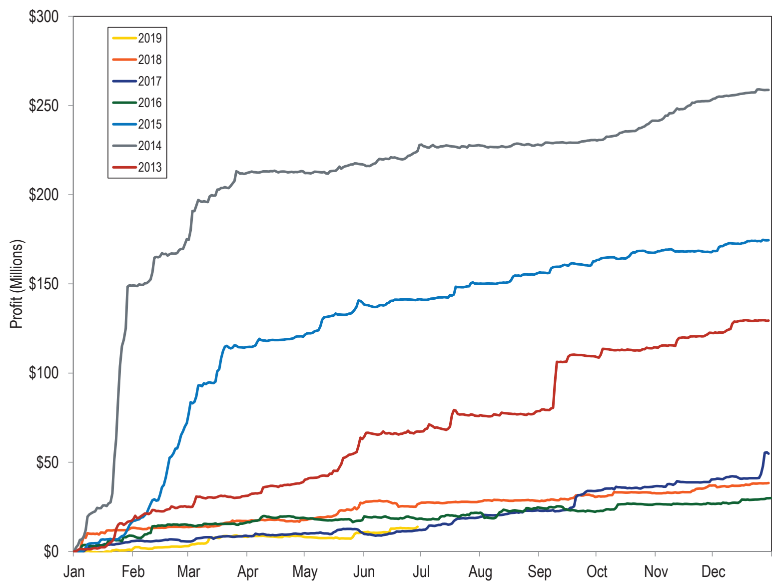


Table 3-44 shows UTC profits by month for January 1, 2013 through June 30, 2019. May 2016, September 2016, February 2017 and June 2018 were the only months in the past six years where the total monthly profits were negative.

Table 3-44 UTC profits by month: January 2013 through June 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							$13,818,118

Figure 3-32 shows total INC and DEC daily gross profits and losses and net profits and losses in the first six months of 2019.

Figure 3-32 INC and DEC daily gross profits and losses and net profits: January through June, 2019[51]

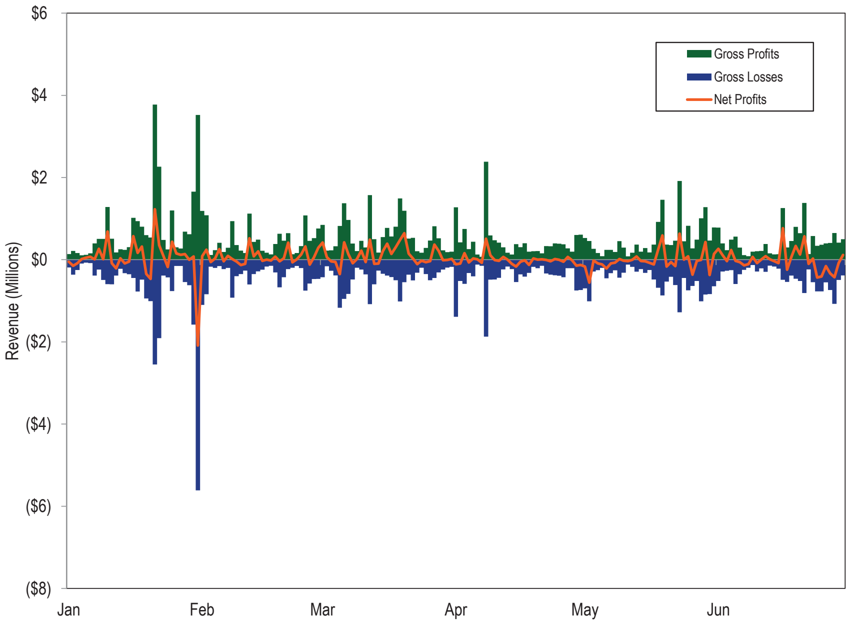
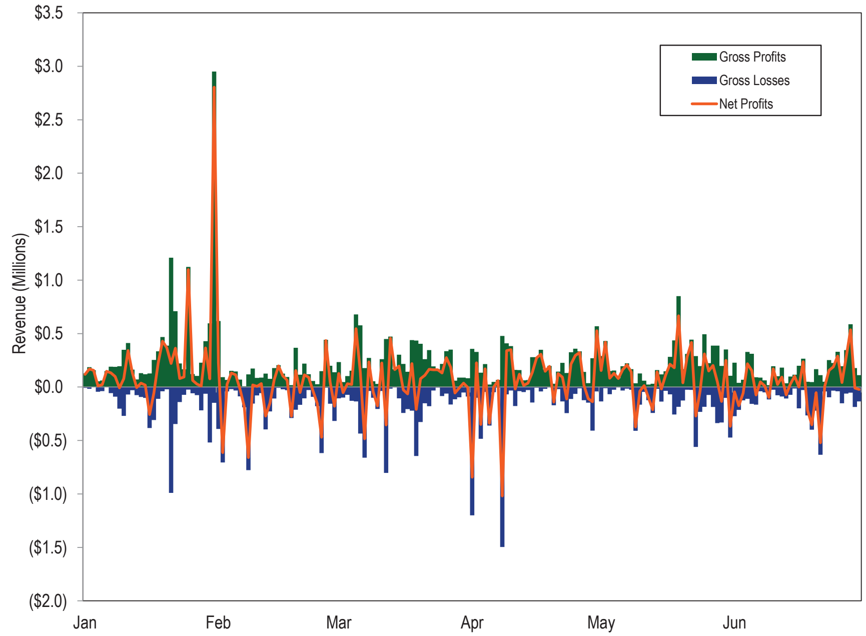


Figure 3-33 shows total INC daily gross profits and losses and net profits and losses in the first six months of 2019.

Figure 3-33 INC daily gross profits and losses and net profits: January through June, 2019[52]



51 Calculations exclude PJM administrative charges.

52 Calculations exclude PJM administrative charges.

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

Figure 3-34 DEC daily gross profits and losses and net profits: January through June, 2019[53]

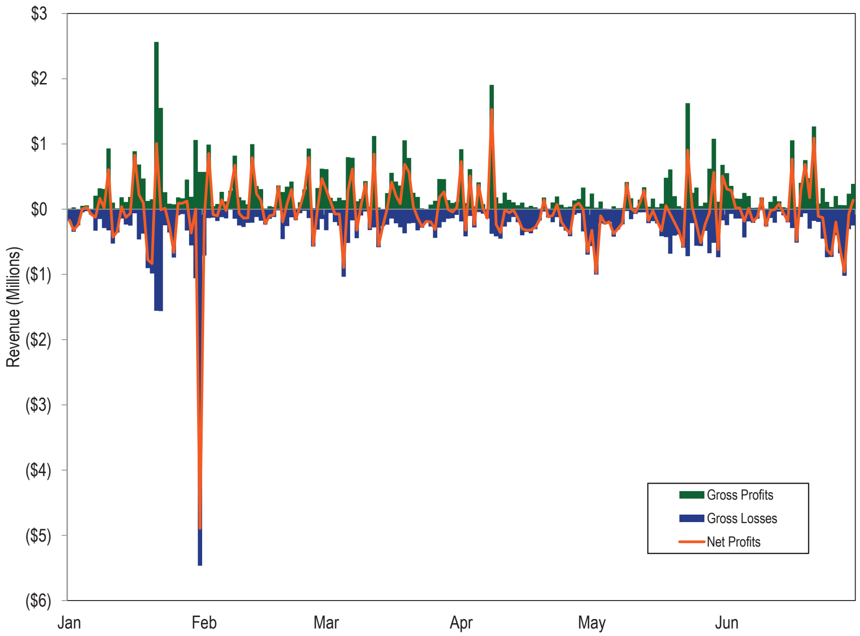


Figure 3-35 shows the cumulative INC and DEC daily profits for January 1, through June 30, 2019.

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

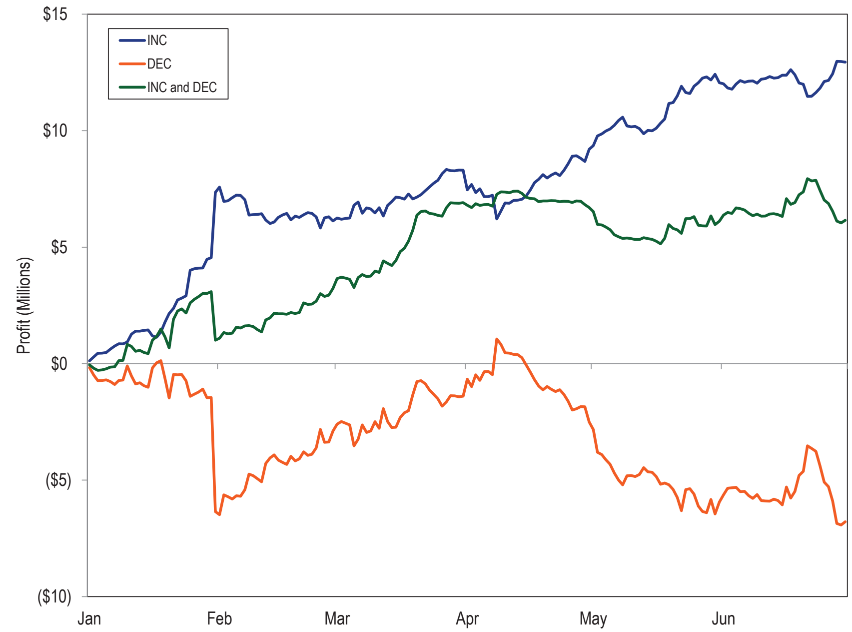


Table 3-45 shows INC and DEC profits by month for January 1, through June 30, 2019.

Table 3-45 INC and DEC profits by month: January through June, 2019

	January	February	March	April	May	June	Total
INCs	$7,354,057	($1,229,270)	$2,180,622	$898,417	$2,853,902	$885,231	$12,942,958
DECs	($6,349,787)	$3,455,508	$1,497,078	($1,109,340)	($3,439,754)	($841,301)	($6,787,597)
INCs and DECs	$1,004,269	$2,226,238	$3,677,699	($210,923)	($585,853)	$43,930	$6,155,361

53 Calculations exclude PJM administrative charges.

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 3-46 shows that the difference between the average real-time price and the average day-ahead price was $0.98 per MWh in the first six months of 2018, and -$0.45 per MWh in the first six months of 2019. The difference between average peak real-time price and the average peak day-ahead price was $0.15 per MWh in the first six months of 2018 and -$0.76 per MWh in the first six months of 2019.

Table 3-46 Day-ahead and real-time average LMP (Dollars per MWh): January through June, 2018 and 2019[54]

	2018 (Jan-Jun)				2019 (Jan-Jun)			
	Day-Ahead	Real-Time	Difference	Percent of Real Time	Day-Ahead	Real-Time	Difference	Percent of Real Time
Average	$37.90	$38.82	$0.93	2.4%	$26.86	$26.41	($0.45)	(1.7%)
Median	$30.08	$27.21	($2.87)	(10.5%)	$25.31	$23.81	($1.51)	(6.3%)
Standard deviation	$29.14	$38.76	$9.61	24.8%	$9.56	$15.75	$6.19	39.3%
Peak average	$42.65	$42.80	$0.15	0.3%	$30.61	$29.85	($0.76)	(2.6%)
Peak median	$34.87	$30.99	($3.88)	(12.5%)	$28.15	$25.88	($2.27)	(8.8%)
Peak standard deviation	$29.70	$35.32	$5.63	15.9%	$10.35	$19.44	$9.09	46.8%
Off peak average	$33.65	$35.27	$1.62	4.6%	$23.56	$23.39	($0.17)	(0.7%)
Off peak median	$25.33	$24.06	($1.27)	(5.3%)	$22.46	$21.55	($0.91)	(4.2%)
Off peak standard deviation	$27.97	$41.27	$13.30	32.2%	$7.37	$10.69	$3.32	31.0%

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.

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

Table 3-47 shows the difference between the real-time and the day-ahead energy market prices for the first six months of 2001 through 2019.

Table 3-47 Day-ahead and real-time average LMP (Dollars per MWh): January through June, 2001 through 2019

(Jan-Jun)	Day-Ahead	Real-Time	Difference	Percent of Real Time
2001	$35.02	$33.10	($1.92)	(5.5%)
2002	$24.76	$24.10	($0.66)	(2.7%)
2003	$42.83	$41.31	($1.53)	(3.6%)
2004	$44.02	$44.99	$0.97	2.2%
2005	$45.63	$45.71	$0.07	0.2%
2006	$48.33	$49.36	$1.03	2.1%
2007	$53.03	$55.03	$2.00	3.8%
2008	$70.12	$70.19	$0.08	0.1%
2009	$40.01	$40.12	$0.11	0.3%
2010	$43.81	$43.27	($0.54)	(1.2%)
2011	$44.75	$45.51	$0.76	1.7%
2012	$30.44	$29.74	($0.69)	(2.3%)
2013	$37.11	$36.56	($0.55)	(1.5%)
2014	$63.52	$62.14	($1.38)	(2.2%)
2015	$39.98	$38.87	($1.11)	(2.8%)
2016	$26.24	$25.84	($0.40)	(1.5%)
2017	$29.03	$28.72	($0.31)	(1.1%)
2018	$37.90	$38.82	$0.93	2.4%
2019	$26.86	$26.41	($0.45)	(1.7%)

Table 3-48 provides frequency distributions of the differences between PJM real-time hourly LMP and PJM day-ahead hourly LMP for the first six months of 2018 and 2019.

Table 3-48 Frequency distribution by hours of real-time LMP minus day-ahead LMP (Dollars per MWh): January through June, 2018 and 2019

	2018 (Jan-Jun)		2019 (Jan-Jun)	
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	0.09%	0	0.00%
($100) to ($50)	27	0.71%	5	0.12%
($50) to $0	2,787	64.89%	3,022	69.70%
$0 to $50	1,403	97.19%	1,290	99.40%
$50 to $100	85	99.15%	15	99.75%
$100 to $150	22	99.65%	8	99.93%
$150 to $200	5	99.77%	1	99.95%
$200 to $250	7	99.93%	1	99.98%
$250 to $300	1	99.95%	0	99.98%
$300 to $350	1	99.98%	0	99.98%
$350 to $400	0	99.98%	0	99.98%
$400 to $450	1	100.00%	0	99.98%
$450 to $500	0	100.00%	0	99.98%
$500 to $750	0	100.00%	1	100.00%
$750 to $1,000	0	100.00%	0	100.00%
$1,000 to $1,250	0	100.00%	0	100.00%
>= $1,250	0	100.00%	0	100.00%

Figure 3-36 shows the hourly differences between day-ahead and real-time hourly LMP in the first six months of 2019.

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

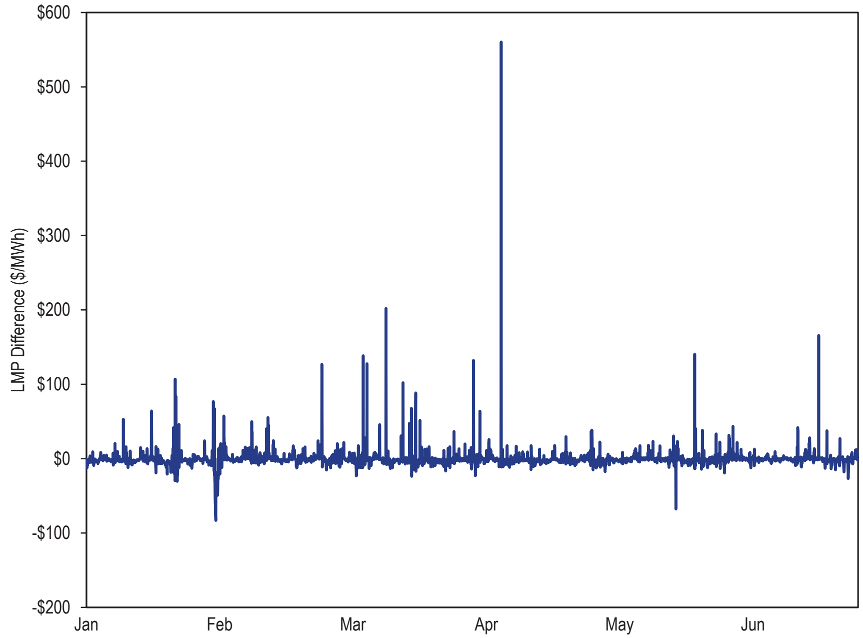


Figure 3-37 shows the monthly average of the differences between the day-ahead and real-time PJM average LMPs from January 1, 2013, through June 30, 2019.

Figure 3-37 Monthly average of real-time minus day-ahead LMP: January 2013 through June 2019

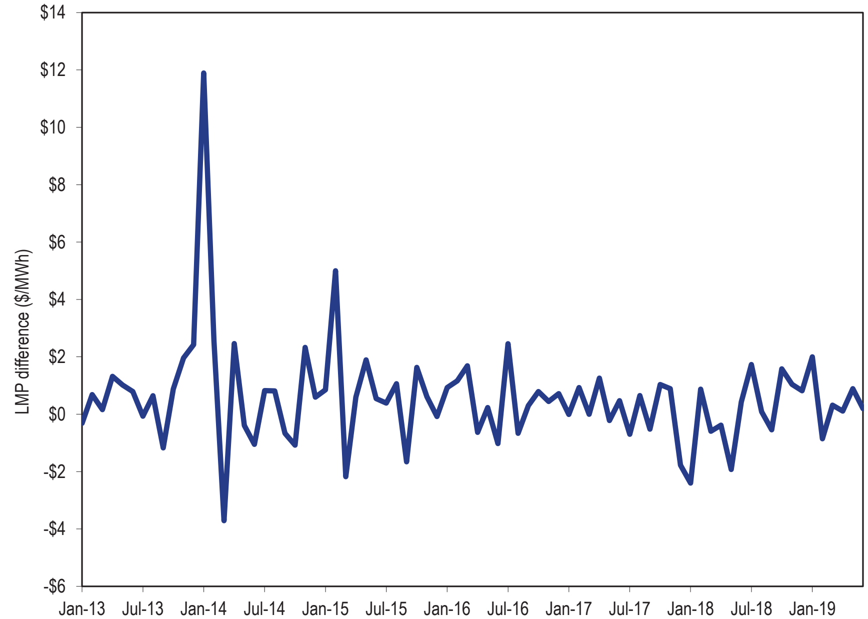


Figure 3-38 shows the monthly average of the absolute value of the differences between the day-ahead and real-time hourly, nodal LMPs from January 1, 2013, through June 30, 2019.

Figure 3-38 Monthly average of absolute value of real-time minus day-ahead LMP by pnode: January 2013 through June 2019

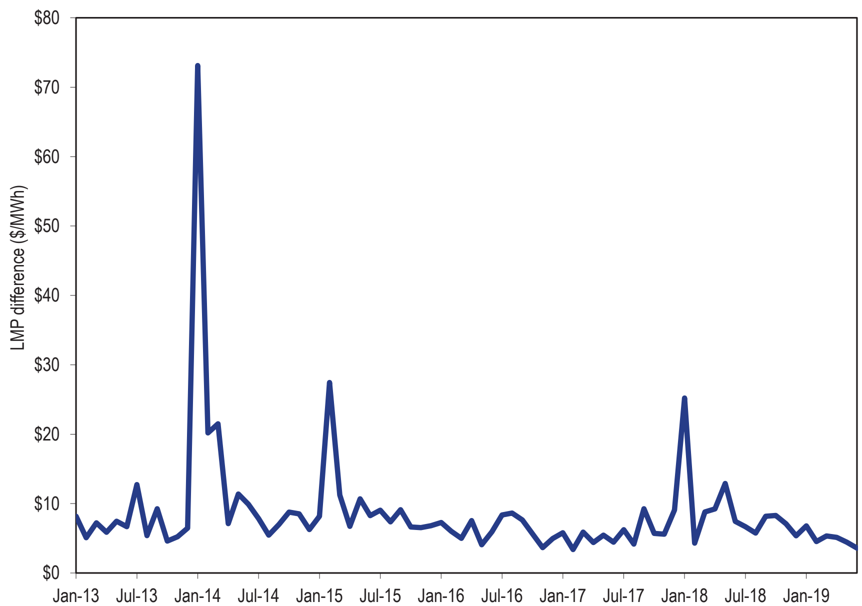
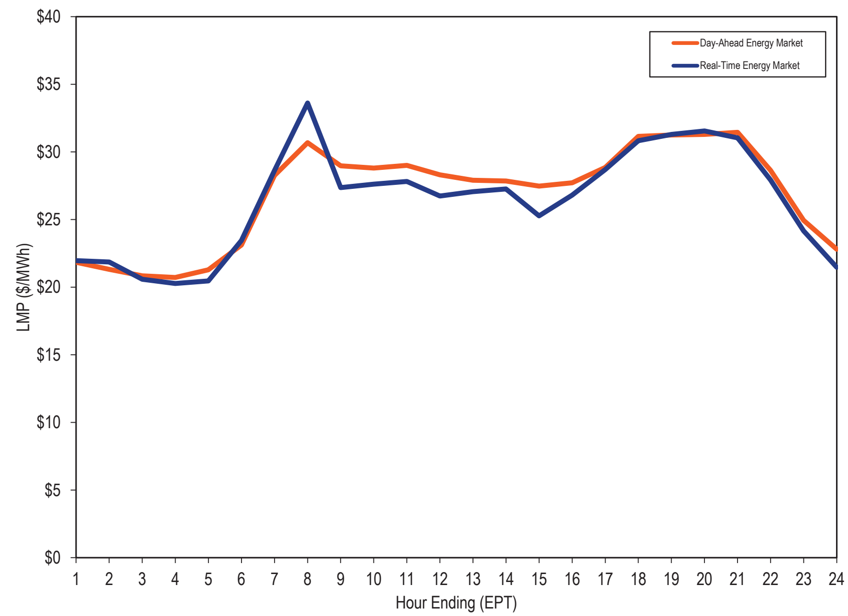


Figure 3-39 shows day-ahead and real-time LMP on an average hourly basis for the first six months of 2019. Hour ending 8 had the largest difference between the DA and RT LMP, at $2.93 per MWh, and hour ending 19 had the smallest difference at $0.04 per MWh. The average for the first six months of 2019 was -$0.45 per MWh lower in the RT LMP than DA LMP.

Figure 3-39 System hourly average LMP: January through June, 2019



Zonal LMP and Dispatch

Table 3-49 shows zonal real-time, and real-time, load-weighted, average LMP in the first six months of 2018 and 2019.

Table 3-49 Zonal real-time and real-time, load-weighted, average LMP (Dollars per MWh): January through June, 2018 and 2019

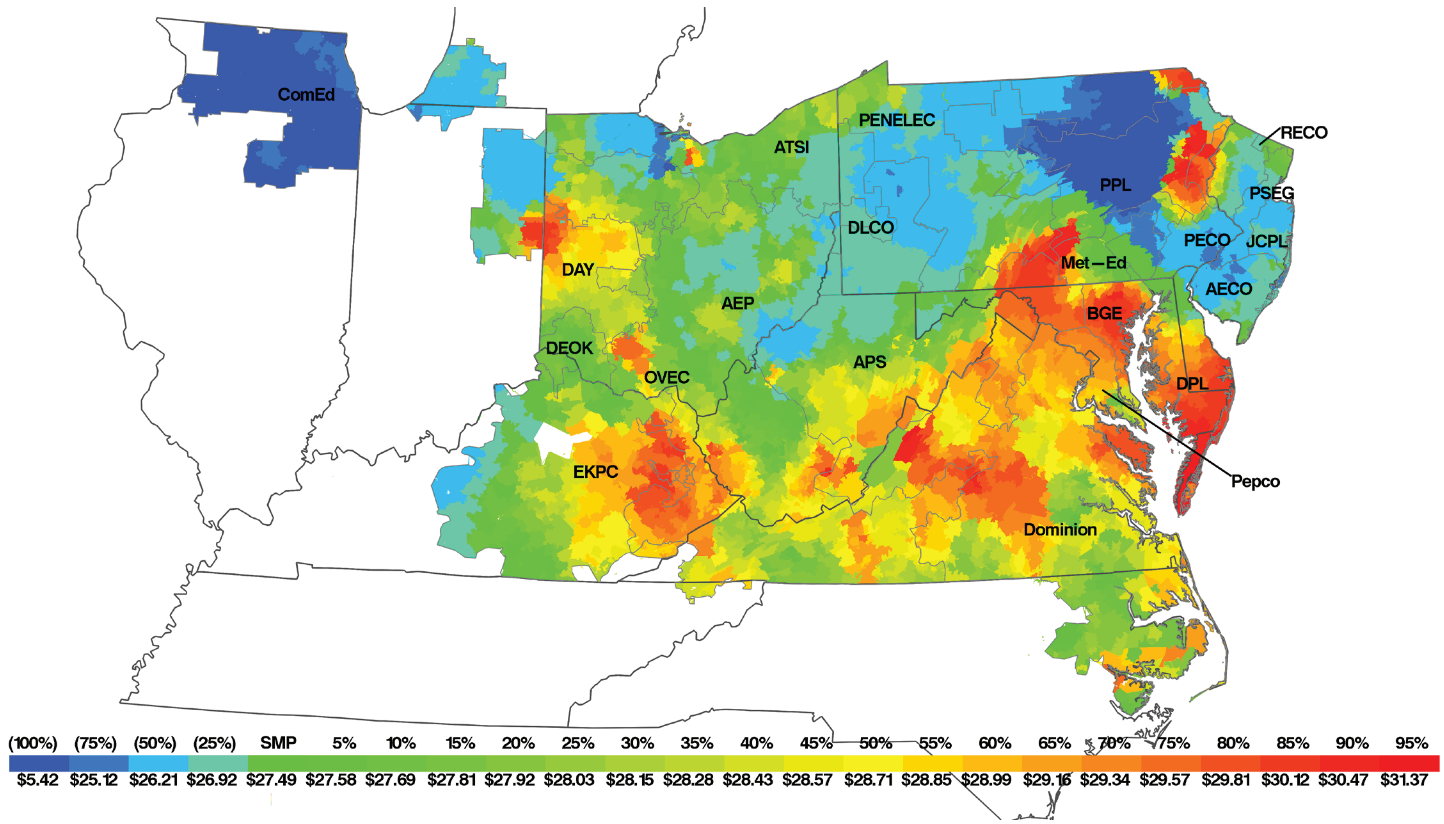
	Real-Time Average LMP			Real-Time, Load-Weighted, Average LMP		
Zone	2018 (Jan-Jun)	2019 (Jan-Jun)	Percent Change	2018 (Jan-Jun)	2019 (Jan-Jun)	Percent Change
AECO	$36.98	$25.82	(30.2%)	$40.49	$26.96	(33.4%)
AEP	$38.20	$26.66	(30.2%)	$41.23	$27.65	(32.9%)
APS	$40.59	$26.71	(34.2%)	$44.74	$27.89	(37.7%)
ATSI	$40.96	$26.86	(34.4%)	$43.91	$27.74	(36.8%)
BGE	$46.00	$28.70	(37.6%)	$52.10	$30.33	(41.8%)
ComEd	$27.83	$24.22	(13.0%)	$29.33	$24.97	(14.9%)
DAY	$38.93	$27.57	(29.2%)	$41.76	$28.67	(31.3%)
DEOK	$39.81	$26.50	(33.4%)	$43.29	$27.46	(36.6%)
DLCO	$44.35	$27.62	(37.7%)	$51.20	$28.93	(43.5%)
Dominion	$40.03	$26.23	(34.5%)	$47.15	$28.29	(40.0%)
DPL	$40.66	$26.37	(35.1%)	$43.94	$27.15	(38.2%)
EKPC	$34.53	$26.26	(24.0%)	$38.69	$27.64	(28.6%)
JCPL	$37.40	$25.75	(31.1%)	$41.37	$27.04	(34.6%)
Met-Ed	$36.68	$26.08	(28.9%)	$41.10	$27.45	(33.2%)
OVEC	NA	$25.82	NA	NA	$26.31	NA
PECO	$36.99	$25.35	(31.5%)	$41.24	$26.53	(35.7%)
PENELEC	$38.47	$25.86	(32.8%)	$41.30	$26.78	(35.2%)
Pepco	$44.68	$27.91	(37.5%)	$50.27	$29.35	(41.6%)
PPL	$35.71	$24.43	(31.6%)	$40.39	$25.71	(36.4%)
PSEG	$37.71	$26.21	(30.5%)	$40.93	$27.34	(33.2%)
RECO	$37.61	$26.21	(30.3%)	$40.42	$27.11	(32.9%)
PJM	$38.82	$26.41	(32.0%)	$42.44	$27.49	(35.2%)

Table 3-50 Zonal day-ahead and day-ahead, load-weighted, average LMP (Dollars per MWh): January through June, 2018 and 2019

	Day-Ahead Average LMP			Day-Ahead, Load-Weighted, Average LMP		
Zone	2018 (Jan-Jun)	2019 (Jan-Jun)	Percent Change	2018 (Jan-Jun)	2019 (Jan-Jun)	Percent Change
AECO	$36.91	$25.87	(29.9%)	$39.91	$26.98	(32.4%)
AEP	$37.01	$27.10	(26.8%)	$39.55	$28.19	(28.7%)
APS	$39.59	$27.32	(31.0%)	$42.73	$28.55	(33.2%)
ATSI	$38.74	$27.58	(28.8%)	$40.80	$28.55	(30.0%)
BGE	$44.80	$29.53	(34.1%)	$49.72	$31.18	(37.3%)
ComEd	$27.10	$24.52	(9.5%)	$28.48	$25.23	(11.4%)
DAY	$37.93	$28.07	(26.0%)	$40.39	$29.19	(27.7%)
DEOK	$39.70	$27.21	(31.5%)	$42.98	$28.27	(34.2%)
DLCO	$43.53	$28.45	(34.6%)	$49.61	$30.05	(39.4%)
Dominion	$39.75	$26.28	(33.9%)	$46.11	$28.27	(38.7%)
DPL	$38.57	$27.01	(30.0%)	$40.90	$27.85	(31.9%)
EKPC	$33.92	$26.56	(21.7%)	$37.37	$28.02	(25.0%)
JCPL	$37.20	$25.67	(31.0%)	$40.47	$26.81	(33.8%)
Met-Ed	$36.74	$25.93	(29.4%)	$40.04	$27.08	(32.4%)
OVEC	NA	$26.19	NA	NA	$29.38	NA
PECO	$36.91	$25.24	(31.6%)	$40.26	$26.28	(34.7%)
PENELEC	$37.16	$26.67	(28.2%)	$39.93	$28.06	(29.7%)
Pepco	$43.70	$28.87	(33.9%)	$48.47	$30.48	(37.1%)
PPL	$35.84	$24.71	(31.1%)	$39.57	$25.85	(34.7%)
PSEG	$38.13	$26.19	(31.3%)	$41.27	$27.27	(33.9%)
RECO	$37.85	$26.61	(29.7%)	$40.51	$27.86	(31.2%)
PJM	$37.90	$26.86	(29.1%)	$40.96	$27.97	(31.7%)

Figure 3-40 is a map of the real-time, load-weighted, average LMP in the first six 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.

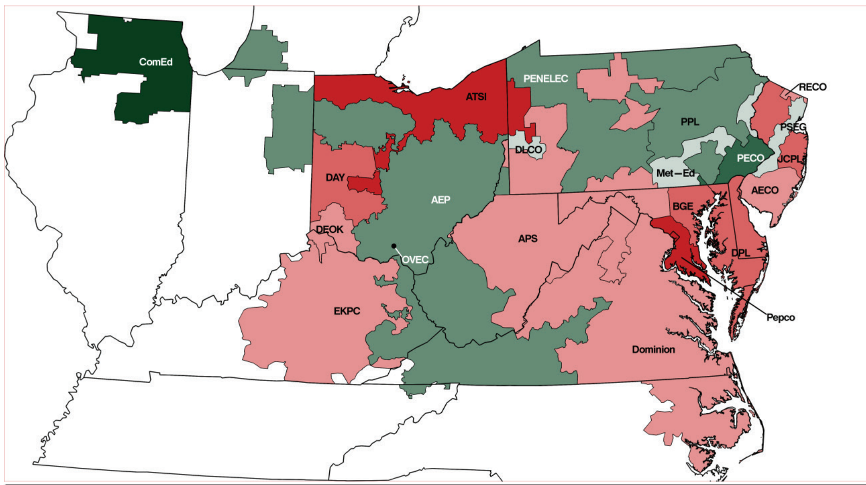
Figure 3-40 Real-time, load-weighted, average LMP: January through June, 2019



Net Generation by Zone

Figure 3-41 shows the difference between the PJM real-time generation and real-time load by zone in in the first six months of 2019. Figure 3-41 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 3-51 shows the difference between the PJM real-time generation and real-time load by zone in the first six months of 2018 and 2019.

Figure 3-41 Map of real-time generation, less real-time load, by zone: January through June, 2019[55]



Zone	Net Gen Minus Load (GWh)	Zone	Net Gen Minus Load (GWh)	Zone	Net Gen Minus Load (GWh)	Zone	Net Gen Minus Load (GWh)
AECO	(1,743)	DAY	(8,001)	JCPL	(5,037)	PPL	10,351
AEP	11,433	DEOK	(2,983)	Met-Ed	3,592	PSEG	1,115
APS	(724)	Dominion	(1,576)	OVEC	5,171	RECO	(663)
ATSI	(12,793)	DPL	(6,601)	PECO	14,997		
BGE	(6,488)	DLCO	1,936	PENELEC	12,211		
ComEd	21,291	EKPC	(3,344)	Pepco	(9,059)		

55 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 3-51 Real-time generation less real-time load by zone (GWh): January through June, 2018 and 2019

	Zonal Generation and Load (GWh)					
Jan-Jun	2018			2019		
Zone	Generation	Load	Net	Generation	Load	Net
AECO	2,646.4	4,593.3	(1,946.9)	2,786.5	4,529.1	(1,742.6)
AEP	79,085.3	64,307.0	14,778.4	73,304.8	61,871.9	11,432.9
APS	23,432.3	24,824.7	(1,392.4)	23,739.4	24,463.4	(724.0)
ATSI	18,804.0	33,064.9	(14,260.9)	18,985.3	31,778.6	(12,793.4)
BGE	10,777.8	15,346.2	(4,568.3)	8,623.1	15,111.2	(6,488.1)
ComEd	64,406.4	47,174.6	17,231.7	66,268.4	44,976.9	21,291.5
DAY	4,142.5	8,684.6	(4,542.1)	352.0	8,353.2	(8,001.2)
DEOK	7,240.5	13,507.4	(6,266.9)	9,888.4	12,870.9	(2,982.5)
Dominion	46,310.2	49,258.9	(2,948.7)	47,333.6	48,910.0	(1,576.4)
DPL	2,988.7	9,059.2	(6,070.5)	2,199.7	8,801.2	(6,601.5)
DLCO	8,080.1	6,695.3	1,384.8	8,363.8	6,427.9	1,936.0
EKPC	4,399.9	6,667.0	(2,267.1)	2,880.6	6,224.8	(3,344.1)
JCPL	8,125.2	10,651.0	(2,525.9)	5,218.4	10,255.2	(5,036.8)
Met-Ed	11,002.7	7,680.7	3,322.0	11,175.8	7,584.0	3,591.7
OVEC	0.0	0.0	0.0	5,238.2	66.9	5,171.3
PECO	32,633.1	19,473.3	13,159.8	34,140.0	19,142.5	14,997.4
PENELEC	22,117.0	8,584.1	13,533.0	20,586.7	8,375.8	12,210.9
Pepco	5,857.5	14,658.7	(8,801.3)	5,175.5	14,234.2	(9,058.7)
PPL	24,467.2	20,306.1	4,161.1	30,431.5	20,080.4	10,351.1
PSEG	21,437.6	20,638.3	799.3	21,182.6	20,067.4	1,115.2
RECO	0.0	688.2	(688.2)	0.0	663.3	(663.3)

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 3-52 shows PJM generation by fuel source in GWh for the first six months of 2018 and 2019. In the first six months of 2019, generation from coal units decreased 16.7 percent, generation from natural gas units increased 18.4 percent, and generation from oil decreased 64.1 percent compared to the first six months of 2018.[56] The increase in gas fired generation offsets the decreases in coal, oil and nuclear generation. Wind and solar output rose by 1,837 GWh compared to the first six months of 2018, supplying 3.7 percent of PJM energy in the first six months of 2019.

Table 3-52 Generation (By fuel source (GWh)): January through June, 2018 and 2019[57 58 59]

		2018 (Jan - Jun)		2019 (Jan - Jun)		Change in
		GWh	Percent	GWh	Percent	Output
Coal		119,918.8	29.7%	99,864.2	24.8%	(16.7%)
	Bituminous	100,884.4	25.0%	84,501.8	21.0%	(16.2%)
	Sub Bituminous	15,006.8	3.7%	11,708.4	2.9%	(22.0%)
	Other Coal	4,027.6	1.0%	3,654.1	0.9%	(9.3%)
Nuclear		141,179.9	35.0%	138,609.7	34.4%	(1.8%)
Gas		115,143.0	28.5%	136,016.0	33.8%	18.1%
	Natural Gas	113,983.3	28.2%	134,943.6	33.5%	18.4%
	Landfill Gas	1,159.4	0.3%	1,072.2	0.3%	(7.5%)
	Other Gas	0.3	0.0%	0.2	0.0%	(35.7%)
Hydroelectric		8,797.9	2.2%	9,817.5	2.4%	11.6%
	Pumped Storage	2,582.9	0.6%	2,188.8	0.5%	(15.3%)
	Run of River	5,364.5	1.3%	7,002.2	1.7%	30.5%
	Other Hydro	850.5	0.2%	626.6	0.2%	(26.3%)
Wind		12,081.6	3.0%	13,644.9	3.4%	12.9%
Waste		2,208.6	0.5%	2,125.6	0.5%	(3.8%)
	Solid Waste	2,072.2	0.5%	2,052.7	0.5%	(0.9%)
	Miscellaneous	136.4	0.0%	73.0	0.0%	(46.5%)
Oil		2,529.6	0.6%	907.5	0.2%	(64.1%)
	Heavy Oil	428.0	0.1%	6.5	0.0%	(98.5%)
	Light Oil	825.5	0.2%	88.1	0.0%	(89.3%)
	Diesel	350.4	0.1%	65.1	0.0%	(81.4%)
	Gasoline	0.0	0.0%	0.0	0.0%	NA
	Kerosene	56.6	0.0%	9.9	0.0%	(82.5%)
	Jet Oil	8.0	0.0%	0.0	0.0%	(100.0%)
	Other Oil	861.1	0.2%	738.0	0.2%	(14.3%)
Solar, Net Energy Metering		1,076.2	0.3%	1,349.6	0.3%	25.4%
Battery		7.5	0.0%	10.9	0.0%	45.9%
Biofuel		876.8	0.2%	592.1	0.1%	(32.5%)
Total		403,819.9	100.0%	402,938.1	100.0%	(0.2%)

56 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.

57 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.

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

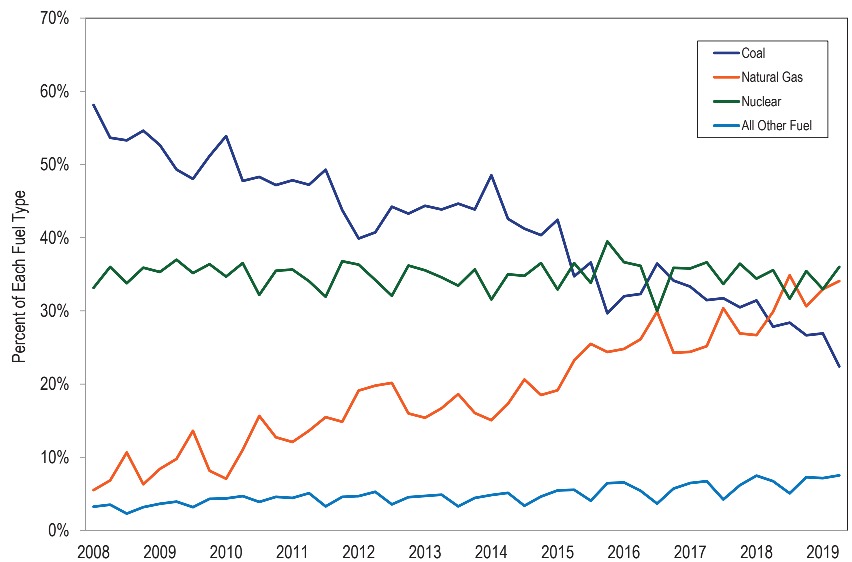
59 Other Gas includes: Propane, Butane, Hydrogen, Gasified Coal, and Refinery Gas. Other Coal includes: Lignite, Liquefied Coal, Gasified Coal, and Waste Coal.

Table 3-53 Monthly generation (By fuel source (GWh)): January through June, 2019

	Jan	Feb	Mar	Apr	May	Jun	Total
Coal	23,151.4	16,444.7	17,418.6	12,890.5	14,846.9	15,112.1	99,864.2
Bituminous	19,242.9	13,611.1	14,630.3	10,530.5	12,913.2	13,573.7	84,501.8
Sub Bituminous	3,093.6	2,185.0	2,106.3	1,889.3	1,457.1	977.2	11,708.4
Other Coal	814.9	648.6	682.0	470.8	476.6	561.2	3,654.1
Nuclear	25,595.0	22,303.6	21,899.6	21,078.7	23,997.8	23,735.1	138,609.7
Gas	23,457.9	23,274.3	23,627.3	19,184.6	20,646.8	25,825.1	136,016.0
Natural Gas	23,265.9	23,104.3	23,443.2	19,012.7	20,465.9	25,651.6	134,943.6
Landfill Gas	192.0	170.0	184.2	171.9	180.9	173.3	1,072.2
Other Gas	0.0	0.0	0.0	0.0	0.0	0.2	0.2
Hydroelectric	1,805.1	1,453.6	1,699.3	1,593.8	1,742.6	1,523.0	9,817.5
Pumped Storage	337.2	322.7	326.3	348.9	454.4	399.2	2,188.8
Run of River	1,361.4	1,037.2	1,289.2	1,159.2	1,155.5	999.6	7,002.2
Other Hydro	106.5	93.7	83.7	85.7	132.7	124.2	626.6
Wind	2,611.7	2,228.4	2,467.1	2,665.7	1,925.4	1,746.6	13,644.9
Waste	385.1	317.6	332.2	338.6	372.1	380.1	2,125.6
Solid Waste	362.0	298.3	307.3	332.8	372.1	380.1	2,052.7
Miscellaneous	23.0	19.3	24.9	5.7	0.0	0.0	73.0
Oil	214.5	127.2	145.4	99.1	169.0	152.3	907.5
Heavy Oil	5.6	0.8	0.0	0.0	0.0	0.0	6.5
Light Oil	41.8	15.0	13.5	4.6	8.6	4.6	88.1
Diesel	15.5	4.6	41.9	1.2	1.2	0.7	65.1
Gasoline	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	9.9
Jet Oil	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	738.0
Solar, Net Energy Metering	130.1	145.8	230.4	254.5	293.2	295.6	1,349.6
Battery	2.0	2.0	2.2	1.9	1.7	1.3	10.9
Biofuel	107.3	80.7	108.3	96.1	98.5	101.4	592.1
Total	77,460.1	66,377.8	67,930.3	58,203.5	64,093.8	68,872.5	402,938.1

Figure 3-42 shows total generation percentage of natural gas, coal, nuclear and all other fuel types in the Real-Time Energy Market since 2008.

Figure 3-42 Historical generation By fuel source (Percentage): January 2008 through June 2019



Fuel Diversity

Figure 3-43 shows the fuel diversity index (FDI_e) for PJM energy generation.[60] 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 3-53 with nonzero generation values. As fuel diversity has increased, seasonality in the FDI_e has decreased and the FDI_e has exhibited less

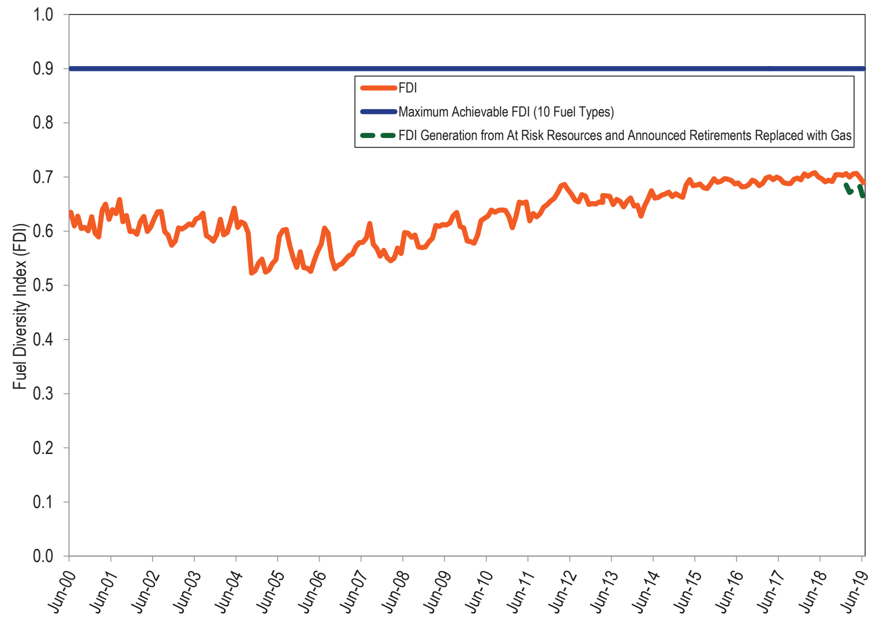
60 Monitoring Analytics developed the FDI to provide an objective metric of fuel diversity. The FDI metric is similar to the HHI used to measure market concentration. The FDI is calculated separately for energy output and for installed capacity.

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.[61] 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 24.8 percent for the first six months of 2019. Gas generation as a share of total generation was 7.4 percent for 2008 and 33.8 percent for the first six months of 2019. Wind generation as a share of total generation was 0.5 percent for 2008 and 3.4 percent for the first six months of 2019.

The average FDI_e decreased 0.3 percent in the first six months of 2019 compared to the first six months in 2018. The FDI_e was also used to measure the impact on fuel diversity of potential retirements. Twenty-seven units with installed capacity totaling 14,954 MW were identified as being at risk of retirement.[62] The at risk units consists of 12,017 MW of coal and 2,937 MW of nuclear capacity. Generation owners that intend to retire a generator are required by the tariff to notify PJM at least 90 days in advance.[63] There are 11,852 MW of generation that have requested retirement after June 30, 2019.[64] The at risk units and other generators with deactivation notices generated 43.3 GWh in the first six months of 2019. The dashed line in Figure 3-43 shows a counterfactual result for FDI_e assuming the 43.3 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 six months of 2019 under the counterfactual assumption would have been 3.8 percent lower than the actual FDI_e.

61 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.
62 See the *2018 State of the Market Report for PJM*, Volume 2, Section 7: Net Revenue, Units at Risk.
63 See PJM. OATT: § V "Generation Deactivation."
64 See Table 12-9.

Figure 3-43 Fuel diversity index for monthly generation: June 2000 through June 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 3-54 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 six months of 2019, coal units were 27.3 percent and natural gas units were 69.6 percent of marginal resources. In the first six months of 2019, natural gas combined cycle units were 64.8 percent of marginal resources. In the first six months of 2018, coal units were 29.7 percent and natural gas units were 60.9 percent of the total marginal resources. In the first six months of 2018, natural gas combined cycle units were 53.2 percent of the total marginal resources. In the first six months of 2019, 91.8 percent of the wind marginal units had negative offer prices, 8.2 percent had zero offer prices and none had positive offer prices. In the first six months of 2018, 76.0 percent of the wind marginal units had negative offer prices, 15.5 percent had zero offer prices and 8.5 percent had positive offer prices.

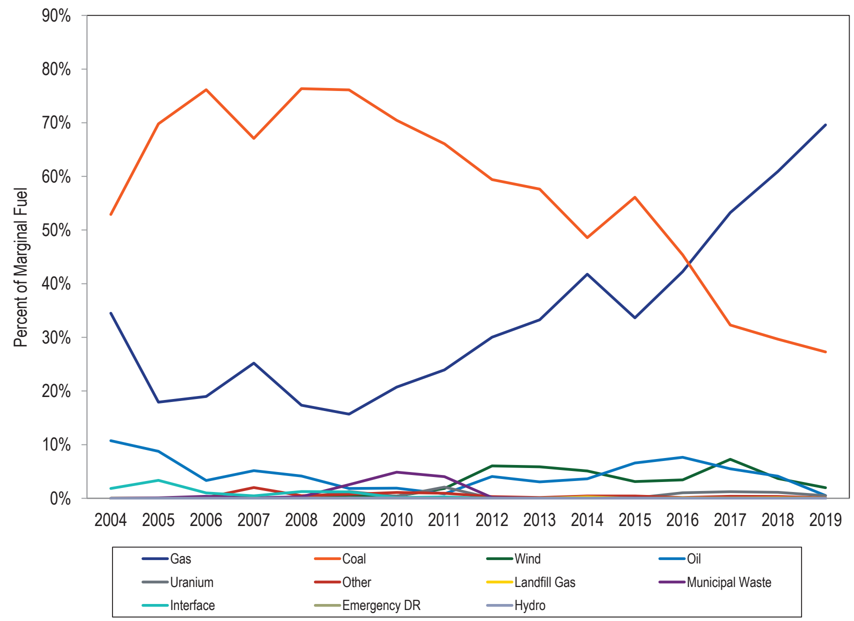
The proportion of marginal nuclear units decreased from 1.12 percent in the first six months of 2018 to 0.49 percent in the first six months of 2019. Most nuclear units are offered as fixed generation in the PJM market. A small number of nuclear units were offered with a dispatchable range since 2016. The dispatchable nuclear units do not always respond to dispatch instructions.

Table 3-54 Type of fuel used and technology (By real-time marginal units): January through June, 2015 through 2019[65]

		(Jan - Jun)				
Fuel	Technology	2015	2016	2017	2018	2019
Gas	CC	27.36%	31.50%	44.63%	53.21%	64.78%
Coal	Steam	56.12%	45.38%	32.28%	29.65%	27.29%
Gas	CT	3.20%	5.96%	4.70%	5.85%	3.62%
Wind	Wind	3.11%	3.43%	7.28%	3.71%	1.98%
Gas	Steam	2.98%	4.70%	3.53%	1.34%	0.77%
Uranium	Steam	0.05%	1.03%	1.23%	1.12%	0.49%
Gas	RICE	0.06%	0.10%	0.39%	0.52%	0.43%
Oil	CT	3.71%	7.16%	5.18%	3.19%	0.41%
Oil	RICE	1.82%	0.38%	0.26%	0.14%	0.09%
Other	Steam	0.42%	0.12%	0.19%	0.23%	0.08%
Other	Solar	0.01%	0.03%	0.18%	0.11%	0.02%
Landfill Gas	CT	0.00%	0.01%	0.01%	0.03%	0.01%
Oil	CC	0.84%	0.04%	0.01%	0.25%	0.01%
Landfill Gas	RICE	0.01%	0.05%	0.01%	0.05%	0.01%
Landfill Gas	Steam	0.00%	0.04%	0.05%	0.04%	0.01%
Oil	Steam	0.21%	0.06%	0.05%	0.55%	0.00%
Municipal Waste	Steam	0.06%	0.01%	0.01%	0.01%	0.00%
Gas	Fuel Cell	0.04%	0.01%	0.00%	0.00%	0.00%

Figure 3-44 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 3-44 Type of fuel used (By real-time marginal units): January through June, 2004 through 2019



65 The unit type RICE refers to Reciprocating Internal Combustion Engines.

Table 3-55 shows the type and fuel type where relevant, of marginal resources in the Day-Ahead Energy Market. In the first six months of 2019, up to congestion transactions were 57.8 percent of marginal resources. Up to congestion transactions were 66.9 percent of marginal resources in the first six months of 2018.

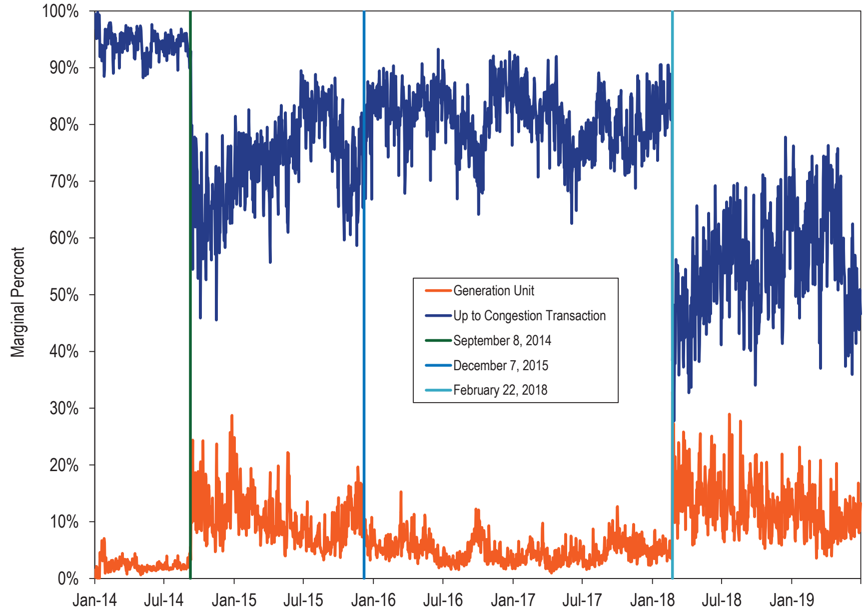
Table 3-55 Day-ahead marginal resources by type/fuel: January through June, 2011 through 2019

		(Jan - Jun)								
Type/Fuel	Technology	2011	2012	2013	2014	2015	2016	2017	2018	2019
Up to Congestion Transaction	NA	82.54%	82.54%	82.54%	82.54%	71.97%	82.54%	80.59%	66.89%	57.80%
DEC	NA	7.23%	7.23%	7.23%	7.23%	8.85%	7.23%	9.63%	14.65%	18.22%
INC	NA	3.76%	3.76%	3.76%	3.76%	5.20%	3.76%	5.33%	8.38%	13.33%
Gas	Steam	3.01%	3.01%	3.01%	3.01%	4.19%	3.01%	2.21%	5.08%	5.97%
Coal	Steam	2.59%	2.59%	2.59%	2.59%	8.58%	2.59%	1.61%	4.15%	4.19%
Gas	CT	0.11%	0.11%	0.11%	0.11%	0.30%	0.11%	0.09%	0.26%	0.16%
Dispatchable Transaction	NA	0.06%	0.06%	0.06%	0.06%	0.37%	0.06%	0.03%	0.11%	0.11%
Wind	Wind	0.05%	0.05%	0.05%	0.05%	0.18%	0.05%	0.23%	0.18%	0.11%
Gas	RICE	0.01%	0.01%	0.01%	0.01%	0.00%	0.01%	0.02%	0.04%	0.04%
Uranium	Steam	0.06%	0.06%	0.06%	0.06%	0.00%	0.06%	0.03%	0.08%	0.02%
Other	Solar	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.03%	0.01%
Municipal Waste	RICE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.01%
Other	Steam	0.01%	0.01%	0.01%	0.01%	0.02%	0.01%	0.00%	0.01%	0.01%
Oil	CT	0.56%	0.56%	0.56%	0.56%	0.21%	0.56%	0.21%	0.04%	0.01%
Price Sensitive Demand	NA	0.00%	0.00%	0.00%	0.00%	0.04%	0.00%	0.00%	0.01%	0.00%
Oil	Steam	0.01%	0.01%	0.01%	0.01%	0.03%	0.01%	0.00%	0.08%	0.00%
Oil	RICE	0.00%	0.00%	0.00%	0.00%	0.05%	0.00%	0.02%	0.00%	0.00%
Water	Hydro	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 3-45 shows, for the Day-Ahead Energy Market from January 2014 through June 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.[66] That trend reversed as a result of the expiration of the 15 month uplift refund period for UTC transactions. 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.[67] The order limited UTC trading to hubs, residual metered load, and interfaces. The share of marginal UTCs decreased from 66.9 percent in the first six months of 2018 to 57.8 percent in the first six months of 2019.

66 See 18 CFR § 385.213 (2014).
67 162 FERC ¶ 61,139 (2018).

Figure 3-45 Day-ahead marginal up to congestion transaction and generation units: January 2014 through June 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 and coal prices increased in the first six months of 2019 compared to the first six 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 six months of 2019 compared to the first six months of 2018. The price of eastern natural gas was 43.4 percent lower and the price of western natural gas was 4.6 percent lower. (Figure 3-46) The price of Northern Appalachian coal was 1.1 percent higher; the price of Central Appalachian coal was 4.9 percent higher; and the price of Powder River Basin coal was 0.1 percent lower.[68]

Figure 3-46 Spot average fuel price comparison with fuel delivery charges: January 2012 through June 2019 ($/MMBtu)

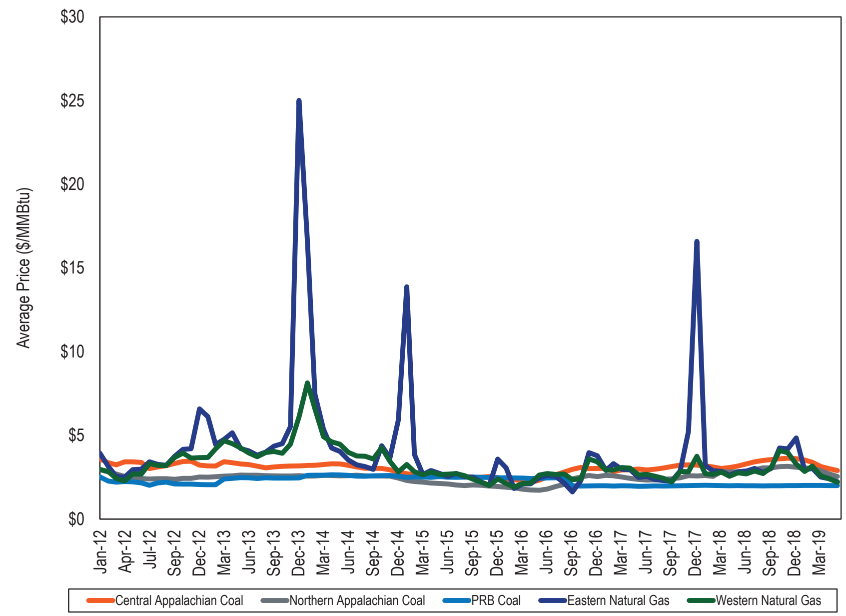


Table 3-56 compares the first six months of 2019 PJM real-time fuel-cost adjusted, load-weighted, average LMP to the first six months of 2019 load-weighted, average LMP.[69] The real-time, load-weighted average LMP for the first six months of 2019 decreased by $14.95 or -35.2 percent from real-time load-weighted, average LMP for the first six months of 2018. The real-time load-weighted, average LMP for the first six months of 2019 was 14.1 percent lower than the real-time fuel-cost adjusted, load-weighted average LMP for

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

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

the first six months of 2019. The real-time, fuel-cost adjusted, load-weighted average LMP for the first six months of 2019 was 24.6 percent lower than the real-time load-weighted, average LMP for the first six months of 2018. If fuel and emissions costs in the first six months of 2019 had been the same as in the first six month of 2018, holding everything else constant, the real-time, load-weighted, average LMP in the first six months of 2019 would have been higher, $31.98 per MWh, than the observed $27.49 per MWh. Only 31 percent of the decrease in real-time, load-weighted, average LMP, $4.49 per MWh out of $14.95 per MWh, is directly attributable to fuel costs. Contributors to the other $10.46 per MWh are decreased load, increased supply, adjusted dispatch, and lower markups.

Table 3-56 Real-time, fuel-cost adjusted, load-weighted average LMP (Dollars per MWh): January through June, 2018 and 2019

	2019 Fuel-Cost Adjusted, Load-Weighted LMP	2019 Load-Weighted LMP	Change	Percent Change
Average	$31.98	$27.49	($4.49)	(14.1%)
	2018 Load-Weighted LMP	2019 Fuel-Cost Adjusted, Load-Weighted LMP	Change	Percent Change
Average	$42.44	$31.98	($10.46)	(24.6%)
	2018 Load-Weighted LMP	2019 Load-Weighted LMP	Change	Change
Average	$42.44	$27.49	($14.95)	(35.2%)

Table 3-57 shows the impact of each fuel type on the difference between the fuel-cost adjusted, load-weighted average LMP and the load-weighted LMP in the first six months of 2019. Table 3-57 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 six months of 2019 from the first six months of 2018.

Table 3-57 Change in real-time, fuel-cost adjusted, load-weighted average LMP ($/MWh) by fuel type: January through June, 2018 to 2019

Fuel Type	Share of Change in Fuel Cost Adjusted, Load Weighted LMP	Percent
Coal	$0.10	(2.2%)
Oil	$0.00	(0.0%)
Other	$0.00	0.0%
Municipal Waste	$0.00	0.0%
Uranium	$0.00	0.0%
Wind	$0.00	0.0%
Gas	($4.60)	102.3%
NA	$0.00	0.0%
Total	($4.49)	100.0%

Table 3-58 shows the first six months of 2019 PJM real-time fuel-cost adjusted, load-weighted, average LMP using the first six months of 2018, 2017, 2016, and 2015 fuel and emission costs. If fuel and emissions costs in the first six months of 2019 had been the same as in first six months of 2015, holding everything else constant, the real-time load-weighted LMP in the first six months of 2019 would have been higher, $28.91 per MWh, than the observed $27.49 per MWh. If only fuel and emission costs of natural gas units in the first six months of 2019 had been the same as in the first six months of 2015, holding everything else constant, the real-time load-weighted LMP in the first six months of 2019 would have been higher, $29.36 per MWh, than the observed $27.49 per MWh.

Table 3-58 Historical Real-time, fuel-cost adjusted, load-weighted average LMP by Fuel Type (Dollars per MWh): January through June, 2015 through 2019

	2019 Fuel-Cost Adjusted, Load Weighted LMP			
	All Units	Gas Units	Coal Units	Oil Units
2019 Fuel and Emission Costs	$27.49	$27.49	$27.49	$27.49
2018 Fuel and Emission Costs	$31.98	$32.08	$27.39	$27.48
2017 Fuel and Emission Costs	$27.68	$27.95	$27.22	$27.48
2016 Fuel and Emission Costs	$23.52	$24.31	$26.70	$27.48
2015 Fuel and Emission Costs	$28.91	$29.36	$27.04	$27.49

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.[70] The FMU adder is the calculated contribution of the FMU and AU adders to LMP that results when units with FMU or AU adders are marginal.

Since the implementation of scarcity pricing on October 1, 2012, PJM jointly optimizes the commitment and dispatch of energy and ancillary services. In periods of scarcity when generators providing energy have to be dispatched down from their economic operating level to meet reserve requirements, the joint optimization of energy and reserves takes into account the opportunity cost of the reduced generation and the associated incremental cost to maintain reserves. If a unit incurring such opportunity costs is a marginal resource in the energy market, this opportunity cost will contribute to LMP. In addition, in periods when generators providing energy cannot meet the reserve requirements, PJM can invoke shortage pricing. PJM invoked shortage pricing on January 6, January 7 of 2014 and September 21 of 2017.[71] During the shortage conditions, the LMPs of marginal generators reflect the cost of not meeting the reserve requirements, the scarcity adder, which is defined by the operating reserve demand curve.

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

71 PJM triggered shortage pricing on January 6, 2015, following a RTO-wide voltage reduction action. PJM triggered shortage pricing on January 7, 2014, due to a RTO-wide shortage of synchronized reserve. PJM triggered shortage pricing on September 21, 2017 due to a sudden decrease in imports from neighboring regions.

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 3-61 shows the frequency and average shadow price of transmission constraints in PJM. In the first six months of 2019, there were 60,762 transmission constraints in the real-time market with a non-zero shadow price. For nearly 4 percent of these transmission constraints, the line limit was violated, meaning that the flow exceeded the facility limit.[72] In the first six months of 2019, the average shadow price of transmission constraints when the line limit was violated was nearly twelve 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, 44 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

72 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.

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 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.

The components of LMP are shown in Table 3-59, including markup using unadjusted cost-based offers.[73] Table 3-59 shows that in the first six months of 2019, 26.6 percent of the load-weighted LMP was the result of coal costs, 45.3 percent was the result of gas costs and 0.80 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 six months of 2019, nearly 17 percent of all five-minute intervals had insufficient data. The percent column is the difference in the proportion of LMP represented by each component between the first six months of 2019 and 2018.

73 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 3-59 Components of real-time (Unadjusted), load-weighted, average LMP: January through June, 2018 and 2019

	2018 (Jan - Jun)		2019 (Jan - Jun)		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change Percent
Gas	$16.24	38.3%	$12.46	45.3%	7.1%
Coal	$7.82	18.4%	$7.30	26.6%	8.1%
Ten Percent Adder	$2.95	6.9%	$2.16	7.8%	0.9%
Markup	$5.05	11.9%	$1.90	6.9%	(5.0%)
VOM	$1.42	3.3%	$1.54	5.6%	2.2%
Increase Generation Adder	$1.06	2.5%	$1.12	4.1%	1.6%
Scarcity Adder	$0.00	0.0%	$0.25	0.9%	0.9%
Ancillary Service Redispatch Cost	$0.60	1.4%	$0.24	0.9%	(0.5%)
CO_2 Cost	$0.04	0.1%	$0.21	0.8%	0.7%
LPA Rounding Difference	$0.70	1.7%	$0.19	0.7%	(1.0%)
NA	$2.95	6.9%	$0.10	0.4%	(6.6%)
Opportunity Cost Adder	$0.00	0.0%	$0.04	0.1%	0.1%
Oil	$3.40	8.0%	$0.02	0.1%	(7.9%)
NO_x Cost	$0.14	0.3%	$0.01	0.0%	(0.3%)
Other	$0.09	0.2%	$0.00	0.0%	(0.2%)
Constraint Violation Adder	$0.00	0.0%	$0.00	0.0%	0.0%
Market-to-Market Adder	$0.01	0.0%	$0.00	0.0%	(0.0%)
Landfill Gas	$0.00	0.0%	$0.00	0.0%	0.0%
SO_2 Cost	$0.01	0.0%	$0.00	0.0%	(0.0%)
Uranium	$0.00	0.0%	$0.00	0.0%	0.0%
Municipal Waste	$0.20	0.5%	$0.00	0.0%	(0.5%)
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	$0.00	0.0%	($0.02)	(0.1%)	(0.1%)
Decrease Generation Adder	($0.20)	(0.5%)	($0.03)	(0.1%)	0.4%
Total	$42.44	100.0%	$27.49	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 3-59 and Table 3-62), markup is simply the difference between the price offer and the cost-based offer (unadjusted markup). In the second approach (Table 3-60 and Table 3-63), 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 3-60, including markup using adjusted cost-based offers.

Table 3-60 Components of real-time (Adjusted), load-weighted, average LMP: January through June, 2018 and 2019

	2018 (Jan - Jun)		2019 (Jan - Jun)		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change Percent
Gas	$16.24	38.3%	$12.46	45.3%	7.1%
Coal	$7.82	18.4%	$7.30	26.6%	8.1%
Markup	$7.96	18.8%	$4.05	14.7%	(4.0%)
VOM	$1.42	3.3%	$1.54	5.6%	2.2%
Increase Generation Adder	$1.06	2.5%	$1.12	4.1%	1.6%
Scarcity Adder	$0.00	0.0%	$0.25	0.9%	0.9%
Ancillary Service Redispatch Cost	$0.60	1.4%	$0.24	0.9%	(0.5%)
CO_2 Cost	$0.04	0.1%	$0.21	0.8%	0.7%
LPA Rounding Difference	$0.70	1.7%	$0.19	0.7%	(1.0%)
NA	$2.95	6.9%	$0.10	0.3%	(6.6%)
Opportunity Cost Adder	$0.00	0.0%	$0.04	0.1%	0.1%
Oil	$3.40	8.0%	$0.02	0.1%	(7.9%)
NO_x Cost	$0.14	0.3%	$0.01	0.0%	(0.3%)
Other	$0.09	0.2%	$0.00	0.0%	(0.2%)
Constraint Violation Adder	$0.00	0.0%	$0.00	0.0%	0.0%
Market-to-Market Adder	$0.01	0.0%	$0.00	0.0%	(0.0%)
Landfill Gas	$0.00	0.0%	$0.00	0.0%	0.0%
Ten Percent Adder	$0.03	0.1%	$0.00	0.0%	(0.1%)
SO_2 Cost	$0.01	0.0%	$0.00	0.0%	(0.0%)
Uranium	$0.00	0.0%	$0.00	0.0%	0.0%
Municipal Waste	$0.20	0.5%	$0.00	0.0%	(0.5%)
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	$0.00	0.0%	($0.02)	(0.1%)	(0.1%)
Decrease Generation Adder	($0.20)	(0.5%)	($0.03)	(0.1%)	0.4%
Total	$42.44	100.0%	$27.49	100.0%	0.0%

Table 3-61 Frequency and average shadow price of transmission constraints: January through June, 2018 and 2019

	Frequency		Average Shadow Price	
Description	2018 (Jan - Jun)	2019 (Jan - Jun)	2018 (Jan - Jun)	2019 (Jan - Jun)
PJM Internal Violated Transmission Constraints	7,699	2,651	$1,329.69	$1,312.35
PJM Internal Binding Transmission Constraints	55,526	37,176	$201.16	$105.79
Market to Market Transmission Constraints	28,334	20,935	$458.88	$203.49
All Transmission Constraints	91,559	60,762	$375.81	$192.09

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.[74] 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 3-62 shows the components of the PJM day-ahead, annual, load-weighted average LMP. In the first six months of 2019, 23.4 percent of the load-weighted LMP was the result of coal costs, 20.8 percent of the load-weighted LMP was the result of gas costs, 20.4 percent was the result of DEC bid costs, 20.5 percent was the result of INC bid costs and 2.1 percent was the result of the up to congestion transaction costs.

74 New Jersey withdrew from RGGI, effective January 1, 2012 and rejoined RGGI, effective January 29, 2018.

Table 3-62 Components of day-ahead, (unadjusted), load-weighted, average LMP (Dollars per MWh): January through June, 2018 and 2019

	2018 (Jan - Jun)		2019 (Jan - Jun)		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change Percent
Coal	$6.52	15.9%	$6.53	23.4%	7.4%
Gas	$7.66	18.7%	$5.83	20.8%	2.1%
INC	$6.85	16.7%	$5.73	20.5%	3.8%
DEC	$11.80	28.8%	$5.71	20.4%	(8.4%)
Ten Percent Cost Adder	$1.72	4.2%	$1.37	4.9%	0.7%
VOM	$1.00	2.4%	$1.22	4.4%	1.9%
Up to Congestion Transaction	$1.51	3.7%	$0.60	2.1%	(1.5%)
Markup	$1.17	2.9%	$0.48	1.7%	(1.2%)
Dispatchable Transaction	$0.59	1.4%	$0.35	1.3%	(0.2%)
CO_2	$0.04	0.1%	$0.13	0.5%	0.4%
Price Sensitive Demand	$0.15	0.4%	$0.02	0.1%	(0.3%)
NO_x	$0.12	0.3%	$0.01	0.0%	(0.3%)
Other	($0.00)	(0.0%)	$0.01	0.0%	0.0%
SO_2	$0.01	0.0%	$0.00	0.0%	(0.0%)
DASR Offer Adder	$0.00	0.0%	$0.00	0.0%	(0.0%)
DASR LOC Adder	($0.00)	(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%)
Oil	$1.82	4.5%	($0.00)	(0.0%)	(4.5%)
Wind	($0.00)	(0.0%)	($0.00)	(0.0%)	(0.0%)
Constrained Off	$0.00	0.0%	($0.02)	(0.1%)	(0.1%)
Total	$40.96	100.0%	$27.97	100.0%	0.0%

Table 3-63 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 3-63 Components of day-ahead, (adjusted), load-weighted, average LMP (Dollars per MWh): January through June, 2018 and 2019

	2018 (Jan - Jun)		2019 (Jan - Jun)		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change Percent
Coal	$6.52	15.9%	$6.53	23.4%	7.4%
Gas	$7.67	18.7%	$5.83	20.8%	2.1%
INC	$6.85	16.7%	$5.73	20.5%	3.8%
DEC	$11.80	28.8%	$5.71	20.4%	(8.4%)
Markup	$2.85	7.0%	$1.81	6.5%	(0.5%)
VOM	$1.00	2.4%	$1.22	4.4%	1.9%
Up to Congestion Transaction	$1.51	3.7%	$0.60	2.1%	(1.5%)
Dispatchable Transaction	$0.59	1.4%	$0.35	1.3%	(0.2%)
CO_2	$0.04	0.1%	$0.13	0.5%	0.4%
Ten Percent Cost Adder	$0.03	0.1%	$0.03	0.1%	0.0%
Price Sensitive Demand	$0.15	0.4%	$0.02	0.1%	(0.3%)
NO_x	$0.12	0.3%	$0.01	0.0%	(0.3%)
Other	($0.00)	(0.0%)	$0.01	0.0%	0.0%
SO_2	$0.01	0.0%	$0.00	0.0%	(0.0%)
DASR Offer Adder	$0.00	0.0%	$0.00	0.0%	(0.0%)
DASR LOC Adder	($0.00)	(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%)
Oil	$1.82	4.5%	($0.00)	(0.0%)	(4.5%)
Wind	($0.00)	(0.0%)	($0.00)	(0.0%)	(0.0%)
Constrained Off	$0.00	0.0%	($0.02)	(0.1%)	(0.1%)
Total	$40.96	100.0%	$27.97	100.0%	0.0%

Scarcity

PJM's energy market experienced five minute shortage pricing for 20 intervals on eleven days in the first six months of 2019. Table 3-64 shows a summary of the number of days emergency alerts, warnings and actions were declared in PJM in the first six months of 2018 and 2019.

Table 3-64 Summary of emergency events declared: January through June, 2018 and 2019

	Number of days events declared	
Event Type	Jan -Jun, 2018	Jan - Jun, 2019
Cold Weather Alert	12	9
Hot Weather Alert	9	3
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	11
Energy export recalls from PJM capacity resources	0	0

Figure 3-47 shows the number of days that weather and capacity emergency alerts were issued in PJM in the first six months from 2015 through 2019. Figure 3-48 shows the number of days emergency warnings were issued and actions were taken in PJM in the first six months from 2015 through 2019.

Figure 3-47 Declared emergency alerts: January through June, 2015 through 2019

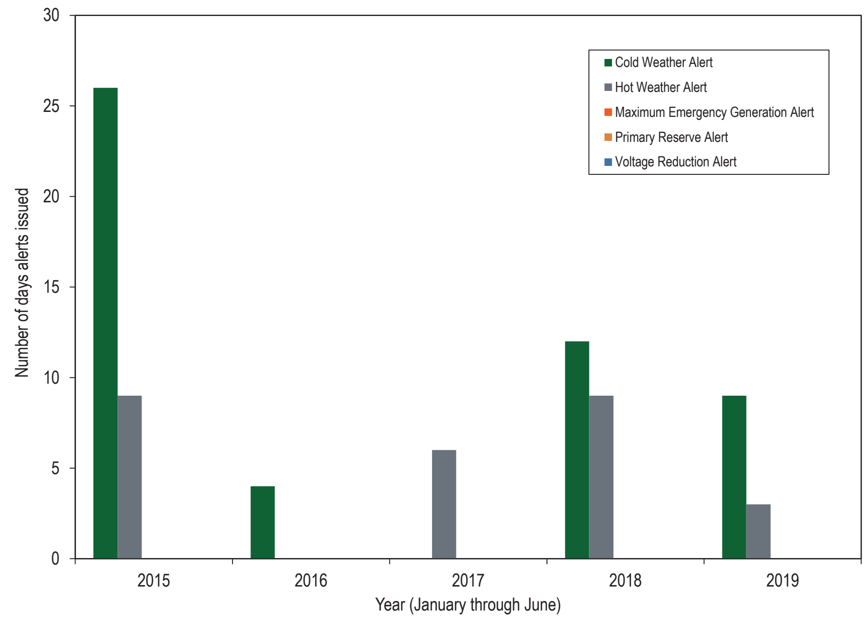
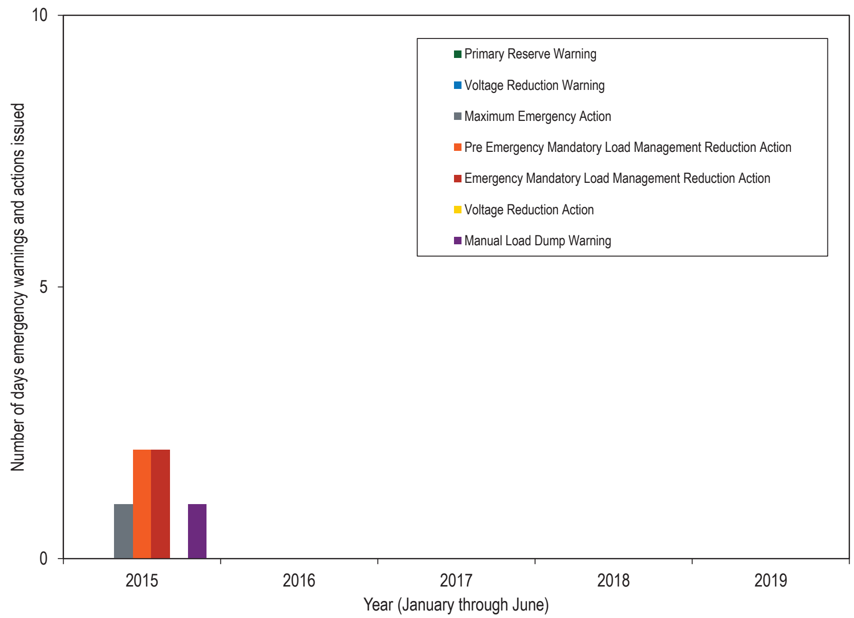


Figure 3-48 Declared emergency warnings and actions: January through June, 2015 through 2019



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 3-65 provides a description of PJM declared emergency procedures.[75 76 77 78]

Table 3-65 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.

75 See PJM. "Manual 13: Emergency Operations," Rev. 70 (May 30, 2019), Section 3.3 Cold Weather Alert.
76 See PJM. "Manual 13: Emergency Operations," Rev. 70 (May 30, 2019), Section 3.4 Hot Weather Alert.
77 See PJM. "Manual 13: Emergency Operations," Rev. 70 (May 30, 2019), Section 2.3.1 Advanced Notice Emergency Procedures: Alerts.
78 See PJM. "Manual 13: Emergency Operations," Rev. 70 (May 30, 2019), 2.3.2 Real-Time Emergency Procedures (Warnings and Actions).

Table 3-66 shows the dates when emergency alerts and warnings were declared and when emergency actions were implemented in the first six months of 2019.

Table 3-66 Declared emergency alerts, warnings and actions: January through June, 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												

PAIs and Capacity Performance

In the first six 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 six months of 2019, there were 20 five minute intervals with shortage pricing that occurred on eleven 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.[79] 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 prices should reflect that condition, even if the data does not show a shortage of reserves.[80]

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.[81] The updates to the ORDC went into effect on July 12, 2017.

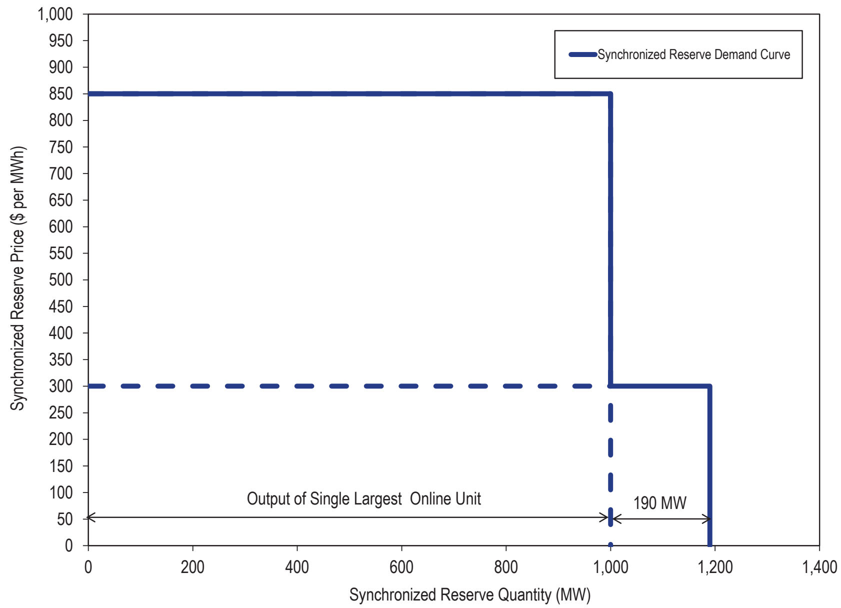
PJM revised the synchronized reserve requirement in a reserve zone or a subzone from the economic maximum of the largest unit on the system to 100 percent of the actual output of the single largest online unit in that reserve zone or subzone. PJM revised the primary reserve requirement in a reserve zone 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 3-49 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.

79 *Id* at P 162.

80 *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).

81 See PJM Filing, FERC Docket No. ER17-1590-000 (May 12, 2017).

Figure 3-49 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 3-49 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.

Shortage Pricing Intervals in 2019

There were twenty intervals with five minute shortage pricing that occurred on eleven days in the first six months of 2019, compared to zero intervals in the first six months of 2018, in PJM. In all eighteen of the twenty intervals, shortage pricing was triggered due to synchronized reserves being short of the extended synchronized reserve requirement but greater than or equal to the reliability synchronized reserve requirement.[82] In two of the twenty intervals, shortage pricing was triggered due to synchronized reserves being short of the reliability synchronized reserve requirement. There were no five minute intervals with primary reserve shortage in the first six months of 2018 or 2019. Table 3-67 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 twenty intervals with shortage pricing. 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 MAD reserve subzone during the twenty intervals with shortage pricing.

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.[83] 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 twenty intervals in the first six 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 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.

82 The extended synchronized reserve requirement is defined as the reliability synchronized reserve requirement plus 190 MW.

83 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.

Table 3-67 RTO Synchronized Reserve Shortage Intervals: January through June, 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

Table 3-68 MAD Synchronized Reserve Shortage Intervals: January through June, 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

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.[84]

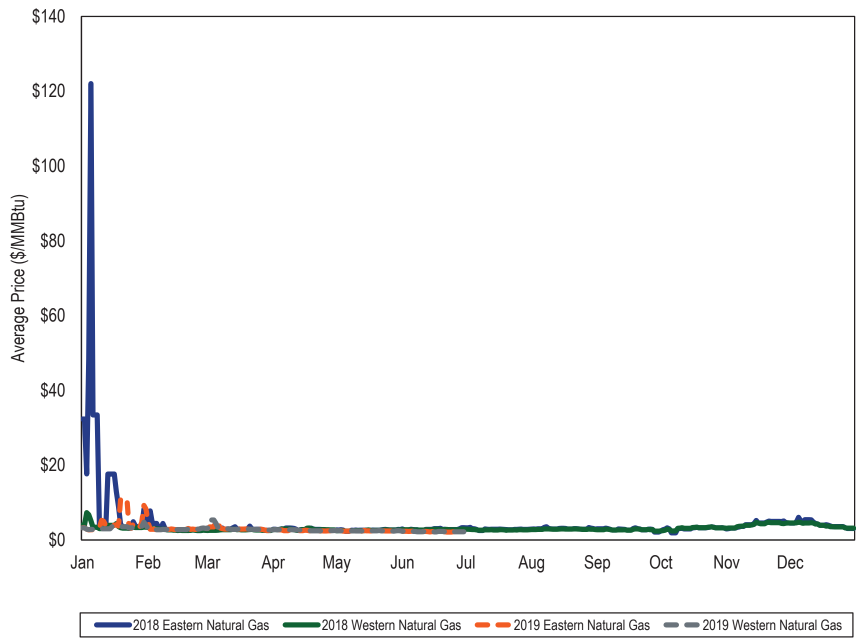
84 See Comments of the Independent Market Monitor for PJM, Docket No. RM15-24-000 (December 1, 2015) at 9.

PJM Cold Weather Operations 2019

Natural Gas Supply and Prices

As of June 30, 2019, gas fired generation was 41.9 percent (78,476.4 MW) of the total installed PJM capacity (187,457.6 MW).[85] Figure 3-50 shows the average daily price of delivered natural gas for eastern and western parts of PJM service territory in 2018 and the first six months of 2019.[86]

Figure 3-50 Average daily delivered price for natural gas: 2018 and 2019 ($/MMBtu)



During the first six 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 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 six months of 2019 indicates low concentration in the base load segment, moderate concentration in the intermediate segment and high concentration in 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

85 *2019 Quarterly State of the Market Report for PJM: January through June*, 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.

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.

possible to have pivotal suppliers in the aggregate market even when the HHI level does not indicate a highly concentrated market structure. It is possible to have an exercise of market power even when the HHI level does not indicate a highly concentrated market structure.

When transmission constraints exist, local markets are created with ownership that is typically significantly more concentrated than the overall energy market. PJM offer capping rules that limit the exercise of local market power were generally effective in preventing the exercise of market power in the first six 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 3-69).

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

Hourly HHIs were also calculated for baseload, intermediate and peaking segments of generation supply. Hourly energy market HHIs by supply curve segment were calculated based on hourly energy market shares, unadjusted for imports.

The “Merger Policy Statement” of FERC states that a market can be broadly characterized as:

- **Unconcentrated.** Market HHI below 1000, equivalent to 10 firms with equal market shares;
- **Moderately Concentrated.** Market HHI between 1000 and 1800; and
- **Highly Concentrated.** Market HHI greater than 1800, equivalent to between five and six firms with equal market shares.[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 demand elasticity ranging from -0.2 to -0.4.[90] These elasticities imply, for example, an average markup ranging

88 *See* Tirole, Jean. *The Theory of Industrial Organization*, MIT (1988), Chapter 5: Short-Run Price Competition.

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

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 marginal costs of $25.59 per MWh and an average HHI of 792 in the first six months of 2019, average PJM prices theoretically range from $32 to $42 per MWh, exceeding marginal costs as a result of the exercise of market power. Actual prices, averaging $27.49 per MWh, and markups, at 6.9 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 six months of 2019 was unconcentrated (Table 3-69).

Table 3-69 Hourly energy market HHI: January through June, 2018 and 2019[92]

	Hourly Market HHI (Jan - Jun, 2018)	Hourly Market HHI (Jan - Jun, 2019)
Average	852	792
Minimum	651	599
Maximum	1172	1098
Highest market share (One hour)	28%	26%
Average of the highest hourly market share	20%	19%
# Hours	4,343	4,343
# Hours HHI > 1800	0	0
% Hours HHI > 1800	0%	0%

Table 3-70 includes HHI values by supply curve segment, including base, intermediate and peaking plants for the first six months of 2018 and 2019. The PJM energy market was unconcentrated overall with low concentration in the baseload, moderate concentration in the intermediate segment and high concentration in the peaking segment.

Table 3-70 Hourly energy market HHI (By supply segment): January through June, 2018 and 2019

	Jan - Jun, 2018			Jan - Jun, 2019		
	Minimum	Average	Maximum	Minimum	Average	Maximum
Base	732	928	1260	675	832	1126
Intermediate	762	1434	4274	665	1612	9069
Peak	846	5736	10000	706	6204	10000

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 This analysis includes all hours in the first six months of 2018 and 2019, regardless of congestion.

Figure 3-51 shows the total installed capacity (ICAP) MW of units in the baseload, intermediate and peaking segments by fuel source in the first six months of 2019.

Figure 3-51 Fuel source distribution in unit segments: January through June, 2019[93]

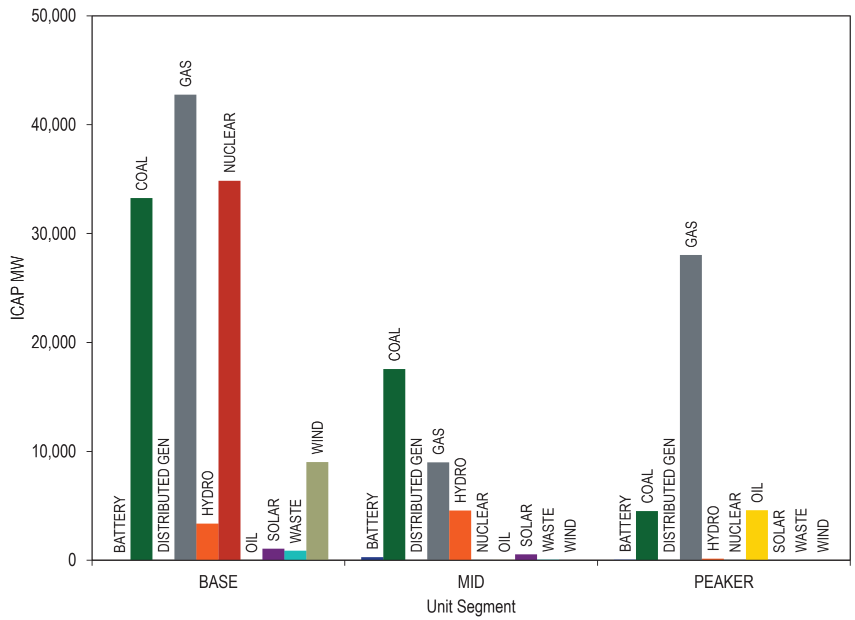
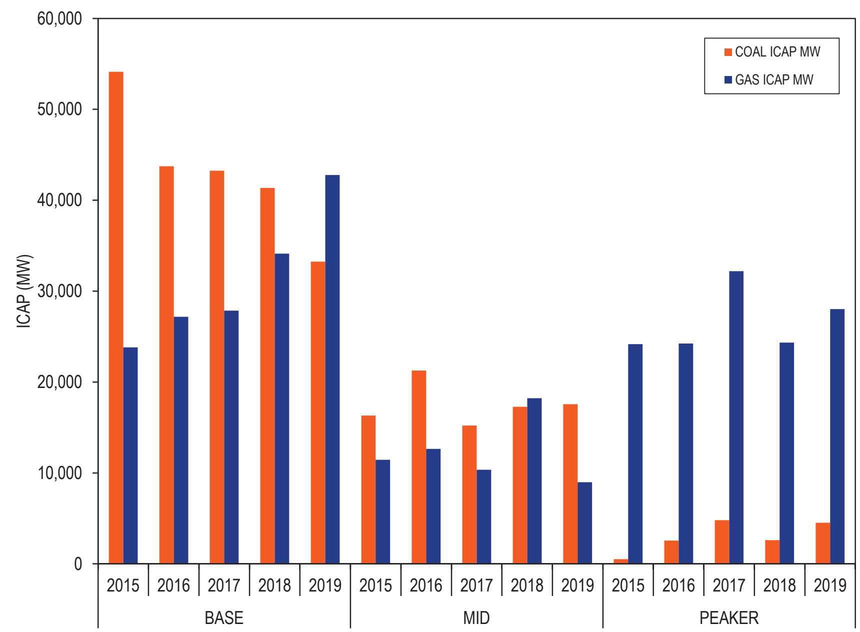


Figure 3-52 shows the ICAP of coal fired and gas fired units in PJM that are classified as baseload, intermediate and peaking segments for the first six months from 2015 through 2019. Figure 3-52 shows that the total ICAP of coal fired units in PJM that are classified as baseload has been steadily decreasing 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 2015 through 2019. In the first six months of 2019, ICAP of gas fired units classified as baseload exceeded ICAP of coal fired units classified as baseload.

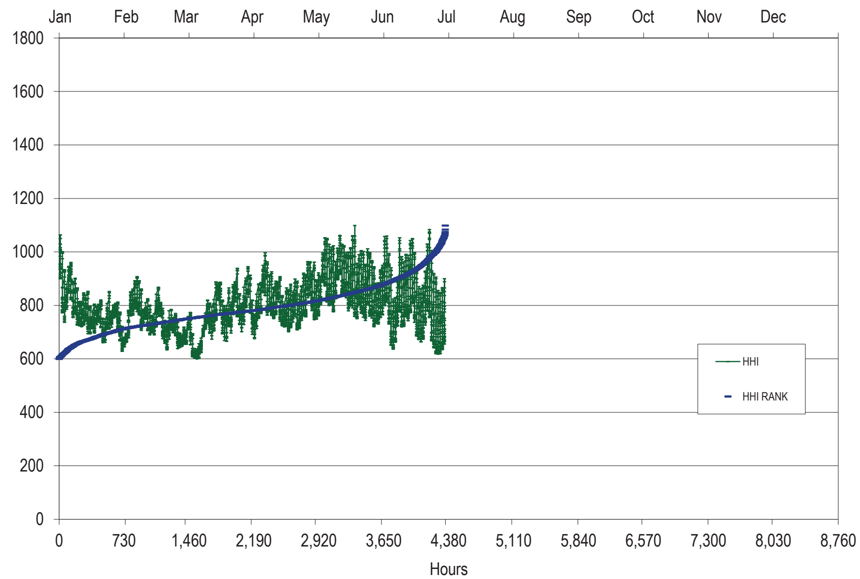
Figure 3-52 Unit segment classification by fuel: January through June, 2015 through 2019



93 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>.

Figure 3-53 presents the hourly HHI values in chronological order and an HHI duration curve for the first six months of 2019.

Figure 3-53 Hourly energy market HHI: January through June, 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."[94]

FERC applies tests set forth in the 1996 Merger Policy Statement.[95] FERC currently is reviewing those guidelines.[96]

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, the 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. The 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.[97] The MMU has proposed that FERC adopt this approach when evaluating mergers in PJM.[98] FERC has considered the MMU's analysis in reviewing mergers.[99]

The MMU has also facilitated settlements for mitigation of market power, in cases where market power concerns have been identified.[100] 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

94 18 U.S.C. § 824b.
95 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).
96 See 156 FERC ¶ 61,214 (2016); FERC Docket No. RM16-21-000.
97 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)
98 See Comments of the Independent Market Monitor for PJM, Docket No. RM16-21 (Dec. 12, 2016).
99 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).
100 See 138 FERC ¶ 61,167 at P 19.

the $10,000,000 minimum value for transactions requiring the Commission's review.[101]

Aggregate Market Pivotal Supplier Results

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

In the PJM Day-Ahead Energy Market, two suppliers were jointly pivotal on two days, and three suppliers were jointly pivotal on 77 days in the first six months of 2019. The frequency of pivotal suppliers increased during the summer months of 2018 and 2019, on high demand days in September 2018, 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.

The existing market power mitigation measures do not address aggregate market power.[102] 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.[103] 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 3-54 shows the number of days in 2018 and in the first six 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 or in 2019. Two suppliers were jointly pivotal on 42 days in 2018 and on two days in the first six months of 2019. Three suppliers were jointly pivotal on 212 days in 2018 and 77 days in the first three months of 2019, despite average HHIs at persistently unconcentrated levels. In 2018, the highest levels of aggregate market power occur in the third quarter, PJM's peak load season. In the first six months of 2019, the highest levels of aggregate market power occurred on January 22, 2019 and June 28, 2019.

101 See 166 FERC ¶ 61,120 (2019), Docket No. RM19-4.
102 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).
103 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.

Figure 3-54 Days with pivotal suppliers and numbers of pivotal suppliers in the Day-Ahead Energy Market by quarter

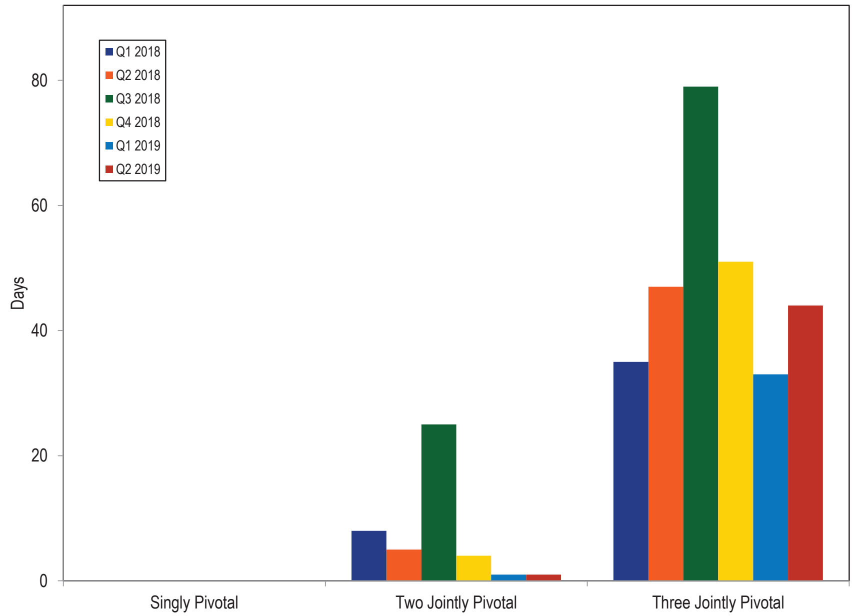


Table 3-71 provides the frequency with which each of the top 10 pivotal suppliers was singly or jointly pivotal for the Day-Ahead Energy Market in 2019. The first and third pivotal suppliers were each one of two pivotal suppliers on January 22, 2019, and the first and second pivotal suppliers were each one of two pivotal suppliers on June 28, 2019. All of the top 10 suppliers were one of three pivotal suppliers on at least 13 days, and the first, second, and fourth suppliers were one of three pivotal suppliers on at least 75 days in the first six months of 2019.

Table 3-71 Day-ahead market pivotal supplier frequency: January through June, 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	0	0.0%	2	1.1%	77	42.5%
2	0	0.0%	1	0.6%	75	41.4%
3	0	0.0%	1	0.6%	16	8.8%
4	0	0.0%	0	0.0%	76	42.0%
5	0	0.0%	0	0.0%	57	31.5%
6	0	0.0%	0	0.0%	46	25.4%
7	0	0.0%	0	0.0%	26	14.4%
8	0	0.0%	0	0.0%	16	8.8%
9	0	0.0%	0	0.0%	14	7.7%
10	0	0.0%	0	0.0%	13	7.2%

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.[104] If the TPS is failed, market power mitigation is implemented by offer capping the resources of the owners who have 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

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

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.

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 six months of 2019, the AECO, AEP, ATSI, BGE, ComEd, Met-Ed, PECO, PENELEC, PPL and PSEG control zones experienced congestion resulting from one or more constraints binding for 50 or more hours or resulting from an interface constraint (Table 3-72). The APS, DAY, DEOK, DLCO, Dominion, DPL, EKPC, JCPL, OVEC, Pepco, and RECO control zones did not have constraints binding for 50 or more hours in the first six months of 2019. Table 3-72 shows that AEP, BGE, ComEd, and PSEG were the control zones that experienced congestion resulting from one or more constraints binding for 50 or more hours or resulting from an interface constraint that was binding for one or more hours in every year from the first six months of 2009 through 2019.

Table 3-72 Congestion hours resulting from one or more constraints binding for 50 or more hours or from an interface constraint: January through June, 2009 through 2019

	(Jan - Jun)										
	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
AECO	149	69	88	0	0	0	0	383	0	0	136
AEP	932	355	1,409	322	811	1,773	1,902	471	456	1,020	137
APS	198	410	52	113	51	170	451	79	0	81	0
ATSI	101	0	0	1	70	403	464	0	483	1,866	237
BGE	90	154	184	1,556	316	1,142	3,079	4,923	772	1,861	205
ComEd	576	1,406	153	845	1,678	1,729	1,727	2,910	748	564	283
DEOK	0	0	0	58	0	0	69	0	0	68	0
DLCO	156	342	0	209	0	281	747	0	0	57	0
Dominion	310	589	659	200	0	52	1,422	759	80	136	0
DPL	0	0	0	126	142	560	1,199	1,399	326	295	0
EKPC	0	0	0	0	0	65	0	0	0	159	0
JCPL	0	0	0	0	0	0	79	0	0	0	0
Met-Ed	0	0	0	68	73	0	182	0	0	1,235	182
PECO	59	0	130	53	256	944	485	732	852	130	187
PENELEC	55	0	0	0	0	1,441	1,385	551	1,537	1,127	1,009
Pepco	0	0	59	203	85	39	0	0	0	0	0
PPL	176	0	52	146	188	147	0	0	741	177	682
PSEG	438	479	605	316	1,462	2,023	2,591	220	159	334	248

The local market structure in the Real-Time Energy Market associated with each of the frequently binding constraints was analyzed using the three pivotal supplier results in the first six months of 2019.[105] 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 3-73 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.

105 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>.

Table 3-73 includes 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 3-73 Three pivotal supplier test details for interface constraints: January through June, 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

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 3-74 provides, for the identified interface constraints, information on total tests applied, the subset of three pivotal supplier tests that could have resulted in offer capping and the portion of those tests that did result in offer capping. The three pivotal supplier tests that resulted in offer capping do not explain all the offer capped units in the Real-Time Energy Market. PJM operators also manually commit units for reliability reasons other than providing relief to a binding constraint.

Table 3-74 Summary of three pivotal supplier tests applied for interface constraints: January through June, 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%

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.[106] 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:

$$\text{Total Dispatch Cost} = \text{Startup Cost} + \sum_{\text{Min Run}} \text{Hourly Dispatch Cost}$$

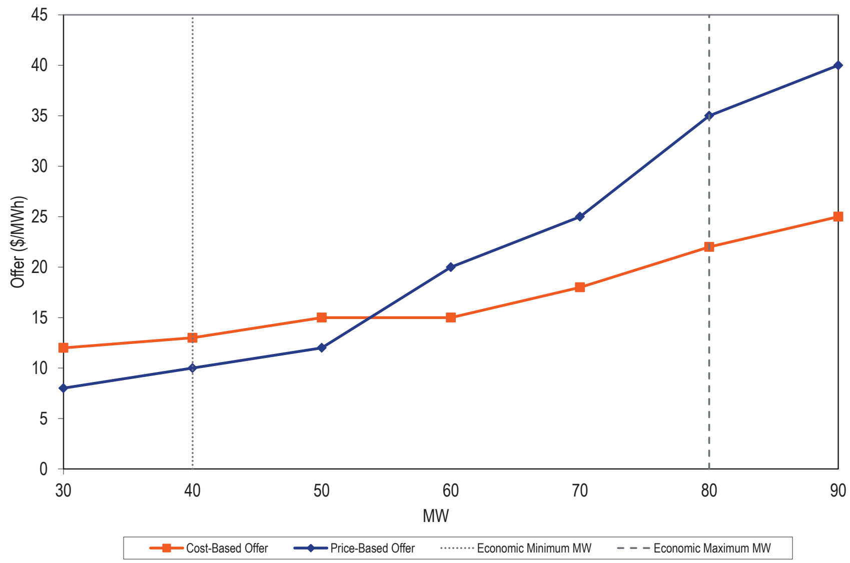
where the hourly dispatch cost is calculated for each hour using the offers applicable for that hour as:

$$\text{Hourly Dispatch Cost} = (\text{Incremental Energy Offer@EcoMin} \times \text{EcoMin MW}) + \text{NoLoad Cost}$$

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 3-55 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.

106 See PJM Operating Agreement Schedule 1 § 6.4.1(g).

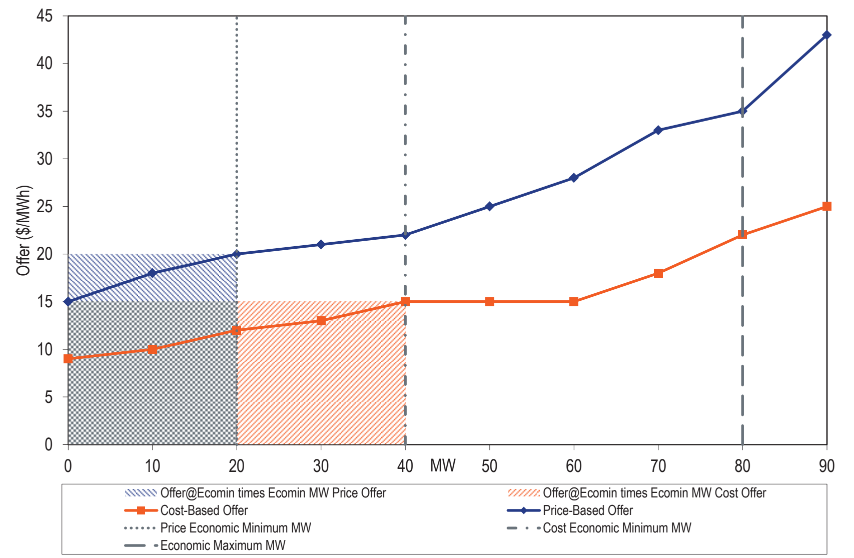
Figure 3-55 Offers with varying markups at different MW output levels



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.

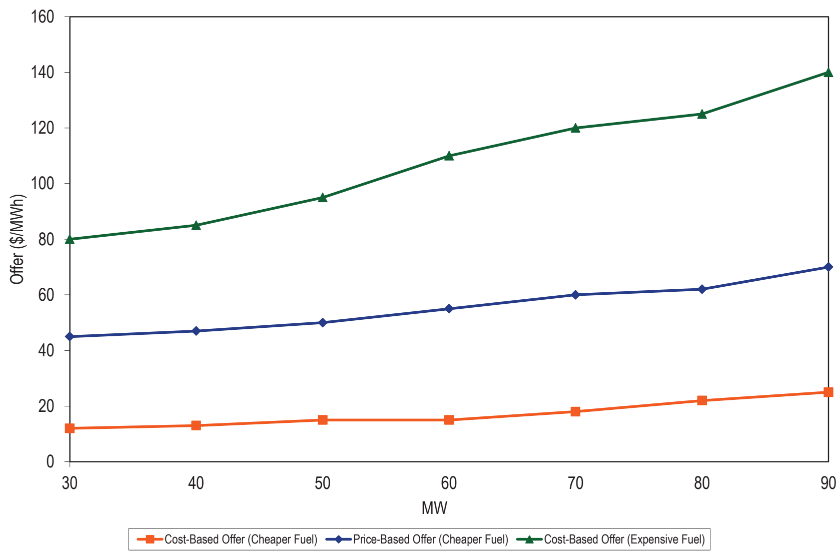
A unit may offer a lower economic minimum MW level on the price-based offer than the cost-based offer. Such a unit may appear to be cheaper to commit on the price-based offer even with a positive markup. A unit with a positive markup can have lower dispatch cost with the price-based offer with a lower economic minimum level compared to cost-based offer. Figure 3-56 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 3-56 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 3-57 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 3-57 Dual fuel unit offers



These issues can be solved by simple rule changes.[107] 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 3-76. 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 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.[108] 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 3-75 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.[109] 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 3-75 Offer capping statistics – energy only: January through June, 2015 to 2019

	Real-Time		Day-Ahead	
(Jan-Jun)	Unit Hours Capped	MWh Capped	Unit Hours Capped	MWh Capped
2015	0.6%	0.4%	0.3%	0.2%
2016	0.3%	0.2%	0.1%	0.1%
2017	0.2%	0.1%	0.0%	0.0%
2018	1.3%	0.5%	0.1%	0.1%
2019	0.8%	0.7%	0.5%	0.4%

Table 3-76 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

107 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.

108 See OATT Attachment K Appendix § 6.4.1.

109 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.

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 3-75.

Table 3-76 Offer capping statistics for energy and reliability: January through June, 2015 to 2019

	Real-Time		Day-Ahead	
(Jan-Jun)	Unit Hours Capped	MWh Capped	Unit Hours Capped	MWh Capped
2015	1.0%	1.0%	0.8%	0.8%
2016	0.4%	0.2%	0.1%	0.1%
2017	0.3%	0.5%	0.2%	0.4%
2018	1.5%	0.8%	0.2%	0.4%
2019	0.8%	0.7%	0.5%	0.4%

Table 3-77 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 3-77 is the difference between the offer cap percentages shown in Table 3-76 and Table 3-75.

Table 3-77 Offer capping statistics for reliability: January through June, 2015 to 2019

	Real-Time		Day-Ahead	
(Jan-Jun)	Unit Hours Capped	MWh Capped	Unit Hours Capped	MWh Capped
2015	0.4%	0.6%	0.5%	0.6%
2016	0.1%	0.0%	0.1%	0.0%
2017	0.1%	0.4%	0.2%	0.4%
2018	0.2%	0.3%	0.1%	0.3%
2019	0.0%	0.0%	0.0%	0.0%

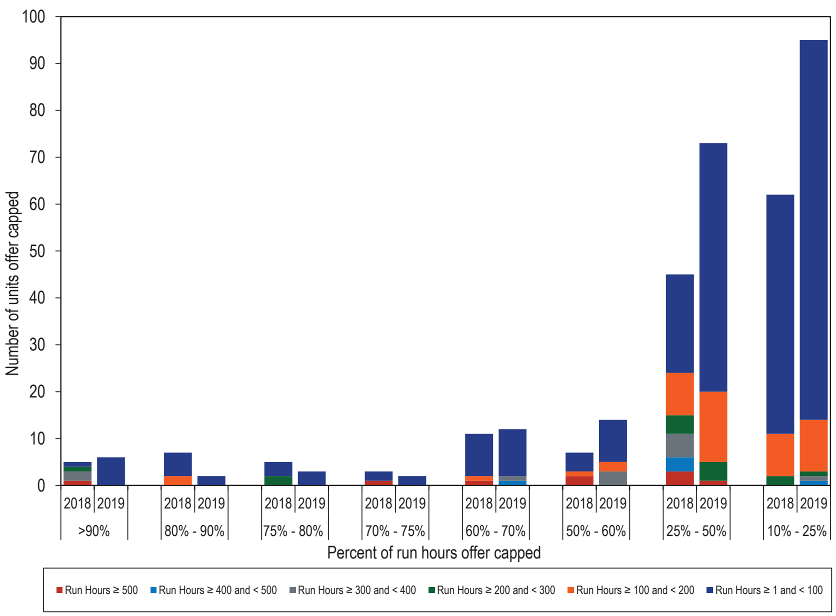
Table 3-78 presents data on the frequency with which units were offer capped in the first six months of 2018 and 2019 as a result of failing the TPS test to provide energy for constraint relief in the Real-Time Energy Market and for reliability reasons. Table 3-78 shows that six units were offer capped for 90 percent or more of their run hours in the first six months of 2019 compared to five units in the first six months of 2018.

Table 3-78 Real-time offer capped unit statistics: January through June, 2018 and 2019

		Offer-Capped Hours					
Run Hours Offer-Capped, Percent Greater Than Or Equal To:	Jan - Jun	Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	2018	1	0	2	1	0	1
	2019	0	0	0	0	0	6
80% and < 90%	2018	0	0	0	0	2	5
	2019	0	0	0	0	0	2
75% and < 80%	2018	0	0	0	2	0	3
	2019	0	0	0	0	0	3
70% and < 75%	2018	1	0	0	0	0	2
	2019	0	0	0	0	0	2
60% and < 70%	2018	1	0	0	0	1	9
	2019	0	1	1	0	0	10
50% and < 60%	2018	2	0	0	0	1	4
	2019	0	0	3	0	2	9
25% and < 50%	2018	3	3	5	4	9	21
	2019	1	0	0	4	15	53
10% and < 25%	2018	0	0	0	2	9	51
	2019	0	1	1	1	11	81

Figure 3-58 shows the frequency with which units were offer capped in the first six 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 3-58 Real-time offer capped unit statistics: January through June, 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.[110] The markup index is normalized and can vary from -1.00 when the offer price is less than short run marginal cost, to 1.00 when the offer price is higher than short run marginal cost. The markup index does not measure the impact of unit markup on total LMP. The dollar markup for a unit is the difference between price and cost.

Real-Time Markup Index

Table 3-79 shows the average markup index of marginal units in the Real-Time Energy Market, by offer price category using unadjusted cost-based offers. Table 3-80 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.[111] 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.

The unadjusted markup is calculated as the difference between the price-based offer and the cost-based offer including the additional 10 percent in the cost-based offer for coal, gas and oil fired units. The adjusted markup is calculated as the difference between the price-based offer and the cost-based offer excluding the additional 10 percent from the cost-based offers of coal,

110 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.

111 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.

gas and oil fired units. Even the adjusted markup overestimates the negative markup because units facing increased competitive pressure have excluded both the 10 percent and 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.[112]

In the first six months of 2019, 97.4 percent of marginal units had offer prices less than $50 per MWh. The average dollar markups of units with offer prices less than $25 was positive ($0.53 per MWh) when using unadjusted cost-based offers. The average dollar markups of units with offer prices between $25 and $50 was positive ($2.10 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 six month of 2019, less than 0.1 percent had offer prices above $400 per MWh. Among the units that were marginal in the first six 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 six months of 2019 was more than $300, while the highest markup in the first six months of 2018 was more than $500.

112 See PJM. "Manual 15: Cost Development Guidelines," Rev. 32 (May 13, 2019).

Table 3-79 Average, real-time marginal unit markup index (By offer price category unadjusted): January through June, 2018 and 2019

	2018 (Jan - Jun)			2019 (Jan - Jun)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $25	0.04	($0.56)	58.1%	0.04	$0.53	76.2%
$25 to $50	0.06	$2.01	31.2%	0.07	$2.10	21.2%
$50 to $75	0.33	$18.39	3.3%	0.31	$18.25	1.1%
$75 to $100	0.29	$23.75	1.2%	0.47	$40.47	0.4%
$100 to $125	0.17	$18.08	0.7%	0.29	$31.65	0.4%
$125 to $150	0.10	$13.96	1.5%	0.39	$54.32	0.1%
$150 to $400	0.08	$16.11	4.0%	0.08	$17.64	0.5%
>= $400	0.48	$238.58	0.1%	0.10	$45.99	0.0%

Table 3-80 Average, real-time marginal unit markup index (By offer price category adjusted): January through June 2018 and 2019

	2018 (Jan - Jun)			2019 (Jan - Jun)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $25	0.12	$1.09	58.1%	0.13	$2.22	76.2%
$25 to $50	0.14	$4.69	31.2%	0.15	$4.64	21.2%
$50 to $75	0.39	$21.90	3.3%	0.37	$21.82	1.1%
$75 to $100	0.35	$29.29	1.2%	0.52	$44.50	0.4%
$100 to $125	0.25	$26.50	0.7%	0.36	$38.58	0.4%
$125 to $150	0.19	$24.96	1.5%	0.45	$61.80	0.1%
$150 to $400	0.17	$33.60	4.0%	0.18	$32.73	0.5%
>= $400	0.52	$259.30	0.1%	0.20	$84.46	0.0%

Table 3-81 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.[113] Table 3-82 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 six months of 2019, using unadjusted cost-based offers for coal units, 51.37 percent of marginal coal units had negative markups. In the first six months of 2019, using adjusted cost-based offers for coal units, 35.15 percent of marginal coal units had negative markups.

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

Table 3-81 Percent of marginal units with markup below, above and equal to zero (By fuel type unadjusted): January through June, 2018 and 2019

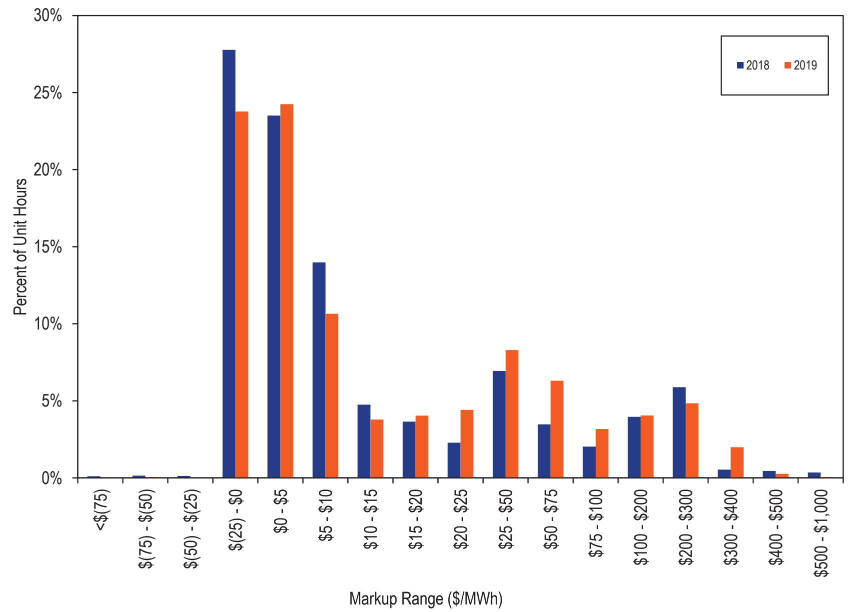
	2018 (Jan - Jun)			2019 (Jan - Jun)		
Type/Fuel	Negative	Zero	Positive	Negative	Zero	Positive
Coal	52.75%	21.51%	25.74%	51.37%	21.22%	27.41%
Gas	46.69%	11.44%	41.87%	32.48%	8.07%	59.45%
Oil	11.83%	77.15%	11.03%	3.03%	95.32%	1.65%

Table 3-82 Percent of marginal units with markup below, above and equal to zero (By fuel type adjusted): January through June, 2018 and 2019

	2018 (Jan - Jun)			2019 (Jan - Jun)		
Type/Fuel	Negative	Zero	Positive	Negative	Zero	Positive
Coal	18.52%	0.10%	81.38%	35.15%	0.41%	64.44%
Gas	9.28%	0.07%	90.65%	10.56%	0.02%	89.42%
Oil	0.80%	0.00%	99.20%	1.38%	0.00%	98.62%

Figure 3-59 shows the frequency distribution of hourly markups for all gas units offered in the first six 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.[114] Of the gas units offered in the PJM market in the first six months of 2019, nearly23.9 percent of gas unit-hours had a maximum markup that was negative. More than 11.2 percent of gas fired unit-hours had a maximum markup above $100 per MWh.

Figure 3-59 Frequency distribution of highest markup of gas units offered using unadjusted cost offers: January through June, 2018 and 2019



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

Figure 3-60 shows the frequency distribution of hourly markups for all coal units offered in the first six months of 2018 and 2019 using unadjusted cost-based offers. Of the coal units offered in the PJM market in the first six months of 2019, nearly 37 percent of coal unit-hours had a maximum markup that was negative or equal to zero.

Figure 3-60 Frequency distribution of highest markup of coal units offered using unadjusted cost offers: January through June, 2018 and 2019

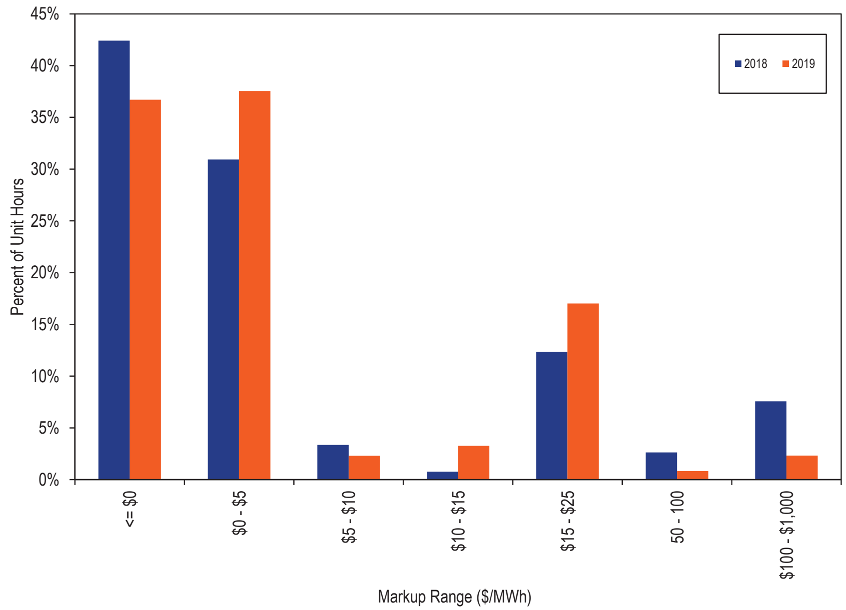
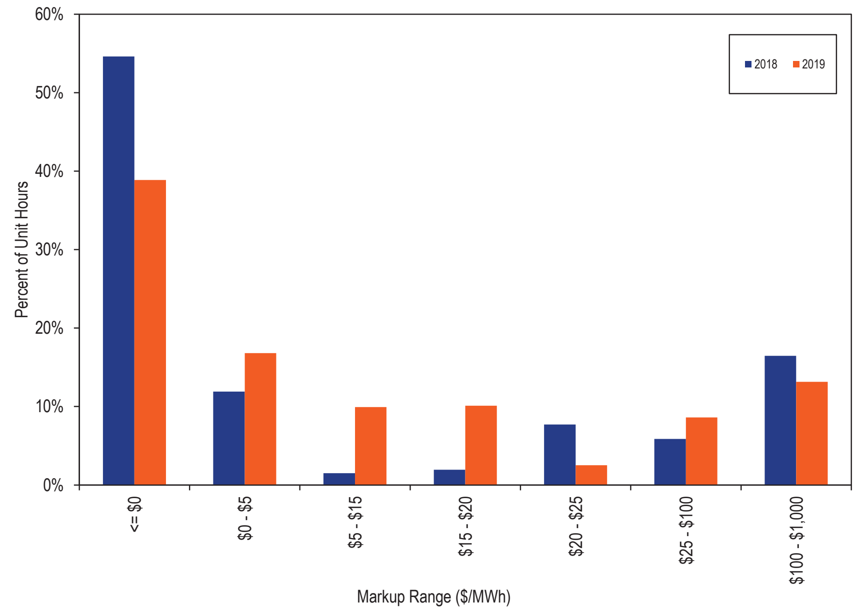


Figure 3-61 shows the frequency distribution of hourly markups for all offered oil units in the first six months of 2018 and 2019 using unadjusted cost-based offers. Of the oil units offered in the PJM market in the first six months of 2019, nearly 39 percent of oil unit-hours had a maximum markup that was negative or equal to zero. More than 13 percent of oil fired unit-hours had a maximum markup above $100 per MWh.

Figure 3-61 Frequency distribution of highest markup of oil units offered using unadjusted cost offers: January through June, 2018 and 2019

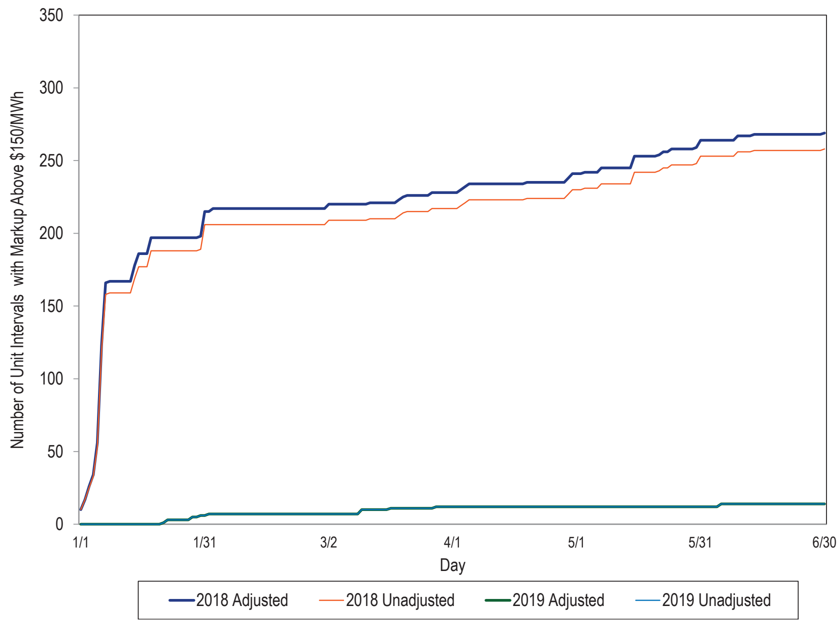


The markup frequency distributions show that a significant proportion of units make price-based offers less than the cost-based offers permitted under the PJM market rules. This behavior means that competitive price-based offers reveal actual unit marginal costs and that PJM market rules permit the inclusion 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 3-62 shows the number of marginal unit intervals in the first six 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 3-62 Cumulative number of unit intervals with markups above $150 per MWh: January through June, 2018 and 2019



Day-Ahead Markup Index

Table 3-83 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 six months of 2019, 98.5 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 ($0.71 per MWh) when using unadjusted cost-based offers. The average dollar markups of units with offer prices between $25 and $50 was positive ($1.57 per MWh) when using unadjusted cost-based offers.

Some marginal units did have substantial markups. Among the units that were marginal in the day-ahead market in January through June, 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 six months of 2019 was about $90 per MWh while the highest markup in the first six months of 2018 was about $200 per MWh.

Table 3-83 Average day-ahead marginal unit markup index (By offer price category, unadjusted): January through June, 2018 and 2019

	2018 (Jan - Jun)			2019 (Jan - Jun)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $25	0.04	$0.07	56.3%	0.17	$0.71	67.8%
$25 to $50	0.08	$2.61	38.1%	0.05	$1.57	30.8%
$50 to $75	0.25	$13.88	2.2%	0.17	$9.52	0.9%
$75 to $100	0.20	$14.85	0.7%	0.30	$27.58	0.1%
$100 to $125	0.02	$1.85	0.6%	0.48	$49.48	0.1%
$125 to $150	0.06	$7.26	0.8%	0.32	$45.31	0.2%
>= $150	0.07	$14.76	1.3%	0.20	$34.53	0.2%

Table 3-84 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 six 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 six months of 2018, to 0.25 in the first six months of 2019 in the offer price category less than $25.

Table 3-84 Average day-ahead marginal unit markup index (By offer price category, adjusted): January through June, 2018 and 2019

	2018 (Jan - Jun)			2019 (Jan - Jun)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $25	0.13	$1.79	56.3%	0.25	$2.42	67.8%
$25 to $50	0.16	$5.20	38.1%	0.13	$4.04	30.8%
$50 to $75	0.32	$17.79	2.2%	0.24	$13.82	0.9%
$75 to $100	0.27	$21.04	0.7%	0.36	$33.15	0.1%
$100 to $125	0.11	$11.80	0.6%	0.53	$54.07	0.1%
$125 to $150	0.14	$18.56	0.8%	0.38	$53.81	0.2%
>= $150	0.15	$31.88	1.3%	0.27	$48.36	0.2%

Energy Market Cost-Based Offers

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

Short Run Marginal Costs

There are three types of costs identified under PJM rules:

- Short run marginal costs. Cost of inputs consumed or converted to produce energy, and the costs associated with byproducts that result from consuming or converting materials to produce energy, net of any revenues from the sale of those byproducts. The categories of short run marginal costs are:
  - Fuel costs: Includes commodity costs, delivery costs (such as variable transportation costs), fuel supplier fees and taxes;
  - Emission allowance costs: Includes costs of emission allowances and any variable regulatory fees;
  - Operating costs: Includes water purchases, water or waste water treatment control reagents, emission control reagents, equipment lubricants, electricity byproducts disposal;
  - Energy market opportunity costs;[115]
- Avoidable costs. Annual costs that would be avoided if energy were not produced over an annual period, e.g. overhaul and maintenance costs;
- Fixed costs. Costs associated with an investment in a facility including the return on and of capital.

115 See PJM Operating Agreement Schedule 2 (a)

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

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

Fuel Cost Policies

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 policies are submitted under four scenarios:[116]

1. During the annual review process: The annual review begins on June 15 (the deadline for Market sellers to submit fuel cost policies per the annual review) and ends on November 1 (the deadline for PJM to approve or reject policies submitted as part of the annual review).
2. Outside the annual review process: Market sellers can submit new fuel cost policies. PJM and the MMU have 30 business days to review the submitted fuel cost policy.
3. New units: Owners of new units are required to submit a provisional fuel cost policy 45 days prior to the first day the market seller expects to make a cost-based offer, or a later date approved by PJM. Also, new units are required to submit a final fuel cost policy 90 days after the unit has been declared commercially available.
4. Unit transfers: Owners for existing units that are being transferred are required to submit a fuel cost policy 45 days prior to the unit transfer or a later date approved by PJM.

116 See PJM "Manual 15: Cost Development Guidelines," Rev. 32 (May 13, 2019).

Fuel Cost Policy Review

Table 3-85 shows the status of all Fuel Cost Policies as of June 30, 2019. As of June 30, 2019, 1,149 units (86 percent) had an FCP passed by the MMU, 17 units (one percent) had an FCP under the MMU review (submitted) and 175 units (13 percent) had an FCP failed by the MMU. Out of the 17 units under review by June 30, 2019, two subsequently failed the MMU evaluation and 15 passed the MMU evaluation. The number of units with fuel cost policies failed by the MMU included units with 28,263 MW. All units had an FCP approved by PJM. As of June 30, 2019, nine units had FCPs under PJM's review. The number of units with fuel cost policies passed by the MMU decreased one percentage point from 87 percent in 2018 Annual Fuel Cost Policy Review to 86 percent as of June 30, 2019.

Table 3-85 FCP Status: June 30, 2019

	MMU Status			
PJM Status	Pass	Submitted	Fail	Total
Submitted	0	0	0	0
Under Review	0	9	0	9
Customer Input Required	0	0	0	0
Approved	1,149	8	175	1,332
Revoked	0	0	0	0
Expired	0	0	0	0
Total	1,149	17	175	1,341

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:[117]

- Verifiable: Must provide a fuel price that can be calculated by the MMU after the fact with the same data available to the Market Seller at the time the decision was made and documentation for that data from a public or a private source.
- Systematic: Document a standardized method or methods for calculating fuel costs including objective triggers for each method.[118]

PJM and FERC did not agree that Fuel Cost Policies should be algorithmic:[119]

- Algorithmic: Must use a set of defined, logical steps. These steps may be as simple as a single number from a contract, a simple average of broker quotes, a simple average of bilateral offers, or the weighted average index price posted on the Intercontinental Exchange trading platform ('ICE').[120]

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:[121]

1. Accuracy: Reflect applicable costs accurately;
2. Procurement Practices: Provide information sufficient for the verification of the market seller's fuel procurement practices;
3. Fuel Contracts: Reflect the market seller's applicable commodity and/or transportation contracts (to the extent it holds such contracts).

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.

117 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.

118 Protest of the Independent Market Monitor for PJM, Docket No. ER16-372-002 (September 16, 2016) ("September 16th Filing") at P 8.
119 October 7th Filing at P12; 158 FERC ¶ 61,133 at P 57 (2017) ("February 3rd Order").
120 September 16th Filing at P 8.
121 See PJM Operating Agreement Schedule 2 § 2.3 (a).

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

- Unverifiable cost estimates. Some of these policies include options under which the estimate of the natural gas commodity cost would be calculated by the market seller without specifying a verifiable, quantitative method. For example, some FCPs specify that the source of the natural gas cost would be communications with traders within the market seller's organization. A fuel cost from discretionary and undocumented decision making within the market seller's organization is not verifiable. 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. 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.

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.[122] Penalties became effective May 15, 2017.

In the first six months of 2019, 33 penalty cases were identified, 32 resulted in assessed cost-based offer penalties, zero resulted in disagreement between the MMU and PJM, and one remains pending PJM's determination. These cases were from 33 units owned by 12 different companies. Table 3-87 shows the penalties by the year in which participants were notified.

Table 3-86 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	153	26	8	137	35
2019	33	32	0	1	33	12
Total	277	241	27	9	217	49

122 158 FERC ¶ 61,133 (2017) ("February 3rd Order").

Since 2017, 277 penalty cases have been identified, 241 resulted in assessed cost-based offer penalties, 27 resulted in disagreement between the MMU and PJM, and nine remain pending PJM's determination. The 241 cases were from 217 units owned by 49 different companies. The total penalties were $2.1 million, charged to units that totaled 56,827 available MW. The average penalty was $1.66 per available MW.[123] Table 3-87 shows the total cost-based offer penalties since 2017 by year.

Table 3-87 Cost-based offer penalties by year: May 2017 through June 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	119	33	$1,135,696	25,189	$2.11
2019	36	11	$358,024	14,708	$1.04
Total	247	49	$2,050,546	56,827	$1.66

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 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.[124] 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.[125] 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.

123 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.

124 See PJM Interconnection Maintenance Adder Revisions to the Amended and Restated Operating Agreement, L.L.C., Docket No. EL19-8-000.

125 167 FERC ¶ 61,030.

In the first 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 on the day 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.[126]

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.

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

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 since December 2014.[127]

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 3-88 shows the contribution to real-time, load-weighted LMP by individual marginal resource owners.[128] The contribution of each marginal resource to price at each load bus is calculated for each five-minute interval of the first six months of 2019, and summed by the parent company that offers the marginal resource into the Real-Time Energy Market. In the first six 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 41.0 percent of the real-time, load-weighted, average PJM system LMP. During the first six months of 2018, the offers of one company resulted in 13.5 percent of the real-time, load-weighted PJM system LMP and offers of the top four companies resulted in 40.9 percent of the real-time, load-weighted, average PJM system LMP. In the first six months of 2019, the offers of one company resulted in 15.4 percent of the peak hour real-time, load-weighted PJM system LMP. In the first six months of 2018, the offers of one company resulted in 11.7 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

127 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).

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

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.

Table 3-88 Marginal unit contribution to real-time, load-weighted LMP (By parent company): January through June, 2018 and 2019

2018 (Jan - Jun)						2019 (Jan - Jun)					
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	13.5%	13.5%	1	11.7%	11.7%	1	13.7%	13.7%	1	15.4%	15.4%
2	10.6%	24.1%	2	11.0%	22.7%	2	11.0%	24.8%	2	12.1%	27.5%
3	8.5%	32.6%	3	8.8%	31.5%	3	10.4%	35.2%	3	9.3%	36.8%
4	8.3%	40.9%	4	8.3%	39.8%	4	5.8%	41.0%	4	5.3%	42.1%
5	6.2%	47.1%	5	6.1%	45.9%	5	5.3%	46.3%	5	4.7%	46.8%
6	5.1%	52.2%	6	5.8%	51.7%	6	5.0%	51.2%	6	4.5%	51.3%
7	4.6%	56.8%	7	4.8%	56.5%	7	4.8%	56.0%	7	4.4%	55.7%
8	4.4%	61.2%	8	4.3%	60.7%	8	4.1%	60.2%	8	4.3%	60.0%
9	4.2%	65.4%	9	4.2%	65.0%	9	3.6%	63.8%	9	3.6%	63.7%
Other (76 companies)	34.6%	100.0%	Other (73 companies)	35.0%	100.0%	Other (68 companies)	36.2%	100.0%	Other (64 companies)	36.3%	100.0%

Table 3-89 shows the contribution to day-ahead, load-weighted LMP by individual marginal resource owners.[129] 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 six months of 2019, the offers of one company contributed 9.4 percent of the day-ahead, load-weighted, PJM system LMP and that the offers of the top four companies contributed 29.5 percent of the day-ahead, load-weighted, average, PJM system LMP. In the first six months of 2018, the offers of one company contributed 12.4 percent of the day-ahead, load-weighted PJM system LMP and offers of the top four companies contributed 32.4 percent of the day-ahead, load-weighted, average PJM system LMP.

Table 3-89 Marginal resource contribution to day-ahead, load-weighted LMP (By parent company): January through June, 2018 and 2019

2018 (Jan - Jun)						2019 (Jan - Jun)					
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	12.4%	12.4%	1	14.8%	14.8%	1	9.4%	9.4%	1	10.7%	10.7%
2	7.6%	20.1%	2	7.3%	7.3%	2	8.3%	17.8%	2	6.9%	17.6%
3	7.1%	27.2%	3	6.7%	6.7%	3	7.0%	24.8%	3	6.5%	24.1%
4	5.3%	32.4%	4	5.9%	5.9%	4	4.6%	29.5%	4	5.0%	29.1%
5	4.4%	36.8%	5	5.1%	5.1%	5	3.8%	33.3%	5	4.2%	33.3%
6	4.2%	41.0%	6	4.4%	4.4%	6	3.8%	37.1%	6	3.9%	37.2%
7	4.0%	45.0%	7	3.7%	3.7%	7	3.7%	40.8%	7	3.7%	40.9%
8	3.9%	48.8%	8	3.5%	3.5%	8	3.4%	44.2%	8	3.5%	44.4%
9	3.4%	52.2%	9	3.5%	3.5%	9	3.0%	47.1%	9	3.4%	47.9%
Other (153 companies)	47.8%	100.0%	Other (137 companies)	45.1%	45.1%	Other (137 companies)	52.9%	100.0%	Other (127 companies)	52.1%	100.0%

129 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.[130] 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.

130 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 3-90 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 $7.97 per MWh in the first six months of 2018 to $4.05 per MWh in the first six months of 2019. The adjusted markup contribution of coal units in the first six months of 2019 was $0.95 per MWh. The adjusted markup component of gas fired units in the first six months of 2019 was $3.10 per MWh, a decrease of $1.80 per MWh from the first six 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 six months of 2018, among the wind units that were marginal, 91.8 percent had negative offer prices.

Table 3-90 Markup component of real-time, load-weighted, average LMP by primary fuel type and unit type: January through June, 2018 and 2019[131]

		2018 (Jan - Jun)		2019 (Jan - Jun)	
Fuel	Technology	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)
Coal	Steam	$1.08	$1.95	$0.11	$0.95
Gas	CC	$3.07	$4.36	$1.73	$2.88
Gas	CT	$0.15	$0.48	$0.05	$0.16
Gas	Diesel	$0.00	$0.01	$0.04	$0.05
Gas	Steam	($0.02)	$0.04	($0.02)	$0.00
Landfill Gas	CT	$0.00	$0.00	($0.00)	($0.00)
Landfill Gas	Diesel	$0.00	$0.00	$0.00	$0.00
Municipal Waste	CT	$0.00	$0.00	$0.00	$0.00
Oil	CC	$0.30	$0.34	($0.00)	$0.00
Oil	CT	$0.11	$0.36	$0.01	$0.01
Oil	Diesel	$0.00	$0.00	$0.00	$0.00
Oil	Steam	$0.20	$0.27	($0.00)	$0.00
Other	Steam	$0.13	$0.13	($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		$5.05	$7.97	$1.90	$4.05

Markup Component of Real-Time Price

Table 3-91 shows the markup component, calculated using unadjusted offers, of average prices and of average monthly on peak and off peak prices. Table 3-92 shows the markup component, calculated using adjusted offers, of average prices and of average monthly on peak and off peak prices. In the first six months of 2019, when using unadjusted cost-based offers, $1.90 per MWh of the PJM real-time load-weighted average LMP was attributable to markup. Using adjusted cost-based offers, $4.05 per MWh of the PJM real-time load-weighted, average LMP was attributable to markup. In the first six months of 2019, the peak markup component was highest in February, $3.05 per MWh using unadjusted cost-based offers and peak markup component was highest in January, $5.48 per MWh using adjusted cost-based offers. This corresponds to 10.3 percent and 10.4 percent of the real-time peak load-weighted average LMP in February and January.

131 The unit type RICE refers to Reciprocating Internal Combustion Engines.

Table 3-91 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	$9.29	$11.65	$6.89	$2.11	$1.49	$2.70
Feb	$1.47	$0.95	$1.97	$2.34	$1.63	$3.05
Mar	$4.94	$2.68	$7.15	$2.27	$1.82	$2.74
Apr	$5.71	$3.47	$7.92	$1.59	$0.81	$2.27
May	$5.20	$1.57	$8.45	$1.41	$0.56	$2.19
Jun	$2.86	$1.96	$3.69	$1.56	$1.24	$1.89
Total	$5.05	$4.03	$6.02	$1.90	$1.30	$2.48

Table 3-92 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	$14.99	$17.60	$12.33	$4.66	$3.81	$5.48
Feb	$3.64	$2.96	$4.32	$4.52	$3.72	$5.33
Mar	$7.28	$4.89	$9.63	$4.53	$3.99	$5.11
Apr	$8.16	$5.73	$10.56	$3.60	$2.67	$4.42
May	$7.38	$3.48	$10.86	$3.38	$2.33	$4.33
Jun	$4.94	$3.87	$5.95	$3.42	$2.89	$3.94
Total	$7.96	$6.87	$9.02	$4.05	$3.29	$4.79

Hourly Markup Component of Real-Time Prices

Figure 3-63 shows the markup contribution to the hourly load-weighted LMP using unadjusted cost offers in the first six months of 2019 and 2018. Figure 3-64 shows the markup contribution to the hourly load-weighted LMP using adjusted cost-based offers in the first six 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 3-63 Markup contribution to real-time hourly load-weighted LMP (Unadjusted): 2018 and 2019

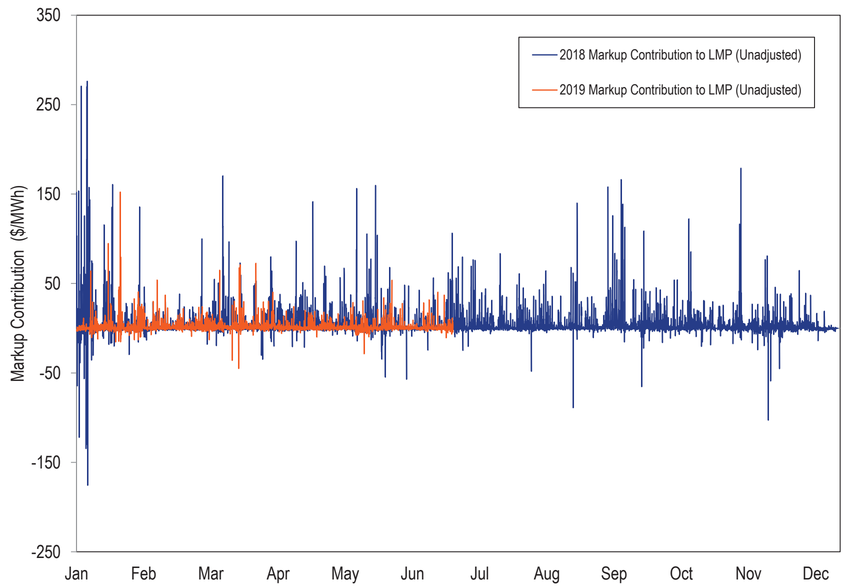
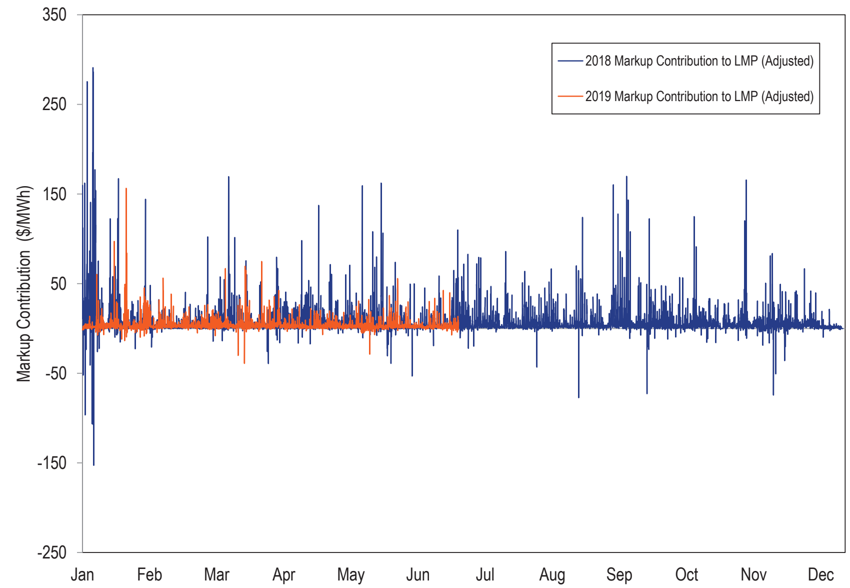


Figure 3-64 Markup contribution to real-time hourly load-weighted LMP (Adjusted): 2018 and 2019



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 six months of 2018 and 2019 in Table 3-93 and for adjusted offers in Table 3-94. The smallest zonal all hours average markup component using unadjusted offers in the first six months of 2019, was in the OVEC Control Zone, 1.50 per MWh, while the highest was in the DPL Control Zone, $2.65 per MWh. The smallest zonal on peak average markup component using unadjusted offers in the first six months of 2019, was in the OVEC Control Zone, 2.06 per MWh, while the highest was in the PSEG Control Zone, $3.27 per MWh.

Table 3-93 Average real-time zonal markup component (Unadjusted): January through June, 2018 and 2019

	2018 (Jan - Jun)			2019 (Jan - Jun)		
	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component
AECO	$4.37	$3.94	$4.79	$2.43	$1.81	$3.06
AEP	$4.65	$3.70	$5.58	$1.72	$1.17	$2.26
APS	$5.40	$4.31	$6.48	$1.79	$1.24	$2.34
ATSI	$5.98	$4.01	$7.86	$1.80	$1.24	$2.35
BGE	$6.84	$5.23	$8.43	$1.75	$1.14	$2.35
ComEd	$3.09	$1.59	$4.49	$1.57	$0.68	$2.41
DAY	$4.84	$3.53	$6.07	$1.81	$1.19	$2.39
DEOK	$5.09	$4.07	$6.07	$1.65	$1.10	$2.19
DLCO	$6.21	$4.41	$7.93	$1.76	$1.19	$2.30
DPL	$4.87	$4.47	$5.26	$2.65	$2.21	$3.08
Dominion	$6.79	$6.14	$7.44	$1.74	$1.21	$2.26
EKPC	$4.76	$4.48	$5.05	$1.62	$1.12	$2.14
JCPL	$4.62	$4.18	$5.03	$2.47	$1.91	$3.01
Met-Ed	$4.75	$4.25	$5.21	$2.13	$1.57	$2.66
OVEC	NA	NA	NA	$1.50	$0.99	$2.06
PECO	$4.24	$3.71	$4.73	$2.43	$1.89	$2.95
PENELEC	$4.96	$3.83	$6.02	$1.89	$1.36	$2.40
PPL	$4.21	$3.54	$4.84	$2.33	$1.73	$2.92
PSEG	$4.46	$3.99	$4.90	$2.62	$1.94	$3.27
Pepco	$6.24	$5.04	$7.38	$1.76	$1.20	$2.29
RECO	$4.54	$3.78	$5.20	$2.33	$1.81	$2.81

Table 3-94 Average real-time zonal markup component (Adjusted): January through June 2018 and 2019

	2018 (Jan - Jun)			2019 (Jan - Jun)		
	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component
AECO	$7.19	$6.69	$7.69	$4.45	$3.71	$5.20
AEP	$7.44	$6.39	$8.47	$3.89	$3.18	$4.60
APS	$8.52	$7.35	$9.68	$4.00	$3.28	$4.71
ATSI	$8.87	$6.68	$10.95	$3.99	$3.25	$4.71
BGE	$10.33	$8.64	$11.99	$4.12	$3.33	$4.90
ComEd	$5.40	$3.81	$6.88	$3.58	$2.51	$4.58
DAY	$7.58	$6.09	$8.96	$4.06	$3.25	$4.81
DEOK	$7.72	$6.58	$8.82	$3.81	$3.09	$4.51
DLCO	$9.10	$7.04	$11.08	$3.91	$3.17	$4.62
DPL	$8.19	$7.67	$8.71	$4.74	$4.18	$5.29
Dominion	$10.25	$9.65	$10.84	$4.02	$3.32	$4.71
EKPC	$7.42	$6.98	$7.87	$3.81	$3.17	$4.48
JCPL	$7.49	$7.00	$7.94	$4.54	$3.83	$5.22
Met-Ed	$7.55	$6.98	$8.09	$4.23	$3.51	$4.92
OVEC	NA	NA	NA	$3.59	$2.94	$4.32
PECO	$7.13	$6.55	$7.68	$4.45	$3.77	$5.10
PENELEC	$7.84	$6.55	$9.05	$4.00	$3.31	$4.65
PPL	$7.05	$6.34	$7.71	$4.36	$3.60	$5.08
PSEG	$7.28	$6.74	$7.78	$4.67	$3.86	$5.43
Pepco	$9.68	$8.42	$10.88	$4.08	$3.33	$4.79
RECO	$7.32	$6.39	$8.13	$4.28	$3.66	$4.84

Markup by Real-Time Price Levels

Table 3-95 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 3-95 Real-time markup contribution (By PJM load-weighted LMP category, unadjusted): January through June, 2018 and 2019

	2018 (Jan - Jun)		2019 (Jan - Jun)	
LMP Category	Markup Component	Frequency	Markup Component	Frequency
< $25	($0.38)	40.1%	$0.10	59.6%
$25 to $50	$3.29	45.5%	$2.80	37.1%
$50 to $75	$15.70	6.6%	$13.92	2.1%
$75 to $100	$16.23	2.3%	$26.56	0.7%
$100 to $125	$20.28	2.0%	$20.32	0.2%
$125 to $150	$18.27	1.0%	$33.87	0.1%
>= $150	$44.50	2.5%	$7.16	0.2%

Table 3-96 Real-time markup contribution (By PJM load-weighted LMP category, adjusted): January through June, 2018 and 2019

	2018 (Jan - Jun)		2019 (Jan - Jun)	
LMP Category	Markup Component	Frequency	Markup Component	Frequency
< $25	$1.56	40.1%	$1.98	59.6%
$25 to $50	$5.84	45.5%	$5.22	37.1%
$50 to $75	$19.23	6.6%	$17.17	2.1%
$75 to $100	$21.83	2.3%	$30.60	0.7%
$100 to $125	$27.35	2.0%	$25.55	0.2%
$125 to $150	$27.46	1.0%	$37.83	0.1%
>= $150	$57.06	2.5%	$9.67	0.2%

Markup by Company

Table 3-97 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 six months of 2019, when using unadjusted cost-based offers, the markup of one company accounted for 2.7 percent of the load-weighted average LMP, the markup of the top five companies accounted for 5.8 percent of the load-weighted average LMP and the markup of all companies accounted for 6.9 percent of the load-weighted average LMP. In the first six months of 2018, when using unadjusted cost-based offers, the markup of one company accounted for 2.8 percent of the load-weighted average LMP, the markup of the top five companies accounted for 8.6 percent of the load-weighted average LMP and the markup of all companies accounted for 11.9 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 six 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 six months of 2019.

Table 3-97 Markup component of real-time, load-weighted, average LMP by Company: January through June, 2018 and 2019

	2018 (Jan - Jun)				2019 (Jan - Jun)			
	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	$1.19	2.8%	$1.57	3.7%	$0.74	2.7%	$0.88	3.2%
Top 2 Companies	$2.03	4.8%	$2.48	5.8%	$1.00	3.6%	$1.41	5.1%
Top 3 Companies	$2.67	6.3%	$3.34	7.9%	$1.24	4.5%	$1.90	6.9%
Top 4 Companies	$3.18	7.5%	$4.01	9.4%	$1.43	5.2%	$2.27	8.3%
Top 5 Companies	$3.64	8.6%	$4.58	10.8%	$1.59	5.8%	$2.51	9.1%
All Companies	$5.05	11.9%	$7.97	18.8%	$1.90	6.9%	$4.05	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 3-98. INC, DEC and up to congestion transactions (UTC) have zero markups. INCs were 13.3 percent of marginal resources and DECs were 18.2 percent of marginal resources in the first six 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 66.9 percent in the first six months of 2018 to 57.8 percent in the first six months of 2019 as the result of a FERC order issued on February 20, 2018, and implemented on February 22, 2018.[132] 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 3-98 shows the markup component of LMP for marginal generating resources. Generating resources were only 10.5 percent of marginal resources in the first six months of 2019. Using adjusted cost-based offers, the markup component of LMP for marginal generating resources decreased for coal fired steam units from $1.27 to $0.51 and decreased for gas fired CT units from $0.13 to $0.03. The markup component of LMP for coal fired steam units decreased from $0.55 in the first six months of 2018 to -$0.24 in the first six months of 2019 using unadjusted cost-based offers

132 162 FERC ¶ 61,139 (2018).

Table 3-98 Markup component of day-ahead, load-weighted, average LMP by primary fuel type and unit type: January through June, 2018 and 2019

		2018 (Jan - Jun)			2019 (Jan - Jun)		
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	$0.55	$1.27	42.6%	($0.24)	$0.51	42.7%
Gas	CT	$0.03	$0.13	3.4%	$0.01	$0.03	1.9%
Gas	RICE	$0.00	$0.00	0.6%	($0.00)	($0.00)	0.5%
Gas	Steam	$0.59	$1.28	47.6%	$0.69	$1.26	52.9%
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	0.1%
Oil	RICE	$0.00	$0.00	0.0%	$0.00	$0.00	0.0%
Oil	Steam	($0.01)	$0.16	1.1%	$0.00	($0.00)	0.0%
Other	Solar	$0.00	$0.00	0.4%	$0.00	$0.00	0.1%
Other	Steam	($0.00)	($0.00)	0.2%	($0.00)	($0.00)	0.1%
Uranium	Steam	$0.00	$0.00	1.1%	$0.00	$0.00	0.3%
Water	Hydro	$0.00	$0.00	0.0%	$0.00	$0.00	0.0%
Wind	Wind	$0.01	$0.01	2.6%	$0.02	$0.02	1.3%
Total		$1.17	$2.85	100.0%	$0.48	$1.81	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 3-99 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 six months of 2019, when using unadjusted cost-based offers, $0.48 per MWh of the PJM day-ahead load-weighted average LMP was attributable to markup. In the first six months of 2019, the peak markup component was highest in January, $1.68 per MWh using unadjusted cost-based offers.

Table 3-99 Monthly markup components of day-ahead (Unadjusted), load-weighted LMP: January 2018 through June 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	$1.59	$2.10	$1.06	$0.78	$1.68	($0.16)
Feb	$0.42	$0.81	$0.02	$0.60	$0.80	$0.41
Mar	$0.23	$0.31	$0.15	$0.65	$0.99	$0.32
Apr	$0.55	$0.77	$0.32	$0.15	$0.30	($0.03)
May	$0.42	$0.62	$0.20	$0.11	$0.13	$0.09
Jun	$0.15	$0.35	($0.06)	$0.45	$0.38	$0.53
Jul	$1.39	$2.50	$0.20			
Aug	$1.03	$1.76	$0.11			
Sep	$1.96	$3.14	$0.85			
Oct	$1.21	$1.56	$0.80			
Nov	$1.26	$1.98	$0.53			
Dec	$0.81	$1.37	$0.33			
Annual	$1.17	$1.70	$0.61	$0.48	$0.74	$0.19

Table 3-100 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 six months of 2019, when using adjusted cost-based offers, $1.81 per MWh of the PJM day-ahead load-weighted average LMP was attributable to markup. In the first six months of 2019, the peak markup component was highest in January, $3.33 per MWh using adjusted cost-based offers.

Table 3-100 Monthly markup components of day-ahead (Adjusted), load-weighted LMP: January 2018 through June 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	$3.18	$3.69	$2.66	$2.45	$3.33	$1.55
Feb	$1.20	$1.63	$0.76	$2.09	$2.32	$1.87
Mar	$0.89	$0.97	$0.82	$2.01	$2.27	$1.77
Apr	$1.10	$1.24	$0.95	$1.24	$1.25	$1.23
May	$1.01	$1.14	$0.87	$1.28	$1.15	$1.41
Jun	$0.89	$1.04	$0.73	$1.61	$1.59	$1.64
Jul	$2.73	$3.70	$1.70			
Aug	$2.36	$2.88	$1.71			
Sep	$3.16	$4.17	$2.22			
Oct	$2.44	$2.66	$2.17			
Nov	$2.75	$3.21	$2.28			
Dec	$2.69	$3.24	$2.20			
Annual	$2.85	$3.32	$2.36	$1.81	$2.03	$1.59

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 3-101. The markup component of annual average day-ahead price using adjusted cost-based offers is shown for each zone in Table 3-102. The smallest zonal all hours average markup component using adjusted cost-based offers for the first six months of 2019 was in the BGE Zone, $1.57 per MWh, while the highest was in the PECO Control Zone, $2.29 per MWh. The smallest zonal on peak average markup using adjusted cost-based offers was in the BGE Control Zone, $1.74 per MWh, while the highest was in the PECO Control Zone, $2.68 per MWh.

Table 3-101 Day-ahead, average, zonal markup component (Unadjusted): January through June, 2018 and 2019

	2018 (Jan - Jun)			2019 (Jan - Jun)		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
AECO	$1.47	$1.99	$0.93	$1.00	$1.44	$0.56
AEP	$1.11	$1.68	$0.51	$0.38	$0.63	$0.12
APS	$1.20	$1.75	$0.64	$0.41	$0.64	$0.18
ATSI	$1.09	$1.50	$0.66	$0.37	$0.57	$0.15
BGE	$0.90	$1.32	$0.46	$0.16	$0.38	($0.06)
ComEd	$0.75	$1.30	$0.16	$0.34	$0.48	$0.20
DAY	$1.22	$1.72	$0.68	$0.29	$0.49	$0.08
DEOK	$1.65	$2.62	$0.63	$0.27	$0.50	$0.03
DLCO	$1.24	$1.76	$0.69	$0.36	$0.56	$0.15
Dominion	$1.03	$1.52	$0.55	$0.24	$0.48	($0.00)
DPL	$1.50	$1.97	$1.02	$0.98	$1.35	$0.61
EKPC	$1.63	$2.72	$0.58	$0.46	$0.71	$0.22
JCPL	$1.39	$1.80	$0.94	$0.93	$1.36	$0.46
Met-Ed	$1.54	$2.05	$0.99	$0.71	$1.12	$0.27
OVEC	NA	NA	NA	$0.96	$1.26	$0.60
PECO	$1.54	$2.13	$0.91	$1.00	$1.46	$0.52
PENELEC	$0.96	$1.40	$0.48	$0.65	$0.89	$0.39
Pepco	$0.81	$1.11	$0.50	$0.19	$0.41	($0.04)
PPL	$1.56	$2.17	$0.92	$0.89	$1.31	$0.45
PSEG	$1.41	$1.79	$0.99	$0.98	$1.42	$0.51

Table 3-102 Day-ahead, average, zonal markup component (Adjusted): January through June, 2018 and 2019

	2018 (Jan - Jun)			2019 (Jan - Jun)		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
AECO	$3.28	$3.72	$2.83	$2.27	$2.65	$1.88
AEP	$2.69	$3.20	$2.16	$1.74	$1.93	$1.54
APS	$2.89	$3.35	$2.41	$1.77	$1.94	$1.59
ATSI	$2.68	$3.01	$2.31	$1.74	$1.89	$1.57
BGE	$2.82	$3.16	$2.46	$1.57	$1.74	$1.40
ComEd	$2.19	$2.77	$1.58	$1.63	$1.76	$1.50
DAY	$2.84	$3.28	$2.37	$1.70	$1.86	$1.54
DEOK	$3.22	$4.20	$2.19	$1.65	$1.81	$1.49
DLCO	$2.76	$3.18	$2.30	$1.72	$1.87	$1.57
Dominion	$2.90	$3.30	$2.50	$1.62	$1.78	$1.45
DPL	$3.34	$3.69	$2.99	$2.26	$2.54	$1.98
EKPC	$3.31	$4.45	$2.20	$1.81	$2.02	$1.61
JCPL	$3.18	$3.50	$2.83	$2.25	$2.64	$1.83
Met-Ed	$3.27	$3.69	$2.83	$2.03	$2.35	$1.68
OVEC	NA	NA	NA	$1.89	$1.96	$1.82
PECO	$3.35	$3.85	$2.82	$2.29	$2.68	$1.87
PENELEC	$2.54	$2.90	$2.16	$1.95	$2.12	$1.76
Pepco	$2.68	$2.88	$2.46	$1.60	$1.78	$1.42
PPL	$3.35	$3.86	$2.82	$2.19	$2.54	$1.81
PSEG	$3.20	$3.50	$2.87	$2.25	$2.63	$1.84

Markup by Day-Ahead Price Levels

Table 3-103 and Table 3-104 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 3-103 Average, day-ahead markup component (By LMP category, unadjusted): January through June, 2018 and 2019

	2018 (Jan - Jun)		2019 (Jan - Jun)	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $25	($0.13)	29.6%	($0.04)	49.3%
$25 to $50	$0.52	57.6%	$0.34	48.5%
$50 to $75	$0.22	5.7%	$0.05	1.2%
$75 to $100	$0.08	2.6%	$0.05	0.8%
$100 to $125	$0.10	1.7%	$0.03	0.1%
$125 to $150	$0.09	1.1%	$0.02	0.0%
>= $150	$0.27	1.8%	$0.02	0.0%

Table 3-104 Average, day-ahead markup component (By LMP category, adjusted): January through June, 2018 and 2019

	2018 (Jan - Jun)		2019 (Jan - Jun)	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $25	$0.26	29.6%	$0.57	49.3%
$25 to $50	$1.34	57.6%	$1.03	48.5%
$50 to $75	$0.30	5.7%	$0.07	1.2%
$75 to $100	$0.17	2.6%	$0.06	0.8%
$100 to $125	$0.19	1.7%	$0.04	0.1%
$125 to $150	$0.15	1.1%	$0.03	0.0%
>= $150	$0.44	1.8%	$0.02	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 six months of 2019, energy uplift credits were $37.1 million, including $8.2 million in day-ahead generator credits, $21.4 million in balancing generator credits, $4.0 million in lost opportunity cost credits, and $2.7 million in local constraint control credits.
- **Types of units.** Coal units received 90.1 percent of all day-ahead generator credits. Combustion turbines received 82.7 percent of all balancing generator credits and 90.2 percent of lost opportunity cost credits.
- **Economic and Noneconomic Generation.** In the first six months of 2019, 81.3 percent of the day-ahead generation eligible for operating reserve credits was economic and 66.6 percent of the real-time generation eligible for operating reserve credits was economic.
- **Day-Ahead Unit Commitment for Reliability.** In the first six months of 2019, 0.2 percent of the total day-ahead generation MWh was scheduled as must run by PJM, of which 52.8 percent received energy uplift payments.
- **Concentration of Energy Uplift Credits.** The top 10 units receiving energy uplift credits received 29.3 percent of all credits. The top 10 organizations received 77.3 percent of all credits. The HHI for day-ahead operating reserves was 8523, the HHI for balancing operating reserves was 3867 and the HHI for lost opportunity cost was 6532, all of which are classified as highly concentrated.

4 Demand response payments are addressed in Section 6: Demand Response.

- **Lost Opportunity Cost Credits.** Lost opportunity cost credits decreased by $37.5 million or 90.3 percent, in the first six months of 2019 compared to the first six months of 2018, from $41.5 million to $4.0 million. Generation from combustion turbines and diesels scheduled day-ahead but not requested in real time, receiving lost opportunity cost credits decreased by 527 GWh or 78.1 percent in the first six months of 2019, compared to the first six months of 2018, from 674.9 GWh to 148 GWh.

Energy Uplift Charges

- **Energy Uplift Charges.** Total energy uplift charges decreased by $102.9 million, or 73.6 percent, in the first six months of 2019 compared to the first six months of 2018, from $139.8 million to $36.9 million.
- **Energy Uplift Charges Categories.** The decrease of $102.9 million in the first six months of 2019 is comprised of a $19.4 million decrease in day-ahead operating reserve charges, a $73.2 million decrease in balancing operating reserve charges, and a $10.3 million decrease in reactive services charges.
- **Average Effective Operating Reserve Rates in the Eastern Region.** Day-ahead load paid $0.021 per MWh, real-time load paid $0.028 per MWh, a DEC paid $0.230 per MWh and an INC and any load, generation or interchange transaction deviation paid $0.209 per MWh.
- **Average Effective Operating Reserve Rates in the Western Region.** Day-ahead load paid $0.021 per MWh, real-time load paid $0.025 per MWh, a DEC paid $0.210 per MWh and an INC and any load, generation or interchange transaction deviation paid $0.189 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 $0.016 per MWh, DPL had a rate of $0.011 per MWh, and Dominion had a rate of $0.004 per MWh.

Geography of Charges and Credits

- In the first six months of 2019, 91.0 percent of all uplift charges allocated regionally (day-ahead operating reserves and balancing operating reserves) were paid by transactions at control zones, 2.3 percent by transactions at hubs and aggregates, and 6.7 percent by transactions at interchange interfaces.
- Generators in the Eastern Region received 52.8 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.
- Generators in the Western Region received 446.5 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.
- External generators received 1.6 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.

Recommendations

- The MMU 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.)

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.

- 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.[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.)

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

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.

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.

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 six months of 2018 and 2019.[9] In the first six months of 2019, energy uplift credits decreased by $ 102.7 million or 73.6 percent compared to the first six months of 2018.

Table 4-1 Energy uplift credits by category: January through June, 2018 and 2019

Category	Type	(Jan - Jun) 2018 Credits (Millions)	(Jan - Jun) 2019 Credits (Millions)	Change	Percent Change	(Jan - Jun) 2018 Share	(Jan - Jun) 2019 Share
Day-Ahead	Generators	$27.6	$8.2	($19.4)	(70.2%)	19.8%	22.3%
	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	$51.9	$21.4	($30.5)	(58.8%)	37.2%	58.1%
	Imports	$0.5	$0.0	($0.5)	(100.0%)	0.3%	0.0%
	Load Response	$0.0	$0.0	($0.0)	(100.0%)	0.0%	0.0%
	Local Constraints Control	$7.1	$2.7	($4.5)	(62.7%)	5.1%	7.2%
	Lost Opportunity Cost	$41.5	$4.0	($37.5)	(90.3%)	29.7%	10.9%
Reactive Services	Day-Ahead	$9.5	$0.2	($9.4)	(98.1%)	6.8%	0.5%
	Local Constraints Control	$0.0	$0.0	$0.0	NA	0.0%	0.0%
	Lost Opportunity Cost	$0.0	$0.0	$0.0	83.9%	0.0%	0.0%
	Reactive Services	$0.7	$0.3	($0.4)	(62.7%)	0.5%	0.7%
	Synchronous Condensing	$0.5	$0.0	($0.5)	(100.0%)	0.3%	0.0%
Synchronous Condensing		$0.0	$0.0	($0.0)	(100.0%)	0.0%	0.0%
Black Start Services	Day-Ahead	$0.0	$0.0	$0.0	NA	0.0%	0.0%
	Balancing	$0.1	$0.1	($0.0)	(1.0%)	0.1%	0.3%
	Testing	$0.0	$0.0	($0.0)	(100.0%)	0.0%	0.0%
Total		$139.6	$36.9	($102.7)	(73.6%)	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 July 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 six months of 2018 and 2019. Uplift credits decreased for all unit types. The reduction in uplift credits was largely the result of mild weather. 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 $43.2 million or 64.2 percent.

Table 4-2 Energy uplift credits by unit type: January through June, 2018 and 2019[10 11]

Unit Type	(Jan - Jun) 2018 Credits (Millions)	(Jan - Jun) 2019 Credits (Millions)	Change	Percent Change	(Jan - Jun) 2018 Share	(Jan - Jun) 2019 Share
Combined Cycle	$17.9	$2.2	($15.6)	(87.5%)	12.8%	6.0%
Combustion Turbine	$67.2	$24.0	($43.2)	(64.2%)	48.3%	65.2%
Diesel	$1.1	$0.4	($0.7)	(63.5%)	0.8%	1.1%
Hydro	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%
Nuclear	$0.4	$0.0	($0.4)	(100.0%)	0.3%	0.0%
Solar	$0.0	$0.1	$0.1	17,134.3%	0.0%	0.2%
Steam - Coal	$34.6	$9.5	($25.2)	(72.7%)	24.9%	25.6%
Steam - Other	$16.4	$0.6	($15.7)	(96.2%)	11.8%	1.7%
Wind	$1.5	$0.1	($1.4)	(95.1%)	1.0%	0.2%
Total	$139.1	$36.9	($102.2)	(73.5%)	100.0%	100.0%

Table 4-3 shows the distribution of energy uplift credits by category and by unit type in the first six 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, 90.1 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 49.9 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 82.7 percent of balancing credits and 87.4 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 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 June, 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	4.2%	7.2%	0.0%	8.3%	7.2%	0.0%	0.0%	33.9%
Combustion Turbine	0.2%	82.7%	0.0%	86.8%	87.4%	48.8%	0.0%	66.0%
Diesel	0.1%	0.7%	0.0%	4.8%	2.9%	1.3%	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%	0.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Steam - Coal	90.1%	8.3%	0.0%	0.0%	1.0%	49.9%	0.0%	0.0%
Steam - Other	5.5%	0.7%	0.0%	0.0%	0.6%	0.0%	0.0%	0.0%
Wind	0.0%	0.1%	0.0%	0.0%	0.9%	0.0%	0.0%	0.0%
Total (Millions)	$8.2	$21.4	$0.0	$2.7	$4.2	$0.5	$0.0	$0.1

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 six months of 2019, 0.2 percent of the total day-ahead generation was committed for reliability by PJM, 1.7 percentage points lower than in the first six 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.

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 18, 2017) at 38 <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 June 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%			
Aug	80,864	476	0.6%			
Sep	69,596	659	0.9%			
Oct	64,003	533	0.8%			
Nov	64,183	744	1.2%			
Dec	70,864	215	0.3%			
Total (Jan - Jun)	404,199	7,655	1.9%	401,307	910	0.2%
Total	833,362	11,128	1.3%	401,307	910	0.2%

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 six months of 2019 were $8.2 million. The top 10 units received $7.5 million or 91.2 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 six months of 2019, 52.8 percent of the day-ahead generation committed for reliability by PJM received operating reserve credits, of which 37.1 percent was paid as day-ahead operating reserve credits. The remaining 47.2 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 June, 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
Total (Jan - Jun)	699	1,642	2,090	4,431
Share	15.8%	37.1%	47.2%	100.0%

Total day-ahead operating reserve credits in the first six months of 2019 were $8.2 million, of which $6.7 million or 81.0 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 2.2 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 $17.7 million or 82.7 percent of all balancing operating reserve (BOR) credits in the first six months of 2019. The majority of these credits, 99.2 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.

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 six months of 2019, generation by combustion turbines was 27.5 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 5.9 percent of generation from combustion turbines in the day-ahead market was uneconomic and did not need day-ahead generator credits. In the Real-Time Energy Market, 37.4 percent of generation from combustion turbines was uneconomic and required $17.7 million in BOR credits.

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.

Table 4-6 Characteristics of day-ahead and real-time generation by combustion turbines: January through June, 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%
Total (Jan - Jun)	2,019	5.9%	$0.0	2,785	37.4%	$17.7	27.5%

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 six months of 2019, 42.9 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, 26.0 percent was uneconomic in the real-time market and did not received BOR credits. Of the 57.1 percent of real-time generation by CTs that operated outside of a day-ahead schedule, 46.0 percent was uneconomic in the real-time market and received $17.6 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 June, 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
Total (Jan - Jun)	1,194	42.9%	26.0%	$0.1	1,591	57.1%	46.0%	$17.6

Lost Opportunity Cost Credits

Balancing operating reserve lost opportunity cost (LOC) credits are an incentive for units to follow PJM's dispatch instructions when PJM's dispatch instructions deviate from a unit's desired or scheduled output. 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 six months of 2019. In the first six months of 2019, LOC credits decreased by $37.5 million or 90.3 percent compared to the first six months of 2018. The decrease of $37.5 million is comprised of a $24.8 million decrease in day-ahead LOC and a $12.5 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 also contributed. 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 six months of 2019, 12.0 percent of day-ahead generation by combustion turbines and diesels was not requested in real time, 7.5 percentage points lower than in the first six months of 2018.

Table 4-8 Monthly lost opportunity cost credits (Millions): January 2018 through June 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	$0.5	$0.3	$0.7
Feb	$0.1	$0.0	$0.2	$0.1	$0.0	$0.2
Mar	$3.2	$0.2	$3.4	$0.5	$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			
Aug	$1.7	$0.1	$1.9			
Sep	$2.2	$0.7	$2.8			
Oct	$1.8	$0.7	$2.4			
Nov	$0.6	$0.2	$0.8			
Dec	$0.7	$0.1	$0.7			
Total (Jan - Jun)	$28.6	$12.9	$41.5	$3.8	$0.4	$4.2
Share (Jan - Jun)	68.9%	31.1%	100.0%	89.6%	10.4%	100.0%
Total	$37.6	$14.7	$52.3	$3.8	$0.4	$4.2

Table 4-9 Day-ahead generation from combustion turbines and diesels (GWh): January 2018 through June 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	1,896	382	223	692	38	14
Feb	299	40	19	370	19	4
Mar	1,016	250	109	524	49	12
Apr	1,379	204	71	619	71	21
May	2,095	378	149	848	173	50
Jun	1,432	328	105	938	130	46
Jul	2,343	279	101			
Aug	1,972	181	71			
Sep	1,885	200	68			
Oct	1,398	149	71			
Nov	608	42	15			
Dec	318	37	11			
Total (Jan - Jun)	8,117	1,582	675	3,992	479	148
Share (Jan - Jun)	100.0%	19.5%	8.3%	100.0%	12.0%	3.7%
Total	16,641	2,470	1,012	3,992	479	148

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 six months of 2019, 37.2 percent of generation was pool scheduled in the Day-Ahead Energy Market and 40.8 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 59.2 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 June, 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	51,710	95,685	104,545	66,218	73,527	9,623	401,307	149,367	251,940	117,928
Share of Day-Ahead	12.9%	23.8%	26.1%	16.5%	18.3%	2.4%	100.0%	37.2%	62.8%	29.4%
Real-Time Generation	21,132	42,569	61,442	35,560	44,845	5,875	211,422	86,280	125,142	56,692
Share of Real-Time	10.0%	20.1%	29.1%	16.8%	21.2%	2.8%	100.0%	40.8%	59.2%	26.8%

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 six months of 2019, 81.3 percent of the day-ahead generation eligible for operating reserve credits was economic and 66.6 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 June, 2019

Energy Market	Economic Generation	Noneconomic Generation	Total Eligible Generation	Economic Generation Percent	Noneconomic Generation Percent
Day-Ahead	121,484	27,883	149,367	81.3%	18.7%
Real-Time	89,942	45,173	135,114	66.6%	33.4%

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 six months of 2019, 1.0 percent of the day-ahead generation eligible for operating reserve credits received credits and 1.1 percent of the real-time generation eligible for operating reserve credits received credits.

Table 4-13 Generation receiving operating reserve credits (GWh): January through June, 2019

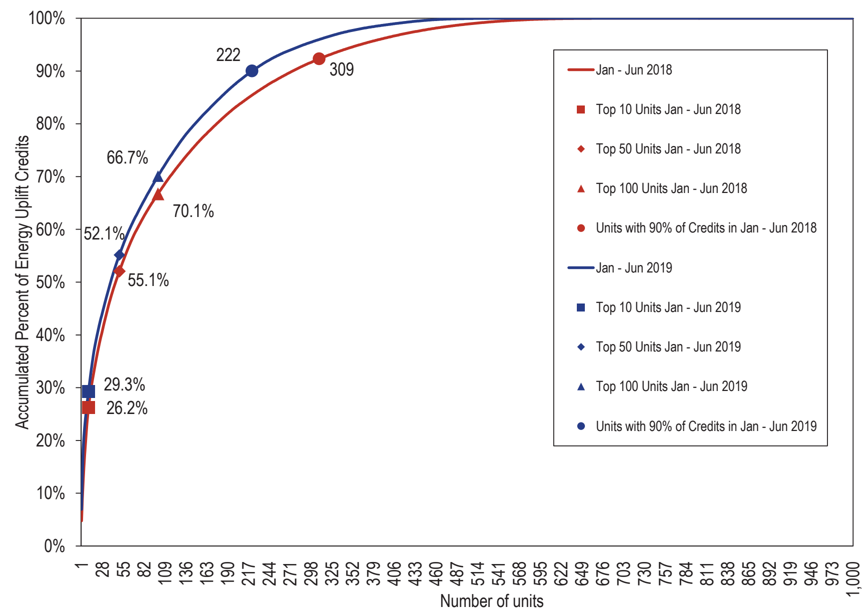
Energy Market	Generation Eligible for Operating Reserve Credits	Generation Receiving Operating Reserve Credits	Generation Receiving Operating Reserve Credits Percent
Day-Ahead	149,367	1,425	1.0%
Real-Time	135,114	1,524	1.1%

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 29.3 percent of total energy uplift credits in the first six months of 2019, compared to 26.2 percent in the first six months of 2018. In the first six months of 2019, 222 units received 90 percent of all energy uplift credits, compared to 309 units in the first six months of 2018.

Figure 4-1 Cumulative share of energy uplift credits: January through June, 2018 and 2019 by unit



19 As a result of FERC Order No. 844, PJM will begin publishing total uplift credits by unit by month for credits incurred after January 1, 2019. Data postings will begin pending FERC's approval of PJM's September 7, 2018 Order No. 844 compliance filing.

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 six months of 2019.

Table 4-14 Top 10 units and organizations energy uplift credits: January through June, 2019

		Top 10 Units		Top 10 Organizations	
Category	Type	Credits (Millions)	Credits Share	Credits (Millions)	Credits Share
Day-Ahead	Generators	$7.5	91.2%	$8.2	99.0%
Balancing	Canceled Resources	$0.0	0.0%	$0.0	0.0%
	Generators	$3.8	17.7%	$16.4	76.6%
	Local Constraints Control	$1.8	67.7%	$2.7	100.0%
	Lost Opportunity Cost	$1.1	27.7%	$3.6	88.8%
Reactive Services		$0.4	98.0%	$0.5	100.0%
Synchronous Condensing		$0.0	0.0%	$0.0	0.0%
Black Start Services		$0.1	57.1%	$0.1	92.7%
Total		$10.9	29.5%	$28.7	77.8%

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 six months of 2019, 57.2 percent of all credits paid to these units were allocated to deviations while the remaining 42.8 percent were paid for reliability reasons.

Table 4-15 Balancing operating reserve credits to top 10 units by category and region: January through June, 2019

	Reliability			Deviations			
	RTO	East	West	RTO	East	West	Total
Credits (Millions)	$1.4	$0.2	$0.1	$1.5	$0.6	$0.0	$3.8
Share	37.1%	4.3%	1.4%	39.7%	17.1%	0.4%	100.0%

In the first six 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 8523, for balancing operating reserve credits to generators was 3867, for lost opportunity cost credits was 6532 and for reactive services credits was 9674. All of these HHI values are characterized as highly concentrated.

20 See the *2019 Quarterly State of the Market Report for PJM: January through June*, 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 June, 2019

Category	Type	Average	Minimum	Maximum	Highest Market Share (One day)	Highest Market Share (All days)
Day-Ahead	Generators	8523	2646	10000	100.0%	54.4%
	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	3867	1003	10000	100.0%	25.0%
	Imports	NA	NA	NA	NA	NA
	Load Response	NA	NA	NA	NA	NA
	Lost Opportunity Cost	6532	1262	10000	100.0%	19.2%
Reactive Services		9674	5518	10000	100.0%	40.5%
Synchronous Condensing		NA	NA	NA	NA	NA
Black Start Services		9303	5727	10000	100.0%	19.9%
Total		3717	1045	10000	100.0%	18.0%

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 4-17 and Table 4-18 show the categories of credits and charges and their relationship. These tables show how the charges are allocated.

Table 4-17 Day-ahead and balancing operating reserve credits and charges

Credits Received For:	Credits Category:		Charges Category:	Charges Paid By:	
		Day-Ahead			
Day-Ahead Import Transactions and Generation Resources	Day-Ahead Operating Reserve Transaction Day-Ahead Operating Reserve Generator	→	Day-Ahead Operating Reserve	Day-Ahead Load Day-Ahead Export Transactions Decrement Bids	in RTO Region
Economic Load Response Resources	Day-Ahead Operating Reserves for Load Response	→	Day-Ahead Operating Reserve for Load Response	Day-Ahead Load Day-Ahead Export Transactions Decrement Bids	in RTO Region
	Unallocated Negative Load Congestion Charges Unallocated Positive Generation Congestion Credits	→	Unallocated Congestion	Day-Ahead Load Day-Ahead Export Transactions Decrement Bids	in RTO Region
		Balancing			
Generation Resources	Balancing Operating Reserve Generator	→	Balancing Operating Reserve for Reliability	Real-Time Load plus Real-Time Export Transactions	in RTO, Eastern or Western Region
			Balancing Operating Reserve for Deviations	Deviations	
			Balancing Local Constraint	Applicable Requesting Party	
Canceled Resources	Balancing Operating Reserve Startup Cancellation	→	Balancing Operating Reserve for Deviations	Deviations	in RTO Region
Lost Opportunity Cost (LOC)	Balancing Operating Reserve LOC				
Real-Time Import Transactions	Balancing Operating Reserve Transaction				
Economic Load Response Resources	Balancing Operating Reserves for Load Response	→	Balancing Operating Reserve for Load Response	Deviations	in RTO Region

Table 4-18 Reactive services, synchronous condensing and black start services credits and charges

Credits Received For:	Credits Category:	Charges Category:	Charges Paid By:
	Reactive		
Resources Providing Reactive Service	Day-Ahead Operating Reserve	Reactive Services Charge	Zonal Real-Time Load
	Reactive Services Generator		
	Reactive Services LOC		
	Reactive Services Condensing	Reactive Services Local Constraint	Applicable Requesting Party
	Reactive Services Synchronous Condensing LOC		
	Synchronous Condensing		
Resources Providing Synchronous Condensing	Synchronous Condensing	Synchronous Condensing	Real-Time Load
	Synchronous Condensing LOC		Real-Time Export Transactions
	Black Start		
Resources Providing Black Start Service	Day-Ahead Operating Reserve	Black Start Service Charge	Zone/Non-zone Peak Transmission Use and Point to Point Transmission Reservations
	Balancing Operating Reserve		
	Black Start Testing		

Energy Uplift Results

Energy Uplift Charges

Total energy uplift charges decreased by $102.9 million or 73.6 percent in the first six months of 2019 compared to the first six months of 2018.

Table 4-19 shows total energy uplift charges by category in the first six months of 2018 and 2019.[22] The decrease of $102.9 million is comprised of a decrease of $19.4 million in day-ahead operating reserve charges, a decrease of $73.2 million in balancing operating reserve charges and a decrease of $10.3 million in reactive service charges.

Table 4-19 Total energy uplift charges by category: January through June, 2018 and 2019

Category	(Jan - Jun) 2018 Charges (Millions)	(Jan - Jun) 2019 Charges (Millions)	Change (Millions)	Percent Change
Day-Ahead Operating Reserves	$27.6	$8.2	($19.4)	(70.2%)
Balancing Operating Reserves	$101.3	$28.1	($73.2)	(72.3%)
Reactive Services	$10.7	$0.5	($10.3)	(95.8%)
Synchronous Condensing	$0.0	$0.0	($0.0)	(100.0%)
Black Start Services	$0.1	$0.1	($0.0)	(17.6%)
Total	$139.8	$36.9	($102.9)	(73.6%)
Energy Uplift as a Percent of Total PJM Billing	0.5%	0.2%	(0.2%)	(38.2%)

22 Table 4-19 includes all categories of charges as defined in Table 4-17 and Table 4-18 and includes all PJM Settlements billing adjustments. Billing data can be modified by PJM Settlements at any time to reflect changes in the evaluation of energy uplift. The billing data reflected in this report were current on July 11, 2019.

Table 4-20 compares monthly energy uplift charges by category for 2018 and the first six months of 2019.

Table 4-20 Monthly energy uplift charges: January 2018 through June 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	$6.6	$0.1	$0.0	$0.0	$7.7
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	$4.1
May	$6.9	$16.1	$2.2	$0.0	$0.1	$25.2	$1.4	$4.3	$0.1	$0.0	$0.1	$5.9
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						
Aug	$0.7	$8.8	$0.2	$0.0	$0.0	$9.8						
Sep	$1.3	$12.8	$1.0	$0.0	$0.0	$15.2						
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 - Jun)	$27.6	$101.3	$10.7	$0.0	$0.1	$139.8	$8.2	$28.1	$0.5	$0.0	$0.1	$36.9
Share (Jan - Jun)	19.8%	72.5%	7.7%	0.0%	0.1%	100.0%	22.3%	76.1%	1.2%	0.0%	0.3%	100.0%
Total	$34.0	$150.8	$13.2	$0.0	$0.3	$198.3	$8.2	$28.1	$0.5	$0.0	$0.1	$36.9
Share	17.1%	76.0%	6.6%	0.0%	0.2%	100.0%	22.3%	76.1%	1.2%	0.0%	0.3%	100.0%

Table 4-21 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 $19.4 million or 70.2 percent in the first six months of 2019 compared to the first six months of 2018. Day-ahead operating reserve charges decreased in the first six months of 2019 as a result of a decrease in day-ahead unit commitments for reliability.

Table 4-21 Day-ahead operating reserve charges: January through June, 2018 and 2019

Type	(Jan - Jun) 2018 Charges (Millions)	(Jan - Jun) 2019 Charges (Millions)	Change (Millions)	(Jan - Jun) 2018 Share	(Jan - Jun) 2019 Share
Day-Ahead Operating Reserve Charges	$27.6	$8.2	($19.4)	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	$27.6	$8.2	($19.4)	100.0%	100.0%

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, totaling $26.9 million.

Table 4-22 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 $73.2 million or 72.3 percent in the first six months of 2019 compared to the first six months of 2018.

Table 4-22 Balancing operating reserve charges: January through June, 2018 and 2019

Type	(Jan - Jun) 2018 Charges (Millions)	(Jan - Jun) 2019 Charges (Millions)	Change (Millions)	(Jan - Jun) 2018 Share	(Jan - Jun) 2019 Share
Balancing Operating Reserve Reliability Charges	$22.5	$10.4	($12.1)	22.2%	36.9%
Balancing Operating Reserve Deviation Charges	$71.7	$15.1	($56.6)	70.7%	53.6%
Balancing Operating Reserve Charges for Load Response	$0.0	$0.0	($0.0)	0.0%	0.0%
Balancing Local Constraint Charges	$7.1	$2.7	($4.5)	7.0%	9.5%
Total	$101.3	$28.1	($73.2)	100.0%	100.0%

Table 4-23 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 six months of 2019, energy lost opportunity cost deviation charges decreased by $437.8 million or 90.4 percent, and make whole deviation charges decreased by $18.8 million or 63.0 percent compared to the first six months of 2018.

Table 4-23 Balancing operating reserve deviation charges: January through June, 2018 and 2019

Charge Attributable To	(Jan - Jun) 2018 Charges (Millions)	(Jan - Jun) 2019 Charges (Millions)	Change (Millions)	(Jan - Jun) 2018 Share	(Jan - Jun) 2019 Share
Make Whole Payments to Generators and Imports	$29.9	$11.0	($18.8)	41.7%	73.4%
Energy Lost Opportunity Cost	$41.8	$4.0	($37.8)	58.3%	26.6%
Canceled Resources	$0.0	$0.0	$0.0	0.0%	0.0%
Total	$71.7	$15.1	($56.6)	100.0%	100.0%

Table 4-24 shows reactive services, synchronous condensing and black start services charges. Reactive services charges decreased by $10.3 million or 95.8 percent in the first six months of 2019, compared to the first six months of 2018. The decrease in reactive service charges resulted from a decrease in the need for reactive service in ComEd.

Table 4-24 Additional energy uplift charges: January through June, 2018 and 2019

Type	(Jan - Jun) 2018 Charges (Millions)	(Jan - Jun) 2019 Charges (Millions)	Change (Millions)	(Jan - Jun) 2018 Share	(Jan - Jun) 2019 Share
Reactive Services Charges	$10.7	$0.5	($10.3)	98.4%	79.7%
Synchronous Condensing Charges	$0.0	$0.0	($0.0)	0.4%	0.0%
Black Start Services Charges	$0.1	$0.1	($0.0)	1.3%	20.3%
Total	$10.9	$0.6	($10.3)	100.0%	100.0%

Table 4-25 and Table 4-26 show the amount and shares of regional balancing charges in the first six 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 six months of 2019 the largest share of regional charges was paid by real-time load which paid 39.3 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 six months of 2019, regional balancing operating reserve charges decreased by $68.8 million compared to the first six months of 2018. Balancing operating reserve reliability charges decreased by $12.1 million or 53.9 percent, and balancing operating reserve deviation charges decreased by $56.7 million, or 79.0 percent.

Table 4-25 Regional balancing charges allocation (Millions): January through June, 2018

Charge	Allocation	RTO		East		West		Total	
Reliability Charges	Real-Time Load	$18.9	20.1%	$1.8	1.9%	$1.2	1.3%	$21.9	23.2%
	Real-Time Exports	$0.5	0.6%	$0.1	0.1%	$0.0	0.0%	$0.6	0.7%
	Total	$19.5	20.7%	$1.9	2.0%	$1.2	1.3%	$22.5	23.9%
Deviation Charges	Demand	$37.6	39.9%	$0.9	1.0%	$1.8	1.9%	$40.3	42.7%
	Supply	$12.1	12.9%	$0.4	0.5%	$0.5	0.5%	$13.1	13.8%
	Generator	$17.1	18.1%	$0.4	0.5%	$0.9	0.9%	$18.4	19.5%
	Total	$66.8	70.9%	$1.8	1.9%	$3.1	3.3%	$71.7	76.1%
Total Regional Balancing Charges		$86.3	91.5%	$3.6	3.9%	$4.3	4.6%	$94.3	100%

Table 4-26 Regional balancing charges allocation (Millions): January through June, 2019

Charge	Allocation	RTO		East		West		Total	
Reliability Charges	Real-Time Load	$8.9	35.0%	$0.8	3.2%	$0.3	1.2%	$10.0	39.3%
	Real-Time Exports	$0.3	1.3%	$0.0	0.1%	$0.0	0.0%	$0.4	1.4%
	Total	$9.2	36.2%	$0.8	3.3%	$0.3	1.3%	$10.4	40.8%
Deviation Charges	Demand	$8.1	31.9%	$0.6	2.3%	$0.2	0.7%	$8.9	34.8%
	Supply	$2.5	9.7%	$0.2	0.8%	$0.1	0.2%	$2.7	10.8%
	Generator	$3.1	12.3%	$0.3	1.1%	$0.1	0.2%	$3.5	13.6%
	Total	$13.7	53.9%	$1.1	4.2%	$0.3	1.1%	$15.1	59.2%
Total Regional Balancing Charges		$22.9	90.1%	$1.9	7.5%	$0.6	2.4%	$25.4	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 4-17 shows how these charges are allocated.[24]

Figure 4-2 shows the daily day-ahead operating reserve rate for 2018 and the first six months of 2019. The average rate in the first six months of 2019 was $0.021 per MWh, $0.048 per MWh lower than the average in the first six months of 2018. The highest rate in the first six 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 six 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 six months of 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 4-2 Daily day-ahead operating reserve rate ($/MWh): January 2018 through June 2019

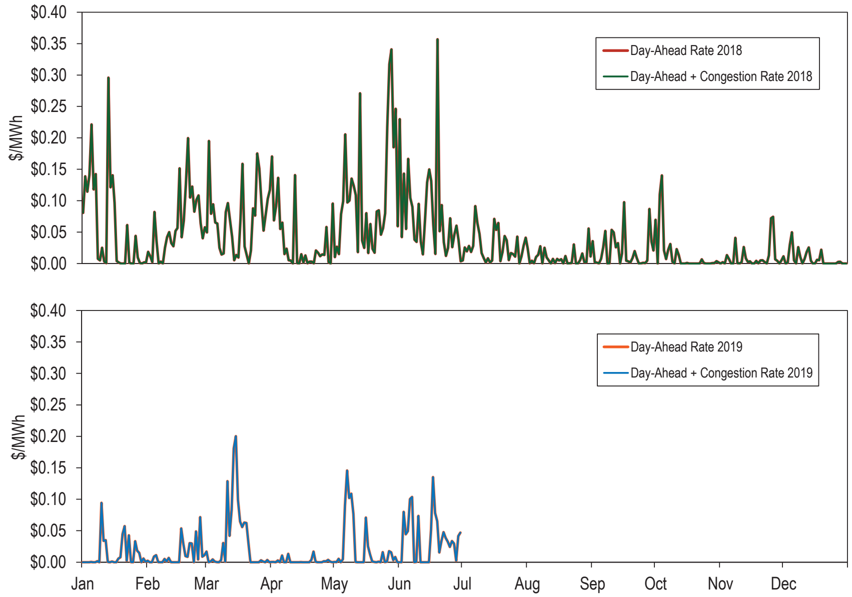


Figure 4-3 shows the RTO and the regional reliability rates for 2018 and the first six months of 2019. The average RTO reliability rate in the first six months of 2019 was $0.024 per MWh. The highest RTO reliability rate in the first six months of 2019 occurred on January 22, when the rate reached $0.368 per MWh, $0.363 per MWh lower than the $0.731 per MWh rate reached in the first six months of 2018, on January 2.

Figure 4-3 Daily balancing operating reserve reliability rates ($/MWh): January 2018 through June 2019

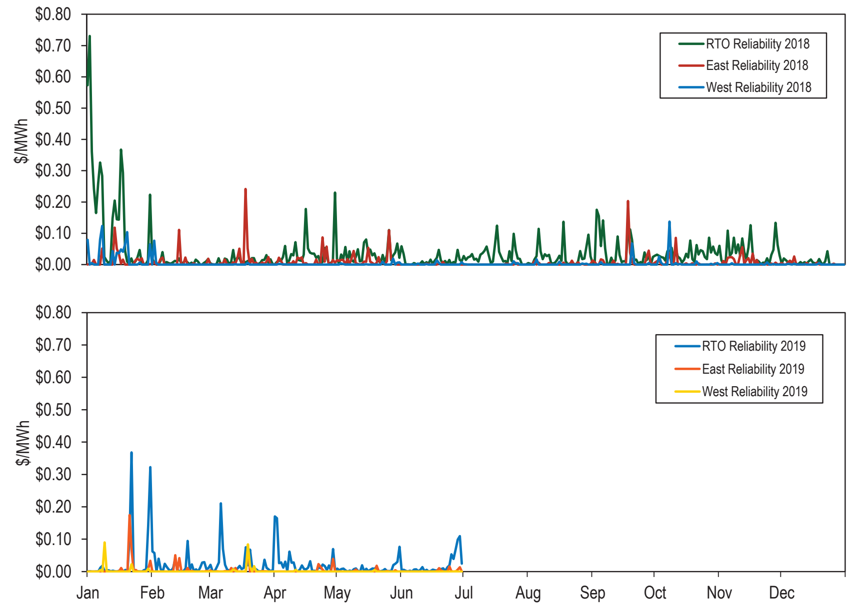


Figure 4-4 shows the RTO and regional deviation rates for 2018 and the first six months 2019. The average RTO deviation rate in the first six months of 2019 was $0.128 per MWh. The highest daily rate in the first six months of 2019 occurred on January 22, when the RTO deviation rate reached $1.019 per MWh, $3.469 per MWh lower than the $4.488 per MWh rate reached in the first six months of 2018, on January 1.

Figure 4-5 shows the daily lost opportunity cost rate and the daily canceled resources rate for 2018 and the first six months of 2019. The average lost opportunity cost rate in the first six months of 2019 was $0.053 per MWh. The highest lost opportunity cost rate in the first six months occurred on May 23, when it reached $2.081 per MWh, $6.935 per MWh lower than the $9.016 per MWh rate reached in the first six months of 2018, on January 7.[25]

Figure 4-4 Daily balancing operating reserve deviation rates ($/MWh): January 2018 through June 2019

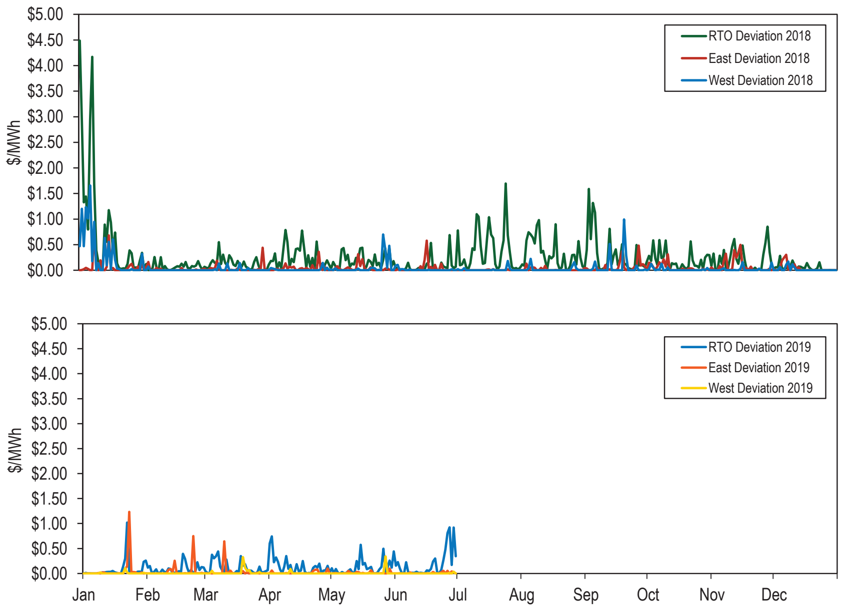
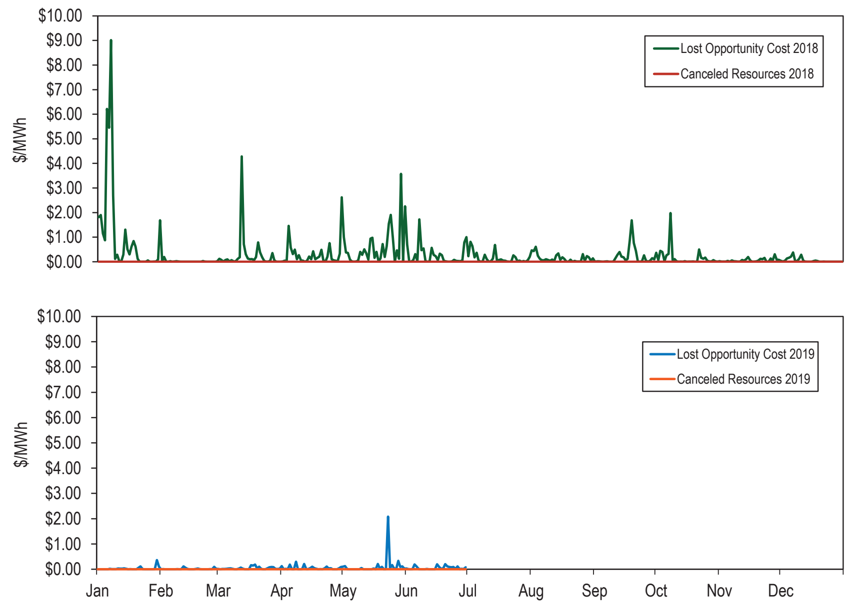


Figure 4-5 Daily lost opportunity cost and canceled resources rates ($/MWh): January 2018 through June 2019



25 For details about this event see *2018 Quarterly State of the Market Report for PJM: January through March*, Section 4: Energy Uplift.

Table 4-27 shows the average rates for each region in each category for the first six months of 2018 and 2019.

Table 4-27 Operating reserve rates ($/MWh): January through June, 2018 and 2019

Rate	(Jan - Jun) 2018 ($/MWh)	(Jan - Jun) 2019 ($/MWh)	Difference ($/MWh)	Percent Difference
Day-Ahead	0.069	0.021	(0.048)	(70.0%)
Day-Ahead with Unallocated Congestion	0.069	0.021	(0.048)	(70.0%)
RTO Reliability	0.049	0.024	(0.025)	(51.9%)
East Reliability	0.010	0.005	(0.005)	(54.3%)
West Reliability	0.006	0.002	(0.004)	(72.8%)
RTO Deviation	0.328	0.128	(0.199)	(60.9%)
East Deviation	0.045	0.028	(0.017)	(38.4%)
West Deviation	0.087	0.008	(0.079)	(90.9%)
Lost Opportunity Cost	0.548	0.053	(0.495)	(90.3%)
Canceled Resources	0.000	0.000	NA	NA

Table 4-28 shows the operating reserve cost of a one MW transaction in the first six months of 2019. For example, a decrement bid in the Eastern Region (if not offset by other transactions) paid an average rate of $0.230 per MWh with a maximum rate of $2.093 per MWh, a minimum rate of $0.000 per MWh and a standard deviation of $0.269 per MWh. The rates in Table 4-28 include all operating reserve charges including RTO deviation charges. Table 4-28 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 4-28 Operating reserve rates statistics ($/MWh): January through June, 2019

		Rates Charged ($/MWh)			
Region	Transaction	Maximum	Average	Minimum	Standard Deviation
East	INC	2.093	0.209	0.000	0.268
	DEC	2.093	0.230	0.000	0.269
	DA Load	0.200	0.021	0.000	0.036
	RT Load	0.437	0.028	0.000	0.055
	Deviation	2.093	0.209	0.000	0.268
West	INC	2.093	0.189	0.000	0.249
	DEC	2.093	0.210	0.000	0.251
	DA Load	0.200	0.021	0.000	0.036
	RT Load	0.391	0.025	0.000	0.048
	Deviation	2.093	0.189	0.000	0.249

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 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 4-29 shows the reactive services rates associated with local voltage support in the first six months of 2018 and 2019. Table 4-29 shows that in the first six 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 $0.016 per MWh for reactive services, and real-time load in the DPL Control Zone paid an average of $0.011 per MWh for reactive services. The third highest rate for reactive

26 See *2018 State of the Market Report for PJM*, Volume 2, Section 10: Ancillary Service Markets.

services was in the Dominion Control Zone, where real-time load paid an average of $0.004 per MWh.

Table 4-29 Local voltage support rates: January through June, 2018 and 2019

Control Zone	(Jan - Jun) 2018 ($/MWh)	(Jan - Jun) 2019 ($/MWh)	Difference ($/MWh)	Percent Difference
AECO	0.000	0.000	0.000	0.0%
AEP	0.012	0.000	(0.012)	(99.7%)
APS	0.000	0.001	0.001	NA
ATSI	0.000	0.000	0.000	NA
BGE	0.000	0.000	0.000	0.0%
ComEd	0.193	0.000	(0.193)	(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	0.004	0.003	724.2%
DPL	0.028	0.011	(0.017)	(59.8%)
EKPC	0.025	0.000	(0.025)	(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	0.041	0.000	(0.041)	(100.0%)
PENELEC	0.000	0.016	0.016	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 4-30 shows the determinants used to allocate the regional balancing operating reserve charges in the first six months of 2018 and 2019. Total real-time load and real-time exports were 391,430 GWh, 2.2 percent higher in 2019 compared to 2018. Total deviations summed across the demand, supply, and generator categories were 75,572 GWh, 1.4 percent lower in 2019 compared to 2018.

Table 4-30 Balancing operating reserve determinants (GWh): January through June, 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 - Jun) 2018	RTO	388,513	11,911	400,424	43,866	14,875	17,917	76,658
	East	182,228	6,219	188,447	21,366	9,043	9,346	39,755
	West	206,284	5,692	211,976	22,090	5,738	8,572	36,400
(Jan - Jun) 2019	RTO	374,789	16,641	391,430	44,303	14,453	16,816	75,572
	East	177,754	7,500	185,254	21,872	8,081	8,656	38,610
	West	197,035	9,141	206,176	22,060	6,000	8,159	36,220
Difference	RTO	(13,723)	4,730	(8,994)	437	(422)	(1,102)	(1,086)
	East	(4,474)	1,281	(3,193)	506	(962)	(689)	(1,145)
	West	(9,250)	3,449	(5,800)	(30)	262	(412)	(180)

Deviations fall into three categories, demand, supply and generator deviations. Table 4-31 shows the different categories by the type of transactions that incurred deviations. In the first six 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 4-31 Deviations by transaction type: January through June, 2019

Deviation Category	Transaction	Deviation (GWh) RTO	East	West	Share RTO	East	West
Demand	DECs Only	11,089	5,518	5,200	14.7%	14.3%	14.4%
	Exports Only	3,601	2,069	1,532	4.8%	5.4%	4.2%
	Load Only	28,511	14,116	14,396	37.7%	36.6%	39.7%
	Combination with DECs	1,099	166	933	1.5%	0.4%	2.6%
	Combination without DECs	3	3	0	0.0%	0.0%	0.0%
Supply	Imports Only	2,605	1,919	686	3.4%	5.0%	1.9%
	INCs Only	11,534	5,895	5,268	15.3%	15.3%	14.5%
	Combination with INCs	314	268	46	0.4%	0.7%	0.1%
	Combination without INCs	0	0	0	0.0%	0.0%	0.0%
Generators		16,816	8,656	8,159	22.3%	22.4%	22.5%
Total		75,572	38,610	36,220	100.0%	100.0%	100.0%

Geography of Charges and Credits

Table 4-32 shows the geography of charges and credits in the first six months of 2019. Table 4-32 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 5.9 percent of all operating reserve charges allocated regionally while resources in the PPL Control Zone were paid 2.8 percent of the corresponding credits. The PPL Control Zone received less operating reserve credits than operating reserve charges paid and had 8.4 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 16.2 percent of the corresponding credits. The BGE Control Zone received more operating reserve credits than operating reserve charges paid and had 33.9 percent of the surplus. The surplus is the net of the credits and charges paid at a location. Table 4-32 also shows that 91.0 percent of all charges were allocated in control zones, 2.3 percent in hubs and aggregates and 6.7 percent in interfaces.

Table 4-32 Geography of regional charges and credits: January through June, 2019

					Shares			
Location		Charges (Millions)	Credits (Millions)	Balance	Total Charges	Total Credits	Deficit	Surplus
Zones	AECO	$0.5	$0.6	$0.1	1.5%	1.8%	0.0%	0.9%
	AEP	$4.8	$3.6	($1.2)	14.4%	10.8%	9.8%	0.0%
	APS	$1.9	$0.9	($0.9)	5.5%	2.7%	7.6%	0.0%
	ATSI	$2.4	$0.5	($1.9)	7.0%	1.4%	15.4%	0.0%
	BGE	$1.3	$5.5	$4.2	3.8%	16.2%	0.0%	33.9%
	ComEd	$3.6	$4.9	$1.2	10.8%	14.4%	0.0%	10.0%
	DAY	$0.6	$0.7	$0.2	1.7%	2.2%	0.0%	1.3%
	DEOK	$1.0	$0.5	($0.5)	2.8%	1.5%	3.7%	0.0%
	DLCO	$0.5	$0.2	($0.3)	1.4%	0.5%	2.4%	0.0%
	Dominion	$3.8	$7.1	$3.4	11.3%	21.2%	0.0%	27.3%
	DPL	$0.8	$1.2	$0.4	2.4%	3.6%	0.0%	3.4%
	EKPC	$0.4	$0.6	$0.2	1.2%	1.9%	0.0%	1.7%
	External	$0.0	$0.4	$0.4	0.0%	1.2%	0.0%	3.2%
	JCPL	$0.9	$0.1	($0.8)	2.6%	0.2%	6.5%	0.0%
	Met-Ed	$0.7	$0.1	($0.6)	2.1%	0.3%	5.1%	0.0%
	OVEC	$0.1	$0.0	($0.1)	0.2%	0.0%	0.5%	0.0%
	PECO	$1.6	$0.4	($1.1)	4.6%	1.3%	9.1%	0.0%
	PENELEC	$1.1	$0.7	($0.4)	3.3%	2.1%	3.1%	0.0%
	Pepco	$1.2	$3.4	$2.2	3.6%	10.2%	0.0%	18.2%
	PPL	$2.0	$0.9	($1.0)	5.9%	2.8%	8.4%	0.0%
	PSEG	$1.6	$1.3	($0.3)	4.7%	3.8%	2.7%	0.0%
	RECO	$0.1	$0.0	($0.1)	0.2%	0.0%	0.6%	0.0%
	All Zones	$30.6	$33.7	$3.1	91.0%	100.0%	75.2%	100.0%
Hubs and Aggregates	AEP - Dayton	$0.2	$0.0	($0.2)	0.4%	0.0%	1.2%	0.0%
	Dominion	$0.1	$0.0	($0.1)	0.4%	0.0%	1.1%	0.0%
	Eastern	$0.0	$0.0	($0.0)	0.1%	0.0%	0.4%	0.0%
	New Jersey	$0.1	$0.0	($0.1)	0.3%	0.0%	0.8%	0.0%
	Ohio	$0.0	$0.0	($0.0)	0.1%	0.0%	0.4%	0.0%
	Western Interface	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%	0.0%
	Western	$0.3	$0.0	($0.3)	0.9%	0.0%	2.5%	0.0%
	RTEP B0328 Source	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%	0.0%
	All Hubs and Aggregates	$0.8	$0.0	($0.8)	2.3%	0.0%	6.4%	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)	0.1%	0.0%	0.2%	0.0%
	Duke Exp	$0.1	$0.0	($0.1)	0.2%	0.0%	0.4%	0.0%
	Duke Imp	$0.0	$0.0	($0.0)	0.1%	0.0%	0.3%	0.0%
	Hudson	$0.1	$0.0	($0.1)	0.2%	0.0%	0.6%	0.0%
	IMO	$0.1	$0.0	($0.1)	0.2%	0.0%	0.5%	0.0%
	Linden	$0.1	$0.0	($0.1)	0.3%	0.0%	0.9%	0.0%
	MISO	$0.8	$0.0	($0.8)	2.5%	0.0%	6.9%	0.0%
	NCMPA Imp	$0.0	$0.0	($0.0)	0.1%	0.0%	0.3%	0.0%
	Neptune	$0.1	$0.0	($0.1)	0.4%	0.0%	1.1%	0.0%
	NIPSCO	$0.0	$0.0	($0.0)	0.1%	0.0%	0.1%	0.0%
	Northwest	$0.0	$0.0	($0.0)	0.1%	0.0%	0.3%	0.0%
	NYIS	$0.3	$0.0	($0.3)	0.7%	0.0%	2.0%	0.0%
	South Exp	$0.3	$0.0	($0.3)	0.9%	0.0%	2.4%	0.0%
	South Imp	$0.3	$0.0	($0.3)	0.8%	0.0%	2.3%	0.0%
	All Interfaces	$2.3	$0.0	($2.2)	6.7%	0.0%	18.4%	0.0%
	Total	$33.7	$33.7	$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 4-33 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 six months of 2019, balancing operating reserve credits would have been $3.6 million or 16.7 percent lower if they were calculated on a daily basis.

Table 4-33 Intraday segments and daily balancing operating reserve credits: January 2018 through June 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	($5.4)	$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)	$2.4	$1.9	($0.5)
Jun	$2.6	$1.7	($0.9)	$4.1	$3.3	($0.8)
Jul	$7.4	$5.2	($2.1)			
Aug	$6.8	$4.8	($2.0)			
Sep	$9.3	$7.0	($2.3)			
Oct	$5.9	$4.5	($1.3)			
Nov	$6.2	$5.3	($0.9)			
Dec	$1.6	$1.3	($0.3)			
Total (Jan - Jun)	$51.9	$41.3	($10.6)	$21.4	$17.9	($3.6)
Total	$89.1	$69.5	($19.5)	$21.4	$17.9	($3.6)

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 4-34 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 six months of 2019, LOC credits would have been $0.4 million or 11.1 percent lower had they been settled on an hourly basis compared to being settled on a five minute basis.

Table 4-34 Five minute settlement and hourly settlement of day-ahead lost opportunity cost credits: April, 2018 through June, 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)			
Aug	$1.7	$1.4	($0.4)			
Sep	$2.2	$1.7	($0.5)			
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)	$3.7	$3.3	($0.4)

27 See PJM. "Manual 28: Operating Reserve Accounting," Rev. 82 (July 25, 2019).

Table 4-35 shows day-ahead LOC credits calculated using intraday segments and LOC credits calculated on a daily basis. In 2018, LOC credits would have been $8.7 million or 23.0 percent lower if they were calculated on a daily basis. In the first six months of 2019, LOC credits would have been $0.9 million or 24.8 percent lower if they were calculated on a daily basis.

Table 4-35 Five minute settlement and daily settlement of lost opportunity cost credits: January 2018 through June 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)			
Aug	$1.7	$1.6	($0.2)			
Sep	$2.2	$2.0	($0.2)			
Oct	$1.8	$1.6	($0.2)			
Nov	$0.6	$0.5	($0.0)			
Dec	$0.7	$0.6	($0.1)			
Total (Jan - Jun)	$28.5	$24.1	($4.4)	$3.7	$2.8	($0.9)
Total	$37.6	$32.2	($5.4)	$3.7	$2.8	($0.9)

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.

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 was conducted in the first six 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," Rev. 41 (Jan. 1, 2019) § 1.5, at p 19.
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 six months of 2019, RPM installed capacity decreased 910.9 MW or 0.5 percent, from 186,496.1 MW on January 1 to 185,585.2 MW on June 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 June 30, 2019, 41.9 percent was gas; 31.0 percent was coal; 17.7 percent was nuclear; 4.7 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 2019/2020 RPM Third Incremental Auction all participants in the total PJM market as well as the LDA RPM markets failed the three pivotal supplier (TPS) test.[13] 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]

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).

- **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

- **2019/2020 RPM Third Incremental Auction.** Of the 137 generation resources that submitted Base Capacity offers, the MMU calculated offer caps for one generation resource (0.7 percent), of which one (0.7 percent) was a unit-specific offer cap. Of the 454 generation resources that submitted Capacity Performance offers, the MMU calculated unit specific offer caps for four generation resources (0.9 percent).

Market Performance

- The 2019/2020 RPM Third Incremental Auction was conducted in the first six 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 is $112.63 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.

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).

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 six months of 2019 was 6.5 percent, a decrease from 8.3 percent for the first six months of 2018.[18]
- **Generator Performance Factors.** The PJM aggregate equivalent availability factor for the first six months of 2019 was 82.5 percent, an increase from 82.0 percent for the first six 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.)
- 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

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 July 24, 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, 2017," <http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Report_on_Capacity_Replacement_Activity_4_20171214.pdf> (December 14, 2017).
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.

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.)

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

- 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 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

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).

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.

The 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 six 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 15,000 ICAP MW on June 1, 2020, based on current positions.[33] A majority of capacity investments in PJM were financed by market sources. Of the 39,451.7 MW of additional capacity that cleared in RPM auctions for the 2007/2008 through 2018/2019 delivery years, 29,923.8 MW (75.8 percent) were based on market funding. Of the 8,340.9 MW of additional capacity that cleared in RPM auctions for the 2019/2020 through 2021/2022 delivery years, 6,367.4 MW (76.3 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, emerged more fully in 2017 and 2018 and the first six months of 2019. 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.

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, 2016," <http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Analysis_of_Replacement_Capacity_for_RPM_Commitments_06012007_to_06012016_20161227.pdf> (December 27, 2016).
32 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).
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.

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 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 June 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

Installed Capacity

On January 1, 2019, RPM installed capacity was 186,496.1 MW (Table 5-3).[34] Over the next six months, new generation, unit deactivations, facility reratings, plus import and export shifts resulted in RPM installed capacity of 187,457.6 MW on June 30, 2019, an increase of 961.5 MW or 0.5 percent from the January 1 level.[35 36] The 961.5 MW increase was the result of new or reactivated generation (3,546.9 MW), uprates (451.2 MW), and an increase in imports (0.4 MW), offset by deactivations (2,896.7 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 187,438.1 MW, an increase of 1,944.6 MW or 1.0 percent from the May 31, 2019 level of 185,493.5 MW.

Table 5-3 Installed capacity (By fuel source): January 1, May 31, June 1, and June 30, 2019

	01-Jan-19		31-May-19		01-Jun-19		30-Jun-19	
	MW	Percent	MW	Percent	MW	Percent	MW	Percent
Coal	60,763.4	32.6%	58,949.1	31.8%	58,159.4	31.0%	58,084.6	31.0%
Gas	75,261.2	40.4%	75,770.8	40.8%	78,475.8	41.9%	78,476.4	41.9%
Hydroelectric	8,888.2	4.8%	8,873.9	4.8%	8,873.9	4.7%	8,873.9	4.7%
Nuclear	32,684.5	17.5%	33,000.7	17.8%	33,001.7	17.6%	33,100.7	17.7%
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%	702.6	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%	185,493.5	100.0%	187,438.1	100.0%	187,457.6	100.0%

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 June 30, 2019.[37] 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

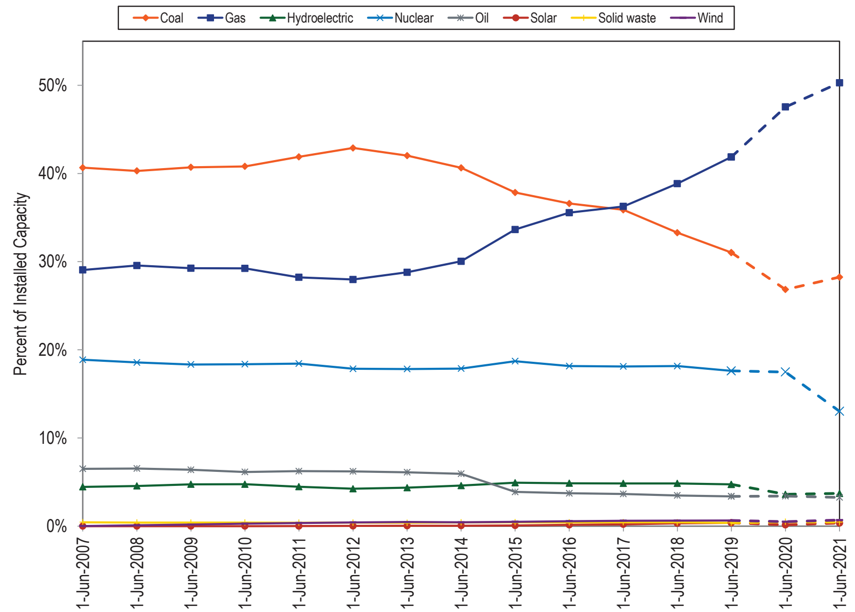


Table 5-4 shows the RPM installed capacity on January 1, 2019, through June 30, 2019, for the top five generation capacity resource owners, excluding FRR committed MW.

34 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.

35 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.

36 Wind resources accounted for 1,192.2 MW, and solar resources accounted for 702.6 MW of installed capacity in PJM on June 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," Rev. 14 (Aug. 1, 2019) § B.3, at p 33.

37 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 Installed capacity by parent company: January 1, May 31, June 1, and June 30, 2019

	01-Jan-19			31-May-19			01-Jun-19			30-Jun-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	22,790.5	13.2%	1
Dominion Resources, Inc.	20,388.9	11.8%	2	20,180.7	11.8%	2	20,143.7	11.6%	2	20,143.7	11.6%	2
FirstEnergy Corp.	14,644.0	8.5%	3	12,495.3	7.3%	3	12,489.3	7.2%	3	12,489.3	7.2%	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	7.0%	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	6.3%	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 June 30, 2019, by funding type.

Table 5-5 Installed capacity by funding type: January 1, May 31, June 1, and June 30, 2018

	01-Jan-19		31-May-19		01-Jun-19		30-Jun-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%	152,892.9	82.4%	155,008.1	82.7%	155,027.6	82.7%
Nonmarket	32,819.2	17.6%	32,600.6	17.6%	32,430.0	17.3%	32,430.0	17.3%
Total	186,496.1	100.0%	185,493.5	100.0%	187,438.1	100.0%	187,457.6	100.0%

Fuel Diversity

Figure 5-2 shows the fuel diversity index (FDI_c) for RPM installed capacity.[38] 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.[39] 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.[40] The average FDI_c for the first six months of 2019 decreased 0.8 percent from the first six 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 were 18 capacity resources with installed capacity totaling 14,954 MW identified as being at risk of retirement.[41] Generation owners that intend to retire a generator are required by the tariff to notify PJM at least 90 days in advance of the retirement.[42] There are 11,852 MW of generation that have requested retirement after June 30, 2019.[43] Generation owners of four 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 a RPM auction from the at risk resources and other resources with deactivation notices is replaced by gas generation.[44] The FDI_c under these assumptions would decrease by 0.021

38 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.

39 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.

40 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.

41 See the *2018 State of the Market Report for PJM*, Volume 2, Section 7: Net Revenue, Units at Risk.

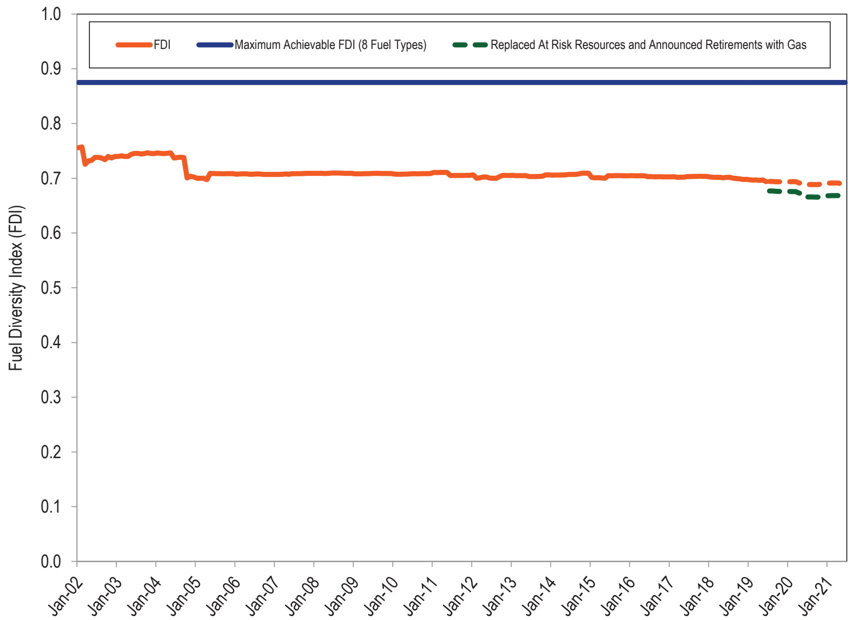
42 See PJM. "PJM Open Access Transmission Tariff," <https://www.pjm.com/library/governing-documents.aspx>.

43 See Table 12-9.

44 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 July 1, 2019.

(3.0 percent) on average from the expected FDI_c for the period July 1, 2019, through June 1, 2021.

Figure 5-2 Fuel Diversity Index for installed capacity: January 1, 2002 through June 1, 2021



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.[45]

In the first six months of 2019, the 2019/2020 RPM Third Incremental Auction was conducted.[46]

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 23,778.7 MW increase was the result of new generation capacity resources (31,629.6 MW), reactivated generation capacity resources (984.3 MW), uprates (6,837.8 MW), integration of external zones (21,967.5 MW), a net increase in capacity imports (183.4 MW), a net decrease in capacity exports (2,304.9 MW), offset by deactivations (36,614.3 MW) and derates (3,514.5 MW).[47]

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 final peak load forecast for the given 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. 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 margin for June 1, 2020, does not account for cleared buy bids that have not been used in replacement capacity transactions. The projected reserve margin for June 1, 2020, accounts for projected replacement capacity using cleared buy bids by applying the rate at which historical buy bids have been used.

45 See *PJM Interconnection, L.L.C.*, Letter Order in Docket No. ER10-366-000 (January 22, 2010).

46 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).

47 The calculation of integration and capacity import MW values was revised from the *2019 Quarterly State of the Market Report for PJM: January through March*.

Future Changes in Generation Capacity[48]

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 677.1 MW after accounting for new capacity resources, reactivations, and uprates (39,451.7 MW) and capacity deactivations and derates (40,128.8 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. Looking ahead, based on expected completion rates of cleared new generation capacity (7,079.9 MW) and pending deactivations (11,840.8 MW), PJM capacity is expected to decrease by 4,760.9 MW for the 2019/2020 through 2021/2022 Delivery Years.

Table 5-6 Generation capacity changes: 2007/2008 to 2019/2020

	ICAP (MW)									
	Total at June 1	New	Reactivations	Uprates	Integration	Net Change in Capacity Imports	Net Change in Capacity Exports	Deactivations	Derates	Net Change
2007/2008	163,659.4	372.8	156.8	1,238.1	0.0	(96.7)	143.9	389.5	617.8	519.8
2008/2009	164,179.2	812.9	6.3	1,108.9	0.0	871.1	(1,702.9)	615.0	612.4	3,274.7
2009/2010	167,453.9	188.1	13.0	370.4	0.0	68.6	735.9	472.4	171.2	(739.4)
2010/2011	166,714.5	1,751.2	16.0	587.3	11,821.6	187.2	(427.0)	1,439.2	286.9	13,064.2
2011/2012	179,778.7	3,095.0	138.0	553.8	5,114.9	(1,244.8)	(1,374.5)	2,758.5	313.0	5,959.9
2012/2013	185,738.6	266.4	79.0	364.5	2,746.0	775.8	(17.3)	4,152.1	267.6	(170.7)
2013/2014	185,567.9	264.7	20.9	397.9	0.0	2,217.2	21.6	4,027.7	421.9	(1,570.5)
2014/2015	183,997.4	3,036.0	0.0	480.4	0.0	859.1	73.3	11,442.9	221.0	(7,361.7)
2015/2016	176,635.7	5,497.8	0.0	409.0	0.0	787.6	285.1	863.4	156.4	5,389.5
2016/2017	182,025.2	2,537.8	537.0	589.8	0.0	(1,011.1)	(36.4)	1,447.3	167.8	1,074.8
2017/2018	183,100.0	5,656.4	4.0	331.5	0.0	(1,442.0)	(220.9)	4,351.6	133.0	286.2
2018/2019	183,386.2	8,150.5	13.3	406.2	2,285.0	(1,788.6)	214.3	4,654.7	145.5	4,051.9
2019/2020	187,438.1									
Total		31,629.6	984.3	6,837.8	21,967.5	183.4	(2,304.9)	36,614.3	3,514.5	23,778.7

Table 5-7 RPM reserve margin: June 1, 2016, to June 1, 2021[49 50]

	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	165,943.4	151,155.1	11,930.9	558.0	138,666.2	15.9%	6.04%	176,610.7	27.4%	11.5%	15,896.6	3,454.4	24.7%
01-Jun-21	160,795.3	152,647.4	12,107.1	510.0	140,030.3	15.8%	5.89%	170,858.9	22.0%	6.2%	8,703.8	0.0	22.0%

48 For more details on future changes in generation capacity, see "Generation Additions and Retirements in the PJM Capacity Market: MW and Funding Sources for Delivery Years 2007/2008 through 2020/2021," <http://www.monitoringanalytics.com/reports/Reports/2018/IMM_Generation_Additions_and_Retirements_in_the_PJM_Capacity_Market_20180309.pdf> (March 9, 2018). An update to this report will be posted in 2019.

49 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.

50 These reserve margin calculations do not consider Fixed Resource Requirement (FRR) load.

Sources of Funding[51]

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 32,613.9 MW (82.7 percent of all additions), with 24,512.3 MW from market funding and 8,101.6 MW from nonmarket funding. Uprates to existing generation capacity from the 2007/2008 DY through the 2018/2019 DY totaled 6,837.8 MW (17.3 percent of all additions), with 5,411.5 MW from market funding and 1,426.3 MW from nonmarket funding. In summary, of the 39,451.7 MW of additional capacity from new, reactivated, and uprated generation that cleared in RPM auctions for the 2007/2008 through 2018/2019 delivery years, 29,923.8 MW (75.8 percent) were based on market funding.

Of the 8,340.9 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, 4,778.0 MW are not yet in service. Of those 4,778.0 MW that have not yet gone into service, 4,707.4 MW have market funding and 70.6 MW have nonmarket funding. Applying the historical completion rates, 3,468.2 MW, or 73.7 percent, of the market funded projects are expected to go into service. Similarly, 48.8 MW, or 69.2 percent, of nonmarket funded projects are expected to go into service. Together, 3,517.0 MW, or 73.6 percent, 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 3,562.9 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, 1,660.0 MW (46.6 percent) are based on market funding and 1,902.9 MW (53.4 percent) are based on nonmarket funding. In summary, 6,367.4 MW (76.3 percent) of the additional generation capacity (1,660.0 MW in service and 4,707.4 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 1,973.5 MW (23.7 percent) of proposed generation that cleared at least one RPM auction for the 2019/2020 through 2021/2022 delivery years.

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.

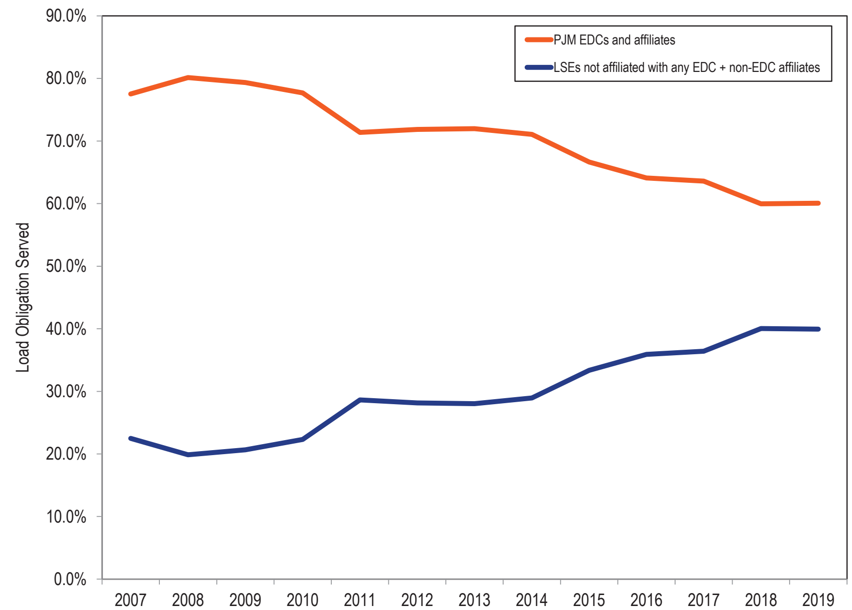
51 For more details on sources of funding for generation capacity, see "Generation Additions and Retirements in the PJM Capacity Market: MW and Funding Sources for Delivery Years 2007/2008 through 2020/2021," <http://www.monitoringanalytics.com/reports/Reports/2018/IMM_Generation_Additions_and_Retirements_in_the_PJM_Capacity_Market_20180309.pdf> (March 9, 2018).

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		
	Obligation (MW)	Percent of total obligation	Obligation (MW)	Percent of total obligation	Change in 2019 from 2018
PJM EDCs and Affiliates	113,202.4	60.0%	113,416.3	60.1%	0.1%
LSEs not affiliated with any EDC + non EDC Affiliates	75,585.7	40.0%	75,445.0	39.9%	(0.1%)
Total	188,788.1	100.0%	188,861.3	100.0%	

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.

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 $6,734,907, 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 $7,605,806. BGE had 306.0 MW of ICTRs due to Incremental Rights-Eligible Required Transmission Enhancements with a value of $8,180,931.

Market Concentration

Auction Market Structure

As shown in Table 5-9, in the 2019/2020 RPM Third Incremental Auction all participants in the total PJM market as well as the LDA RPM markets failed the three pivotal supplier (TPS) test.[52] 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.[53] [54] [55]

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.

52 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.

53 See OATT Attachment DD § 6.5.

54 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).

55 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[56]

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
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

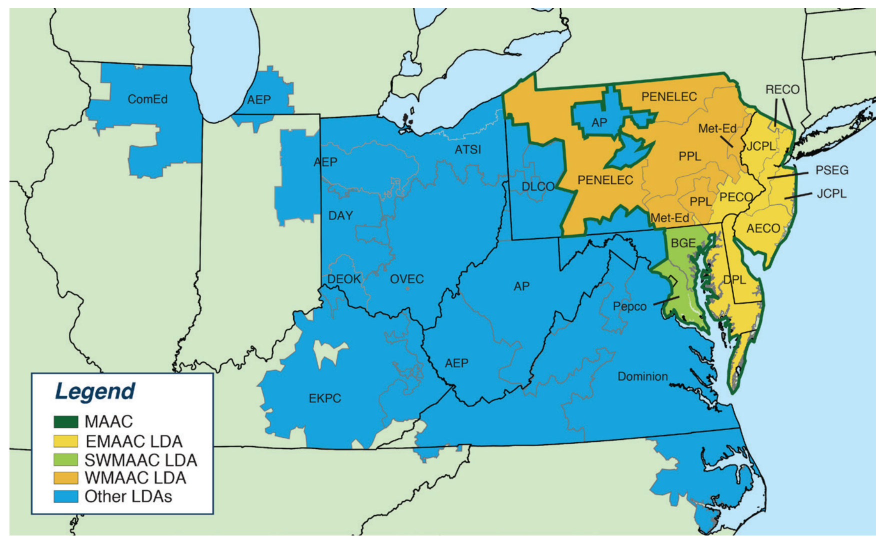
56 The RSI shown is the lowest RSI in the market.

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.[57]

Locational Deliverability Areas are shown in Figure 5-4, Figure 5-5 and Figure 5-6.

Figure 5-4 Map of locational deliverability areas



57 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>.

Figure 5-5 Map of RPM EMAAC subzonal LDAs

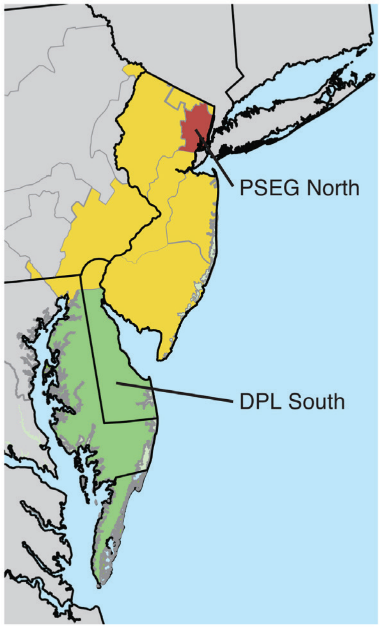
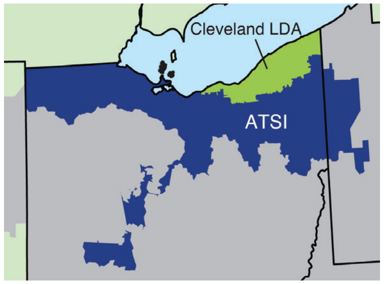


Figure 5-6 Map of RPM ATSI subzonal LDA



Imports and Exports

Units external to the metered boundaries of PJM can qualify as PJM capacity resources if they meet the requirements to be capacity resources. Generators on the PJM system that do not have a commitment to serve PJM loads in the given delivery year as a result of RPM auctions, FRR capacity plans, locational UCAP transactions, and/or are not designated as a replacement resource, are eligible to export their capacity from PJM.[58 59]

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.

Table 5-10 RPM imports: 2007/2008 through 2021/2022 RPM Base Residual Auctions

	UCAP (MW)					
	MISO		Non-MISO		Total Imports	
Base Residual Auction	Offered	Cleared	Offered	Cleared	Offered	Cleared
2007/2008	1,073.0	1,072.9	547.9	547.9	1,620.9	1,620.8
2008/2009	1,149.4	1,109.0	517.6	516.8	1,667.0	1,625.8
2009/2010	1,189.2	1,151.0	518.8	518.1	1,708.0	1,669.1
2010/2011	1,194.2	1,186.6	539.8	539.5	1,734.0	1,726.1
2011/2012	1,862.7	1,198.6	3,560.0	3,557.5	5,422.7	4,756.1
2012/2013	1,415.9	1,298.8	1,036.7	1,036.7	2,452.6	2,335.5
2013/2014	1,895.1	1,895.1	1,358.9	1,358.9	3,254.0	3,254.0
2014/2015	1,067.7	1,067.7	1,948.8	1,948.8	3,016.5	3,016.5
2015/2016	1,538.7	1,538.7	2,396.6	2,396.6	3,935.3	3,935.3
2016/2017	4,723.1	4,723.1	2,770.6	2,759.6	7,493.7	7,482.7
2017/2018	2,624.3	2,624.3	2,320.4	1,901.2	4,944.7	4,525.5
2018/2019	2,879.1	2,509.1	2,256.7	2,178.8	5,135.8	4,687.9
2019/2020	2,067.3	1,828.6	2,276.1	2,047.3	4,343.4	3,875.9
2020/2021	2,511.8	1,671.2	2,450.0	2,326.0	4,961.8	3,997.2
2021/2022	2,308.4	1,909.9	2,162.0	2,141.9	4,470.4	4,051.8

58 For an explanation of importing and exporting capacity see *2018 State of the Market Report for PJM*, Volume 2, Section 5: Capacity Market, at Imports and Exports. <http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2018/2018-som-pjm-sec5.pdf>.

59 OATT Attachment DD § 5.6.6(b).

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[60 61 62 63 64]

		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	9,008.7	2,823.2	1,168.9	481.1	72.6	339.0	152.7	234.6	853.0	227.1	1,623.0	246.5	615.6	211.4	164.1
	EE cleared	2,080.5	683.7	346.7	261.4	8.7	119.6	38.7	114.2	172.0	40.1	722.6	147.2	44.2	53.8	74.1
	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	11,089.2	3,506.9	1,515.6	742.5	81.3	458.6	191.4	348.8	1,025.0	267.2	2,345.6	393.7	659.8	265.2	238.2
01-Jun-21	DR cleared	11,125.8	3,413.4	1,378.9	624.9	66.3	407.9	188.6	345.9	1,142.4	272.8	1,997.8	279.0	684.7	227.7	213.8
	EE cleared	2,832.0	938.7	617.0	207.0	13.6	240.1	72.9	102.6	148.2	36.2	770.5	104.4	72.4	60.1	89.7
	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	13,957.8	4,352.1	1,995.9	831.9	79.9	648.0	261.5	448.5	1,290.6	309.0	2,768.3	383.4	757.1	287.8	303.5

60 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.

61 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.

62 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.

63 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.

64 The reported DR net replacements for June 1, 2018, were revised from the *2019 Quarterly State of the Market Report for PJM: January through March*.

Table 5-12 RPM commitments, replacements, and registrations for demand resources: June 1, 2007 to June 1, 2021[65 66 67 68]

	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	9,008.7	0.0	0.0	9,008.7	0.0	9,008.7	0.0	1.089	0.0
01-Jun-21	11,125.8	0.0	0.0	11,125.8	0.0	11,125.8	0.0	1.090	0.0

Table 5-13 RPM commitments and replacements for energy efficiency resources: June 1, 2007 to June 1, 2021[69 70]

	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	2,080.5	0.0	0.0	2,080.5	0.0	2,080.5
01-Jun-21	2,832.0	0.0	0.0	2,832.0	0.0	2,832.0

65 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.
66 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.
67 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.
68 The reported DR net replacements for June 1, 2018, were revised from the *2019 Quarterly State of the Market Report for PJM: January through March.*
69 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.
70 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.[71]

2019/2020 RPM Third Incremental Auction

As shown in Table 5-14, 137 generation resources submitted Base Capacity offers in the 2019/2020 RPM Third Incremental Auction. The MMU calculated offer caps for one generation resource (0.7 percent), of which zero were based on the technology specific default (proxy) ACR values and one was a unit-specific offer cap (0.7 percent of all generation resources), of which all included an APIR component. Of the 137 generation resources with Base Capacity offers, 112 generation resources elected the offer cap option of 1.1 times the BRA clearing price (81.8 percent), two Planned Generation Capacity Resources had uncapped offers (1.5 percent), and the remaining 22 generation resources were price takers (16.1 percent). Market power mitigation was applied to the Base Capacity sell offers of zero generation resources, including 0.0 MW.

As shown in Table 5-14, 454 generation resources submitted Capacity Performance offers in the 2019/2020 RPM Third Incremental Auction. The MMU calculated offer caps for four generation resources (0.9 percent), all of which were unit-specific with an APIR component. Of the 454 generation resources, 394 generation resources had the net CONE times B offer cap (86.8 percent), 37 generation resources elected the offer cap option of 1.1 times the BRA clearing price (8.1 percent), one Planned Generation Capacity Resource had an uncapped offer (0.2 percent), and the remaining 18 generation resources were price takers (4.0 percent). Market power mitigation was applied to the Capacity Performance sell offers of zero generation resources, including 0.0 MW.

71 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 210.2 ICAP MW of MOPR Unit-Specific Exception requests for the 2019/2020 RPM Third Incremental Auction, requests for 210.2 MW were granted.

Table 5-14 ACR statistics: 2019/2020 RPM Auctions

	2019/2020 Base Residual Auction				2019/2020 First Incremental Auction				2019/2020 Second Incremental Auction				2019/2020 Third Incremental Auction			
	Base Capacity		Capacity Performance		Base Capacity		Capacity Performance		Base Capacity		Capacity Performance		Base Capacity		Capacity Performance	
Offer Cap/Mitigation Type	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered
Default ACR	171	33.9%	0	0.0%	17	21.0%	1	0.3%	10	13.9%	NA	NA	0	0.0%	NA	NA
Unit specific ACR (APIR)	34	6.7%	8	0.8%	11	13.6%	5	1.3%	8	11.1%	5	1.2%	1	0.7%	4	0.9%
Unit specific ACR (APIR and CPQR)	0	0	17	1.7%	0	0	1	0.3%	0	0	1	0.2%	0	0	0	0.0%
Unit specific ACR (non-APIR)	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Unit specific ACR (non-APIR and CPQR)	0	0	0	0.0%	0	0	0	0.0%	0	0	0	0.0%	0	0	0	0.0%
Opportunity cost input	7	1.4%	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Default ACR and opportunity cost	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%	NA	NA	0	0.0%	0	0.0%
Net CONE times B	NA	NA	888	88.5%	NA	NA	362	94.8%	NA	NA	350	85.6%	NA	NA	394	86.8%
Offer cap of 1.1 times BRA clearing price elected	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	112	81.8%	37	8.1%
Uncapped planned uprate and default ACR	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%	NA	NA	0	0.0%	NA	NA
Uncapped planned uprate and opportunity cost	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Uncapped planned uprate and Net CONE times B	NA	NA	2	0.2%	NA	NA	0	0.0%	NA	NA	3	0.7%	NA	NA	0	0.0%
Uncapped planned uprate and price taker	0	0.0%	0	0.0%	0	0.0%	1	0.3%	1	1.4%	1	0.2%	0	0.0%	0	0.0%
Uncapped planned uprate and 1.1 times BRA clearing price elected	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	0	0.0%	0	0.0%
Uncapped planned generation resources	9	1.8%	14	1.4%	0	0.0%	1	0.3%	2	2.8%	0	0.0%	2	1.5%	1	0.2%
Existing generation resources as price takers	284	56.2%	74	7.4%	53	65.4%	11	2.9%	51	70.8%	49	12.0%	22	16.1%	18	4.0%
Total Generation Capacity Resources offered	505	100.0%	1,003	100.0%	81	100.0%	382	100.0%	72	100.0%	409	100.0%	137	100.0%	454	100.0%

Table 5-15 MOPR statistics: RPM Auctions conducted in first quarter, 2019[72]

		Number of Requests	ICAP (MW)			UCAP (MW)	
		(Company-Plant Level)	Requested	Granted	Offered	Offered	Cleared
2019/2020 Third Incremental Auction	Competitive Entry Exemption	8	210.2	210.2	5.4	5.3	5.3
	Self-Supply Exemption	0	0.0	0.0	0.0	0.0	0.0
	Unit-Specific Exception for resources	0	0.0	0.0	0.0	0.0	0.0
	Unit-Specific Exception for uprates	0	0.0	0.0	0.0	0.0	0.0
	Other MOPR Screened Generation Resources	0	0.0	0.0	46.2	44.8	0.0
	Total	8	210.2	210.2	51.6	50.1	5.3

72 There were additional MOPR Screened Generation Resources for which no exceptions or exemptions were requested and to which the MOPR floor was applied. Some numbers not reported as a result of PJM confidentiality rules.

Replacement Capacity[73]

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	168,634.0	0.0	(610.1)	168,023.9	0.0	168,023.9
01-Jun-21	163,627.3	0.0	0.0	163,627.3	0.0	163,627.3

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 six months of 2019, and Table 5-18 shows the RPM cleared MW for all RPM auctions held through the first six 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 six 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 six 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 six 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.

73 For more details on replacement capacity, see "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2017," <http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Report_on_Capacity_Replacement_Activity_4_20171214.pdf> (December 14, 2017).

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

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 BRA	Limited	$59.37	$119.13	$59.37	$119.13	$119.13	$119.13	$119.13	$219.00	$219.00	$119.13	$94.45	$59.37	$119.13
2016/2017 BRA	Extended Summer	$59.37	$119.13	$59.37	$119.13	$119.13	$119.13	$119.13	$219.00	$219.00	$119.13	$114.23	$59.37	$119.13
2016/2017 BRA	Annual	$59.37	$119.13	$59.37	$119.13	$119.13	$119.13	$119.13	$219.00	$219.00	$119.13	$114.23	$59.37	$119.13
2016/2017 First Incremental Auction	Limited	$53.93	$89.35	$53.93	$89.35	$89.35	$89.35	$89.35	$214.44	$214.44	$89.35	$94.45	$53.93	$89.35
2016/2017 First Incremental Auction	Extended Summer	$60.00	$119.13	$60.00	$119.13	$119.13	$119.13	$119.13	$244.22	$244.22	$119.13	$100.52	$60.00	$119.13
2016/2017 First Incremental Auction	Annual	$60.00	$119.13	$60.00	$119.13	$119.13	$119.13	$119.13	$244.22	$244.22	$119.13	$100.52	$60.00	$119.13
2016/2017 Second Incremental Auction	Limited	$31.00	$71.00	$31.00	$71.00	$71.00	$71.00	$71.00	$99.01	$212.53	$71.00	$101.50	$31.00	$71.00
2016/2017 Second Incremental Auction	Extended Summer	$31.00	$71.00	$31.00	$71.00	$71.00	$71.00	$71.00	$99.01	$212.53	$71.00	$101.50	$31.00	$71.00
2016/2017 Second Incremental Auction	Annual	$31.00	$71.00	$31.00	$71.00	$71.00	$71.00	$71.00	$99.01	$212.53	$71.00	$101.50	$31.00	$71.00
2016/2017 Capacity Performance Transition Auction	Capacity Performance	$134.00	$134.00	$134.00	$134.00	$134.00	$134.00	$134.00	$134.00	$134.00	$134.00	$134.00	$134.00	$134.00
2016/2017 Third Incremental Auction	Limited	$5.02	$10.02	$5.02	$10.02	$10.02	$10.02	$10.02	$54.76	$184.97	$10.02	$5.02	$5.02	$10.02
2016/2017 Third Incremental Auction	Extended Summer	$5.02	$10.02	$5.02	$10.02	$10.02	$10.02	$10.02	$54.76	$184.97	$10.02	$5.02	$5.02	$10.02
2016/2017 Third Incremental Auction	Annual	$5.02	$10.02	$5.02	$10.02	$10.02	$10.02	$10.02	$54.76	$184.97	$10.02	$5.02	$5.02	$10.02
2017/2018 BRA	Limited	$106.02	$106.02	$106.02	$40.00	$106.02	$106.02	$106.02	$201.02	$201.02	$106.02	$106.02	$106.02	$106.02
2017/2018 BRA	Extended Summer	$120.00	$120.00	$120.00	$53.98	$120.00	$120.00	$120.00	$215.00	$215.00	$120.00	$120.00	$120.00	$120.00
2017/2018 BRA	Annual	$120.00	$120.00	$120.00	$120.00	$120.00	$120.00	$120.00	$215.00	$215.00	$120.00	$120.00	$120.00	$120.00
2017/2018 Capacity Performance Transition Auction	Capacity Performance	$151.50	$151.50	$151.50	$151.50	$151.50	$151.50	$151.50	$151.50	$151.50	$151.50	$151.50	$151.50	$151.50
2017/2018 First Incremental Auction	Limited	$84.00	$84.00	$84.00	$84.00	$84.00	$84.00	$84.00	$143.08	$143.08	$84.00	$84.00	$84.00	$84.00
2017/2018 First Incremental Auction	Extended Summer	$84.00	$84.00	$84.00	$84.00	$84.00	$84.00	$84.00	$143.08	$143.08	$84.00	$84.00	$84.00	$84.00
2017/2018 First Incremental Auction	Annual	$84.00	$84.00	$84.00	$84.00	$84.00	$84.00	$84.00	$143.08	$143.08	$84.00	$84.00	$84.00	$84.00
2017/2018 Second Incremental Auction	Limited	$26.50	$26.50	$26.50	$26.50	$26.50	$26.50	$26.50	$120.43	$179.00	$26.50	$26.50	$26.50	$26.50
2017/2018 Second Incremental Auction	Extended Summer	$26.50	$26.50	$26.50	$26.50	$26.50	$26.50	$26.50	$120.43	$179.00	$26.50	$26.50	$26.50	$26.50
2017/2018 Second Incremental Auction	Annual	$26.50	$26.50	$26.50	$26.50	$26.50	$26.50	$26.50	$120.43	$179.00	$26.50	$26.50	$26.50	$26.50
2017/2018 Third Incremental Auction	Limited	$36.49	$36.49	$36.49	$36.49	$36.49	$36.49	$36.49	$115.76	$115.76	$36.49	$36.49	$36.49	$36.49
2017/2018 Third Incremental Auction	Extended Summer	$36.49	$36.49	$36.49	$36.49	$36.49	$36.49	$36.49	$115.76	$115.76	$36.49	$36.49	$36.49	$36.49
2017/2018 Third Incremental Auction	Annual	$36.49	$36.49	$36.49	$36.49	$36.49	$36.49	$36.49	$115.76	$115.76	$36.49	$36.49	$36.49	$36.49
2018/2019 BRA	Base Capacity	$149.98	$149.98	$149.98	$75.00	$210.63	$149.98	$210.63	$210.63	$210.63	$149.98	$149.98	$200.21	$149.98
2018/2019 BRA	Base Capacity DR/EE	$149.98	$149.98	$149.98	$75.00	$210.63	$59.95	$210.63	$210.63	$210.63	$41.09	$149.98	$200.21	$59.95
2018/2019 BRA	Capacity Performance	$164.77	$164.77	$164.77	$164.77	$225.42	$164.77	$225.42	$225.42	$225.42	$164.77	$164.77	$215.00	$164.77
2018/2019 First Incremental Auction	Base Capacity	$22.51	$22.51	$22.51	$22.51	$80.04	$22.51	$35.68	$80.04	$80.04	$22.51	$22.51	$25.36	$22.51
2018/2019 First Incremental Auction	Base Capacity DR/EE	$22.51	$22.51	$22.51	$22.51	$80.04	$22.51	$35.68	$80.04	$80.04	$22.51	$22.51	$25.36	$22.51
2018/2019 First Incremental Auction	Capacity Performance	$27.15	$27.15	$27.15	$27.15	$84.68	$27.15	$84.68	$84.68	$84.68	$27.15	$27.15	$30.00	$27.15
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

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
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
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

Table 5-18 Capacity market cleared MW: 2007/2008 through 2021/2022 RPM Auctions[74]

		UCAP (MW)															
Delivery Year	Auction	Rest of RTO	Rest of MAAC	APS	EMAAC	SWMAAC	DPL South	PSEG	PSEG North	Pepco	ATSI	ATSI Cleveland	ComEd	BGE	PPL	DAY	DEOK
2007/2008	BASE	88,410.2	-	-	30,797.8	10,201.2	-	-	-	-	-	-	-	-	-	-	-
2008/2009	BASE	88,745.1	-	-	30,231.3	10,621.2	-	-	-	-	-	-	-	-	-	-	-
2008/2009	THIRD	719.5	-	-	292.1	20.6	-	-	-	-	-	-	-	-	-	-	-
2009/2010	BASE	59,684.1	-	30,982.5	31,650.6	9,914.6	-	-	-	-	-	-	-	-	-	-	-
2009/2010	THIRD	503.1	-	178.7	353.8	762.8	-	-	-	-	-	-	-	-	-	-	-
2010/2011	BASE	68,777.4	51,019.9	-	-	10,873.4	1,519.7	-	-	-	-	-	-	-	-	-	-
2010/2011	THIRD	1,313.1	373.6	-	-	127.9	31.2	-	-	-	-	-	-	-	-	-	-
2011/2012	BASE	132,264.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2011/2012	FIRST	361.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2011/2012	THIRD	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	-	-	-	-	-	-	-	-
2012/2013	FIRST	452.2	16.1	-	560.4	38.7	167.8	319.9	133.6	-	-	-	-	-	-	-	-
2012/2013	SECOND	539.1	143.8	-	102.9	4.0	0.1	24.3	23.6	-	-	-	-	-	-	-	-
2012/2013	THIRD	1,871.9	215.0	-	170.2	16.4	56.3	37.5	36.2	-	-	-	-	-	-	-	-
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	-	-	-	-	-	-	-
2013/2014	FIRST	1,719.5	128.5	-	167.8	2.0	1.3	238.7	124.2	5.1	-	-	-	-	-	-	-
2013/2014	SECOND	1,143.7	109.6	-	125.9	24.4	61.7	34.1	17.3	480.0	-	-	-	-	-	-	-
2013/2014	THIRD	1,449.0	404.1	-	301.2	1.8	9.7	1.1	4.7	531.8	-	-	-	-	-	-	-
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	-	-	-	-	-	-	-
2014/2015	FIRST	2,590.2	605.5	-	69.0	764.5	10.3	31.8	143.3	24.5	-	-	-	-	-	-	-
2014/2015	SECOND	2,000.4	215.1	-	271.7	159.6	13.7	5.0	0.9	243.1	-	-	-	-	-	-	-
2014/2015	THIRD	2,517.4	247.9	-	645.7	142.1	61.8	65.4	282.1	15.4	-	-	-	-	-	-	-
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	-	-	-	-	-	-
2015/2016	FIRST	1,523.6	855.2	-	92.8	654.8	.	23.9	268.3	1.7	777.4	-	-	-	-	-	-
2015/2016	SECOND	865.3	70.7	-	48.5	430.6	2.3	3.6	6.6	5.3	346.8	-	-	-	-	-	-
2015/2016	THIRD	1,908.0	464.1	-	71.2	340.9	12.5	29.5	70.1	5.6	402.1	-	-	-	-	-	-
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	-	-	-	-	-
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	-	-	-	-	-
2016/2017	FIRST	1,032.3	304.2	-	417.0	132.9	0.5	409.0	7.5	8.7	295.3	2.1	-	-	-	-	-
2016/2017	SECOND	126.9	4.0	-	30.5	32.9	0.0	10.7	6.7	0.0	16.4	.	-	-	-	-	-
2016/2017	THIRD	790.1	180.6	-	264.0	22.7	11.4	22.8	84.6	71.9	11.2	6.0	-	-	-	-	-
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	-	-
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	-	-
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	-	-
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	-	-
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	-	-
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	-	-
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	-	-
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	-	-
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	-	-
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	-	-
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	-	-
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	-	-
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	-	-
2020/2021	BASE	61,457.0	15,488.6	-	22,926.7	2,138.9	1,647.2	2,126.5	2,975.4	5,987.1	8,068.8	1,857.9	24,109.2	2,380.6	10,370.1	1,528.0	2,445.1
2020/2021	FIRST	1,317.8	331.4	-	181.0	32.5	38.9	5.5	32.1	70.1	389.4	277.5	653.7	38.7	83.5	81.9	20.3
2021/2022	BASE	61,616.5	16,702.8	-	22,325.8	2,220.2	1,673.8	2,241.0	3,135.9	6,076.6	6,765.5	1,248.1	22,632.6	2,022.7	11,284.6	1,638.0	2,758.7

74 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	$75.83	$140.05
APS	$158.20	$93.63	$75.83	$140.05
ATSI	$148.42	$92.97	$74.98	$171.32
Cleveland	$158.68	$89.17	$72.16	$171.33
ComEd	$199.02	$188.90	$184.32	$195.55
DAY	$158.20	$93.63	$74.82	$140.00
DEOK	$158.20	$93.63	$129.12	$140.00
DLCO	$158.20	$93.63	$75.83	$140.05
Dominion	$158.20	$93.63	$75.83	$140.05
EKPC	$158.20	$93.63	$75.83	$140.05
MAAC				
EMAAC				
AECO	$214.31	$112.48	$186.61	$165.68
DPL	$214.31	$112.48	$186.61	$165.68
DPL South	$211.38	$115.95	$184.53	$165.73
JCPL	$214.31	$112.48	$186.61	$165.68
PECO	$214.31	$112.48	$186.61	$165.68
PSEG	$210.92	$110.56	$187.39	$204.20
PSEG North	$211.71	$116.03	$186.33	$204.27
RECO	$214.31	$112.48	$186.61	$165.68
SWMAAC				
BGE	$141.58	$88.20	$85.24	$199.00
Pepco	$144.90	$90.59	$85.54	$140.00
WMAAC				
Met-Ed	$152.65	$93.81	$85.16	$140.00
PENELEC	$152.65	$93.81	$85.16	$140.00
PPL	$147.90	$88.53	$85.70	$140.08

Table 5-20 RPM revenue by type: 2007/2008 through 2021/2022[75] [76]

				Coal		Gas		Hydroelectric		Nuclear	
	Demand Resources	Energy Efficiency Resources	Imports	Existing	New/repower/ reactivated	Existing	New/repower/ reactivated	Existing	New/repower/ reactivated	Existing	New/repower/ reactivated
2007/2008	$5,537,085	$0	$22,225,980	$1,019,060,206	$0	$1,625,158,046	$3,516,075	$209,490,444	$0	$996,085,233	$0
2008/2009	$35,349,116	$0	$60,918,903	$1,835,059,769	$0	$2,115,862,522	$9,784,064	$287,838,147	$12,255	$1,322,601,837	$0
2009/2010	$65,762,003	$0	$56,517,793	$2,409,315,953	$1,854,781	$2,551,967,501	$30,168,831	$364,731,344	$11,173	$1,517,723,628	$0
2010/2011	$60,235,796	$0	$106,046,871	$2,648,278,766	$3,168,069	$2,829,039,737	$58,065,964	$442,410,730	$19,085	$1,799,258,125	$0
2011/2012	$55,795,785	$139,812	$185,421,273	$1,586,775,249	$28,330,047	$1,721,272,563	$98,448,693	$278,529,660	$0	$1,079,386,338	$0
2012/2013	$264,387,897	$11,408,552	$13,260,822	$1,014,858,378	$7,568,127	$1,256,600,367	$76,633,409	$179,117,374	$11,998	$762,719,550	$0
2013/2014	$558,715,114	$21,598,174	$31,804,645	$1,741,613,525	$12,950,135	$2,154,401,813	$167,844,235	$308,853,673	$25,708	$1,346,223,419	$0
2014/2015	$681,315,139	$42,308,549	$135,573,409	$1,935,468,356	$57,078,818	$2,176,442,220	$205,555,569	$333,941,614	$6,649,774	$1,464,950,862	$0
2015/2016	$903,496,003	$66,652,986	$260,806,674	$2,902,870,267	$63,682,708	$2,676,692,075	$535,039,154	$389,540,948	$15,478,144	$1,850,033,226	$0
2016/2017	$466,952,356	$68,709,670	$244,091,507	$2,137,545,515	$72,217,195	$2,217,027,225	$667,098,133	$283,613,426	$13,927,638	$1,483,759,630	$0
2017/2018	$515,145,457	$86,147,605	$218,710,769	$2,452,687,763	$62,790,145	$2,550,970,172	$984,733,791	$348,972,234	$15,219,121	$1,694,447,711	$0
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
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
2020/2021	$343,544,146	$93,092,140	$74,256,199	$1,318,324,680	$36,115,158	$2,080,256,094	$1,146,062,527	$209,060,912	$7,737,607	$1,421,992,631	$0
2021/2022	$631,409,762	$166,627,498	$130,197,690	$2,079,667,778	$66,256,260	$2,670,256,030	$1,676,705,702	$295,309,520	$11,589,480	$1,181,920,902	$0

				Oil		Solar		Solid waste		Wind		
	Demand Resources	Energy Efficiency Resources	Imports	Existing	New/repower/ reactivated	Existing	New/repower/ reactivated	Existing	New/repower/ reactivated	Existing	New/repower/ reactivated	Total revenue
2007/2008	$5,537,085	$0	$22,225,980	$339,272,020	$0	$0	$0	$31,512,230	$0	$430,065	$0	$4,252,287,381
2008/2009	$35,349,116	$0	$60,918,903	$375,774,257	$4,837,523	$0	$0	$35,011,991	$0	$1,180,153	$2,917,048	$6,087,147,586
2009/2010	$65,762,003	$0	$56,517,793	$447,358,085	$5,676,582	$0	$0	$42,758,762	$523,739	$2,011,156	$6,836,827	$7,503,218,157
2010/2011	$60,235,796	$0	$106,046,871	$440,593,115	$4,339,539	$0	$0	$40,731,606	$413,503	$1,819,413	$15,232,177	$8,449,652,496
2011/2012	$55,795,785	$139,812	$185,421,273	$263,061,402	$967,887	$0	$66,978	$25,636,836	$261,690	$1,072,929	$9,919,881	$5,335,087,023
2012/2013	$264,387,897	$11,408,552	$13,260,822	$248,107,065	$2,772,987	$0	$1,246,337	$26,840,670	$316,420	$812,644	$5,052,036	$3,871,714,635
2013/2014	$558,715,114	$21,598,174	$31,804,645	$385,720,626	$5,670,399	$0	$3,523,555	$43,943,130	$1,977,705	$1,373,205	$13,538,988	$6,799,778,047
2014/2015	$681,315,139	$42,308,549	$135,573,409	$319,758,617	$4,106,697	$0	$3,836,582	$34,281,137	$1,709,533	$1,524,551	$32,766,219	$7,437,267,646
2015/2016	$903,496,003	$66,652,986	$260,806,674	$397,556,965	$5,947,275	$0	$7,064,983	$35,862,368	$6,179,607	$1,829,269	$42,994,253	$10,161,726,902
2016/2017	$466,952,356	$68,709,670	$244,091,507	$261,495,016	$4,030,823	$0	$7,057,256	$32,648,789	$6,380,604	$1,144,873	$26,189,042	$7,993,888,695
2017/2018	$515,145,457	$86,147,605	$218,710,769	$276,148,715	$3,888,126	$0	$10,899,883	$34,771,100	$9,036,976	$1,529,251	$40,577,901	$9,306,676,719
2018/2019	$637,742,320	$103,105,796	$263,475,004	$339,771,633	$2,922,855	$0	$16,928,323	$38,243,467	$9,658,138	$1,166,553	$54,226,228	$11,054,943,851
2019/2020	$375,353,169	$92,569,666	$84,207,557	$187,076,264	$1,818,114	$610,166	$12,246,100	$21,332,647	$5,326,702	$1,296,846	$46,582,019	$7,116,815,360
2020/2021	$343,544,146	$93,092,140	$74,256,199	$212,589,855	$1,408,492	$0	$7,389,376	$26,917,827	$5,428,707	$25,124	$35,671,349	$7,019,872,821
2021/2022	$631,409,762	$166,627,498	$130,197,690	$253,987,440	$2,401,396	$0	$29,673,108	$31,924,862	$7,757,690	$2,089,282	$63,102,701	$9,300,877,101

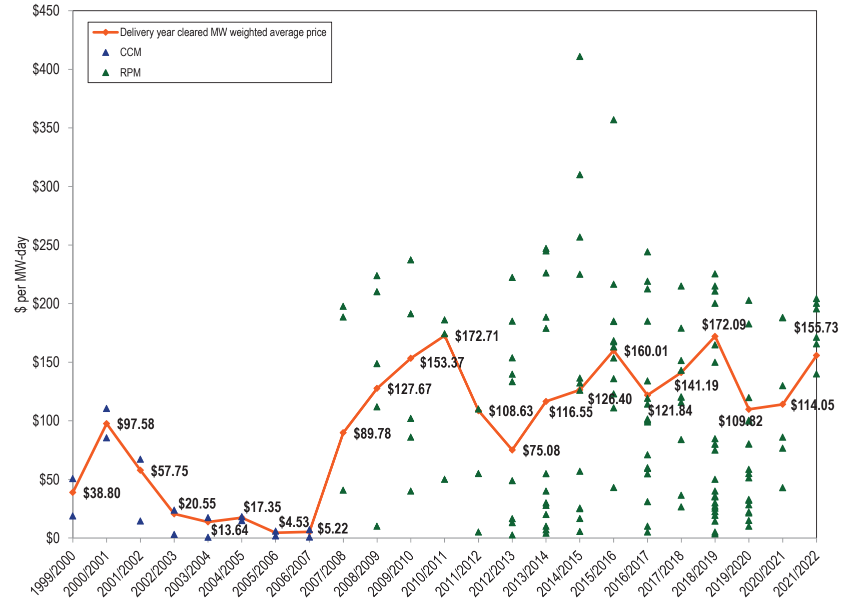
75 A resource classified as "new/repower/reactivated" is a capacity resource addition since the implementation of RPM and is considered "new/repower/reactivated" for its initial offer and all its subsequent offers in RPM Auctions.
76 The results for the ATSI Integration Auctions are not included in this table.

Table 5-21 RPM revenue by calendar year: 2007 through 2022[77]

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	$112.29	172,057.9	366	$7,071,378,359
2021	$138.49	165,333.1	365	$8,357,228,755
2022	$155.73	163,627.3	151	$3,847,760,116

77 The results for the ATSI Integration Auctions are not included in this table.

Figure 5-7 History of capacity prices: 1999/2000 through 2021/2022[78]



78 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

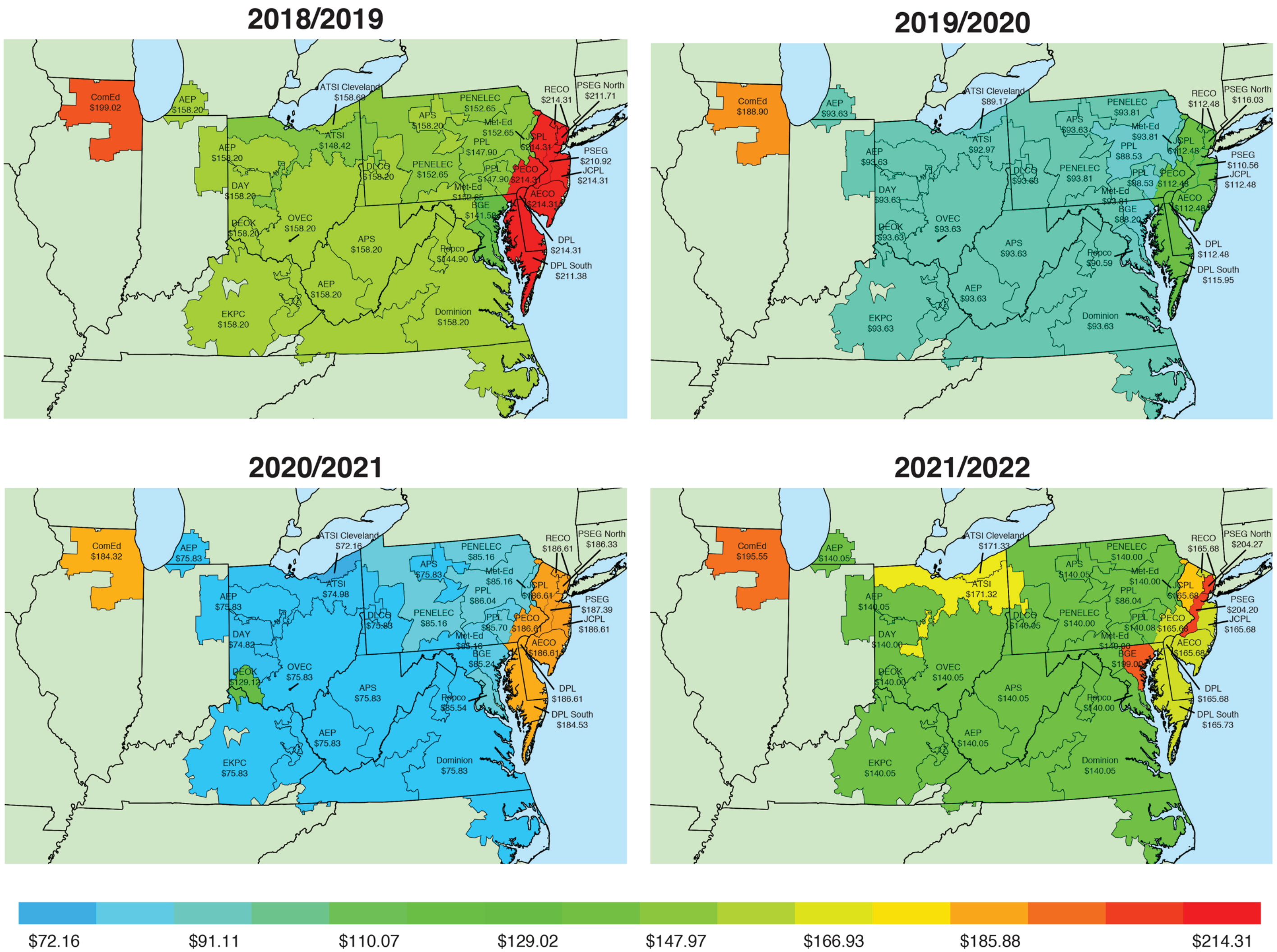


Table 5-22 RPM cost to load: 2018/2019 through 2021/2022 RPM Auctions[79 80 81]

	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	$77.00	69,538.0	$1,954,438,669
Rest of MAAC	$86.89	29,572.5	$937,886,000
Rest of EMAAC	$176.17	34,949.0	$2,247,251,699
ComEd	$183.79	25,040.0	$1,679,743,111
DEOK	$103.53	5,208.1	$196,815,744
Total		164,307.7	$7,016,135,223
2021/2022			
Rest of RTO	$140.53	82,080.4	$4,210,274,861
Rest of EMAAC	$163.08	23,762.8	$1,414,495,718
ATSI	$157.99	14,464.9	$834,165,114
BGE	$161.62	7,435.0	$438,596,021
ComEd	$192.69	24,983.0	$1,757,064,009
PSEG	$184.03	10,901.1	$732,248,951
Total		163,627.3	$9,386,844,675

79 The RPM annual charges are calculated using the rounded, net load prices as posted in the PJM RPM Auction results.
80 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.
81 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.[82] 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.[83 84]

Table 5-23 shows units that have provided RMR service to PJM.

82 OATT Part V.
83 *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.").
84 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 for the first six months of 2018 and 2019. In the first six months of 2019, nuclear units had a capacity factor of 93.1 percent, compared to 93.2 percent in the first six months of 2018; combined cycle units had a capacity factor of 60.9 percent in the first six months of 2019, compared to a capacity factor of 58.6 percent in the first six months of 2018; all steam units had a capacity factor of 35.2 percent in the first six months of 2019, compared to 39.9 percent in the first six months of 2018; coal units had a capacity factor of 40.4 percent in the first six months of 2019, compared to 45.7 percent in the first six months of 2018.

Table 5-24 Capacity factor (By unit type (GWh)): January through June, 2018 and 2019[85] [86]

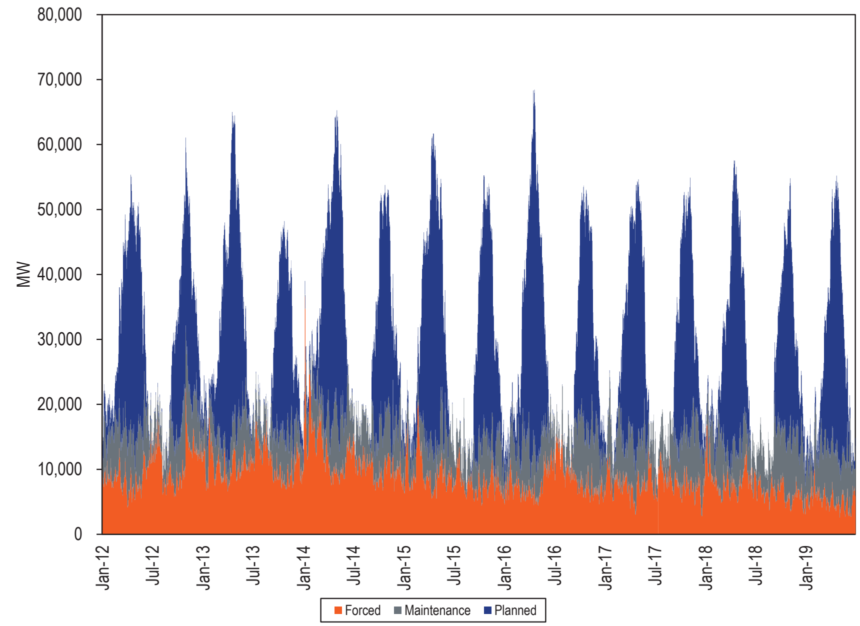
	2018 (Jan-Jun)		2019 (Jan-Jun)		
Unit Type	Generation (GWh)	Capacity Factor	Generation (GWh)	Capacity Factor	Change in 2019 from 2018
Battery	7.5	0.6%	10.9	0.7%	0.1%
Combined Cycle	104,629.3	58.6%	129,454.2	60.9%	2.2%
Single Fuel	86,298.5	62.7%	111,257.0	66.8%	4.1%
Dual Fuel	18,330.8	44.9%	18,197.2	39.5%	(5.4%)
Combustion Turbine	7,786.5	6.2%	4,394.0	3.5%	(2.7%)
Single Fuel	4,816.0	5.2%	2,993.6	3.3%	(1.9%)
Dual Fuel	2,970.5	9.0%	1,400.4	4.1%	(4.9%)
Diesel	178.3	11.5%	108.3	6.8%	(4.7%)
Single Fuel	170.7	12.5%	106.6	7.6%	(4.9%)
Dual Fuel	7.6	4.2%	1.8	1.0%	(3.2%)
Diesel (Landfill gas)	900.7	52.8%	826.3	49.1%	(3.7%)
Fuel Cell	112.2	85.1%	109.3	81.7%	(3.4%)
Nuclear	141,179.9	93.2%	138,609.7	93.1%	(0.1%)
Pumped Storage Hydro	3,236.8	14.7%	2,589.9	11.8%	(2.9%)
Run of River Hydro	5,561.1	43.1%	7,227.6	55.3%	12.2%
Solar	1,073.7	18.8%	1,323.2	19.3%	0.5%
Steam	127,069.6	39.9%	104,613.3	35.2%	(4.7%)
Biomass	3,249.3	62.1%	2,873.8	59.7%	(2.5%)
Coal	120,529.1	45.7%	99,905.2	40.4%	(5.3%)
Single Fuel	117,046.1	47.0%	98,560.0	42.3%	(4.6%)
Dual Fuel	3,483.1	23.9%	1,345.2	9.2%	(14.7%)
Natural Gas	2,933.3	35.2%	1,830.8	38.1%	2.8%
Single Fuel	286.4	41.7%	194.3	47.0%	5.3%
Dual Fuel	2,647.0	22.1%	1,636.5	18.8%	(3.3%)
Oil	357.8	2.3%	3.5	0.0%	(2.3%)
Wind	12,081.6	32.8%	13,644.9	34.0%	1.2%
Total	403,819.5	47.2%	402,914.0	46.3%	(0.9%)

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.

85 The capacity factors in this table are based on nameplate capacity values, and are calculated based on when the units come on line.
86 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.

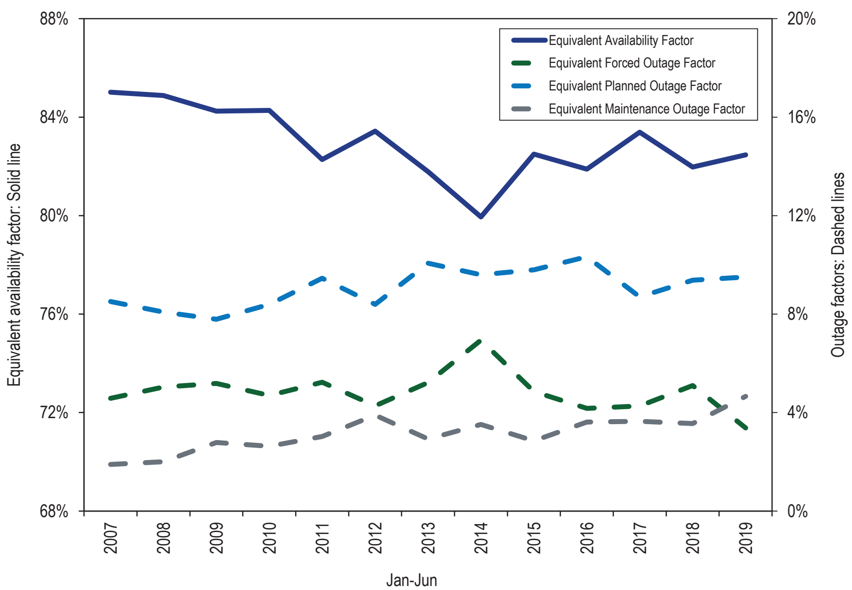
Figure 5-9 Outages (MW): 2012 through June 2019



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



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.[87] The EFORd metric includes all forced outages, regardless of the reason for those outages.

The average PJM EFORd for the first six months of 2019 was 6.5 percent, a decrease from 8.3 percent for the first six months of 2018. Figure 5-11 shows the average EFORd since 1999 for all units in PJM.[88]

Table 5-25 EFOF, EPOF, EMOF and EAF by unit type: January through June, 2007 through 2019

	Coal				Combined Cycle				Combustion Turbine				Diesel				Hydroelectric				Nuclear				Other			
	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 (Jan-Jun)	6.5%	12.2%	2.5%	78.8%	1.8%	7.8%	1.6%	88.8%	5.7%	3.1%	2.4%	88.9%	9.1%	0.8%	2.3%	87.8%	1.6%	5.7%	2.0%	90.7%	1.1%	4.8%	0.3%	93.9%	6.2%	11.5%	2.2%	80.1%
2008 (Jan-Jun)	8.0%	9.1%	2.4%	80.5%	1.7%	7.3%	1.6%	89.4%	3.2%	5.2%	2.4%	89.2%	9.2%	1.8%	1.4%	87.7%	1.4%	6.7%	2.3%	89.7%	1.0%	7.1%	0.5%	91.4%	8.3%	11.7%	3.0%	77.1%
2009 (Jan-Jun)	7.1%	9.5%	3.1%	80.3%	3.1%	7.1%	3.6%	86.2%	1.4%	3.6%	2.4%	92.5%	6.8%	0.4%	1.5%	91.4%	2.0%	9.8%	2.9%	85.3%	4.0%	5.7%	0.7%	89.6%	8.9%	10.9%	5.3%	74.9%
2010 (Jan-Jun)	7.4%	10.9%	3.5%	78.2%	2.8%	9.5%	4.1%	83.6%	2.0%	2.7%	1.8%	93.5%	4.1%	0.7%	1.0%	94.1%	0.6%	10.5%	2.2%	86.7%	1.2%	6.0%	0.6%	92.2%	8.1%	9.6%	3.0%	79.3%
2011 (Jan-Jun)	8.5%	11.4%	4.0%	76.0%	2.5%	10.2%	2.8%	84.5%	1.4%	3.9%	1.9%	92.8%	2.4%	0.0%	2.7%	94.9%	1.3%	13.0%	1.6%	84.1%	1.8%	7.7%	2.0%	88.6%	8.5%	10.8%	3.4%	77.3%
2012 (Jan-Jun)	6.6%	10.4%	6.7%	76.4%	2.2%	8.7%	2.1%	87.0%	2.1%	3.0%	1.8%	93.1%	3.9%	0.1%	1.9%	94.1%	3.6%	5.4%	1.5%	89.4%	1.0%	8.3%	0.8%	89.8%	7.2%	9.6%	4.3%	79.0%
2013 (Jan-Jun)	7.3%	13.4%	4.4%	74.9%	1.9%	11.5%	3.1%	83.4%	5.1%	4.0%	1.4%	89.5%	4.3%	0.4%	1.6%	93.7%	0.5%	7.3%	2.1%	90.2%	1.4%	7.2%	0.6%	90.8%	11.1%	11.7%	4.2%	73.0%
2014 (Jan-Jun)	9.6%	10.5%	5.3%	74.5%	3.2%	12.3%	2.4%	82.1%	9.5%	4.1%	1.8%	84.6%	14.6%	0.8%	2.9%	81.7%	1.9%	10.7%	3.5%	83.9%	1.9%	8.1%	0.7%	89.2%	9.0%	14.4%	6.0%	70.6%
2015 (Jan-Jun)	8.0%	10.1%	4.1%	77.8%	2.4%	11.5%	2.0%	84.0%	3.2%	5.0%	2.2%	89.6%	9.4%	0.6%	2.7%	87.4%	2.0%	9.9%	1.5%	86.6%	1.2%	6.8%	1.1%	91.0%	7.4%	20.1%	4.5%	68.0%
2016 (Jan-Jun)	7.9%	11.2%	6.1%	74.8%	3.2%	11.7%	1.9%	83.2%	2.1%	5.6%	2.6%	89.7%	5.8%	0.3%	3.4%	90.5%	2.1%	8.0%	3.6%	86.3%	1.0%	6.3%	1.4%	91.2%	3.5%	22.2%	3.8%	70.6%
2017 (Jan-Jun)	9.7%	10.2%	6.8%	73.2%	2.1%	11.2%	1.6%	85.1%	1.2%	5.5%	2.2%	91.2%	5.1%	0.3%	2.0%	92.6%	2.2%	6.6%	3.0%	88.2%	0.4%	6.7%	0.6%	92.3%	3.2%	9.8%	5.2%	81.8%
2018 (Jan-Jun)	11.5%	12.1%	6.6%	69.9%	1.8%	10.9%	1.3%	86.0%	2.0%	6.0%	1.7%	90.2%	5.5%	1.2%	2.8%	90.5%	2.6%	5.5%	3.3%	88.7%	0.5%	6.5%	0.3%	92.8%	4.7%	11.2%	7.1%	77.0%
2019 (Jan-Jun)	6.7%	10.1%	9.1%	74.0%	1.8%	10.7%	1.7%	85.9%	1.1%	6.5%	1.8%	90.6%	5.6%	1.4%	3.0%	90.0%	0.9%	5.1%	3.8%	90.2%	0.6%	10.4%	1.4%	87.6%	6.7%	11.2%	8.0%	74.1%

87 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.

88 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.

Figure 5-11 Trends in the equivalent demand forced outage rate (EFORd): 1999 through 2019

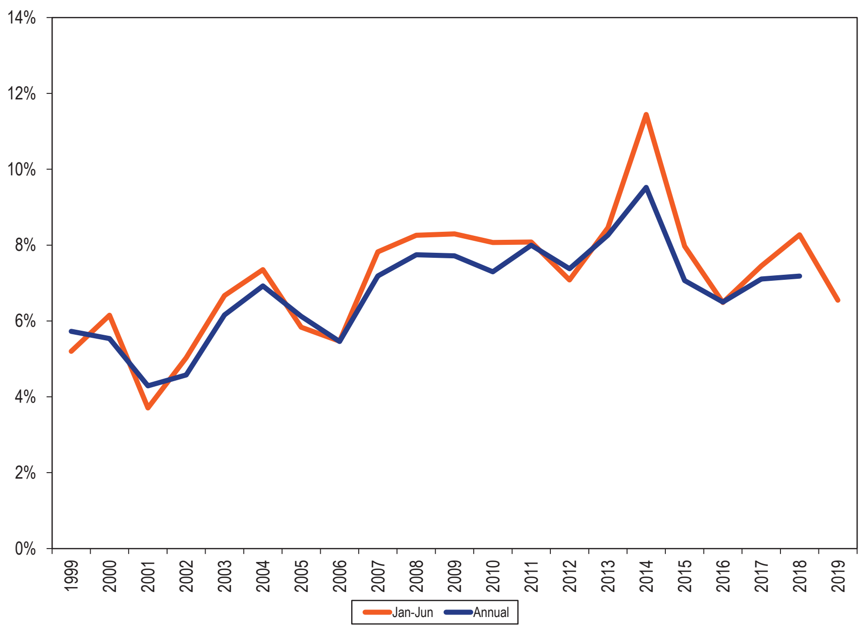


Table 5-26 shows the class average EFORd by unit type.

Table 5-26 EFORd data for different unit types: January through June, 2007 through 2019

	Jan-Jun												
	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Coal	7.9%	9.2%	8.8%	9.1%	10.6%	9.5%	9.6%	12.3%	9.8%	10.1%	13.0%	14.7%	10.7%
Combined Cycle	4.0%	3.6%	5.3%	4.5%	3.6%	2.9%	2.8%	5.6%	3.3%	4.5%	2.8%	3.0%	2.6%
Combustion Turbine	17.9%	14.6%	10.6%	14.7%	8.8%	8.9%	14.3%	23.1%	13.3%	7.6%	7.1%	9.3%	6.5%
Diesel	10.6%	10.0%	8.5%	5.8%	6.4%	5.1%	4.4%	15.8%	10.7%	8.1%	5.9%	5.8%	6.0%
Hydroelectric	2.2%	2.1%	2.4%	1.1%	1.8%	5.1%	0.7%	3.1%	2.5%	3.1%	3.1%	3.3%	1.2%
Nuclear	1.2%	1.1%	4.0%	1.5%	2.1%	1.2%	1.6%	2.3%	1.2%	1.2%	0.5%	0.6%	0.7%
Other	11.5%	16.1%	16.4%	12.8%	15.8%	11.4%	18.9%	18.7%	14.7%	7.8%	13.5%	12.3%	16.6%
Total	7.8%	8.3%	8.3%	8.1%	8.1%	7.1%	8.5%	11.4%	8.0%	6.5%	7.4%	8.3%	6.5%

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.[89] 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 3.4 percent in the first six months of 2019. This means there was 3.4 percent lost availability because of forced outages. Table 5-27 shows that forced outages for boiler tube leaks, at 18.5 percent of the systemwide EFOF, were the largest single contributor to EFOF.

89 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.

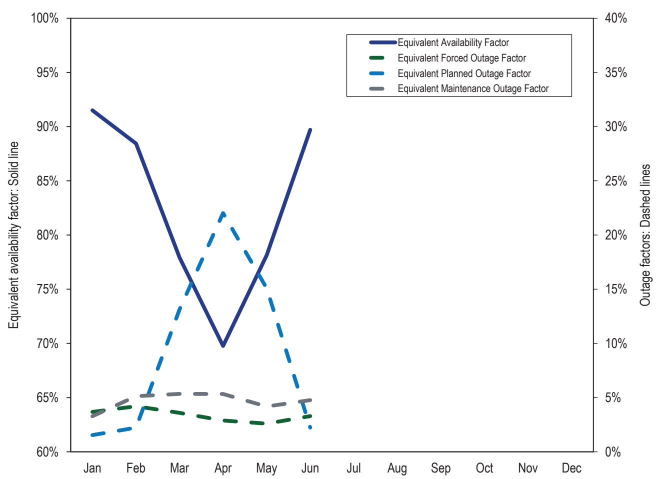
Table 5-27 Contribution to EFOF by unit type by cause: January through June, 2019

	Coal	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Other	System
Boiler Tube Leaks	26.1%	3.6%	0.0%	0.0%	0.0%	0.0%	8.1%	18.5%
Economic	0.0%	2.5%	20.4%	1.4%	2.4%	0.0%	60.8%	10.8%
Boiler Fuel Supply from Bunkers to Boiler	14.2%	0.2%	0.0%	0.0%	0.0%	0.0%	0.8%	9.4%
Miscellaneous (Pollution Control Equipment)	11.8%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	7.7%
Boiler Air and Gas Systems	7.2%	0.0%	0.0%	0.0%	0.0%	0.0%	6.9%	5.8%
Electrical	5.3%	3.7%	8.1%	4.9%	3.6%	23.2%	2.2%	5.5%
Feedwater System	3.1%	1.2%	0.0%	0.0%	0.0%	14.9%	2.3%	3.0%
Auxiliary Systems	2.5%	2.7%	18.3%	0.0%	3.2%	0.5%	0.1%	2.8%
Exciter	1.6%	12.6%	1.3%	0.6%	0.7%	11.8%	0.6%	2.8%
Boiler Piping System	2.9%	2.2%	0.0%	0.0%	0.0%	0.0%	0.4%	2.2%
Low Pressure Turbine	1.5%	13.2%	0.0%	0.0%	0.0%	0.0%	0.0%	2.1%
Unit Testing	1.9%	0.0%	5.6%	32.1%	14.2%	0.0%	0.9%	2.1%
Fuel Quality	2.9%	0.1%	0.1%	4.0%	0.0%	0.0%	0.4%	2.0%
Wet Scrubbers	3.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.9%
Generator	0.3%	17.1%	4.3%	0.7%	2.3%	0.0%	0.1%	1.9%
Controls	0.6%	2.3%	1.3%	21.3%	2.7%	17.4%	0.7%	1.6%
Fuel, Ignition and Combustion Systems	0.0%	8.3%	13.4%	0.0%	0.0%	0.0%	0.0%	1.4%
Slag and Ash Removal	1.9%	0.0%	0.0%	0.0%	0.0%	0.0%	0.8%	1.4%
Miscellaneous (Generator)	0.9%	2.0%	5.0%	2.0%	8.8%	0.0%	1.3%	1.3%
All Other Causes	12.2%	28.3%	22.2%	33.0%	62.3%	32.2%	13.5%	15.8%
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 six months of 2019, total demand response revenue increased by $25.6 million, 9.4 percent, from $271.9 million in the first six months of 2018 to $297.5 million in the first six months of 2019. Emergency demand response revenue accounted for 99.0 percent of all demand response revenue, economic demand response for 0.2 percent, demand response in the Synchronized Reserve Market for 0.4 percent and demand response in the regulation market for 0.4 percent.

  Total emergency demand response revenue increased by $29.1 million, 10.9 percent, from $265.5 million in the first six months of 2018 to $294.6 million in the first six months of 2019. This increase consisted entirely of capacity market revenue.[2]

  Economic demand response revenue decreased by $1.0 million, 66.7 percent, from $1.6 million in the first six months of 2018 to $0.5 million in the first six months of 2019.[3] Demand response revenue in the Synchronized Reserve Market decreased by $2.0 million, 62.3 percent, from $3.2 million in the first six months of 2018 to $1.2 million in the first six months of 2019. Demand response revenue in the regulation market decreased by $0.5 million, 62.3 percent, from $1.6 million in the first six months of 2018 to $1.2 million in the first six 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 six months of 2019. The HHI for economic resource reductions increased by 373 points from 7541 in 2018 to 7914 in the first six months of 2019. The ownership of emergency demand response resources was moderately concentrated in the first six 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 July 23, 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 June 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. New recommendation. 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. ER19-1012-000 (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]

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.

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

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 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 six 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 six months of 2019, total demand response revenue increased by $25.6 million, 9.4 percent, from $272.0 million in the first six months of 2018 to $297.5 million in the first six months of 2019. Total emergency demand response revenue increased by $29.1 million, 10.9 percent, from $265.5 million in the first six months of 2018 to $294.6 million in the first six months of 2019. This increase consisted entirely of capacity market revenue.[23] In the first six months of 2019, demand resource revenue, which includes capacity and emergency energy revenue, accounted for 99.0 percent of all revenue received by demand response providers, the economic program for 0.2 percent, synchronized reserve for 0.4 percent and the regulation market for 0.4 percent.

Economic demand response revenue decreased by $1.0 million, 66.7 percent, from $1.6 million in the first six months of 2018 to $0.5 million in the first six months of 2019.[24] Demand response revenue in the Synchronized Reserve Market decreased by $2.0 million, 62.3 percent, from $3.2 million in the first six months of 2018 to $1.2 million in the first six months of 2019. Demand response revenue in the regulation market decreased by $0.5 million, 28.8 percent, from $1.6 million in the first six months of 2018 to $1.2 million in the first six months of 2019.

Higher demand resource revenues were in part a result of higher capacity market prices in the 2018/2019 RPM auction clearing price. The capacity revenue in 2018 is from 2017/2018 RPM auction clearing prices and the capacity revenue in 2019 is from 2018/2019 RPM auction clearing prices. The annual capacity market prices increased $13.20 per MW-day from $151.50 in the 2017/2018 Delivery Year to $164.77 in the 2018/2019 Delivery Year, a 8.7 percent increase.

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.

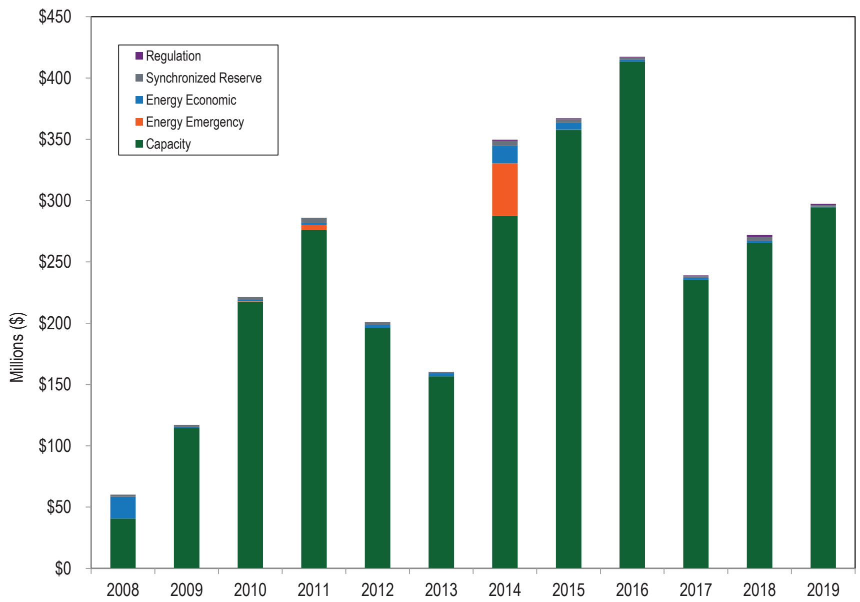
21 PJM Operating Agreement Schedule 1 § 1.5A.3.1.

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 July 17, 2019 and may change as a result of continued PJM billing updates. There was no emergency energy revenue in the first six months of 2019.

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

Figure 6-1 Demand response revenue by market: January through June, 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 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.

25 157 FERC ¶ 61,115 (2016).
26 *Id.* at 8.

Table 6-2 shows registered sites and MW for the last day of each month for the period January 1, 2015, through June 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 six months of 2019 compared to the first six months of 2018. Average monthly registrations decreased by 121, 24.4 percent, from 494 in the first six months of 2018 to 373 in the first six months of 2019. Average monthly registered MW increased by 192 MW, 7.4 percent, from 2,609 MW in the first six months of 2018 to 2,801 MW in the first six months of 2019.

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.

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	375	2,702
Feb	1,076	2,956	835	2,557	842	2,578	537	2,628	371	2,690
Mar	1,075	2,949	834	2,556	850	2,576	519	2,641	379	2,698
Apr	1,076	2,938	832	2,556	897	2,574	501	2,624	367	2,645
May	980	2,846	829	2,545	977	2,626	471	2,615	374	3,248
Jun	871	2,614	518	2,500	577	1,305	397	2,576	372	2,823
Jul	870	2,609	519	2,421	589	1,548	374	2,591		
Aug	869	2,609	805	2,569	590	1,541	382	2,609		
Sep	867	2,608	831	2,608	588	1,663	378	2,580		
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	373	2,801

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 June 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 decreased by 97 MW, 49.7 percent, from 195 MW in the first six months of 2018 to 98 MW in the first six months of 2019.[28] The peak dispatched MW in the first six months of 2019, 98 MW, were 2,703 MW less than the average MW registered in the first six months of 2019, 2,801 MW.

Table 6-3 Sum of peak MW reductions for all registrations per month: 2010 through June 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	21
Jun	209	561	954	433	483	833	121	240	105	5
Jul	999	561	1,631	1,088	665	1,362	1,316	936	518	
Aug	794	161	952	497	358	272	249	141	581	
Sep	276	84	451	530	795	816	263	140	112	
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	98

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 July 17, 2019 and may change as a result of continued PJM billing updates.

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 six months of 2010 through 2019. The average credits per MWh paid decreased by $10.24 per MWh, 19.1 percent, from $53.74 per MWh in the first six months of 2018 to $43.50 per MWh in the first six months of 2019. The PJM real-time, load-weighted, average LMP was 35.2 percent lower in the first six months of 2019 than in the first six months of 2018, $27.49 per MWh versus $42.44 per MWh. Curtailed energy for the economic program decreased by 17,167 MWh, 58.9 percent, from 29,155 MWh in the first six months of 2018 to 11,988 MWh in the first six months of 2019. Total credits paid for economic DR in the first six months of 2018 decreased by $1.0 million, 66.7 percent, from $1.6 million in the first six months of 2018 to $0.5 million in the first six months of 2019.

Table 6-4 Credits paid to the PJM economic program participants: January through June, 2010 through 2019

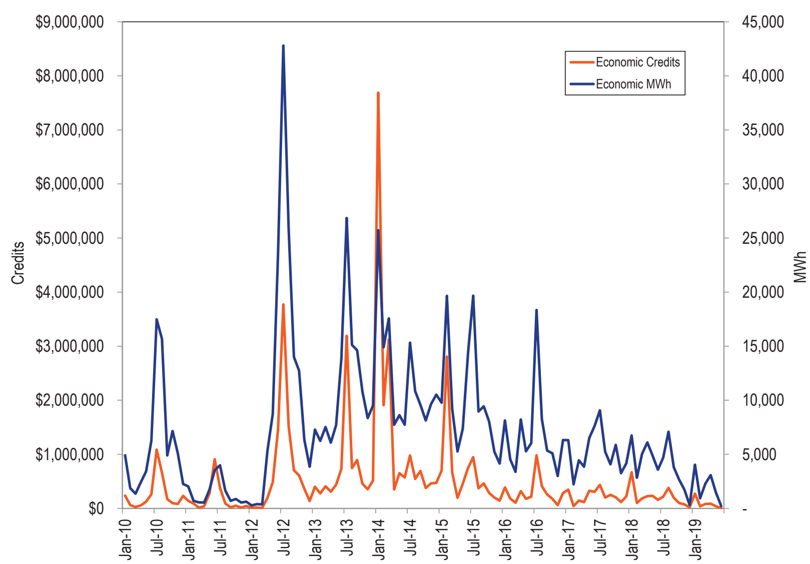
(Jan-Jun)	Total MWh	Total Credits	$/MWh
2010	20,225	$761,854	$37.67
2011	9,055	$1,456,324	$160.84
2012	38,692	$2,172,454	$56.15
2013	48,711	$2,559,831	$52.55
2014	82,273	$14,298,502	$173.79
2015	65,653	$5,576,152	$84.93
2016	35,559	$1,381,972	$38.86
2017	30,954	$1,281,762	$41.41
2018	29,155	$1,566,879	$53.74
2019	11,988	$521,491	$43.50

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

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 June 30, 2019.

Figure 6-2 Economic program credits and MWh by month: 2010 through June 2019



30 PJM. "Manual 11: Energy & Ancillary Services Market Operations," § 10.4.5, Rev. 106 (May 30, 2019).
31 FERC Order No. 831.

Table 6-5 shows performance for the first six months of 2018 and 2019 in the economic program by control zone. Total reductions under the economic program decreased by 17,167 MWh, 58.9 percent, from 29,155 MW in the first six months of 2018 to 11,988 MW in the first six months of 2019. Total revenue under the economic program decreased by $1.0 million, 66.7 percent, from $1.6 million in the first six months of 2018 to $0.5 million in the first six months of 2019.[32]

Table 6-5 PJM economic program participation by zone: January through June, 2018 and 2019

	Credits			MWh Reductions			Credits per MWh Reduction		
Zones	2018 (Jan-Jun)	2019 (Jan-Jun)	Percent Change	2018 (Jan-Jun)	2019 (Jan-Jun)	Percent Change	2018 (Jan-Jun)	2019 (Jan-Jun)	Percent Change
AECO	$0.00	$0.00	NA	0	0	NA	NA	NA	NA
AEP	$0.00	$1,057.59	NA	0	17	NA	NA	$63.38	NA
APS	$43,300.32	$70.19	(99.8%)	710	1	(99.9%)	$60.97	$87.88	44.1%
ATSI	$589,795.33	$0.00	NA	10,691	0	NA	$55.17	NA	NA
BGE	$0.00	$0.00	NA	0	0	NA	NA	NA	NA
ComEd	$147,867.75	$246.50	(99.8%)	4,024	15	(99.6%)	$36.74	$16.08	(56.3%)
DAY	$0.00	$0.00	NA	0	0	NA	NA	NA	NA
DEOK	$0.00	$0.00	NA	0	0	NA	NA	NA	NA
Dominion	$37,747.59	$267.33	(99.3%)	162	4	(97.7%)	$232.46	$71.78	(69.1%)
DPL	$0.00	$0.00	NA	0	0	NA	NA	NA	NA
DLCO	$0.00	$0.00	NA	0	0	NA	NA	NA	NA
JCPL	$137,431.03	$0.00	NA	1,711	0	NA	$80.35	NA	NA
Met-Ed	$10,761.24	$15,173.32	41.0%	209	295	41.4%	$51.56	$51.41	(0.3%)
OVEC	$0.00	$0.00	NA	0	0	NA	NA	NA	NA
PECO	$37,866.04	$117,734.28	210.9%	542	1,914	253.0%	$69.85	$61.52	(11.9%)
PENELEC	$120,679.73	$63,832.92	(47.1%)	4,000	2,050	(48.8%)	$30.17	$31.15	3.2%
Pepco	$0.00	$842.53	NA	0	14	NA	NA	$58.46	NA
PPL	$116,662.68	$125,578.93	7.6%	920	1,936	110.3%	$126.76	$64.87	(48.8%)
PSEG	$324,767.12	$196,687.75	(39.4%)	6,185	5,743	(7.2%)	$52.51	$34.25	(34.8%)
Total	$1,566,878.84	$521,491.34	(66.7%)	29,155	11,988	(58.9%)	$53.74	$43.50	(19.1%)

Table 6-6 shows total settlements submitted for the first six 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 June, 2010 through 2019

(Jan-Jun)	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Number of Settlements	1,345	317	1,348	820	1,806	1,091	652	800	737	426

Table 6-7 shows the number of CSPs, and the number of participants in their portfolios, submitting settlements for the first six months of 2010 through 2019. The number of active participants decreased by six, 20.0 percent, from 30 in the first six months of 2018 to 24 in the first six months of 2019. All participants must be registered through a CSP.

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 6-7 Participants and CSPs submitting settlements in the economic program by year: January through June, 2010 through 2019

(Jan-Jun)	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Active CSPs	10	9	18	12	17	12	6	8	11	9
Active Participants	131	129	331	85	144	68	20	42	30	24

The ownership of economic demand response resources was highly concentrated in 2018 through June 2019.[33] Table 6-8 shows the average hourly HHI for each month and the average hourly HHI for January 1, 2018 through June 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 six months of 2019, 91.4 percent of all economic DR reductions and 87.0 percent of economic DR revenue were attributable to the four largest companies. The HHI for economic demand response increased by 373 from 7541 for the first six months of 2018 to 7914 for the first six months of 2019.

Table 6-8 Average hourly MWh HHI and market concentration in the economic program: January 2018 through June 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	8410	25.7%	98.3%	99.9%	(1.6%)	97.9%	99.9%	(2.0%)
Jun	8375	9817	17.2%	97.4%			96.2%		
Jul	8256			90.2%			82.7%		
Aug	7588			90.0%			87.0%		
Sep	9306			97.4%			97.2%		
Oct	6805			95.6%			93.9%		
Nov	7038			91.6%			91.8%		
Dec	8082								
Total	7541	7914	5.0%	84.9%	91.4%	6.5%	83.0%	87.0%	3.9%

Table 6-9 shows average MWh reductions and credits by hour for the first six months of 2018 and 2019. In the first six months of 2018, 84.7 percent of reductions and 80.5 percent of credits occurred in hours ending 0900 to 2100, and in the first six months of 2019, 83.5 percent of reductions and 78.0 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 June, 2018 and 2019

	MWh Reductions			Program Credits		
Hour Ending (EPT)	2018 (Jan-Jun)	2019 (Jan-Jun)	Percent Change	2018 (Jan-Jun)	2019 (Jan-Jun)	Percent Change
1 through 6	1,161	522	(55%)	$90,825	$31,808	(65%)
7	834	264	(68%)	$59,819	$17,158	(71%)
8	1,349	471	(65%)	$88,784	$29,210	(67%)
9	1,652	731	(56%)	$90,224	$31,811	(65%)
10	1,756	722	(59%)	$83,119	$29,203	(65%)
11	1,848	722	(61%)	$88,347	$30,837	(65%)
12	1,932	734	(62%)	$89,095	$27,179	(69%)
13	1,908	734	(62%)	$89,811	$25,938	(71%)
14	1,984	731	(63%)	$89,446	$25,236	(72%)
15	1,913	712	(63%)	$89,385	$22,225	(75%)
16	1,908	721	(62%)	$89,760	$22,289	(75%)
17	1,967	763	(61%)	$101,573	$28,154	(72%)
18	2,062	831	(60%)	$121,824	$40,782	(67%)
19	2,121	842	(60%)	$122,001	$38,946	(68%)
20	2,008	901	(55%)	$109,663	$40,187	(63%)
21	1,620	866	(47%)	$96,513	$43,745	(55%)
22	713	437	(39%)	$41,820	$22,273	(47%)
23 through 24	419	284	(32%)	$24,868	$14,510	(42%)
Total	29,155	11,988	(59%)	$1,566,879	$521,491	(67%)

Table 6-10 shows the distribution of economic program MWh reductions and credits by ranges of real-time zonal, load-weighted, average LMP in the first six months of 2018 and 2019. In the first six months of 2019, 1.4 percent of MWh reductions and 5.2 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 June 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 June, 2018 and 2019

	MWh Reductions			Program Credits		
LMP	2018 (Jan-Jun)	2019 (Jan-Jun)	Percent Change	2018 (Jan-Jun)	2019 (Jan-Jun)	Percent Change
$0 to $25	3,287	3,053	(7%)	$60,329	$70,492	17%
$25 to $50	16,675	6,139	(63%)	$581,930	$217,350	(63%)
$50 to $75	3,504	1,473	(58%)	$196,110	$97,130	(50%)
$75 to $100	1,725	620	(64%)	$144,758	$53,732	(63%)
$100 to $125	1,223	350	(71%)	$122,616	$35,097	(71%)
$125 to $150	869	81	(91%)	$103,389	$10,207	(90%)
$150 to $175	420	99	(76%)	$59,225	$10,274	(83%)
> $175	1,452	173	(88%)	$298,522	$27,209	(91%)
Total	29,155	11,988	(59%)	$1,566,879	$521,491	(67%)

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 June 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 June 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	
Aug	$35.57		$24.47	$28.58	$29.85	$23.17	$23.24	$22.75	$23.53	
Sep	$34.07		$24.93	$28.80	$29.83	$21.69	$24.70	$21.51	$22.23	
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	$23.11

Table 6-12 shows the number of hours that at least one zone in PJM had day-ahead LMP or real-time LMP higher than the NBT threshold price. In the first six months of 2019, the highest zonal LMP in PJM was higher than the NBT threshold price 3,422 hours out of 4,343 hours, or 78.8 percent of all hours. Reductions occurred in 1,309 hours, 38.3 percent, of those 3,422 hours in the

35 "PJM Manual 11: Energy & Ancillary Services Market Operations," §10.3.1, Rev. 106 (May 30, 2019).

first six months of 2019. The last three columns illustrate how often economic demand response activity occurred when LMPs exceeded NBT threshold prices for January 1, 2018 through June 30, 2019. There are no economic payments when demand response occurs and zonal LMP is below the NBT threshold. Demand response reductions occurred in 0.08 percent (1 hour) of the hours in which LMP was below the NBT threshold price in the first six 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 June 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%	42.5%	(20.2%)
Jun	720	720	503	488	(3.0%)	64.0%	15.0%	(49.1%)
Jul	744		549			74.0%		
Aug	744		560			72.5%		
Sep	720		643			64.2%		
Oct	744		699			50.9%		
Nov	721		702			43.9%		
Dec	744		627			12.1%		
Total	8,760	4,343	7,420	3,422	(53.9%)	56.7%	38.3%	(18.5%)

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 six months of 2019.

Table 6-13 Zonal DR charge: January through June, 2019

Zone	January	February	March	April	May	June	Total
AECO	$3,107	$402	$813	$712	$276	$65	$5,374
AEP	$43,073	$6,115	$12,606	$14,331	$6,825	$803	$83,754
APS	$18,269	$2,567	$5,104	$5,370	$2,610	$310	$34,229
ATSI	$20,920	$3,150	$6,706	$7,709	$3,483	$392	$42,360
BGE	$12,438	$1,635	$3,148	$3,355	$1,634	$227	$22,436
ComEd	$18,936	$4,237	$8,395	$9,312	$4,522	$593	$45,994
DAY	$6,000	$837	$1,776	$2,122	$932	$117	$11,784
DEOK	$7,798	$1,224	$2,557	$2,943	$1,463	$183	$16,169
Dominion	$36,308	$4,935	$9,651	$10,745	$5,710	$722	$68,069
DPL	$7,438	$901	$1,691	$1,522	$508	$118	$12,178
DLCO	$4,108	$623	$1,264	$1,464	$752	$90	$8,301
EKPC	$4,559	$614	$1,299	$1,289	$634	$76	$8,472
JCPL	$7,427	$911	$1,989	$1,863	$667	$145	$13,003
Met-Ed	$5,815	$775	$1,522	$1,530	$638	$102	$10,382
OVEC	$38	$6	$13	$13	$6	$1	$78
PECO	$14,213	$1,755	$3,650	$3,583	$1,110	$239	$24,550
PENELEC	$5,304	$860	$1,751	$1,940	$848	$103	$10,807
Pepco	$11,147	$1,511	$2,897	$3,118	$1,629	$218	$20,520
PPL	$15,052	$2,006	$4,004	$3,848	$1,327	$237	$26,472
PSEG	$15,476	$1,711	$3,783	$3,709	$1,323	$274	$26,276
RECO	$424	$59	$125	$136	$50	$11	$804
Exports	$14,962	$1,827	$4,862	$5,507	$2,436	$255	$29,849
Total	$272,811	$38,661	$79,605	$86,121	$39,382	$5,280	$521,861

Table 6-14 shows the total zonal DR charge per MWh of real-time load and exports in the first six months of 2019.

Table 6-14 Zonal DR charge per MWh of load and exports: January through June 2019

Zone	January	February	March	April	May	June	Zonal Average
AECO	$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
APS	$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
BGE	$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
DAY	$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
Dominion	$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
DLCO	$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
JCPL	$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
OVEC	$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
PENELEC	$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
PPL	$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
RECO	$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
Monthly Average	$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 June 2019. The day-ahead DR charges decreased by $0.2 million, 38.1 percent, from $0.6 million in the first six months of 2018 to $0.4 million in the first six months of 2019. The real-time DR charges decreased $0.8 million, 84.4 percent, from $1.0 million in the first six months of 2018 to $0.2 million in the first six months of 2019.

Table 6-15 Monthly day-ahead and real-time economic DR charge: 2018 through June 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	$35,897	(58.9%)	$143,598	$3,485	(97.6%)
Jun	$56,538	$5,280	(90.7%)	$101,014	$0	(100.0%)
Jul	$63,540			$153,191		
Aug	$70,708			$308,315		
Sep	$44,648			$152,727		
Oct	$57,842			$40,317		
Nov	$32,131			$42,017		
Dec	$9,890			$6,369		
Total	$876,201	$370,078	(57.8%)	$1,672,373	$151,413	(90.9%)

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

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.

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.

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.

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).

38 The RTO LDA refers to the rest of RTO.

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 six months of 2019. Capacity market revenue increased in the first six months of 2019 by $29.1 million, 10.9 percent, from $265.5 million in the first six months of 2018 to $294.6 million in the first six months of 2019. Higher demand resource revenues were in part a result of higher capacity market prices in the 2018/2019 RPM auction clearing price. The capacity revenue in the first quarter of 2018 is from 2017/2018 RPM auction clearing prices and the capacity revenue in the first quarter of 2019 is from 2018/2019 RPM auction clearing prices. The annual capacity market prices increased $13.20 per MW-day from $151.50 in the 2017/2018 Delivery Year to $164.77 in the 2018/2019 Delivery Year, a 8.7 percent increase.

Table 6-18 Zonal monthly capacity revenue: January through June, 2019

Zone	January	February	March	April	May	June	Total
AECO	$1,063,052	$960,176	$1,063,052	$1,028,760	$1,063,052	$436,515	$5,614,605
AEP, EKPC	$7,363,738	$6,651,118	$7,363,738	$7,126,198	$7,363,738	$3,867,902	$39,736,430
APS	$4,638,234	$4,189,373	$4,638,234	$4,488,614	$4,638,234	$2,285,119	$24,877,807
ATSI	$4,254,499	$3,842,773	$4,254,499	$4,117,257	$4,254,499	$2,344,392	$23,067,919
BGE	$1,471,812	$1,329,378	$1,471,812	$1,424,334	$1,471,812	$630,148	$7,799,295
ComEd	$11,763,628	$10,625,212	$11,763,628	$11,384,156	$11,763,628	$9,639,882	$66,940,134
DAY	$1,082,665	$977,891	$1,082,665	$1,047,740	$1,082,665	$533,882	$5,807,508
DEOK	$996,130	$899,730	$996,130	$963,997	$996,130	$608,291	$5,460,409
DLCO	$3,841,793	$3,470,007	$3,841,793	$3,717,864	$3,841,793	$1,760,122	$20,473,372
Dominion	$2,760,840	$2,493,662	$2,760,840	$2,671,780	$2,760,840	$1,133,435	$14,581,397
DPL	$1,229,930	$1,110,904	$1,229,930	$1,190,255	$1,229,930	$599,460	$6,590,408
JCPL	$1,324,124	$1,195,983	$1,324,124	$1,281,410	$1,324,124	$605,867	$7,055,632
Met-Ed	$1,527,708	$1,379,865	$1,527,708	$1,478,427	$1,527,708	$775,740	$8,217,157
OVEC	$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	$17,862,263
PENELEC	$1,811,449	$1,636,148	$1,811,449	$1,753,015	$1,811,449	$830,090	$9,653,600
Pepco	$806,881	$728,796	$806,881	$780,853	$806,881	$142,570	$4,072,863
PPL	$2,314,965	$2,090,936	$2,314,965	$2,240,289	$2,314,965	$1,801,961	$13,078,082
PSEG	$2,521,890	$2,277,836	$2,521,890	$2,440,539	$2,521,890	$1,157,439	$13,441,484
RECO	$48,971	$44,232	$48,971	$47,392	$48,971	$30,889	$269,427
Total	$54,164,419	$48,922,701	$54,164,419	$52,417,179	$54,164,419	$30,766,656	$294,599,792

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]

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.

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.

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.

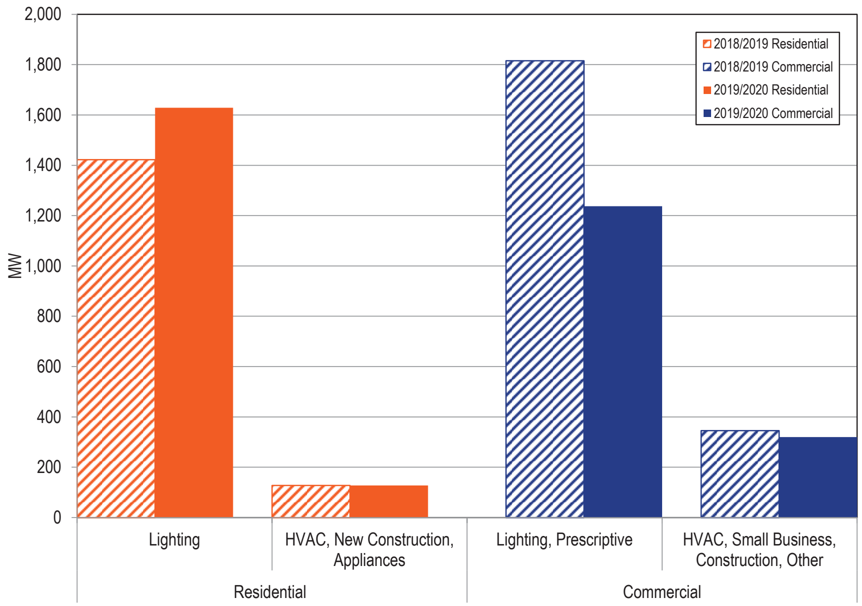
The MMU recommends that energy efficiency MW not be included in the PJM capacity market. The measurement and verification protocols for energy efficiency are too imprecise to rely on as a source of capacity. Energy efficiency measures reduce energy usage and capacity usage directly. The reduced market 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.

42 PJM. "Manual 18: Capacity Market," § 4.4, Rev. 41 (Jan. 1, 2019).

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, 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]

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. 41 (Jan. 1, 2019).
48 "PJM Manual 18: PJM Capacity Market," § 4.3.1, Rev. 41 (January 1, 2019).
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>.

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

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

50 Real-time load is hourly metered load.

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.

51 135 FERC ¶ 61,212.
52 "PJM Manual 18: PJM Capacity Market," § 4.3.7, Rev. 41 (January 1, 2019).
53 "PJM Manual 18: PJM Capacity Market," § 8.7A, Rev.41 (January 1, 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.

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.

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

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.

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 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.

61 "PJM Manual 18: Capacity Market," § 8.7A, Rev. 41 (Jan. 1, 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.

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 (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.

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. 41 (Jan. 1, 2019).

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.

67 OA Schedule 1 § 8.9.

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 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.

68 OA Schedule 1 § 8.9.
69 157 FERC ¶ 61,067 (2016).

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.

70 OA Schedule 1 § 8.2.

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 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.

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>.

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. 41 (Jan. 1, 2019).

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

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 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

74 *Id.*

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. 30 (Dec. 4, 2018).

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.

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

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).

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.

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 six months of 2019 than in the first six months of 2018 as a result of lower gas prices. Coal prices were slightly higher.
- In the first six months of 2019, average energy market net revenues decreased by 65 percent for a new CT, 44 percent for a new CC, 87 percent for a new CP, 34 percent for a new nuclear plant, 87 percent for a new DS, 30 percent for a new on shore wind installation, 30 percent for a new off shore wind installation and 23 percent for a new solar installation compared to the first six months of 2018.
- The relative prices of fuel varied during the first six months of 2019. As a result, the marginal cost of the new CC was consistently below that of the new CP in 2018, 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 CTs and CCs for three representative locations shows that CT and CC units that entered the PJM markets in 2007 have not covered their total costs, including the return on and of capital, on a cumulative basis. The analysis also shows that theoretical new entrant CTs that entered the PJM markets in 2012 have covered their total costs on a cumulative basis in the eastern PSEG and BGE zones but have not covered total costs in the western ComEd Zone. 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 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.

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. CT and CC units that entered the PJM markets in 2007

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.

have not covered 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 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.

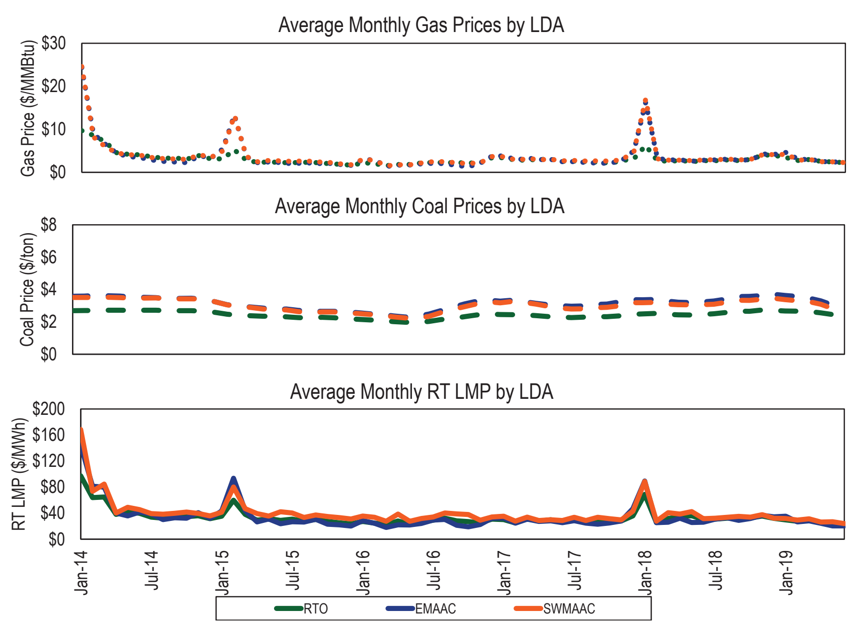
Net Revenue

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 35.2 percent lower in the first six months of 2019 than in the first six months of 2018, \$27.49 per MWh versus \$42.44 per MWh. Eastern and western natural gas prices decreased in the first six months of 2019. The price of Northern Appalachian coal was 1.1 percent higher; the price of Central Appalachian coal was 4.9 percent higher; the price of Powder River Basin coal was 0.1 percent lower; the price of eastern natural gas was 43.4 percent lower; and the price of western natural gas was 4.6 percent lower (Figure 7-1).

Figure 7-1 Energy market net revenue factor trends: 2014 through June 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 six 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 June 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-Jun)	$13.07	$13.24	$27.18	$9.07	$20.89	$22.47	$8.00	$3.31	$24.25	$10.42	$10.63	$24.58

Table 7-2 Peak hour spread standard deviation ($/MWh): 2014 through June 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-Jun)	$24.3	$24.9	$24.9	$18.9	$19.0	$19.0	$21.5	$25.6	$26.0	$20.2	$20.0	$20.1

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 June 2019[2]

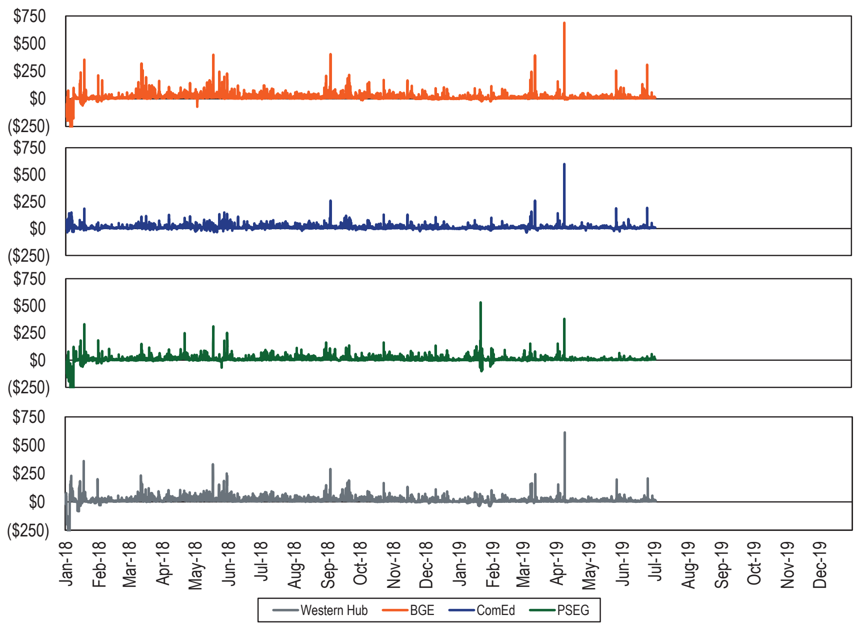
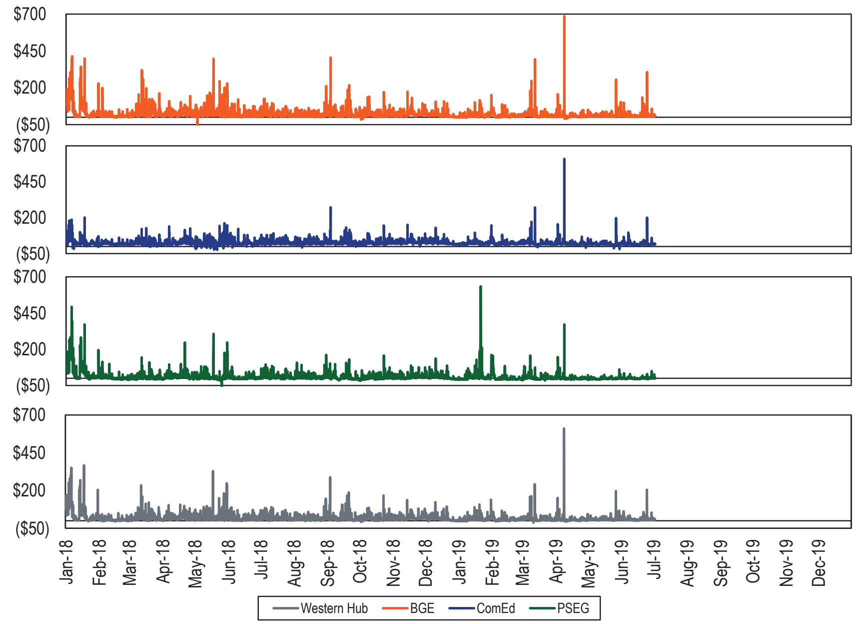


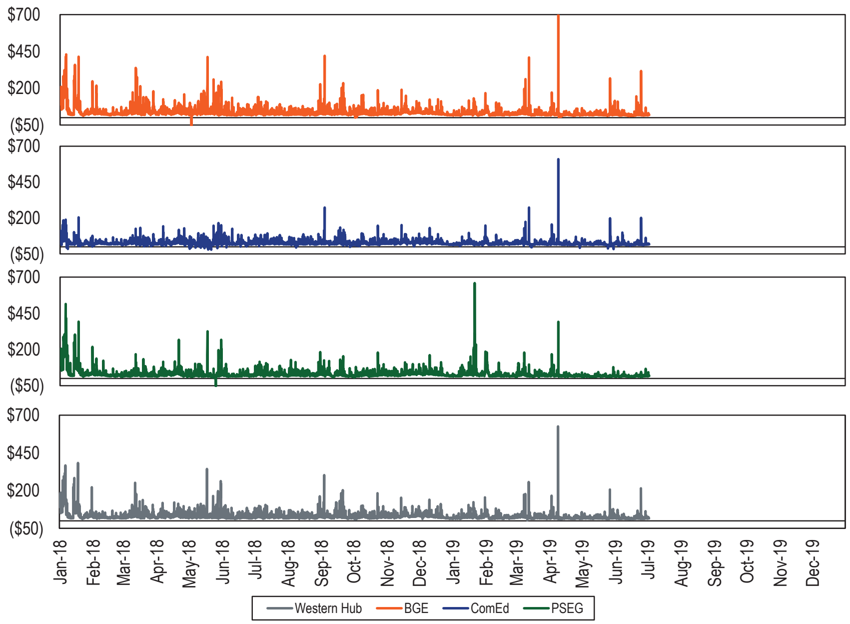
Figure 7-3 Hourly dark spread (coal) for peak hours ($/MWh): 2018 through June 2019[3]



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 June 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.

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.

4 Quark spreads use a heat rate of 10,000 Btu/kWh, zonal hourly LMPs, and daily uranium prices.

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]

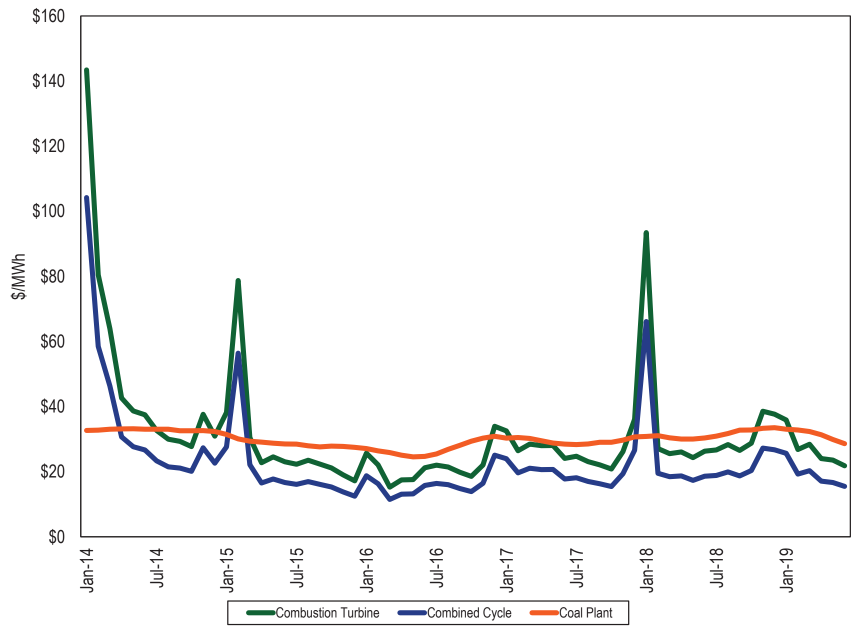
Short run marginal cost includes fuel costs, emissions costs, and the short run marginal component of VOM costs.[12] [13] Average short run marginal costs are shown, including all components, in Table 7-3 and the short run marginal component of VOM is also shown separately.

Table 7-3 Average short run marginal costs: 2019

Unit Type	Short Run Marginal Costs ($/MWh)	Heat Rate (Btu/kWh)	VOM ($/MWh)
CT	$26.76	9,241	$0.38
CC	$19.07	6,296	$1.39
CP	$31.34	9,250	$4.16
DS	$149.85	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

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 June 2019



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.

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 June, 2014 through 2019

	CT	CC	CP	DS	Nuclear
2014 (Jan-Jun)	2,180	3,945	3,887	148	4,368
2015 (Jan-Jun)	3,109	4,129	3,301	110	4,368
2016 (Jan-Jun)	3,578	4,281	2,498	25	4,392
2017 (Jan-Jun)	2,369	4,250	2,368	12	4,368
2018 (Jan-Jun)	2,837	4,166	2,537	105	4,368
2019 (Jan-Jun)	2,868	4,167	2,630	103	4,368

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 in the first six months of 2019 than in the first six months of 2018 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 June, 2014 through 2019 (Dollars per installed MW-year)[14] [15]

Zone	2014 (Jan-Jun)	2015 (Jan-Jun)	2016 (Jan-Jun)	2017 (Jan-Jun)	2018 (Jan-Jun)	2019 (Jan-Jun)	Change in 2019 from 2018
AECO	$49,295	$26,071	$24,868	$12,593	$16,157	$11,983	(26%)
AEP	$59,609	$42,762	$34,549	$16,026	$51,364	$18,914	(63%)
APS	$74,182	$66,331	$27,435	$14,429	$55,217	$9,490	(83%)
ATSI	$41,997	$37,018	$31,099	$16,911	$61,218	$19,830	(68%)
BGE	$58,886	$38,448	$45,199	$17,637	$34,645	$12,556	(64%)
ComEd	$26,693	$17,202	$18,025	$10,604	$19,267	$9,038	(53%)
DAY	$37,561	$33,178	$30,991	$15,442	$56,960	$21,301	(63%)
DEOK	$34,262	$30,796	$28,939	$13,137	$64,866	$18,540	(71%)
DLCO	$24,138	$36,127	$32,926	$13,877	$31,620	$9,822	(69%)
Dominion	$48,078	$35,931	$39,586	$17,177	$37,992	$15,882	(58%)
DPL	$44,946	$19,199	$9,020	$6,285	$13,016	$6,048	(54%)
EKPC	$53,138	$32,610	$30,690	$13,510	$37,240	$15,669	(58%)
JCPL	$52,013	$26,947	$21,965	$15,214	$17,246	$10,893	(37%)
Met-Ed	$51,080	$46,697	$30,870	$20,742	$23,490	$11,356	(52%)
PECO	$52,263	$44,824	$28,574	$16,390	$22,107	$9,888	(55%)
PENELEC	$94,883	$88,250	$45,374	$20,417	$59,086	$17,181	(71%)
Pepco	$53,936	$28,205	$26,740	$12,101	$28,723	$8,549	(70%)
PPL	$161,377	$112,546	$36,533	$20,504	$64,877	$12,130	(81%)
PSEG	$66,370	$54,086	$33,236	$19,804	$25,294	$11,489	(55%)
RECO	$44,065	$29,578	$24,114	$15,166	$17,570	$10,866	(38%)
PJM	$58,381	$42,340	$30,037	$15,398	$36,898	$13,071	(65%)

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 in the first six months of 2019 than in the first six months of 2018 (Table 7-6).

Table 7-6 Energy net revenue for a new entrant CC under economic dispatch: January through June, 2014 through 2019 (Dollars per installed MW-year)[17]

Zone	2014 (Jan-Jun)	2015 (Jan-Jun)	2016 (Jan-Jun)	2017 (Jan-Jun)	2018 (Jan-Jun)	2019 (Jan-Jun)	Change in 2019 from 2018
AECO	$87,784	$47,143	$36,352	$27,788	$34,453	$30,556	(11%)
AEP	$90,890	$65,964	$48,022	$31,684	$74,182	$40,350	(46%)
APS	$117,381	$98,880	$53,855	$33,891	$84,506	$33,235	(61%)
ATSI	$64,588	$60,890	$45,570	$32,211	$82,982	$41,212	(50%)
BGE	$103,496	$68,721	$71,724	$37,846	$63,108	$37,783	(40%)
ComEd	$38,421	$32,432	$31,094	$21,150	$31,745	$23,523	(26%)
DAY	$57,714	$56,990	$45,557	$31,323	$79,738	$43,238	(46%)
DEOK	$51,249	$53,324	$43,235	$27,982	$86,856	$39,766	(54%)
DLCO	$44,807	$49,847	$45,493	$28,880	$53,618	$27,695	(48%)
Dominion	$80,367	$60,248	$54,373	$33,474	$57,914	$37,048	(36%)
DPL	$76,583	$35,423	$21,314	$11,972	$22,729	$8,916	(61%)
EKPC	$80,584	$55,218	$44,127	$28,425	$59,844	$36,087	(40%)
JCPL	$92,944	$48,160	$33,344	$30,487	$35,790	$29,777	(17%)
Met-Ed	$86,174	$67,572	$41,639	$35,514	$43,342	$30,752	(29%)
PECO	$90,454	$67,747	$39,320	$31,458	$44,157	$27,966	(37%)
PENELEC	$136,447	$103,904	$55,224	$35,820	$80,294	$38,423	(52%)
Pepco	$92,210	$58,044	$52,586	$30,267	$54,100	$31,058	(43%)
PPL	$198,142	$123,171	$46,325	$35,255	$81,806	$30,103	(63%)
PSEG	$115,064	$79,268	$44,488	$35,263	$48,193	$31,491	(35%)
RECO	$83,979	$49,520	$35,219	$30,398	$35,276	$30,366	(14%)
PJM	$100,026	$64,123	$44,443	$30,554	$57,732	$32,467	(44%)

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 June, 2014 through 2019 (Dollars per installed MW-year)[18]

Zone	2014 (Jan-Jun)	2015 (Jan-Jun)	2016 (Jan-Jun)	2017 (Jan-Jun)	2018 (Jan-Jun)	2019 (Jan-Jun)	Change in 2019 from 2018
AECO	$127,671	$49,512	$5,563	$1,814	$34,217	$3,841	(89%)
AEP	$106,327	$40,388	$17,675	$19,562	$49,742	$8,702	(83%)
APS	$111,873	$41,949	$5,274	$9,129	$41,230	$3,785	(91%)
ATSI	$118,146	$43,499	$14,454	$20,231	$49,961	$7,544	(85%)
BGE	$171,503	$73,596	$24,941	$8,478	$51,400	$5,557	(89%)
ComEd	$100,248	$29,357	$9,146	$16,608	$18,636	$8,506	(54%)
DAY	$108,663	$40,526	$13,494	$18,091	$48,274	$8,085	(83%)
DEOK	$99,661	$36,725	$11,611	$14,670	$55,279	$6,162	(89%)
DLCO	$93,481	$32,566	$12,509	$17,974	$49,590	$6,148	(88%)
Dominion	$152,402	$78,357	$28,316	$12,028	$59,415	$8,770	(85%)
DPL	$168,361	$70,399	$9,118	$6,154	$45,112	$5,908	(87%)
EKPC	$97,739	$31,520	$10,117	$13,561	$33,422	$4,502	(87%)
JCPL	$133,495	$49,827	$3,719	$2,303	$35,180	$3,567	(90%)
Met-Ed	$160,156	$66,639	$7,951	$9,407	$44,905	$6,195	(86%)
PECO	$124,808	$47,682	$3,374	$1,847	$34,169	$3,410	(90%)
PENELEC	$130,436	$55,207	$11,689	$7,006	$38,667	$5,211	(87%)
Pepco	$128,923	$41,993	$6,556	$1,742	$34,105	$2,512	(93%)
PPL	$123,789	$46,517	$3,412	$2,127	$33,525	$2,090	(94%)
PSEG	$181,265	$76,831	$7,082	$5,988	$40,502	$5,200	(87%)
RECO	$176,398	$77,524	$6,718	$5,906	$38,529	$6,068	(84%)
PJM	$155,324	$51,531	$10,636	$9,731	$41,793	$5,588	(87%)

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 June, 2014 through 2019 (Dollars per installed MW-year)[20]

Zone	2014 (Jan-Jun)	2015 (Jan-Jun)	2016 (Jan-Jun)	2017 (Jan-Jun)	2018 (Jan-Jun)	2019 (Jan-Jun)	Change in 2019 from 2018
AECO	$265,091	$142,527	$59,775	$77,994	$116,221	$75,438	(35%)
AEP	$190,891	$112,394	$70,532	$82,292	$116,628	$80,771	(31%)
APS	$213,794	$132,923	$74,094	$84,025	$127,195	$81,714	(36%)
ATSI	$202,329	$115,700	$70,888	$85,307	$123,701	$82,850	(33%)
BGE	$288,161	$171,572	$104,753	$94,159	$148,506	$91,327	(39%)
ComEd	$165,670	$86,653	$60,710	$75,825	$76,097	$69,588	(9%)
DAY	$192,110	$111,674	$70,986	$84,326	$120,415	$85,001	(29%)
DEOK	$182,574	$107,801	$68,747	$80,603	$127,634	$81,259	(36%)
DLCO	$176,246	$104,093	$68,723	$82,921	$123,035	$80,379	(35%)
Dominion	$249,960	$154,475	$84,656	$89,727	$143,295	$86,623	(40%)
DPL	$283,809	$158,970	$73,045	$84,257	$127,849	$77,212	(40%)
EKPC	$180,525	$102,334	$67,191	$79,376	$103,988	$78,440	(25%)
JCPL	$270,761	$142,928	$56,534	$81,006	$117,423	$74,588	(36%)
Met-Ed	$257,376	$138,116	$56,634	$82,492	$115,515	$75,680	(34%)
PECO	$260,534	$139,277	$54,417	$77,959	$116,210	$72,692	(37%)
PENELEC	$226,372	$129,215	$66,142	$81,248	$117,247	$78,892	(33%)
Pepco	$281,053	$161,231	$92,072	$91,112	$144,004	$88,445	(39%)
PPL	$258,425	$138,562	$56,625	$79,569	$111,850	$70,397	(37%)
PSEG	$290,672	$151,524	$59,471	$82,200	$121,207	$76,830	(37%)
RECO	$285,370	$152,446	$59,010	$82,459	$120,059	$78,666	(34%)
PJM	$236,086	$132,721	$68,750	$82,943	$120,904	$79,340	(34%)

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 as a result of lower energy prices (Table 7-9).

Table 7-9 Energy market net revenue for a new entrant DS: January through June, 2014 through 2019 (Dollars per installed MW-year)

Zone	2014 (Jan-Jun)	2015 (Jan-Jun)	2016 (Jan-Jun)	2017 (Jan-Jun)	2018 (Jan-Jun)	2019 (Jan-Jun)	Change in 2019 from 2018
AECO	$33,053	$11,524	$2,098	$290	$10,305	$1,413	(86%)
AEP	$14,711	$3,035	$496	$93	$4,045	$835	(79%)
APS	$18,342	$6,396	$585	$185	$6,580	$814	(88%)
ATSI	$14,371	$2,775	$462	$300	$6,848	$777	(89%)
BGE	$50,389	$12,857	$4,596	$993	$12,654	$1,407	(89%)
ComEd	$11,536	$1,712	$244	$0	$630	$715	13%
DAY	$14,518	$2,878	$458	$80	$3,590	$892	(75%)
DEOK	$13,670	$2,293	$566	$123	$6,064	$822	(86%)
DLCO	$13,221	$2,247	$427	$288	$7,695	$743	(90%)
Dominion	$43,359	$9,906	$1,780	$666	$14,668	$1,220	(92%)
DPL	$37,127	$13,507	$1,694	$971	$12,015	$1,841	(85%)
EKPC	$14,728	$2,218	$670	$34	$1,760	$821	(53%)
JCPL	$33,304	$12,118	$558	$435	$11,467	$1,414	(88%)
Met-Ed	$32,359	$11,953	$534	$378	$11,311	$776	(93%)
PECO	$32,611	$11,438	$557	$530	$10,137	$1,360	(87%)
PENELEC	$16,281	$5,514	$410	$333	$5,542	$507	(91%)
Pepco	$52,117	$9,894	$2,246	$519	$12,368	$1,249	(90%)
PPL	$33,320	$12,104	$474	$457	$9,062	$388	(96%)
PSEG	$32,872	$11,598	$634	$429	$10,626	$1,778	(83%)
RECO	$30,367	$12,842	$668	$381	$9,797	$1,697	(83%)
PJM	$29,787	$7,940	$1,008	$374	$8,358	$1,073	(87%)

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 a 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 in the first six months of 2019 as a result of lower prices and less wind.

Table 7-10 Energy market net revenue for an on shore wind installation (Dollars per installed MW-year): January through June, 2014 through 2019

	2014 (Jan-Jun)	2015 (Jan-Jun)	2016 (Jan-Jun)	2017 (Jan-Jun)	2018 (Jan-Jun)	2019 (Jan-Jun)	Change in 2019 from 2018
AEP	$79,038	$47,237	$37,105	$40,662	$58,573	$39,589	(32%)
APS	$68,397	$46,892	$31,633	$43,983	$60,002	$34,382	(43%)
ComEd	$63,594	$37,372	$30,380	$40,615	$36,832	$35,988	(2%)
PENELEC	$90,237	$60,266	$32,862	$43,985	$60,645	$33,890	(44%)

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 in the first six months of 2019 than 2018 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 March, 2014 through 2019

	2014 (Jan-Jun)	2015 (Jan-Jun)	2016 (Jan-Jun)	2017 (Jan-Jun)	2018 (Jan-Jun)	2019 (Jan-Jun)	Change in 2019 from 2018
AECO	$134,418	$81,270	$46,240	$53,639	$72,276	$50,462	(30%)

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 in the first six months of 2019 as a result of lower energy prices.

Table 7-12 Energy market ne ue for a solar installation (Dollars per installed MW-year): January through June, 2014 through 2019

	2014 (Jan-Jun)	2015 (Jan-Jun)	2016 (Jan-Jun)	2017 (Jan-Jun)	2018 (Jan-Jun)	2019 (Jan-Jun)	Change in 2019 from 2018
AECO	$31,086	$22,706	$14,716	$16,026	$18,428	$13,932	(24%)
Dominion	-	-	$32,249	$33,865	$36,260	$24,267	(33%)
DPL	-	-	$15,461	$21,260	$23,663	$17,496	(26%)
JCPL	$29,720	$16,706	$11,853	$12,894	$14,064	$10,795	(23%)
PSEG	$27,631	$19,910	$13,759	$13,977	$15,412	$13,894	(10%)

Historical New Entrant CT and CC Revenue Adequacy

Total unit net revenues include energy and capacity revenues. Analysis of the total unit revenues of theoretical new entrant CTs and CCs for three representative locations shows that CT and CC units that entered the PJM markets in 2007 have not covered their total costs, including the return on and of capital, on a cumulative basis. The analysis also shows that theoretical

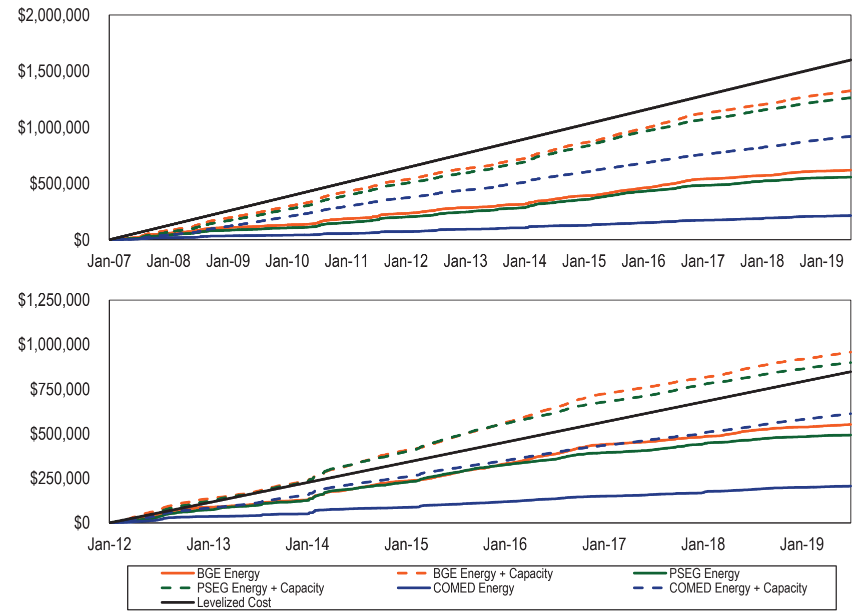
22 The 1603 payment is a direct payment of 30 percent of the project cost.

new entrant CTs that entered the PJM markets in 2012 have covered their total costs on a cumulative basis in the eastern PSEG and BGE zones but have not covered total costs in the western ComEd Zone. 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 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.

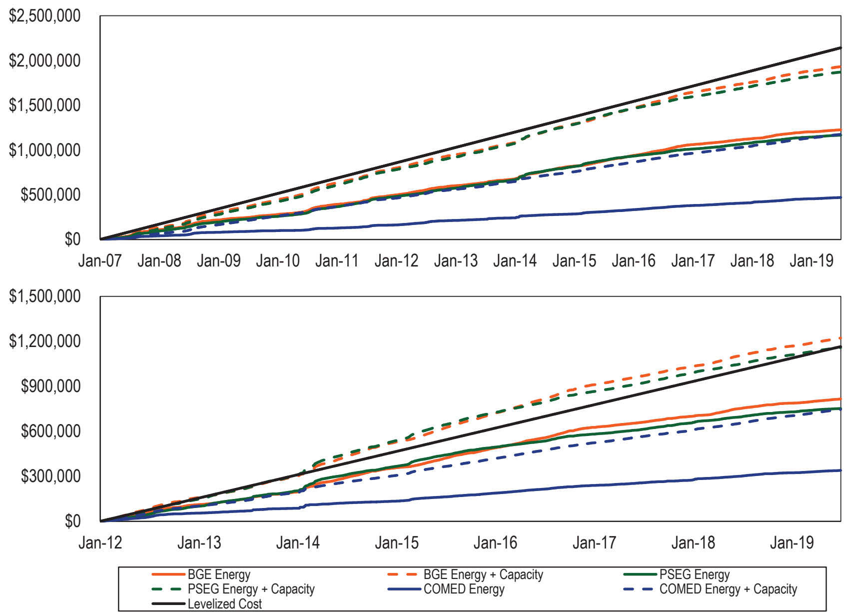
Figure 7-6 and Figure 7-7 compare cumulative energy market net revenues and energy market net revenues plus capacity market revenues to cumulative levelized costs for a new entrant CT and CC that began operation on January 1, 2007, and new entrant CT and CC that began operation on January 1, 2012. In each figure, the solid black line shows the total net revenue required to cover total costs. The solid colored lines show net energy revenue by zone. The dashed colored lines show the sum of net energy and capacity revenue by zone.

Figure 7-6 Historical new entrant CT revenue adequacy: January 2007 through June 2019 and January 2012 through June 2019[23]



23 The gas pipeline pricing points used in this analysis is Zone 6 non-NY for BGE, Chicago City Gate for ComEd, and Texas Eastern M3 for PSEG.

Figure 7-7 Historical new entrant CC revenue adequacy: January 2007 through June 2019 and January 2012 through June 2019[24]



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 CT	2012 CT	2007 CC	2012 CC
Project Cost CT	$311,737,000	$319,167,000	$658,598,000	$665,995,000
Fixed O&M ($/MW-Year)	$14,475	$14,628	$20,016	$20,126
End of Life Value	$0	$0	$0	$0
Loan Term	20 years	20 years	20 years	20 years
Percent Equity (%)	50%	50%	50%	50%
Percent Debt (%)	50%	50%	50%	50%
Loan Interest Rate (%)	7%	7%	7%	7%
Federal Income Tax Rate (%)	35%	35%	35%	35%
State Income Tax Rate (%)	9%	9%	9%	9%
General Escalation (%)	2.5%	2.5%	2.5%	2.5%
Technology	GE Frame 7FA.04	GE Frame 7FA.05	GE Frame 7FA.04	GE Frame 7FA.05
ICAP (MW)	336	410	601	655
Depreciation MACRS 150% declining balance	15 years	15 years	20 years	20 years

24 The gas pipeline pricing points used in this analysis is Zone 6 non-NY for BGE, Chicago City Gate for ComEd, and Texas Eastern M3 for PSEG.

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.[25] [26] The analysis includes the most recent operating cost data and incremental capital expenditure data published by NEI, for 2017. 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 (19.0 percent decrease from 2012 through 2017 for all plants including single and multiple unit plants). NEI average incremental capital expenditures have decreased since their peak in 2012 (40.8 percent decrease from 2012 through 2017 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.

The results for nuclear plants are sensitive to small changes in PJM energy and capacity prices, both actual and forward prices.[27] 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.[28] 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

25 Operating costs from: Nuclear Energy Institute (October, 2018). "Nuclear Costs in Context," <https://www.nei.org/CorporateSite/media/filefolder/resources/reports-and-briefs/nuclear-costs-context-201810.pdf>. 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.

26 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.

27 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.

28 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.*

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 shows capacity market prices and Table 7-17 shows nuclear cost data for the 18 nuclear plants in PJM and Oyster Creek, which retired September 17, 2018.[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.

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
Cook	2,069	$52.26	$32.20	$36.52	$37.41	$30.09	$34.14	$40.49	$29.94	$26.93	$28.03	$31.44
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

29 Installed capacity is from NEI, "Map of U.S. Nuclear Plants," <https://www.nei.org/resources/map-of-us-nuclear-plants>.

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
Cook	2,069	$41	$112	$102	$174	$110	$16	$28	$126	$136	$59	$120	$165	$100	$77	$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

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
Cook	2,069	$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
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

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>.

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>.

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	$30.89
Braidwood	2,337	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$30.89
Byron	2,300	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$30.89
Calvert Cliffs	1,708	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$30.89
Cook	2,069	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$30.89
Davis Besse	894	$35.31	$39.36	$41.23	$45.45	$47.41	$44.16	$44.32	$44.51	$41.39	$42.66	$42.66
Dresden	1,797	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$30.89
Hope Creek	1,172	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$30.89
LaSalle	2,271	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$30.89
Limerick	2,242	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$30.89
North Anna	1,892	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$30.89
Oyster Creek	608	$35.31	$39.36	$41.23	$45.45	$47.41	$44.16	$44.32	$44.51	$41.39	$42.66	$42.66
Peach Bottom	2,347	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$30.89
Perry	1,240	$35.31	$39.36	$41.23	$45.45	$47.41	$44.16	$44.32	$44.51	$41.39	$42.66	$42.66
Quad Cities	1,819	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$30.89
Salem	2,328	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$30.89
Surry	1,676	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$30.89
Susquehanna	2,520	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$30.89
Three Mile Island	803	$35.31	$39.36	$41.23	$45.45	$47.41	$44.16	$44.32	$44.51	$41.39	$42.66	$42.66

Table 7-18 shows the surplus or shortfall in $/MWh for the 18 nuclear plants in PJM and Oyster Creek calculated using this cost data and historic LMPs.[34] In 2016, 15 nuclear plants, with a total capacity of 27,947 MW, in addition to Oyster Creek, did not recover all their fuel costs, operating costs, and capital expenditures. In 2017, eight nuclear plants with a total capacity of 13,461 MW, in addition to Oyster Creek, did not recover all their fuel costs, operating costs, and capital expenditures. In 2018, two nuclear plants, with a total capacity of 1,697 MW, in addition to Oyster Creek, did not recover all their 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 six months of 2019.[41]

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>.
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.

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	$11.9
Braidwood	2,337	$24.9	$2.5	$6.4	$3.4	($6.1)	($2.6)	$7.2	($1.2)	($3.4)	($1.7)	$3.9
Byron	2,300	$24.5	($1.3)	$3.4	($0.6)	($9.4)	($3.6)	$4.9	($6.1)	($9.7)	($2.9)	$3.8
Calvert Cliffs	1,708	$60.6	$20.9	$28.6	$17.9	$4.5	$14.6	$31.6	$14.1	$7.1	$5.9	$14.3
Cook	2,069	$29.1	$6.9	$11.4	$8.8	($3.6)	$1.3	$10.4	$2.8	($0.7)	$1.3	$7.0
Davis Besse	894	NA	NA	NA	NA	($13.2)	($7.0)	$6.6	($1.2)	($4.3)	($8.6)	($1.8)
Dresden	1,797	$25.6	$3.0	$7.6	$4.4	($5.2)	($1.0)	$9.1	$0.3	($1.8)	($0.4)	$5.1
Hope Creek	1,172	$54.0	$17.0	$24.5	$16.9	$2.6	$12.4	$26.0	$6.3	($2.4)	$1.2	$10.0
LaSalle	2,271	$24.8	$2.5	$6.4	$3.3	($6.1)	($1.9)	$7.7	($0.9)	($3.7)	($2.0)	$4.0
Limerick	2,242	$54.1	$17.1	$24.7	$16.6	$2.6	$12.2	$25.7	$6.5	($2.2)	$1.4	$10.2
North Anna	1,892	$52.0	$14.6	$25.5	$16.8	$0.2	$5.7	$23.2	$10.9	$2.8	$4.6	$14.0
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	$9.7
Perry	1,240	NA	NA	NA	NA	($13.2)	($6.4)	$5.5	($0.3)	($4.2)	($7.6)	$1.0
Quad Cities	1,819	$24.1	($0.4)	$2.4	($1.8)	($13.2)	($6.9)	$0.6	($7.7)	($9.6)	($3.6)	$2.4
Salem	2,328	$54.0	$17.1	$24.5	$16.9	$2.6	$12.4	$26.0	$6.2	($2.4)	$1.1	$10.0
Surry	1,676	$48.8	$13.8	$24.2	$16.4	($0.0)	$5.1	$21.6	$10.8	$2.4	$4.4	$14.0
Susquehanna	2,520	$46.8	$15.2	$22.4	$16.1	$1.4	$11.1	$24.6	$6.3	($1.9)	$1.5	$7.9
Three Mile Island	803	$40.7	$6.5	$13.3	$4.6	($9.6)	$0.9	$13.7	($6.8)	($12.4)	($10.3)	($4.5)

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.

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 July 1, 2019. The capacity prices are known based on PJM capacity auction results. The 2019 energy prices include actual day-ahead market prices through June 30, 2019, and forward prices for July through December 2019. The 2019 energy prices decreased by an average of $3.23 per MWh or 11.4 percent as a result of a decline in actual energy prices and forward prices. The 2020 forward prices for Western Hub decreased $5.16 per MWh or 16.0 percent and 2021 forward prices decreased $4.49 per MWh or 14.5 percent since April 1, 2019.

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.
43 Forward prices on July 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.

Table 7-19 Forward prices in PJM energy and capacity markets and annual costs[44 45]

	ICAP	Average Forward LMP ($/MWh)			Capacity Revenue ($/MWh)			2017 NEI Costs ($/MWh)		
	(MW)	2019	2020	2021	2019	2020	2021	Fuel	Operating	Capital
Beaver Valley	1,808	$26.72	$27.89	$27.28	$5.56	$3.79	$4.99	$6.44	$18.46	$5.99
Braidwood	2,337	$23.01	$22.20	$21.72	$9.12	$8.52	$8.44	$6.44	$18.46	$5.99
Byron	2,300	$22.95	$22.19	$21.71	$9.12	$8.52	$8.44	$6.44	$18.46	$5.99
Calvert Cliffs	1,708	$27.45	$28.29	$27.71	$5.57	$4.03	$5.16	$6.44	$18.46	$5.99
Cook	2,069	$25.13	$25.07	$24.54	$5.56	$3.79	$4.99	$6.44	$18.46	$5.99
Davis Besse	894	$26.71	$27.10	$26.54	$5.56	$3.79	$5.80	$6.42	$27.32	$8.92
Dresden	1,797	$23.83	$23.04	$22.54	$9.12	$8.52	$8.44	$6.44	$18.46	$5.99
Hope Creek	1,172	$24.35	$24.47	$23.95	$7.17	$7.00	$7.67	$6.44	$18.46	$5.99
LaSalle	2,271	$23.01	$22.20	$21.72	$9.12	$8.52	$8.44	$6.44	$18.46	$5.99
Limerick	2,242	$24.46	$24.52	$24.00	$7.17	$7.00	$7.67	$6.44	$18.46	$5.99
North Anna	1,892	$27.16	$27.95	$27.38	$5.56	$3.79	$4.99	$6.44	$18.46	$5.99
Peach Bottom	2,347	$23.88	$24.36	$23.84	$7.17	$7.00	$7.67	$6.44	$18.46	$5.99
Perry	1,240	$27.48	$28.44	$27.82	$5.56	$3.79	$5.80	$6.42	$27.32	$8.92
Quad Cities	1,819	$22.05	$21.06	$20.60	$9.12	$8.52	$8.44	$6.44	$18.46	$5.99
Salem	2,328	$24.34	$24.45	$23.93	$7.17	$7.00	$7.67	$6.44	$18.46	$5.99
Surry	1,676	$26.85	$27.81	$27.24	$5.56	$3.79	$4.99	$6.44	$18.46	$5.99
Susquehanna	2,520	$22.75	$23.93	$23.42	$5.56	$4.03	$5.16	$6.44	$18.46	$5.99
Three Mile Island	803	$24.14	$23.53	$23.01	$5.56	$4.03	$5.16	$6.42	$27.32	$8.92

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 2017 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.

The results of the forward analysis are quite different from prior results due to the significant decline in PJM energy market forward prices. Prior forward analysis showed that three nuclear plants would not cover their annual avoidable costs. The prior results were consistent and showed that the three plants would not cover their costs for each of the three forward years and that the other plants would cover their costs for each of the three forward years. The current analysis, based on forward prices for energy and known forward prices for capacity, shows different results by year for some plants. Five nuclear plants would not cover their annual avoidable costs in each year over the next three years (2019 through 2021). Of these five plants, the same three plants that prior analysis showed not covering costs, Davis Besse, Perry, and Three Mile Island, show much higher shortfalls, with an average annual shortfall of $11.57 per MWh, than the two additional plants. The three plants are single unit sites which have higher operating costs per MWh than multiple unit plants. In May 2017, TMI requested deactivation in 2019. In March 2018, Davis Besse and Perry requested deactivation in 2021 but reversed the decision based on new subsidies in Ohio. The two additional plants are Cook and Susquehanna, with an average annual shortfall of $1.90 per MWh. Susquehanna has reduced its operating costs and is not operating at a loss when the unit specific information is accounted for.[46] Cook nuclear units are designated FRR and receive cost of service revenues and are not subject to PJM market revenues.[47] In addition to the five plants that would not cover their avoidable costs over all three forward years, four plants would

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>.
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.
47 See PJM. "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>.

not cover avoidable costs in two of the three years with an average annual shortfall of $0.73 per MWh during shortfall years, given current forward prices: Braidwood; Byron; LaSalle; and Quad Cities.

Table 7-20 Nuclear unit forward annual surplus (shortfall) ($/MWh)[48 49]

	Surplus (Shortfall) ($/MWh)		
	2019	2020	2021
Beaver Valley	$1.40	$0.78	$1.38
Braidwood	$1.24	($0.17)	($0.73)
Byron	$1.18	($0.18)	($0.74)
Calvert Cliffs	$2.13	$1.43	$1.99
Cook	($0.20)	($2.03)	($1.36)
Davis Besse	($10.39)	($11.78)	($10.32)
Dresden	$2.06	$0.67	$0.09
Hope Creek	$0.63	$0.59	$0.74
LaSalle	$1.24	($0.17)	($0.73)
Limerick	$0.75	$0.63	$0.78
North Anna	$1.83	$0.85	$1.48
Peach Bottom	$0.16	$0.47	$0.62
Perry	($9.62)	($10.44)	($9.04)
Quad Cities	$0.28	($1.31)	($1.84)
Salem	$0.62	$0.57	$0.72
Surry	$1.52	$0.70	$1.34
Susquehanna	($2.58)	($2.93)	($2.31)
Three Mile Island	($12.95)	($15.10)	($14.49)

Table 7-21 Nuclear unit forward annual surplus (shortfall) ($ in millions)[50 51]

	Surplus (Shortfall) ($ in millions)		
	2019	2020	2021
Beaver Valley	$20.8	$11.7	$20.6
Braidwood	$24.0	($3.2)	($14.1)
Byron	$22.3	($3.5)	($14.0)
Calvert Cliffs	$30.0	$20.3	$28.0
Cook	($3.4)	($34.8)	($23.2)
Davis Besse	($76.6)	($87.1)	($76.2)
Dresden	$30.5	$9.9	$1.3
Hope Creek	$6.1	$5.7	$7.1
LaSalle	$23.2	($3.2)	($13.7)
Limerick	$13.8	$11.7	$14.5
North Anna	$28.6	$13.3	$23.1
Peach Bottom	$3.2	$9.1	$12.1
Perry	($98.5)	($107.1)	($92.5)
Quad Cities	$4.2	($19.7)	($27.7)
Salem	$12.0	$10.9	$13.8
Surry	$21.0	$9.7	$18.5
Susquehanna	($53.7)	($61.1)	($48.0)
Three Mile Island	($85.8)	($100.3)	($96.0)

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>.

49 Three Mile Island is scheduled to retire on September 30, 2019 <https://www.pjm.com/planning/services-requests/gen-deactivations.aspx>.

50 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>.

51 Three Mile Island is scheduled to retire on September 30, 2019 <https://www.pjm.com/planning/services-requests/gen-deactivations.aspx>.

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

- **EPA Mercury and Air Toxics Standards Rule.** The U.S. Environmental Protection Agency's (EPA) Mercury and Air Toxics Standards rule (MATS) applies the Clean Air Act (CAA) maximum achievable control technology (MACT) requirement to new or modified sources of emissions of mercury and arsenic, acid gas, nickel, selenium and cyanide.[1] 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]
- **National Emission Standards for Reciprocating Internal Combustion Engines.** The national emissions standards uniformly apply to RICE.[3] RICE are allowed to operate during emergencies, including declared Energy Emergency Alert Level 2 or five percent voltage/frequency deviations.[4]
- **Greenhouse Gas Emissions Rule.** On June 19, 2019, the EPA repealed the prior administration's Clean Power Plan and replaced it with the Affordable Clean Energy (ACE) rule, which establishes emission guidelines for states to develop plans to address greenhouse gas emissions from existing coal fired power plants.[5] [6]
- **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]

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 in the process of resuming participation.[8] Virginia

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

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).

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 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>.

is making preparations to join.[9] The auction price in the June 5, 2019, auction for the 2018/2020 compliance period was $5.62 per ton. The clearing price is equivalent to a price of $6.19 per metric tonne, the unit used in other carbon markets. The price increased by $0.35 per ton, 6.6 percent, from $5.27 per ton from March 13, 2019, to $5.62 per ton for June 5, 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 June 30, 2019, Delaware, Illinois, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, and Washington, DC had renewable portfolio standards. Virginia and Indiana had voluntary renewable portfolio standards. Kentucky, 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.[10]

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.

9 See Regulation for Emissions Trading, 9 VAC 5-140. The Virginia Air Pollution Control Board is developing the regulation and considering public comments.

10 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.

- **Emissions Controls.** As of June 30, 2019, 93.8 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 94.5 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 3.4 percent of total generation in PJM for the first six months of 2019. Tier I generation was 5.7 percent of total generation in PJM and Tier II generation was 2.3 percent of total generation in PJM for the first six months of 2019. Only Tier I generation is renewable.

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. New recommendation. 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.[11] 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, DC to $31.78 per tonne in Pennsylvania. The price of carbon implied by SREC prices ranges from $44.50 per tonne in Pennsylvania to $768.99 per tonne in Washington, DC. The effective prices for carbon compare to the RGGI clearing price in June 2019 of $6.19 per tonne and to the social cost of carbon which is estimated in the range of $50 per tonne.[12] The impact on the cost of generation from a new combined cycle unit of a $700 per tonne carbon price would be $233.89 per MWh. 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

11 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.").

12 "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>.

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.[13] The RPS compliance cost for the most recent year for which there was complete data 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 $2.2 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 $1.3 billion. The costs of a carbon price are the impact on energy market prices, net of the revenue returned to states/customers.

13 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 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.[14 15] EPA regulation of air quality covers:[16]

- **Control of Mercury and Other Hazardous Air Pollutants:** Section 112 of the CAA requires the EPA to promulgate emissions control standards, known as the National Emission Standards for Hazardous Air Pollutants (NESHAP), from both new and existing area and major sources. On December 21, 2011, the U.S. Environmental Protection Agency (EPA) issued its Mercury and Air Toxics Standards rule (MATS), which applies the CAA maximum achievable control technology (MACT) requirement to new or modified sources of emissions of mercury and arsenic, acid gas, nickel, selenium and cyanide. This rule remains under challenge in the courts, but the industry has already taken measures to come into compliance.
- **Air Quality Standards: Control of NO_X, SO_2 and O_3 Emissions Allowances:** The CAA requires each state to attain and maintain compliance with fine particulate matter and ozone national ambient air quality standards (NAAQS). Under NAAQS, the EPA establishes emission standards for six air pollutants, including NO_X, SO_2, O_3 at ground level, PM, CO, and

14 42 U.S.C. § 7401 et seq. (2000).

15 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.

16 For more details, see the *2018 State of the Market Report for PJM*, Volume II, Appendix I: "Environmental and Renewable Energy Regulations."

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 states, including all of the PJM states except Delaware, and also excluding the District of Columbia.

- **Emission Standards for Reciprocating Internal Combustion Engines (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). The national emissions standards uniformly apply to RICE.[17] 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).[18]

17 EPA, Memorandum, Peter Tsirigotis Guidance on Vacatur of RICE NESHAP and NSPS Provisions for Emergency Engines (April 15, 2016).
18 See 40 CFR § 63.6640(f).

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.

The EPA also administers the Clean Water Act (CWA), which regulates water pollution. The EPA implements the CWA through a permitting process, which regulates discharges from point sources that impact water quality and temperature in navigable waterways. In 2014, the EPA implemented new regulations for cooling water intakes under section 316(b) of the CWA.

MATS

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.[19] 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.[20] The EPA determined the quantifiable benefits attributable to regulating hazardous air pollutant (HAP) emissions ranged from $4 to $6 million annually.[21] 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.[22] [23] 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.[24]

CSAPR

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

19 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).*
20 *Id.* at 2676.
21 *Id.*
22 Michigan v. EPA, 135 S.Ct. 2699 (2015).
23 84 Fed. Reg. at 2676–2678.
24 *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).").

NAAQS. CSAPR emissions prices may be compared with RGGI emissions prices.

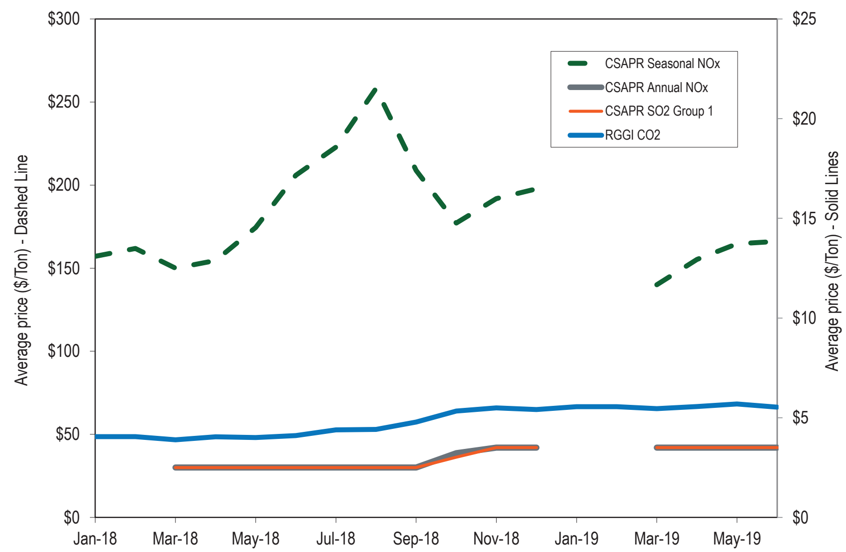
Section 126 of the CAA permits a downwind state to file a petition with the EPA to regulate the emissions from particular resources in another state. On October 5, 2018, EPA denied petitions filed under this provision filed by Delaware and Maryland.[25]

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 June 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 six months of 2019, CSAPR annual NO_x prices were 20.0 percent higher than in the first six months of 2018. The CSAPR Seasonal NO_x price hit a peak of $258.15 in August 2018.

25 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.

Figure 8-1 Spot monthly average emission price comparison: January 2018 through June 2019



Federal Regulation of Greenhouse Gas Emissions

The EPA regulates CO_2 as a pollutant using CAA provisions that apply to pollutants not subject to NAAQS.[26] [27]

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."[28] The Court rejected claims raised by petitioners that raised concerns that the Social Cost of Carbon

26 See CAA § 111.
27 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.
28 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).

estimates were arbitrary, were not developed through transparent processes, and were based on inputs that were not peer reviewed.[29] 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.[30] [31] The proposed rule includes two limits for fossil fuel fired utility boilers and integrated gasification combined cycle (IGCC) units based on the compliance period selected: 1,100 lb CO_2/MWh gross over a 12 operating month period, or 1,000–1,050 lb CO_2/MWh gross over an 84 operating month (seven year) period. The proposed rule also includes two standards for natural gas fired stationary combustion units based on the size: 1,000 lb CO_2/MWh gross for larger units (> 850 MMBtu/hr), or 1,100 lb CO_2/MWh gross for smaller units (≤ 850 MMBtu/hr).

On June 19, 2019, the EPA repealed the prior administration's Clean Power Plan and replaced it with the Affordable Clean Energy (ACE) rule.[32] [33] 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[34] and (ii) lists "candidate technologies" that states can use to establish standards of performance and incorporate into their plans. [35]

29 *Id.*
30 *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>.
31 79 Fed. Reg. 1352 (Jan. 8, 2014).
32 *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.
33 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").
34 See CAA § 111(d).
35 *Id.*

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.[36] As a result, the impact on coal fired generation depends upon actions taken in their host state.

The EPA finalized regulations governing implementation of ACE and any future emission guidelines issued under Section 111(d) of the CAA. The implementing 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.

The ACE rule as proposed on August 21, 2018, also included changes to New Source Review (NSR) regulations.[37] The ACE rule defers reform of NSR regulations to a separate future action.[38] As proposed, NSR would apply to new units or existing units receiving major modification. Under the proposed NSR, only modifications that increase a plant's hourly rate of emissions would be deemed major and require an 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.

36 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.
37 82 Fed. Reg. 48035.
38 84 Fed. Reg. 32520, 32521.

Federal Regulation of Environmental Impacts on Water

The Clean Water Act (CWA) applies to the navigable waters, which are defined as waters of the United States (WOTUS).[39] On June 17, 2017, the EPA issued a rulemaking to rescind the definition of WOTUS proposed in the 2015 Clean Water Rule.[40] 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.[41] 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.[42] 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.[43]

On December 11, 2018, the EPA and Department of the Army proposed a replacement definition of "waters of the United States."[44] 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."[45] 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 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."[46] The new rule would specifically exclude from EPA jurisdiction waters that are now included.

The EPA issues under the CWA effluent limitation guidelines ("ELGs"), which apply a Best Available Technology Economically Available ("BAT") to identified waste streams.[47] On September 30, 2015, EPA issued a rule updating the standard for certain waste streams from steam power plants.[48] 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).[49] 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.[50]

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.

NPDES permits must satisfy the more stringent of a technology based standard, known at Best Technology Available (BTA), or water quality standards. NDPES permits include limits designed to prevent discharges that would cause or contribute to violations of water quality standards. Water quality standards include thermal limits.

39 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.").
40 80 Fed. Reg. 37054 (June 29, 2015).
41 The stay was issued by the U.S. Court of Appeals for the Sixth Circuit on October 9, 2015.
42 *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).
43 Rapanos v. U.S., 547 U.S. 715 (2006).
44 See *Revised Definition of "Waters of the United States,"* EPA Docket No. EPA-HQ-OW-2018-0149, 84 Fed. Reg. 4154 (Feb. 14, 2019).
45 *Id.* at 4155.
46 *Id.*
47 *See* 33 U.S.C. § 1311, 1314, 1362(11).
48 *See Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category*, 80 Fed. Reg. 67,838 (Nov. 3, 2015).
49 *See Southwestern Electric Power Co., et al. v. EPA*, Slip. Op. 15-60821.
50 *Id.* at 3.

PJM states are authorized to issue NPDES permits, with the exception of Washington, DC. 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).[51]

Existing facilities withdrawing 125 mgd must conduct studies that may result in a requirement to install site-specific controls for reducing entrainment of aquatic organisms (drawn into intake structures). If a new generating unit is added to an existing facility, the rule requires addition of BTA that either (i) reduces actual intake flow at the new unit to a level at least commensurate with what can be attained using a closed-cycle recirculating system or (ii) reduces entrainment mortality of all stages of aquatic organisms that pass through a sieve with a maximum opening dimension of 0.56 inches to a prescribed level.

Federal Regulation of Coal Ash

The EPA administers the Resource Conservation and Recovery Act (RCRA), which governs the disposal of solid and hazardous waste.[52]

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.[53] 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.

51 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).

52 42 U.S.C. §§ 6901 *et seq.*

53 *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.[54] 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 in CCR units closing for cause in certain situations.[55] 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:[56]

- **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,

54 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).

55 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).

56 For more details, see the *2018 State of the Market Report for PJM*, Volume II, Appendix I: "Environmental and Renewable Energy Regulations."

New York, Rhode Island, and Vermont to cap CO_2 emissions from power generation facilities.[57]

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.[58] The Virginia Air Pollution Control Board approved a regulation that would allow Virginia to join RGGI. However subsequent budget legislation prevents Virginia's participation.[59] Pennsylvania Governor Tom Wolf recently asked the state legislature to pursue a path to Pennsylvania's participation in RGGI.[60]

PJM has initiated a task force to investigate the issues associated with the introduction of a carbon price in the PJM energy market.[61]

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 June 5, 2019, in short tons and metric tonnes.[62] Prices for auctions held June 5, 2019, were $5.62 per allowance (equal to one short ton of CO_2), above the current price floor of $2.21 for RGGI auctions.[63] The RGGI base budget for CO_2 will be reduced by 2.5 percent per year each year from 2015 through 2020. The price increased from the last auction clearing price of $5.27 in March 2019.

57 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>.
58 "Statement on New Jersey Greenhouse Gas Rule," RGGI Inc., (June 17, 2019) <https://www.rggi.org/news-releases/rggi-releases>.
59 "Statement Regarding Virginia State Budget," RGGI Inc., (May 6, 2019), <https://www.rggi.org/news-releases/rggi-releases>.
60 "Wolf wants power plant emission plan to fight climate change," AP News (June 18, 2019), <https://www.apnews.com/e92b39b02d4145c5964333b81b3a41ed>.
61 Carbon Pricing Senior Task Force, PJM (July 2019) <https://www.pjm.com/committees-and-groups/task-forces/cpstf.aspx>.
62 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.
63 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[64]

	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

64 See Regional Greenhouse Gas Initiative, "Auction Results," <http://www.rggi.org/market/co2_auctions/results>

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.[65] 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.[66]

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 $1.2 billion per year to $2.2 billion per year depending on associated reductions in carbon emission levels (Table 8-3).[67] CO_2 emissions for the PJM states were approximately five times the total CO_2 emissions for the nine RGGI states.[68] 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's has chosen an emission cap of 18,000,000 short tons for 2020 for reentry into RGGI, 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.[69]

Table 8-3 Estimated CO_2 allowance revenue at June 2019 RGGI price level[70 71 72]

		Estimated CO_2 allowance revenue ($ millions), carbon price $5.62 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	$15.1	$14.3	$13.5	$12.7	$11.9	$7.9
Illinois	34,918,315.6	$186.4	$176.6	$166.8	$157.0	$147.2	$98.1
Indiana	49,202,850.2	$262.7	$248.9	$235.0	$221.2	$207.4	$138.3
Kentucky	29,989,896.2	$160.1	$151.7	$143.3	$134.8	$126.4	$84.3
Maryland	17,167,736.9	$91.7	$86.8	$82.0	$77.2	$72.4	$48.2
Michigan	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
New Jersey	15,521,984.9	$82.9	$78.5	$74.1	$69.8	$65.4	$43.6
North Carolina	302,169.7	$1.6	$1.5	$1.4	$1.4	$1.3	$0.8
Ohio	88,921,973.3	$474.8	$449.8	$424.8	$399.8	$374.8	$249.9
Pennsylvania	81,414,231.3	$434.7	$411.8	$388.9	$366.0	$343.2	$228.8
Tennessee	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Virginia	34,399,627.4	$183.7	$174.0	$164.3	$154.7	$145.0	$96.7
Washington, DC	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
West Virginia	64,849,471.6	$346.2	$328.0	$309.8	$291.6	$273.3	$182.2
Total	419,508,561.7	$2,239.8	$2,121.9	$2,004.0	$1,886.1	$1,768.2	$1,178.8

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.[73] At the end of the first control period, 57,449,495 banked allowances were held by market participants.[74] 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 budget, brings the overall

65 "The Economic Impacts of the Regional Greenhouse Gas Initiative on Nine Northeast and Mid-Atlantic States," at 2, Analysis Group (April 17, 2018).

66 *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>.

67 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.

68 Based on 2018 CO_2 emissions data from the EPA Continuous Emission Monitoring System (CEMS).

69 "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>.

70 The 2018 CO_2 emissions data is from the EPA Continuous Emission Monitoring System (CEMS) from generators located within the PJM footprint.

71 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.

72 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.

73 A banked allowance is an allowance acquired during a previous control period that was not used to fulfill a RGGI allowance obligation.

74 "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>.

cap adjustment to 8,207,664 allowances per year.[75] 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.[76] 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[77 78]

	Control Period	RGGI Average Clearing Price ($ per short ton)	RGGI Cap (short tons)	Percent Change	RGGI Adjusted Cap (short tons)	Percent Change
2009	1st	$2.77	188,000,000		188,000,000	
2010		$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	2nd	$1.93	165,000,000	(12.2%)	165,000,000	(12.2%)
2013		$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	3rd	$6.10	88,725,000	(2.5%)	66,833,592	(19.3%)
2016		$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	4th	$4.41	82,235,598	(2.5%)	60,344,190	(3.4%)
2019		$5.45	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.

75 Ibid 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.
76 "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>.
77 See Regional Greenhouse Gas Initiative, "Elements of RGGI" and "Auction Results," <https://www.rggi.org/> (Accessed June 25, 2019).
78 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, DC	$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, DC	$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, DC	$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

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).[79] Some state rules allow nonrenewable energy sources as part of their Renewable Portfolio Standard.

As of June 30, 2019, Delaware, Illinois, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, and Washington, DC had renewable portfolio standards that are mandatory and include penalties in the form of alternative compliance payments for underperformance.

Two PJM jurisdictions have enacted voluntary renewable portfolio standards. Load serving entities in states with voluntary standards are not bound by law to participate and face no alternative compliance payments. Instead, incentives are offered to load serving entities to develop renewable generation or, to a more limited extent, purchase RECs. As of June 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.[80]

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.[81]

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 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.[82]

Table 8-6 shows the percent of retail electric load that must be served by renewable and/or alternative energy resources under each PJM jurisdictions’

79 *Renewable Energy Explained*, U.S. Energy Information Administration, <https://www.eia.gov/energyexplained/index.php?page=renewable_home> (Accessed March 1, 2019).

80 See the Indiana Utility Regulatory Commission’s “2018 Annual Report,” at 36 (Oct. 2018) <https://www.in.gov/iurc/files/IURC%20AR%202018%20WEB3.pdf>.

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

82 Pennsylvania General Assembly, “Alternative Energy Portfolio Standards Act – Enactment Act of Nov. 30, 2004, P.L. 1672, No. 213,” Section (e)(6).

RPS by year. The District of Columbia revised their RPS earlier this year with the passage of the Clean Energy DC Omnibus Amendment Act of 2018.[83] The legislation increased the Tier I standard to 100 percent for the year 2032. The 2019 Tier I standard is 21.0 percent, of which 1.85 percent must be solar. The solar standard increases to 5.5 percent for 2032. In 2041, 10.0 percent of the tier I standard must be met with solar energy.[84] RPS legislation enacted on May 24, 2018, in New Jersey raised New Jersey's RPS requirement to 21 percent by 2020, 35 percent by 2025, and 50 percent by 2030. The New Jersey statute requires generators to source increasing amounts of electricity from behind the meter solar, 4.3 percent by 2019, 4.9 percent by 2020, and 5.1 percent by 2021. The legislation also included provisions promoting the development of solar power in the state.[85] 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.

On December 15, 2016, the Michigan State Senate approved Senate Bill 438 (S.B. 438) which increased the Michigan RPS percent requirements. The previous version of the bill required that 10 percent of retail electric load in Michigan be served by renewable and alternative energy resources in 2015 and subsequent years. S.B. 438 increased the percent of retail electric load to be served by renewable and alternative energy resources in Michigan to be 12.5 percent in 2019 and 2020 and 15 percent in 2021 and subsequent years.[86] The Michigan legislation also repealed provisions that had allowed advanced cleaner energy credits to be substituted for RECs.[87] In February 2017, the Maryland State House approved House Bill 1106 which increased the total RPS requirement from 20 percent by 2022 to 25 percent by 2020. In 2016, Maryland legislation established a pilot program for community solar energy systems.[88] Regulations for a three year pilot program developed by the Maryland Public Service Commission became effective July 18, 2016.

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.[89]

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).[90] 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.[91]

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.

83 "CleanEnergy DC Omnibus Amendment Act of 2018," March 22, 2019 <https://dcpsc.org/Utility-Information/Electric/RPS.aspx>.
84 See "Code of the District of Columbia," Title 34, §§ 1431–1434, <https://code.dccouncil.us/dc/council/code/>.
85 N.J. S. 2314/A. 3723.
86 See Michigan Legislature. Senate Bill 0438 (2015) <http://legislature.mi.gov/doc.aspx?2015-SB-0438> (Accessed April 26, 2018).
87 See footnote 4 in "Report on the Implementation and Cost-Effectiveness of the P.A. 295 Renewable Energy Standard," Michigan Public Service Commission, February 15, 2019. Advanced cleaner energy credits are associated with power generation that uses coal gasification, industrial cogeneration or carbon capture technologies.
88 Md. S.B. 1087.
89 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.
90 N.J. S. 2314/A. 3723.
91 BPU Docket No. QO18080851.

Table 8-6 Renewable and alternative energy standards of PJM jurisdictions: 2019 to 2030[92]

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	20.40%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
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%	6.50%	7.50%	8.50%	9.50%	10.50%	11.50%	12.50%	12.50%	12.50%	12.50%	12.50%
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, DC	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											

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, DC 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 8-7 shows the Tier I standards for PJM states.[93] All eligible technologies for the RPS standards in Table 8-7 satisfy the EIA definition of renewable energy.[94]

Table 8-7 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	20.40%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
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, DC	17.50%	20.00%	26.25%	32.50%	38.75%	45.00%	52.00%	59.00%	66.00%	73.00%	80.00%	87.00%

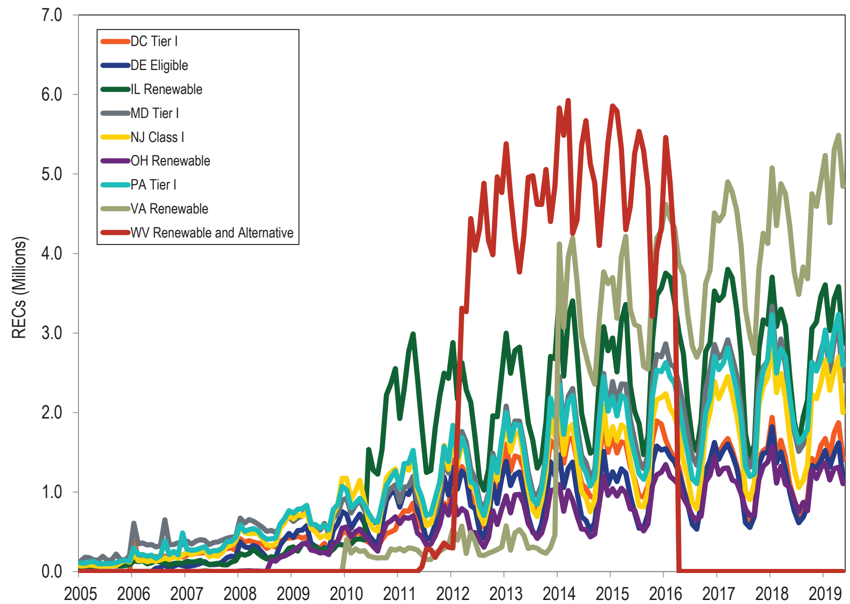
Delaware, Illinois, Michigan, North Carolina, and Ohio do not classify the resources eligible for their RPS standards by tiers. In these states eligible technologies are largely but not completely renewable resources.[95]

92 This shows the total standard of alternative resources in all PJM jurisdictions, including Tier I and Tier II.
93 This includes New Jersey's Class I renewable standard.
94 *Renewable Energy Explained*, U.S. Energy Information Administration, <https://www.eia.gov/energyexplained/index.php?page=renewable_home> (Accessed March 1, 2019).
95 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.

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 May 31, 2019.[96] 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 8-14 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 DC, 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 May 2019[97]



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, DC, but in the other states REC prices are not publicly available.

Figure 8-3 shows the average Tier I REC price by jurisdiction from January 1, 2009, through June 30, 2019. Tier I REC prices are lower than SREC prices.

96 Tier I REC volume obtained through PJM Environmental Information Services <https://www.pjm-eis.com/reports-and-events/public-reports.aspx> (Accessed July 17, 2019).

97 West Virginia eligible MW drop to 0 in 2016 with the repeal of the state's renewable portfolio standard.

Figure 8-3 Average Tier I REC price by jurisdiction: January 2009 through June 2019

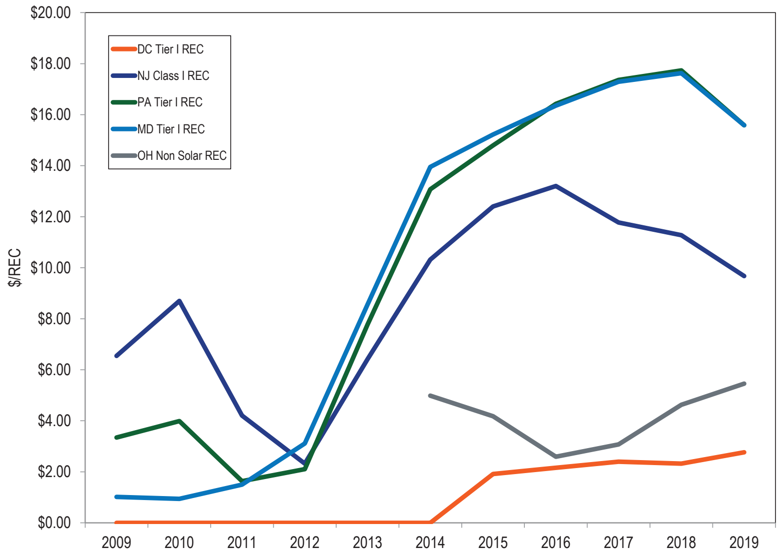


Table 8-8 shows the percent of retail electric load that must be served by Tier II or a specific type of resource under each PJM jurisdiction's RPS by year. Tier II resources are generally not renewable resources. Table 8-8 also shows specific technology requirements that PJM jurisdictions have added to their renewable portfolio standards. The standards shown in Table 8-8 are included in the total RPS requirements presented in Table 8-6. 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, DC 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.[98]

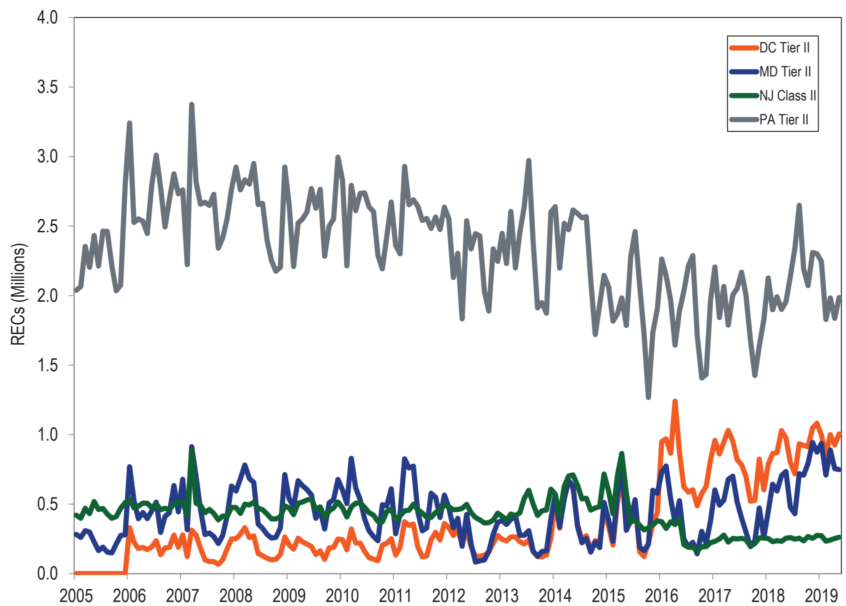
Table 8-8 Additional renewable standards of PJM jurisdictions: 2019 to 2030

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	0.00%	0.00%	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, DC	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%

98 Public Service Commission of Maryland, 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>.

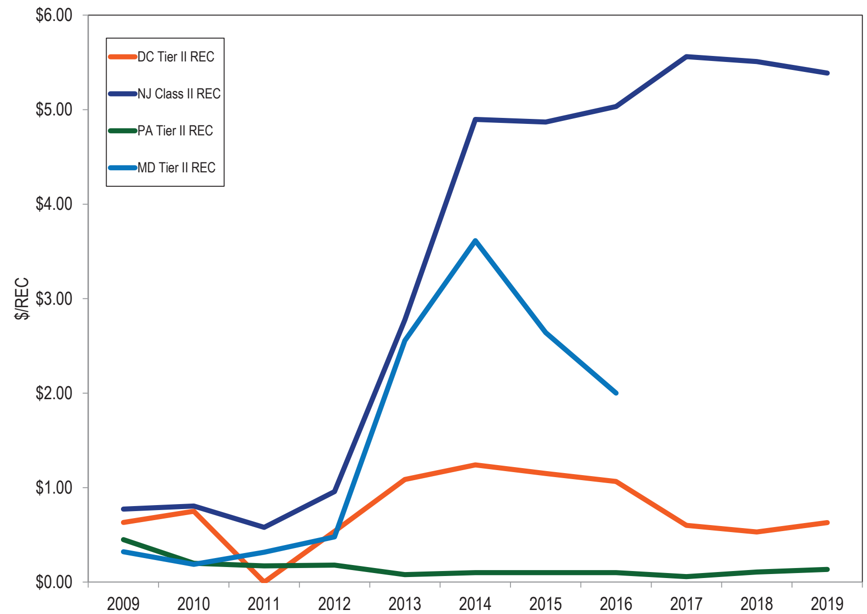
Figure 8-4 shows the number of Tier II RECs eligible monthly by state for January 1, 2005, through May 31, 2019.[99] The figure includes Tier II or the equivalent REC type available in each state. Washington DC, Maryland, and Pennsylvania classify these RECs as Tier II and New Jersey classifies the RECs as Class II.

Figure 8-4 Number of Tier II RECs eligible monthly by state: January 2005 through May 2019



Tier II prices are lower than SREC and Tier I REC prices. Figure 8-5 shows the average Tier II REC price by jurisdiction for January 1, 2009 through June 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.[100]

Figure 8-5 Average Tier II REC price by jurisdiction: January 2009 through June 2019[101]



Some PJM jurisdictions have specific solar resource RPS requirements. These solar requirements are included in the total requirements shown in Table 8-6 but must be met by solar RECs (SRECs) only. Table 8-9 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, DC have requirements for the proportion of load to be served by solar. Pennsylvania and Delaware allow only solar photovoltaic resources to fulfill their solar requirements. Solar thermal units like solar hot water heaters that do not generate electricity are considered Tier II. Indiana, Kentucky, Michigan, Tennessee, Virginia, and West Virginia have no specific solar standards. The New Jersey legislature in

99 Tier II REC volume obtained through PJM Environmental Information Services <https://www.pjm-eis.com/reports-and-events/public-reports.aspx> (Accessed July 17, 2019).
100 Tier II REC price information obtained through Evomarkets <http://www.evomarkets.com> (Accessed July 10, 2019). There were not any reported cleared purchases for January 1, through June 30, 2019, for MD Tier II RECs.
101 Tier II REC price information obtained through Evomarkets <http://www.evomarkets.com> (Accessed Jan. 24, 2019). There were not any reported cleared purchases for January 1, 2017 through December 31, 2018 for DC Tier II REC or MD Tier II RECs.

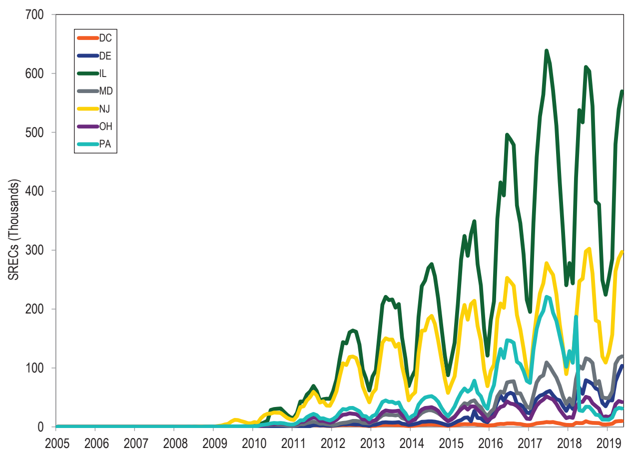
May 2018 increased the solar standard from 3.2 percent to 4.3 percent for 2018. The new solar standard is 5.1 percent for energy years 2020 through 2022 and the standard gradually decreases to 1.1 percent for 2032.[102]

Table 8-9 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	1.95%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
Michigan	No Minimum Solar Requirement											
New Jersey	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%	0.26%	0.30%	0.34%	0.38%	0.42%	0.46%	0.50%	0.50%	0.50%	0.50%	0.50%
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, DC	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											

Figure 8-6 shows the number of SRECs eligible monthly by state for January 1, 2005, through May 31, 2019.[103]

Figure 8-6 Number of SRECs eligible monthly by state: January 2005 through May 2019



102 "Assembly, No. 3723" State of New Jersey, 218th Legislature (March 22, 2018), <http://www.njleg.state.nj.us/2018/Bills/A4000/3723_I1.PDF>.
103 SREC volume obtained through PJM Environmental Information Services <https://www.pjm-eis.com/reports-and-events/public-reports.aspx> (Accessed July 17, 2019).

Figure 8-7 shows the average solar REC (SREC) price by jurisdiction for January 1, 2009, through June 30, 2019. The average NJ SREC prices dropped from $673 per SREC in 2009 to $192 per SREC in 2019. The limited supply of solar facilities in Washington, DC compared to the RPS requirement resulted in higher SREC prices. The average Washington, DC SREC price increased from $197 per SREC in 2011 to $377 per SREC in 2019.[104]

Figure 8-7 Average SREC price by jurisdiction: January 2009 through June 2019

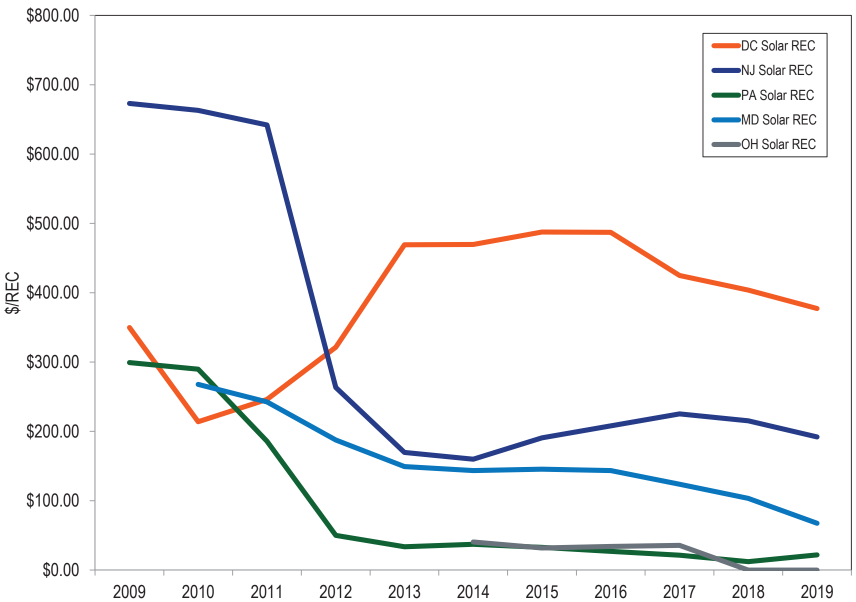
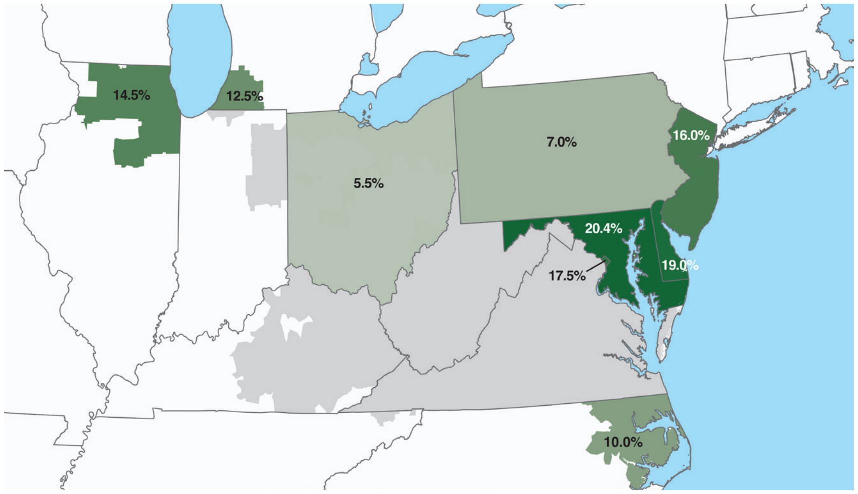


Figure 8-8 and Figure 8-9 show the percent of retail electric load that must be served by Tier I resources and Tier 2 resources in each PJM jurisdiction with a mandatory RPS. Figure 8-8 shows the percent of retail load that must be met with Tier I resources only. Because states that do not group eligible technologies into tiers generally classify eligible technologies in their RPS that are identical to Tier I resources, they are included in Figure 8-8.

104 Solar REC average price information obtained through Evomarkets, <http://www.evomarkets.com> (Accessed July 10, 2019).

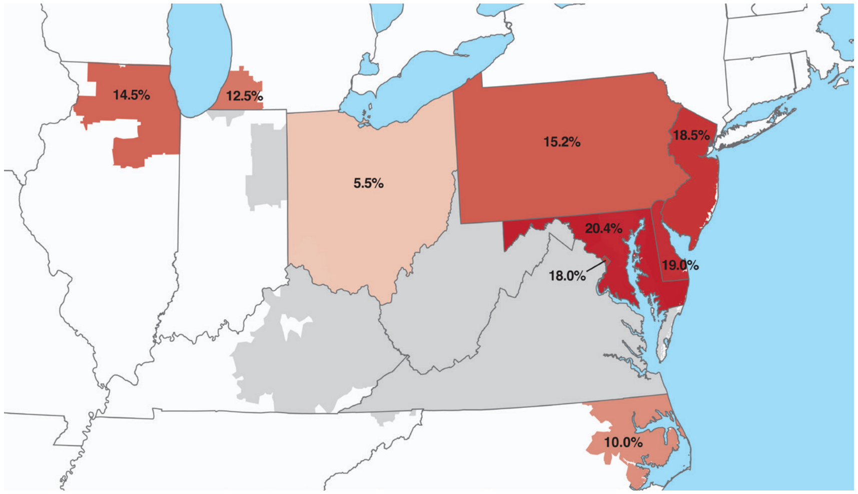
Figure 8-9 shows the percent of retail load that must be met with all eligible technologies, including Tier I, Tier II and alternative energy resources in all PJM jurisdictions with RPS. States with higher percent requirements for renewable and alternative energy resources are shaded darker. Jurisdictions with no standards or with only voluntary renewable standards are shaded gray. Pennsylvania's RPS illustrates the need to differentiate between percent requirements for Tier I and Tier II resources separately. 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 8-9 overstates the percent of retail electric load in Pennsylvania that must be served by renewable energy resources. The 7.0 percent number in Figure 8-8 is a more accurate measure of the percent of retail electric load in Pennsylvania that must be served by renewable energy resources.

Figure 8-8 Map of retail electric load shares under RPS - Renewable resources: 2019[105]



105 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.

Figure 8-9 Map of retail electric load shares under RPS – All renewable and alternative energy resources: 2019



Under the existing state renewable portfolio standards, approximately 10.1 percent of PJM load must be served by renewable and alternative energy resources in 2019 and, if the proportion of load among states remains constant, 18.1 percent of PJM load must be served by renewable and alternative energy resources in 2029 under defined RPS rules. Approximately 8.2 percent of PJM load must be served by renewables in 2019 and, if the proportion of load among states remains constant, 15.9 percent of PJM load must be served by renewables in 2029 under defined RPS rules.

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 8-10 shows generation by jurisdiction and resource type for the first six months of 2019. Wind output was 13,645.0 GWh of 22,755.9 Tier I GWh, or 60.0 percent, in the PJM footprint. As shown in Table 8-10, 31,776.6 GWh were generated by Tier I and Tier II resources, of which Tier I resources were 71.6 percent. Total wind and solar generation was 3.4 percent of total generation in PJM for the first six months of 2019. Tier I generation was 5.7 percent of total generation in PJM and Tier II was 2.3 percent of total generation in PJM for the first six months of 2019. Landfill gas, solid waste and waste coal were 7,508.1 GWh, or 23.6 percent of the total Tier I and Tier II.

Table 8-10 Tier I and Tier II generation by jurisdiction and renewable resource type (GWh): January through June, 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	19.7	0.0	0.0	0.0	19.7	0.0	0.0	0.0	0.0	19.7
Illinois	52.9	0.0	6.6	5,957.8	6,017.3	0.0	0.0	0.0	0.0	6,017.3
Indiana	9.8	25.3	5.9	3,153.7	3,194.6	0.0	0.0	0.0	0.0	3,194.6
Kentucky	0.0	158.6	0.0	0.0	158.6	0.0	0.0	0.0	0.0	158.6
Maryland	30.2	0.0	224.3	375.1	629.6	0.0	256.4	0.0	256.4	886.0
Michigan	10.5	35.8	3.4	0.0	49.6	0.0	0.0	0.0	0.0	49.6
New Jersey	130.7	22.5	355.2	8.9	517.1	139.4	651.5	0.0	790.9	1,308.0
North Carolina	0.0	539.7	379.9	292.7	1,212.2	0.0	0.0	0.0	0.0	1,212.2
Ohio	180.7	410.9	0.6	1,117.1	1,709.2	0.0	0.0	0.0	0.0	1,709.2
Pennsylvania	351.4	3,834.4	12.4	1,898.3	6,096.4	858.8	691.2	3,200.6	4,750.6	10,846.9
Tennessee	0.0	845.4	0.0	0.0	845.4	0.0	0.0	0.0	0.0	845.4
Virginia	269.6	384.2	321.0	0.0	974.9	1,591.8	451.1	709.4	2,752.3	3,727.2
Washington, DC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
West Virginia	21.8	467.8	0.0	841.5	1,331.1	0.0	0.0	470.6	470.6	1,801.7
Total	1,077.2	6,724.5	1,309.1	13,645.0	22,755.9	2,589.9	2,050.3	4,380.6	9,020.8	31,776.6
Percent of Renewable Generation	3.4%	21.2%	4.1%	42.9%	71.6%	8.2%	6.5%	13.8%	28.4%	100.0%
Percent of Total Generation	0.3%	1.7%	0.3%	3.4%	5.7%	0.7%	0.5%	1.1%	2.3%	8.0%

Figure 8-10 shows the average hourly output by fuel type for January 1 through June 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.[106]

106 See the *2018 Quarterly State of the Market Report for PJM: January through June*, Section 3: Energy Market, Table 3-9.

Figure 8-10 Average hourly output by fuel type: January through June, 2014 through 2019

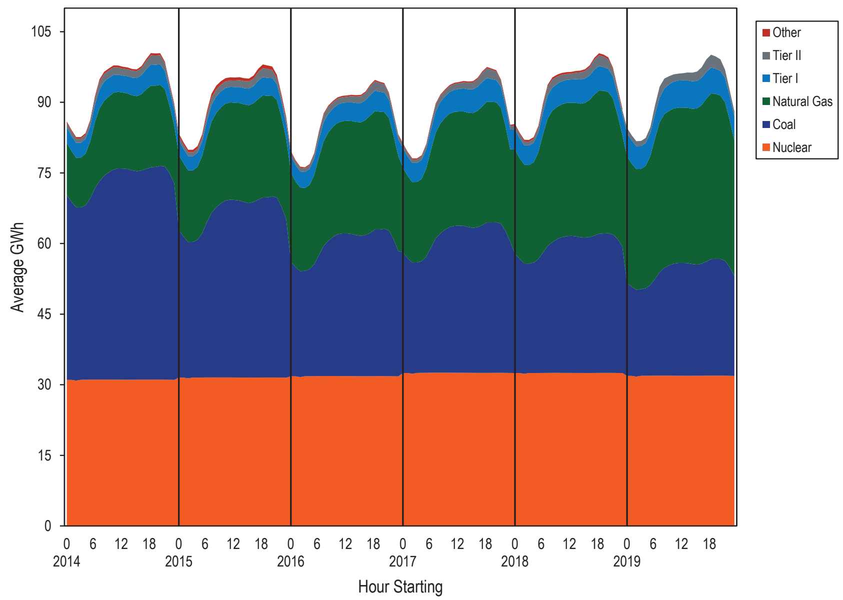


Table 8-11 shows the capacity of Tier I and Tier II resources in PJM by jurisdiction, as defined by primary fuel type. This capacity includes coal and natural gas units that qualify because they have a renewable fuel as an alternative fuel. For example, a coal generator that can also burn waste coal 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, 543.3 MW, or 29.1 percent of the total solar capacity. New Jersey's SREC prices were the highest in PJM at $673 per REC in 2009, and at $192 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 8-11 PJM renewable capacity by jurisdiction (MW): June 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	543.3	162.0	0.0	4.5	1,251.4
North Carolina	0.0	0.0	0.0	0.0	0.0	465.0	575.7	0.0	0.0	208.0	1,248.7
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, DC	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	1,866.6	675.0	2,311.0	8,843.4	34,564.7

Table 8-12 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 5,647.7 MW of which 2,199.3 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 8-12 Renewable capacity by jurisdiction, non-PJM units registered in GATS (MW), on June 30, 2019[107]

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	111.7	0.0	2.1	116.0
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	97.3	0.0	5.5	0.0	118.5	0.0	300.3	543.0
Indiana	0.0	0.0	49.6	0.0	5.2	109.6	107.1	0.0	180.0	451.5
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	36.9	93.0	0.0	911.1
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	921.0	15.0	0.3	1,014.0
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	2,199.3	0.0	4.8	2,264.1
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	1,037.7	151.5	0.0	1,619.6
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	202.6	92.8	47.4	478.9
Pennsylvania	109.7	31.7	45.2	90.5	16.6	5.0	362.8	8.6	3.3	673.3
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	17.9	11.3	0.0	3.1	0.0	166.6	287.6	0.0	486.4
Washington, DC	0.0	0.0	0.0	0.0	49.4	12.8	65.5	0.0	0.0	127.7
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	680.5	385.9	142.5	123.9	159.8	5,647.7	1,311.4	1,715.5	10,996.9

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.[108] 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.[109] 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.[110] 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.[111]

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.

107 See PJM – EIS (Environmental Information Services), Generation Attribute Tracking System, "Renewable Generators Registered in GATS," <https://gats.pjm-eis.com/gats2/PublicReports/RenewableGeneratorsRegisteredinGATS> (Accessed April 1, 2019).

108 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).

109 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.").

110 See DSIRE, NC Clean Energy Technology Center. Delaware Renewable Portfolio Standard, <http://programs.dsireusa.org/system/program/detail/1231> (Accessed November 3, 2018).

111 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 8-13 shows the REC tracking systems used by each state within the PJM footprint.

Table 8-13 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, DC	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 8-14 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

Table 8-14 Geographic restrictions on REC purchases for renewable portfolio standard compliance in PJM states

State with RPS	RPS Contains In-state Provision	Geographical Requirements for RPS Compliance
Delaware	No	RECs must be purchased from resources located either within PJM or from resources outside of PJM that are directly deliverable into Delaware.
Illinois	Yes	All RECs must first be purchased from resources located within Illinois or resources located in a state directly adjoining Illinois. If there are insufficient RECs from Illinois and adjoining states to fulfill the RPS requirements, utilities may purchase RECs from anywhere.
Maryland	No	RECs must come from within PJM, 10-30 miles offshore the coast of Maryland or from a control area adjacent to PJM that is capable of delivering power into PJM.
Michigan	Yes	RECs must either come from resources located within Michigan or anywhere in the service territory of retail electric provider in Michigan that is not an alternative electric supplier. There are many exceptions to these requirements (see Michigan S.B. 213).
New Jersey	No	RECs must either be purchased from resources located within PJM or from resources located outside of PJM for which the energy associated with the REC is delivered to PJM via dynamic scheduling.
North Carolina	Yes	Dominion, the only utility located in both the state of North Carolina and PJM, may purchase RECs from anywhere. Other utilities in North Carolina not located in PJM are subject to different REC requirements (see G.S. 62-113.8).
Ohio	Yes	All RECs must be generated from resources that are located in the state of Ohio or have the capability to deliver power directly into Ohio. Any renewable facility located in a state contiguous to Ohio has been deemed deliverable into the state of Ohio. For renewable resources in noncontiguous states, deliverabilty must be demonstarted to the Public Utilities Commission of Ohio.
Pennsylvania	Yes	RECs must be purchased from resources located within PJM. All SRECs used for compliance with the Solar PV standard must source from solar PV resources within the state of Pennsylvania.
Washington, DC	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.

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. Washington, DC, 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.

Carbon Pricing

Table 8-15 shows the impact of a range of carbon prices on the cost per MWh of producing energy from three basic unit types.[112] [113] For example, if the price of carbon were $50.00 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 8-15 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 8-15 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 $192.00 per MWh through the second 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.

Applying this method to tier I REC and SREC price histories yields the implied carbon prices in Table 8-16. The carbon price implied by the 2019 average REC price in Washington, DC is $5.64 per tonne which is consistent with the most recent RGGI clearing price of $6.19 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.[114] 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. It is not clear why the apparent goal of state policies is such different values for carbon emission reductions among technologies within states.

112 Heat rates from: *2018 State of the Market Report for PJM*, Volume 2, Section 7: Net Revenue, Table 7-4.
113 Carbon emissions rates from: *Table A.3. Carbon Dioxide Uncontrolled Emission Factors*, Energy Information Administration, <https://www.eia.gov/electricity/annual/html/epa_a_03.html> (Accessed July 24, 2018).
114 "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>.

Table 8-16 Implied carbon price based on REC and SREC prices: 2009 through 2019[115]

	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	$10.22	$13.30
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	$23.00	$19.72
Ohio						$10.16	$8.52	$5.29	$6.27	$9.43	$11.12
Pennsylvania	$6.82	$8.13	$3.33	$4.29	$15.87	$26.66	$30.17	$33.49	$35.40	$36.17	$31.78
Washington, DC							$3.91	$4.40	$4.88	$4.74	$5.64
Jurisdiction with Solar REC	**Carbon Price ($ 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	$439.03	$391.50
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	$24.77	$44.50
Washington, D.C.	$712.98	$436.28	$501.62	$655.52	$956.55	$957.46	$994.05	$993.49	$866.17	$823.23	$768.99
Regional Greenhouse Gas Initiative	**CO_2 Allowance Price ($ 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	$6.00

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, with varying standards, to cover any shortfall between the RECs required by the state and those the retail supplier actually purchased. The alternative compliance payments, which are penalties, function as a cap on the market value of RECs. In New Jersey, solar alternative compliance payments are $258.00 per MWh.[116] Pennsylvania requires that the alternative compliance payment for solar credits be 200 percent of the average market value of solar RECs sold in the RTO plus the value of any solar rebates. Figure 8-11 shows the relationship between Pennsylvania solar REC prices and alternative compliance payments. For all states with an alternative compliance payment, the alternative compliance payment creates a cap on REC prices. The 2018 average SREC price in New Jersey was $213.65 compared to the alternative compliance payment level of $268.00 per MWh. In 2011, the solar alternative compliance payment level in New Jersey was $658 per MWh and as shown in Figure 8-7 New Jersey SREC prices exceeded $600 per MWh in 2011. In Michigan and North Carolina, there are no defined values for alternative compliance payments. The public utility commissions in Michigan and North Carolina have the discretionary power to assess what a load serving entity must pay for any RPS shortfalls.

Table 8-17 shows the alternative compliance standards for RPS in PJM jurisdictions.

115 There were no trades in 2018 for Ohio SRECs available in the Evomarkets data.

116 N.J. S. 2314/A. 3723.

Table 8-17 Tier I and Tier II alternative compliance payments in PJM jurisdictions: June 30, 2019[117 118 119]

Jurisdiction with RPS	Standard Alternative Compliance ($/MWh)	Tier II Alternative Compliance ($/MWh)	Solar Alternative Compliance ($/MWh)
Delaware	$25.00		$400.00
Illinois	$1.89		
Maryland	$37.50	$15.00	$175.00
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, DC	$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		

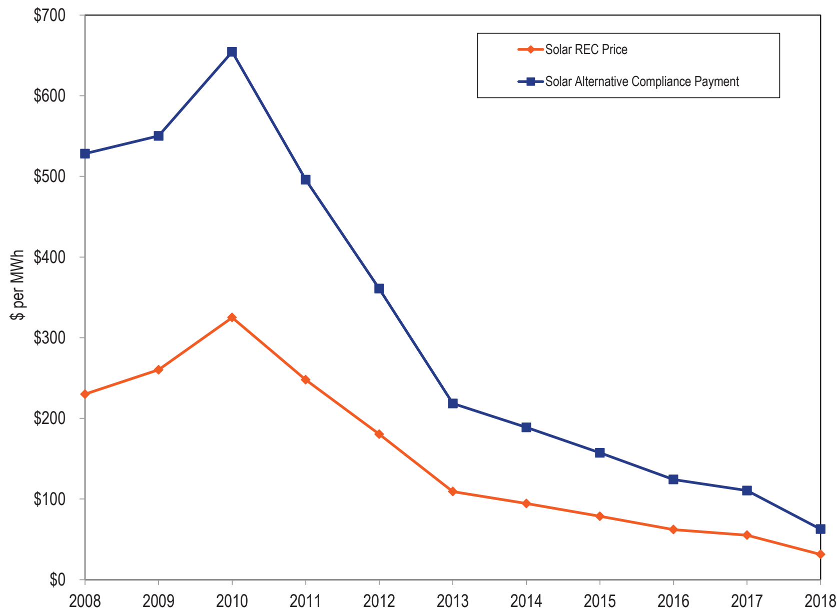
117 The Ohio standard alternative compliance payment (ACP) is updated annually <https://www.puco.ohio.gov/industry-information/industry-topics/acp-non-solar-alternative-compliance-payment-under-orc-492864/>. The Illinois Commerce Commission periodically publishes updates to the effective ACP amount <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/>.

118 See DSIRE, "Database of State Incentives for Renewables & Efficiency, "Policies & Incentives by State," <http://www.dsireusa.org/> (Accessed February 21, 2019).

119 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).

Load serving entities participating in mandatory RPS programs in PJM jurisdictions must submit compliance reports to the relevant jurisdiction's public utility commission.

Figure 8-11 Comparison of Pennsylvania Solar REC Price and ACP: 2008 through 2018[120]



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.[121] 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. 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.[122] 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."[123] 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."[124]

The Public Utilities Commission of Ohio reported that 3,919,366 non solar 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.[125] 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.

120 Historical solar REC price data is from the Pennsylvania Alternative Energy Credit Program website: <https://www.pennaeps.com/aboutaeps/> (Accessed June 5, 2019).

121 "2017 Annual Report – Alternative Energy Portfolio Standards Act of 2004," (March 2018), <http://www.pennaeps.com/reports/>.

122 "Report on the Renewable Energy Portfolio Standard for Compliance Year 2017," Public Service Commission of the District of Columbia (May 1, 2018), <https://www.dcpsc.org/Utility-Information/Electric/Renewables/Renewable-Energy-Portfolio-Standard-Program.aspx>.

123 "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>.

124 Id. at 8.

125 "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/>.

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 567,372 credits for the compliance year ending May 31, 2018, with zero alternative compliance payments.[126] Delmarva Power satisfied their solar REC obligation of 105,352 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.[127]

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.[128] [129] 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.[130]

New Jersey's Office of Clean Energy posted a summary of RPS compliance through the energy year ending May 31, 2018.[131] 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.

Table 8-18 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 8-18 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.[132] 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.

126 "Retail Electricity Supplier's RPS Compliance Report, Compliance Period: June 1, 2016–May 31, 2017," Delmarva Power, (Sept. 25, 2018), <https://depsc.delaware.gov/delawares-renewable-portfolio-standard-green-power-products/>

127 "Annual Report Fiscal Year 2018," Illinois Power Agency (Feb. 15, 2019) at 46, <https://www2.illinois.gov/sites/ipa/Pages/IPA_Reports.aspx>.

128 "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>.

129 Id. at 53. Compliance plan approvals are pending for one municipally-owned electric utility and one electric membership corporation (EMC).

130 "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/0,4639,7-159-16393---,00.html>.

131 See RPS Report Summary 2005-2018, (Nov. 1, 2017), <http://www.njcleanenergy.com/renewable-energy/program-updates/rps-compliance-reports>.

132 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.

Table 8-18 RPS Compliance Cost[133 134 135 136 137 138 139 140 141 142]

Jurisdiction with RPS		2014	2015	2016	2017	2018
Delaware	Total RPS		$16,013,421	$18,409,631	$18,772,855	
	Solar		$7,070,254	$7,748,073	$7,105,726	
	Non-Solar		$8,943,167	$10,661,557	$11,667,129	
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 DC	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	$76,385,224

133 "Delmarva Power & Light's 2017 RPS Compliance Report," Delmarva Power (Sept. 25, 2018), <https://depsc.delaware.gov/delawares-renewable-portfolio-standard-green-power-products/>.
134 "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.
135 "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>.
136 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/0,4639,7-159-16393_55240---,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.
137 "RPS Report Summary 2005-2018," New Jersey's Clean Energy Program, December 31, 2018, <http://njcleanenergy.com/renewable-energy/program-updates/rps-compliance-reports>.
138 "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/>.
139 "2017 Annual Report Alternative Energy Portfolio Standards Act of 2004," Pennsylvania Public Utility Commission, March 2018, <https://www.pennaeps.com/annual-reports/>.
140 "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>.
141 RPS compliance cost information for North Carolina is not available in the North Carolina Utilities Commission annual report on RPS compliance.
142 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.[143] 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 8-19 shows SO_2 emission controls by fossil fuel fired units in PJM.[144 145 146] Coal has the highest SO_2 emission rate, while natural gas and diesel oil have lower SO_2 emission rates.[147] Of the current 64,699.7 MW of coal capacity in PJM, 60,672.4 MW of capacity, 93.8 percent, has some form of FGD (flue-gas desulfurization) technology to reduce SO_2 emissions.

Table 8-19 SO_2 emission controls by fuel type (MW): June 30, 2019[148]

	SO_2 Controlled	No SO_2 Controls	Total	Percent Controlled
Coal	60,672.4	4,027.3	64,699.7	93.8%
Diesel Oil	0.0	5,322.6	5,322.6	0.0%
Natural Gas	0.0	71,633.2	71,633.2	0.0%
Other	325.0	4,805.7	5,130.7	6.3%
Total	60,997.4	85,788.8	146,786.2	41.6%

Table 8-20 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, 138,647.0 MW, 94.5

143 See EPA, "National Ambient Air Quality Standards (NAAQS)," <https://www.epa.gov/criteria-air-pollutants/naaqs-table> (Accessed July 25, 2019).
144 See EPA, "Air Market Programs Data," <http://ampd.epa.gov/ampd/> (Accessed July 25, 2019).
145 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 first quarter of 2019.
146 The total MW are less than the 187,457.6 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 July 25, 2019).
147 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 July 29, 2019).
148 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.

percent, of 146,786.2 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.[149]

Table 8-20 NO_X emission controls by fuel type (MW): As of June 30, 2019

	NO_x Controlled	No NO_x Controls	Total	Percent Controlled
Coal	64,164.9	534.8	64,699.7	99.2%
Diesel Oil	1,612.6	3,710.0	5,322.6	30.3%
Natural Gas	70,217.8	1,415.4	71,633.2	98.0%
Other	2,651.7	2,479.0	5,130.7	51.7%
Total	138,647.0	8,139.2	146,786.2	94.5%

Table 8-21 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 (3.9 percent) and units with other fuel sources (57.9 percent). Typically, technologies such as electrostatic precipitators (ESP) or fabric filters (baghouses) are used to reduce particulate matter from coal steam units.[150] Fabric filters work by allowing the flue gas to pass through a tightly woven fabric which filters out the particulates. In PJM, 64,454.7 MW out of 64,699.7 MW, 99.6 percent, of all coal steam unit MW, have some type of particulate emissions control technology, as of June 30, 2019. All coal steam units in PJM are compliant with the state and federal emissions limits established by MATS.[151] 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, 145 of the 160 coal steam units have baghouse or FGD technology installed, representing 58,356.4 MW out of the 64,699.7 MW total coal capacity, or 90.2 percent.

149 See EPA. "Mercury and Air Toxics Standards, Cleaner Power Plants," <https://www.epa.gov/mats/cleaner-power-plants#controls> (Accessed July 25, 2019).
150 See EPA, "Air Pollution Control Technology Fact Sheet," <https://www3.epa.gov/ttn/catc/dir1/ff-pulse.pdf> (Accessed July 25, 2019).
151 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 July 25, 2019).

Table 8-21 Particulate emission controls by fuel type (MW): As of June 30, 2019

	Particulate Controlled	No Particulate Controls	Total	Percent Controlled
Coal	64,454.7	245.0	64,699.7	99.6%
Diesel Oil	0.0	5,322.6	5,322.6	0.0%
Natural Gas	2,786.0	68,847.2	71,633.2	3.9%
Other	2,970.5	2,160.2	5,130.7	57.9%
Total	70,211.2	76,575.0	146,786.2	47.8%

Emissions

Figure 8-12 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 first quarter of 2019. Figure 8-12 also shows the CO_2 emissions per MWh of total generation within PJM for each quarter from 2010 to the first quarter of 2019.[152] [153] For the period from 1999 through the first quarter of 2019, the minimum CO_2 produced per MWh was 0.73 short tons per MWh in the first quarter of 2019, and the maximum was 0.95 short tons per MWh in the first quarter of 2010. Total PJM generation increased from 208,764.6 GWh in the first quarter of 2018 to 211,768.3 GWh in the first quarter of 2019, while CO_2 produced decreased from 107.4 million short tons in the first quarter of 2018 to 100.6 million short tons in the first quarter of 2019.[154] 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.

152 Unless otherwise noted, emissions are measured in short tons. A short ton is 2,000 pounds.
153 Emissions data for the second 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.
154 See the *2019 Quarterly State of the Market Report for PJM: January through March*. Section 3: Energy Market, Table 3-10.

Figure 8-12 CO_2 emissions by quarter (millions of short tons), by PJM units: 1999 through 2018[155 156]

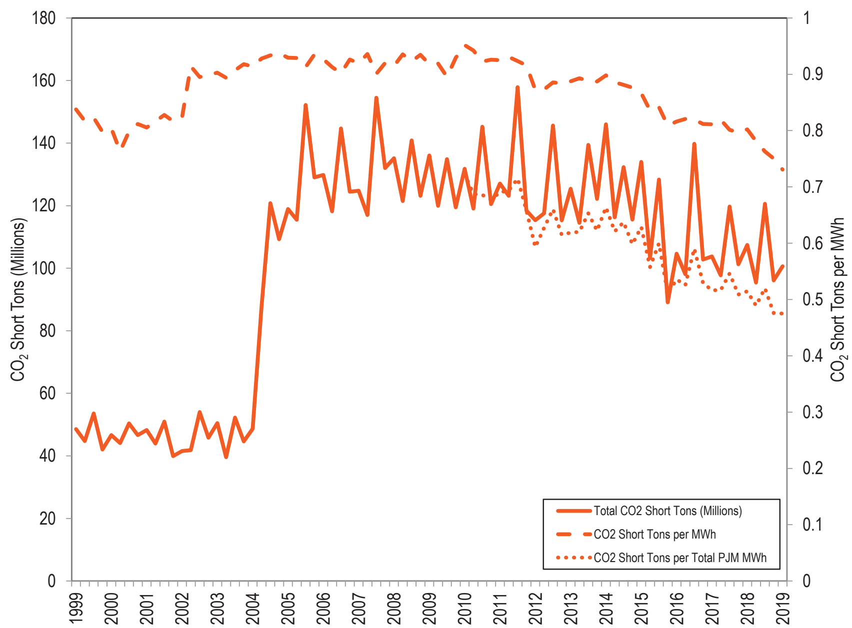


Figure 8-13 Total CO_2 emissions during on and off peak hours by quarter (millions of short tons), by PJM units: 1999 through 2018[157]

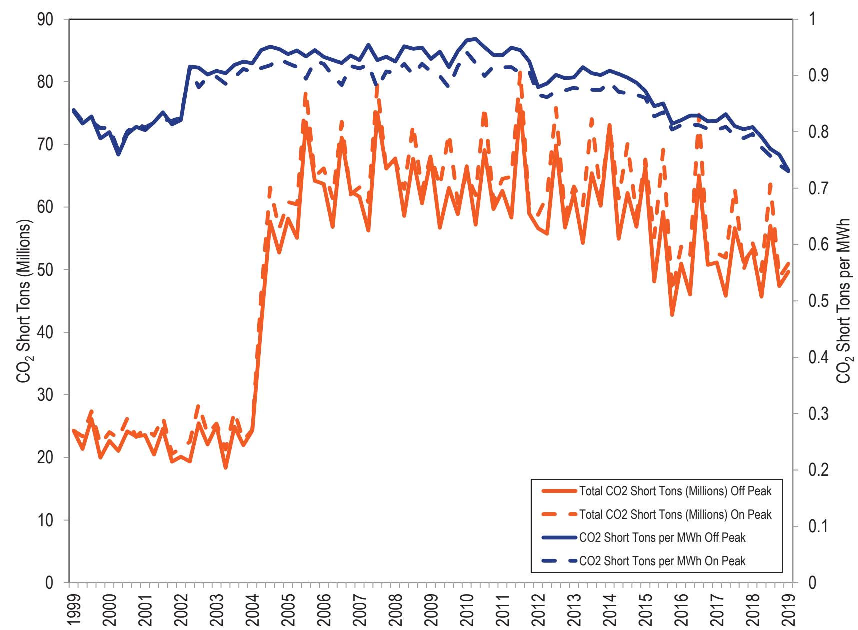


Figure 8-13 shows the total CO_2 emissions on peak and off peak and the CO_2 emissions per MWh for all CO_2 emitting units. Since 1999 the amount of CO_2 produced per MWh during off peak hours was at a minimum of 0.73 short tons per MWh in the first quarter of 2019, and a maximum of 0.96 short tons per 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 0.73 short tons per MWh in the first quarter of 2019, and a maximum of 0.94 short tons per MWh in the first quarter of 2010. In the first quarter of 2019, CO_2 emissions were 0.73 short tons per MWh for both off and on peak hours.

155 The emissions are calculated from the continuous emission monitoring system (CEMS) data from generators located within the PJM footprint.

156 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).

Figure 8-14 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 first quarter of 2019, the minimum SO_2 produced per MWh was 0.000507 short tons per MWh in the first 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 first quarter of 2019, the minimum NO_X produced per MWh was at a 0.000332 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 1999. In the first quarter of 2019, SO_2 emissions were 0.000507 short tons per MWh and NO_X emissions were 0.000380 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,

157 The emissions are calculated from the continuous emission monitoring system (CEMS) data from generators located within the PJM footprint.

an increase in the use of natural gas, and the installation of environmental controls from 2006 to 2019.[158] [159]

Figure 8-14 SO_2 and NO_X emissions by quarter (thousands of short tons), by PJM units: 1999 through 2018[160]

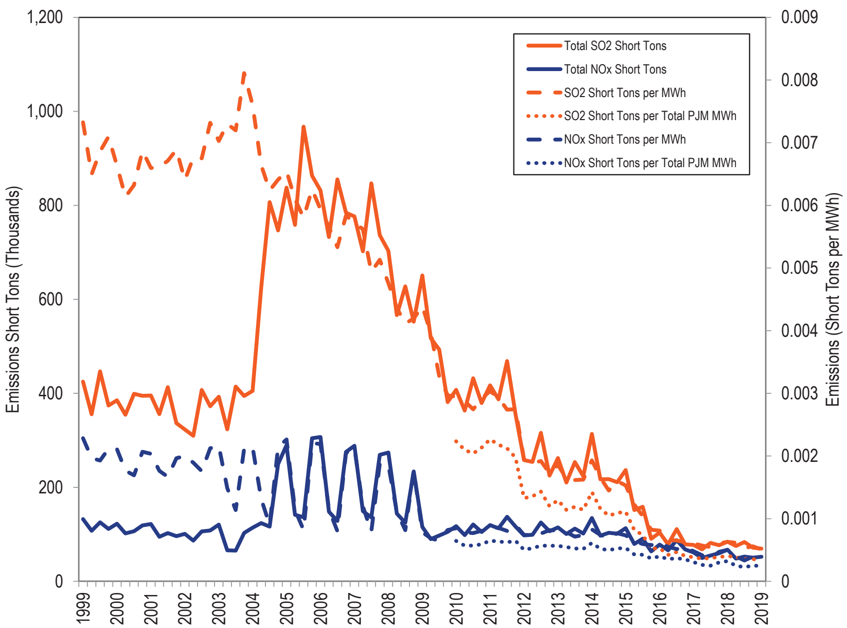
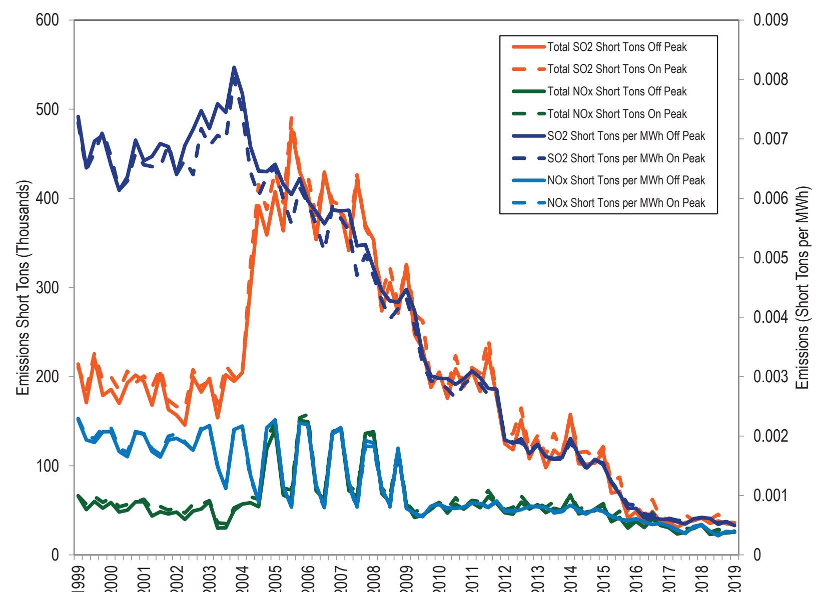


Figure 8-15 shows the total on peak hour and off peak hour SO_2 and NO_X emissions and the emissions per MWh from emitting resources for all SO_2 and NO_X emitting units. For the period from 1999 through the first quarter of 2019, the minimum SO_2 produced per MWh during off peak hours was 0.000496 short tons per MWh in the first quarter of 2019, and the maximum was 0.008202 short tons per MWh in the fourth quarter of 2003. For the period from 1999 through the first quarter of 2019, the minimum SO_2 produced per MWh during on peak hours was 0.000517 short tons per MWh in the first 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 first quarter of 2019, the minimum NO_X produced per MWh during off peak hours was 0.000324 short tons per MWh in the third quarter of 2018, and the maximum was 0.002276 short tons per MWh in the first quarter of 1999. For the period from 1999 through the first quarter of 2019, the minimum NO_X produced per MWh during on peak hours was 0.000340 short tons per MWh in the third quarter of 2018 and the maximum was 0.002292 short tons per MWh in the first quarter of 1999. In the first quarter of 2019, SO_2 emissions were 0.000496 short tons per MWh and 0.000517 short tons per MWh for off and on peak hours. In the first quarter of 2019, NO_X emissions were 0.000324 short tons per MWh and 0.000340 short tons per MWh for off and on peak hours.

Figure 8-15 SO_2 and NO_X emissions during on and off peak hours by quarter (thousands of short tons), by PJM units: 1999 through 2018[161]



158 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 July 29, 2019).

159 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 July 29, 2019).

160 The emissions are calculated from the continuous emission monitoring system (CEMS) data from generators located within the PJM footprint.

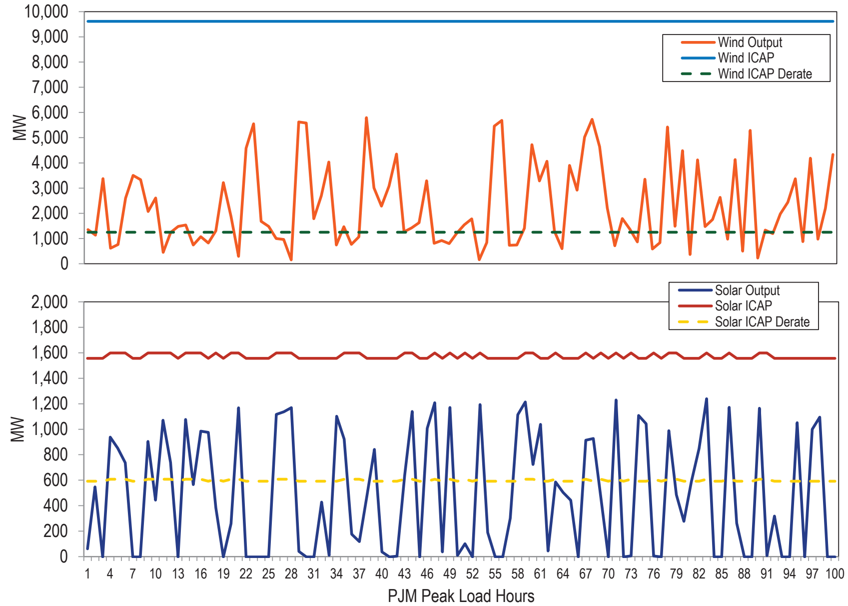
161 The emissions are calculated from the continuous emission monitoring system (CEMS) data from generators located within the PJM footprint.

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 8-16 shows the wind and solar output during the top 100 load hours in PJM for the first six months of 2019. Of the top 100 load hours in PJM during the first six months of 2019, 81 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 ICAP of wind and solar PJM resources derated to 13 and 38 percent.[162] 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 65 hours and below the derated ICAP for 35 hours of the top 100 load hours of the first six months of 2019. The wind capacity factor for the top 100 load hours of 2018 was 23.6 percent. Wind output was above the derated ICAP for 3,503 hours and below the derated ICAP for 840 hours in the first six months of 2019. The wind capacity factor for the first six months of 2019 was 37.6 percent. Solar output was above the derated ICAP for 39 hours and below the derated ICAP for 61 hours of the top 100 load hours of the first six months of 2019. The solar capacity factor for the top 100 load hours of the first six months of 2019 was 30.6 percent. Solar output was above the derated ICAP for 1,091 hours and below the derated ICAP for 3,252 hours for the first six months of 2019. The solar capacity factor for the first six months of 2019 was 23.4 percent.

Figure 8-16 Wind and solar output during the top 100 load hours in PJM: January through June, 2019



Wind Units

Table 8-22 shows the capacity factors of wind units in PJM. In the first six months of 2019, the capacity factor of wind units in PJM was 37.6 percent. Wind units that were capacity resources had a capacity factor of 36.7 percent and an installed capacity of 8,075 MW. Wind units that were energy only had a capacity factor of 43.2 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.[163]

162 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, <https://www.pjm.com/-/media/planning/res-adeq/class-average-wind-capacity-factors.ashx?la=en>

163 PJM. Class Average Capacity Factors, <https://www.pjm.com/-/media/planning/res-adeq/class-average-wind-capacity-factors.ashx?la=en> (Accessed July 17, 2019).

Table 8-22 Capacity factor of wind units in PJM: January through June, 2019[164]

Type of Resource	Capacity Factor	Installed Capacity (MW)
Energy-Only Resource	43.2%	1,547
Capacity Resource	36.7%	8,075
All Units	37.6%	9,622

Figure 8-17 shows the average hourly real-time generation of wind units in PJM, by month for January 1 through June 30, 2019. The hour with the highest average output, 4,021 MW, occurred in April, and the hour with the lowest average output, 2,105 MW, occurred in June. Wind output in PJM is generally higher during off peak hours and lower during on peak hours.

Figure 8-17 Average hourly real-time generation of wind units in PJM: January through June, 2019

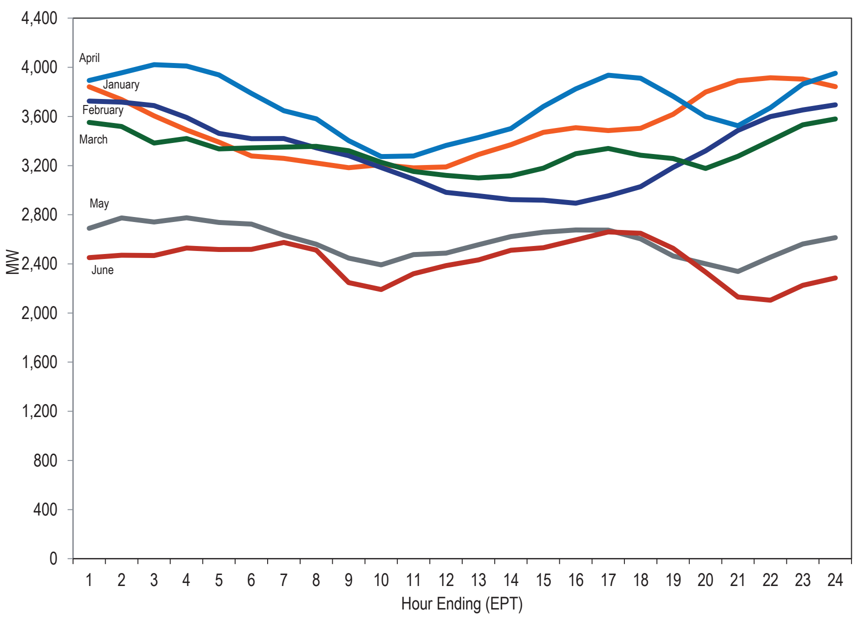


Table 8-23 shows the generation and capacity factor of wind units by month from January 1, 2018, through June 30, 2019.

Table 8-23 Capacity factor of wind units in PJM by month: January 2018 through June 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%		
August	884,856.3	19.0%		
September	1,047,738.1	22.0%		
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%	11,541,739.4	36.7%

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 8-18 shows the average hourly day-ahead generation offers of wind units in PJM, by month.

164 Capacity factor is calculated based on online date of the resource.

Figure 8-18 Average hourly day-ahead generation of wind units in PJM: January through June, 2019

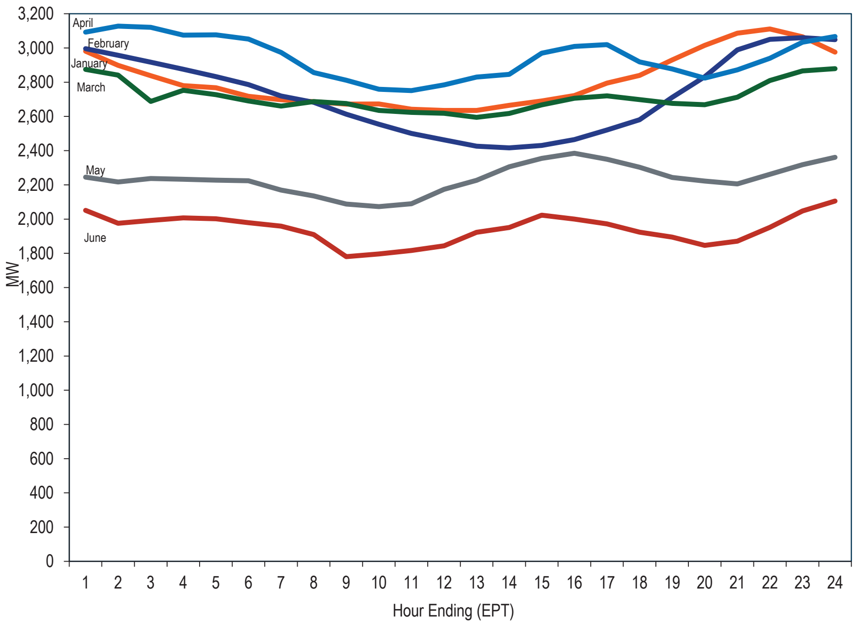
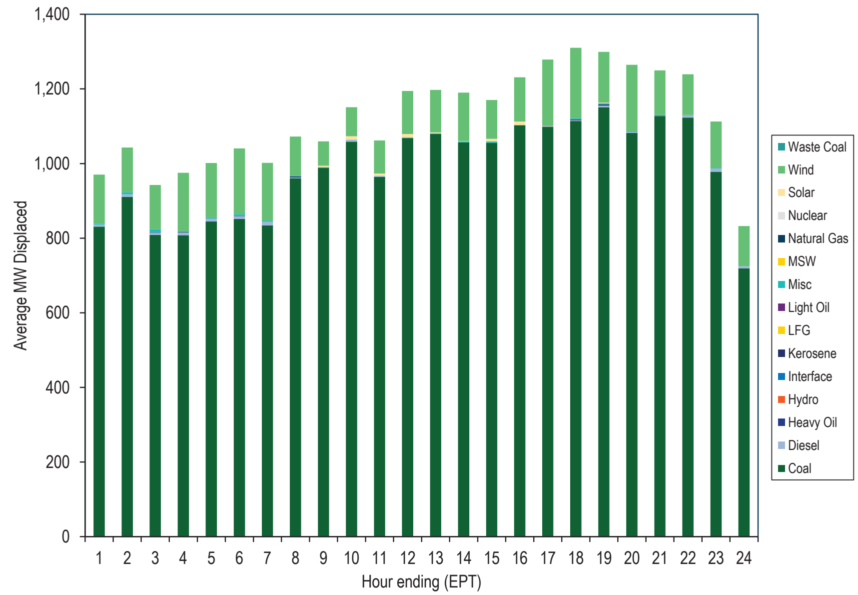


Figure 8-19 Marginal fuel at time of wind generation in PJM: January through June, 2019



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 8-19 and Table 8-24 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 six 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 8-24 Marginal fuel MW at time of wind generation in PJM: January through June, 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	831.0	5.0	0.0	0.0	0.0	0.0	0.0	0.0	2.4	0.0	0.0	0.0	0.0	131.9	0.0	970.4
1	910.4	7.1	0.0	0.0	0.0	0.0	0.0	0.0	5.2	0.0	0.0	0.0	0.0	120.3	0.0	1,042.9
2	808.8	5.7	0.0	0.0	0.0	1.3	0.0	0.0	8.1	0.0	0.0	0.0	0.0	118.8	0.0	942.6
3	807.8	7.2	0.0	0.0	0.0	1.3	0.0	0.0	2.3	0.0	0.0	0.0	0.0	156.5	0.0	975.1
4	844.6	8.2	0.0	0.0	0.0	0.0	0.0	0.0	3.2	0.0	0.0	0.0	0.0	145.5	0.0	1,001.5
5	851.7	6.9	0.0	0.0	0.0	1.5	0.0	0.0	4.2	0.0	0.0	0.0	0.0	176.3	0.0	1,040.7
6	834.1	9.5	0.0	0.0	0.0	0.0	0.0	0.0	3.2	0.0	0.0	0.0	0.0	154.8	0.0	1,001.7
7	960.7	2.2	0.0	0.0	0.0	2.6	0.0	0.0	1.2	0.0	0.0	0.0	0.0	105.7	0.0	1,072.4
8	988.3	0.7	0.0	0.0	0.0	0.0	0.0	0.0	1.3	0.0	0.0	0.0	3.9	65.1	0.0	1,059.3
9	1,058.6	4.2	0.0	0.0	0.0	0.0	0.0	0.0	1.1	0.0	0.0	0.0	9.4	77.7	0.0	1,151.0
10	963.8	2.7	0.0	0.0	0.0	0.0	0.0	0.0	0.6	0.0	0.0	0.0	6.3	88.6	0.0	1,062.0
11	1,068.4	0.8	0.0	0.0	0.0	0.0	0.0	0.0	1.4	0.0	0.0	0.0	8.8	115.0	0.0	1,194.4
12	1,079.2	1.7	0.0	0.0	0.0	0.0	0.0	0.0	0.6	0.0	0.0	0.0	2.1	113.7	0.0	1,197.3
13	1,056.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.0	0.0	0.0	0.0	0.9	129.5	0.0	1,189.9
14	1,055.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.7	0.0	0.0	0.0	7.4	103.8	0.0	1,170.2
15	1,102.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.9	0.0	0.0	0.0	9.1	118.6	0.0	1,231.1
16	1,098.5	0.8	0.0	0.0	0.0	0.8	0.0	0.0	0.0	0.0	0.0	0.0	0.9	177.6	0.0	1,278.6
17	1,114.0	1.9	0.0	0.0	0.0	1.9	0.0	0.0	3.5	0.0	0.0	0.0	0.0	189.0	0.0	1,310.2
18	1,151.2	4.1	0.0	0.0	0.0	3.6	0.0	0.0	3.0	0.0	0.0	0.0	1.5	136.1	0.0	1,299.4
19	1,082.0	2.3	0.0	0.0	0.0	0.0	0.0	0.0	2.8	0.0	0.0	0.0	0.0	177.5	0.0	1,264.5
20	1,127.1	0.7	0.0	0.0	0.0	0.8	0.0	0.0	2.3	0.0	0.0	0.0	0.0	118.8	0.0	1,249.8
21	1,123.1	6.0	0.0	0.0	0.0	0.6	0.0	0.0	0.6	0.0	0.0	0.0	0.0	108.8	0.0	1,239.1
22	977.9	9.1	0.0	0.0	0.0	0.0	0.0	0.0	1.2	0.0	0.0	0.0	0.0	124.6	0.0	1,112.9
23	719.4	5.7	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.0	0.0	0.0	0.0	107.3	0.0	832.6
Average	984.0	3.9	0.0	0.0	0.0	0.6	0.0	0.0	2.3	0.0	0.0	0.0	2.1	127.6	0.0	1,120.4

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 8-11, there are 1,866.6 MW capacity of solar registered in GATS that are PJM units. As shown in Table 8-12, there are 5,647.7 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 8-25 shows the capacity factor of solar units in PJM. In the first six months of 2019, the capacity factor of solar units in PJM was 23.4 percent. Solar units that were capacity resources had a capacity factor of 23.5 percent and an installed capacity of 1,457 MW. Solar units that were energy only had a capacity factor of 22.6 percent and an installed capacity of 141 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.[165]

165 PJM, Class Average Capacity Factors, <https://www.pjm.com/-/media/planning/res-adeq/class-average-wind-capacity-factors.ashx?la=en>

Table 8-25 Capacity factor of solar units in PJM: January through June, 2019

Type of Resource	Capacity Factor	Installed Capacity (MW)
Energy-Only Resource	22.6%	141
Capacity Resource	23.5%	1,457
All Units	23.4%	1,599

Figure 8-20 shows the average hourly real-time generation of solar units in PJM, by month. The hour with the highest peak average output, 1,038 MW, occurred in June, 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 8-20 Average hourly real-time generation of solar units in PJM: January through June, 2019

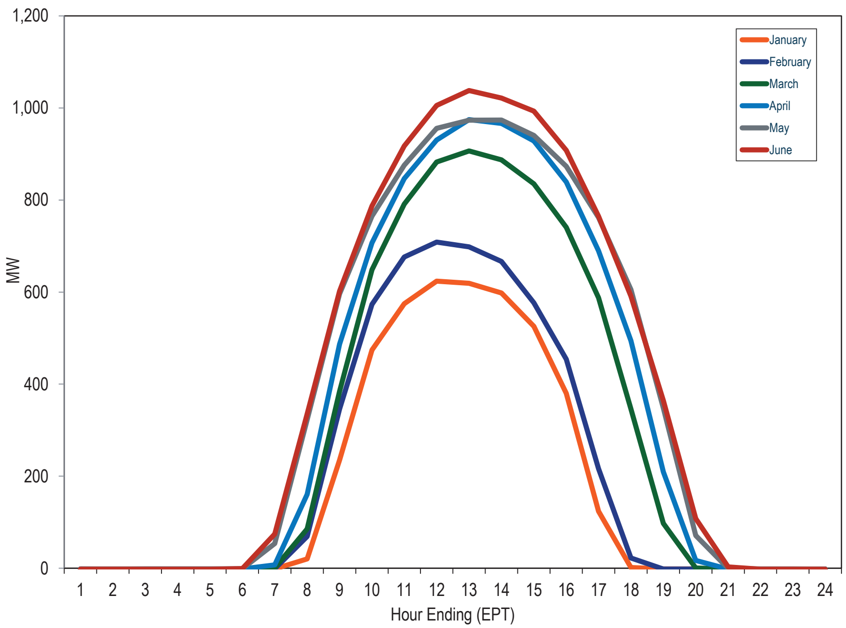


Table 8-26 shows the generation and capacity factor of solar units by month from January 1, 2018, through June 30, 2019.

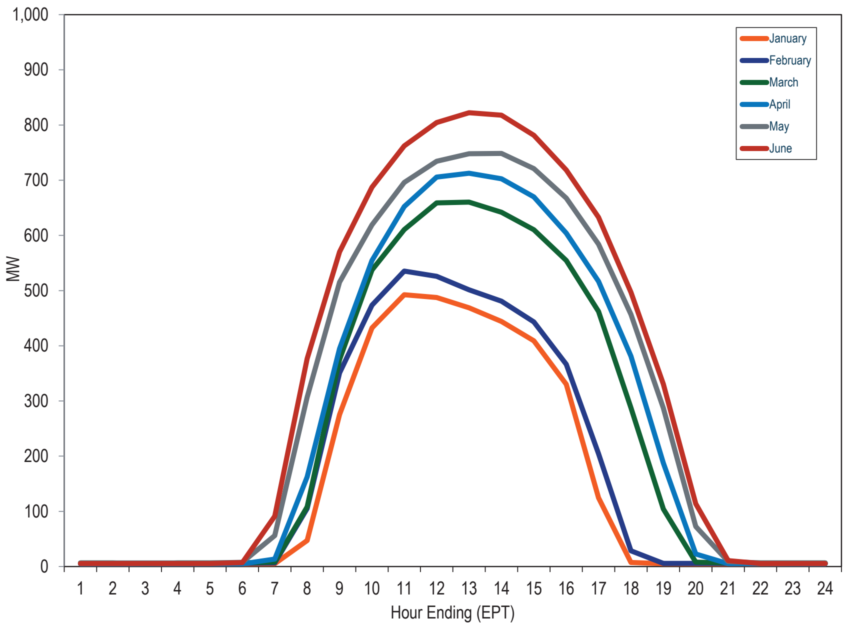
Table 8-26 Capacity factor of solar units in PJM by month: January 2018 through June 2019

	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%		
August	217,755.2	28.9%		
September	142,705.9	21.0%		
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%	1,211,686.1	23.5%

Solar units that are capacity resources are required, like all capacity resources except demand resources, to offer the energy associated with their cleared capacity in the Day-Ahead Energy Market and in the Real-Time Energy Market. Figure 8-21 shows the average hourly day-ahead generation offers of solar units in PJM, by month.[166]

166 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 8-21 Average hourly day-ahead generation of solar units in PJM: January through June, 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 six months of 2019, PJM was a monthly net exporter of energy in the Real-Time Energy Market in all months.[1] In the first six months of 2019, the real-time net interchange was -15,767.1 GWh. The real-time net interchange in the first six months of 2018 was -4,537.3 GWh.
- **Aggregate Imports and Exports in the Day-Ahead Energy Market.** In the first six months of 2019, PJM was a monthly net exporter of energy in the Day-Ahead Energy Market in February and June, and a net importer of energy in the remaining months. In the first six months of 2019, the total day-ahead net interchange was -218.3 GWh. The day-ahead net interchange in the first six months of 2018 was -516.8.
- **Aggregate Imports and Exports in the Day-Ahead and the Real-Time Energy Market.** In the first six months of 2019, gross imports in the Day-Ahead Energy Market were 128.0 percent of gross imports in the Real-Time Energy Market (187.7 percent in the first six months of 2018). In the first six months of 2019, gross exports in the Day-Ahead Energy Market were 472.6 percent of the gross exports in the Real-Time Energy Market (134.7 percent in the first six months of 2018).
- **Interface Imports and Exports in the Real-Time Energy Market.** In the first six 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 six months of 2019, there were net scheduled exports at 9 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 six 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 six 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 six 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 six months of 2019, net scheduled interchange was -15,767 GWh and net actual interchange was -15,770 GWh, a difference of 3 GWh. In the first six months of 2018, the difference was 35 GWh. This difference is inadvertent interchange.
- **Loop Flows.** In the first six 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 -5,658 GWh of net actual interchange, a difference of 5,643 GWh. In the first six months of 2019, the SouthIMP interface pricing point had the largest loop flows of any interface pricing point with 3,203 GWh of net scheduled interchange and 13,858 GWh of net actual interchange, a difference of 10,654 GWh.

Interactions with Bordering Areas

PJM Interface Pricing with Organized Markets

- **PJM and MISO Interface Prices.** In the first six 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 62.2 percent of the hours.

1 Calculated values shown in Section 9, "Interchange Transactions," are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

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

- **PJM and New York ISO Interface Prices.** In the first six 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 59.8 percent of the hours.
- **Neptune Underwater Transmission Line to Long Island, New York.** In the first six 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 72.9 percent of the hours.
- **Linden Variable Frequency Transformer (VFT) Facility.** In the first six 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 67.9 percent of the hours.
- **Hudson DC Line.** In the first six 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 65.6 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 six months of 2019, compared to four such TLR issued in the first six months of 2018.
- **Up To Congestion.** 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.[3] As a result, market participants reduced up to congestion trading effective February 22, 2018. The average number of up to congestion bids submitted in the Day-Ahead Energy Market decreased by 37.0 percent, from 76,114 bids per day in the first six months of 2018 to 47,989 bids per day in the first six months of 2019. The average cleared volume of up to congestion bids submitted in the Day-Ahead Energy Market increased by 15.4 percent, from 431,553 MWh per day in the first six months of 2018, to 497,987 MWh per day in the first six months of 2019.

3 162 FERC ¶ 61,139 (2018).

- **45 Minute Schedule Duration Rule.** Effective May 19, 2014, PJM removed the 45 minute scheduling duration rule in response to FERC Order No. 764.[4] [5] PJM and the MMU issued a statement indicating ongoing concern about market participants' scheduling behavior, and a commitment to address any scheduling behavior that raises operational or market manipulation concerns.[6]

Recommendations

- The MMU recommends that PJM implement rules to prevent sham scheduling. The MMU recommends that PJM apply after the fact market settlement adjustments to identified sham scheduling segments to ensure that market participants cannot benefit from sham scheduling. (Priority: High. First reported 2012. Status: Not adopted. Stakeholder process.)
- The MMU recommends that PJM implement a validation method for submitted transactions that would prohibit market participants from breaking transactions into smaller segments to defeat the interface pricing rule by concealing the true source or sink of the transaction. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM implement a validation method for submitted transactions that would require market participants to submit transactions on paths that reflect the expected actual power flow in order to reduce unscheduled loop flows. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM end the practice of maintaining outdated definitions of interface pricing points, eliminate the NIPSCO, Southeast and Southwest interface pricing points from the Day-Ahead and Real-Time Energy Markets and, with VACAR, assign the transactions created under the reserve sharing agreement to the SouthIMP/EXP pricing point. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM eliminate the IMO interface pricing point, and assign the transactions that originate or sink in the IESO balancing

4 Order No. 764, 139 FERC ¶ 61,246 (2012), *order on reh'g*, Order No. 764-A, 141 FERC ¶ 61231 (2012).
5 *See* Letter Order, Docket No. ER14-381-000 (June 30, 2014).
6 *See* joint statement of PJM and the MMU re Interchange Scheduling issued July 29, 2014, at: <http://www.monitoringanalytics.com/reports/Market_Messages/Messages/PJM_IMM_Statement_on_Interchange_Scheduling_20140729.pdf>.

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. New recommendation. Status: Not adopted.)

Conclusion

Transactions between PJM and multiple balancing authorities in the Eastern Interconnection are part of a single energy market. While some of these balancing authorities are termed market areas and some are termed 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.[7]

Table 9-1 Charges and credits applied to interchange transactions

	Real-Time Transactions				Day-Ahead Transactions				
Billing Item	Import (Firm or Non Firm)	Import (Spot in)	Export	Wheel	Import (Firm or Non Firm)	Import (Spot in)	Export	Wheel	Up to Congestion
Firm or Non-Firm Point-to-Point Transmission Service	X		X[1]	X[1]	X		X[1]	X[1]	
Spot Import Service		X[2]				X[2]			
Day-ahead Spot Market Energy					X	X	X		
Balancing Spot Market Energy	X	X	X						
Day-ahead Transmission Congestion					X	X	X	X	X
Balancing Transmission Congestion	X	X	X	X					X
Day-ahead Transmission Losses					X	X	X	X	X
Balancing Transmission Losses	X	X	X	X					X
PJM Scheduling, System Control and Dispatch Service - Control Area Administration	X		X	X	X		X	X	
PJM Scheduling, System Control and Dispatch Service - Market Support	X	X	X		X	X	X		X
PJM Scheduling, System Control and Dispatch Service - Advanced Second Control Center	X	X	X	X	X	X	X	X	X
PJM Scheduling, System Control and Dispatch Service - Market Support Offset	X	X	X		X	X	X		X
PJM Settlement, Inc.	X	X	X		X	X	X		X
Market Monitoring Unit (MMU) Funding	X	X	X		X	X	X		X
FERC Annual Recovery	X		X	X	X		X	X	
Organization of PJM States, Inc. (OPSI) Funding	X		X	X	X		X	X	
Synchronous Condensing			X				X		
Transmission Owner Scheduling, System Control and Dispatch Service	X		X	X	X		X	X	
Reactive Supply and Voltage Control from Generation and Other Sources Service	X		X	X	X		X	X	
Day-ahead Operating Reserve					X	X	X		
Balancing Operating Reserve	X	X	X						
Black Start Service	X		X	X	X		X	X	
Marginal Loss Surplus Allocation (for those paying for transmission service only)			X				X		

1 No charge if Point of Delivery is MISO
2 No charge for spot in transmission

7 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>.

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.[8] 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.

Table 9-2 shows the real-time and day-ahead scheduled interchange totals for the first six months of 2018 and 2019. In the first six months of 2019, gross imports in the Day-Ahead Energy Market were 128.0 percent of gross imports in the Real-Time Energy Market (187.7 percent in the first six months of 2018). In the first six months of 2019, gross exports in the Day-Ahead Energy Market were 472.6 percent of gross exports in the Real-Time Energy Market (134.7 percent in the first six months of 2018).

Table 9-2 Real-time and day-ahead scheduled interchange volumes (GWh): January through June, 2018 and 2019

Category	Jan-Jun 2018	Jan-Jun 2019	Percent Change
Real-Time Gross Imports	10,683.0	5,794.8	(45.8%)
Real-Time Gross Exports	15,220.3	21,561.9	41.7%
Real-Time Net Interchange	(4,537.3)	(15,767.1)	(247.5%)
Day-Ahead Gross Imports	19,985.3	27,386.1	37.0%
Day-Ahead Gross Exports	20,502.1	27,604.4	34.6%
Day-Ahead Net Interchange	(516.8)	(218.3)	57.8%
Monthly Average Real-Time Gross Exports	2,536.7	3,593.6	41.7%
Monthly Average Real-Time Gross Imports	1,780.5	965.8	(45.8%)
Monthly Average Day-Ahead Gross Exports	3,417.0	4,600.7	34.6%
Monthly Average Day-Ahead Gross Imports	3,330.9	4,564.3	37.0%

In the first six months of 2019, PJM was a monthly net exporter of energy in the Real-Time Energy Market in all months. In the first six months of 2019, PJM was a monthly net exporter of energy in the Day-Ahead Energy Market in February and June, and a net importer of energy in the remaining months (Figure 9-1).[9]

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.[10] In the first six 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.

8 See "Ohio Valley Electric Corporation: Company Background," <http://www.ovec.com/OVECHistory.pdf> (October 15, 2014).

9 Calculated values shown in Section 9, "Interchange Transactions," are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

10 Up to congestion transactions create financial obligations to deliver in real time, but do not pay operating reserve charges.

Figure 9-1 Scheduled imports and exports: January through June, 2019

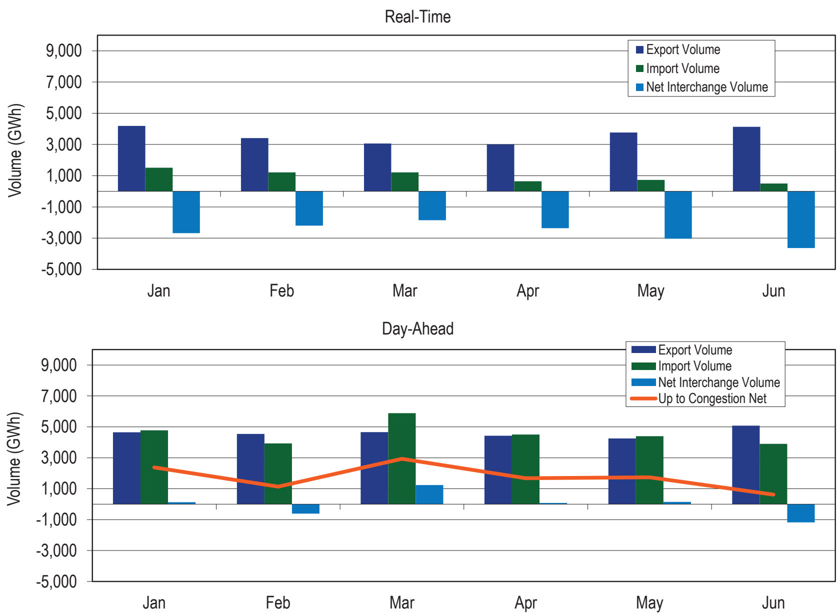
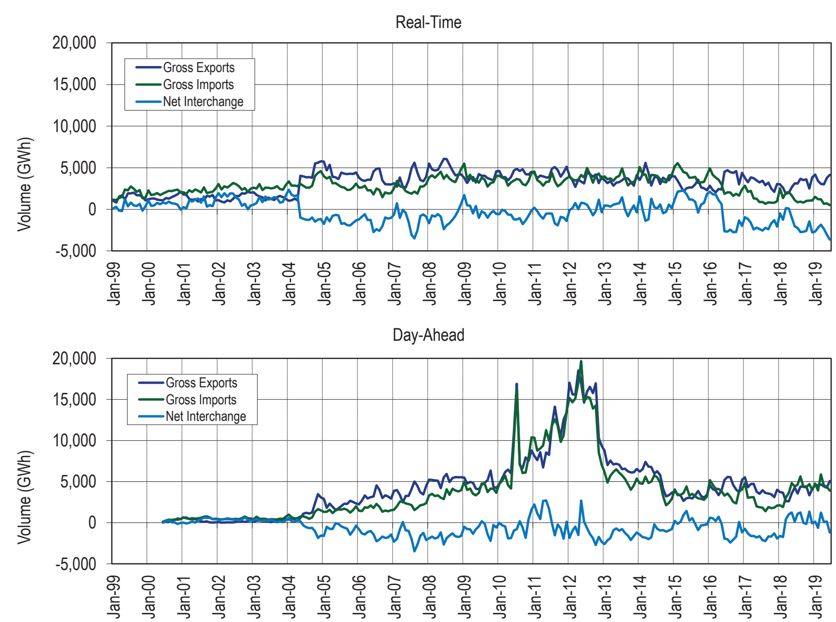


Figure 9-2 shows the real-time and day-ahead import and export volume for PJM from January 1999 through June 2019. PJM shifted from a consistent net importer of energy to relatively consistent net exporter of energy in 2004 in both the Real-Time and Day-Ahead Energy Markets, coincident with the expansion of the PJM footprint that included the integrations of Commonwealth Edison, American Electric Power and Dayton Power and 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 June 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 six months of 2019. Figure 9-3 shows the approximate geographic location of the interfaces. In the first six 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 six 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 six 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 61.7 percent of the total net scheduled exports: PJM/Cinergy (CIN) with 31.2 percent, PJM/MidAmerican Energy Company (MEC) with 15.8 percent and PJM/Neptune (NEPT) with 14.8 percent of the net scheduled export volume. The four separate interfaces that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT, PJM/HUDS and PJM/Linden (LIND)) together represented 35.0 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 64.9 percent of the total net PJM scheduled exports in the Real-Time Energy Market.

In the Real-Time Energy Market, in the first six 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 96.3 percent of the total net scheduled imports: PJM/Ameren-Illinois (AMIL) with 36.0 percent, PJM/ Duke Energy Corp. (DUK) with 42.8 percent and PJM/Carolina Power and Light East (CPLE) with 17.5 percent of the net scheduled import volume.[11] The four separate interfaces that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT, PJM/HUDS and PJM/Linden (LIND)) had net scheduled exports in the Real-Time Energy Market. 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 36.0 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 June, 2019

	Jan	Feb	Mar	Apr	May	Jun	Total
CPLE	46.6	102.2	80.6	0.3	28.5	14.9	273.1
CPLW	(0.0)	0.0	0.3	0.0	0.0	0.0	0.2
DUK	(7.0)	265.4	243.5	81.0	54.8	29.2	667.0
LGEE	22.9	30.5	(4.9)	(11.9)	8.5	(62.2)	(17.1)
MISO	(1,235.4)	(1,568.2)	(756.4)	(1,764.8)	(2,635.6)	(2,723.9)	(10,684.2)
ALTE	(221.4)	(313.8)	(52.3)	(253.5)	(353.2)	(360.0)	(1,554.1)
ALTW	(5.3)	0.6	(4.6)	0.0	(57.6)	(21.0)	(88.0)
AMIL	316.0	106.1	157.8	8.3	4.6	(32.3)	560.5
CIN	(793.1)	(826.3)	(488.5)	(848.5)	(1,258.4)	(1,184.4)	(5,399.1)
CWLP	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)	(626.1)
MEC	(536.0)	(435.1)	(400.4)	(434.5)	(469.0)	(454.4)	(2,729.5)
MECS	129.6	(10.2)	113.2	(70.0)	(182.6)	(250.3)	(270.4)
NIPS	(4.3)	3.9	(0.3)	0.0	(13.8)	0.0	(14.4)
WEC	(84.4)	(58.5)	(22.8)	(39.3)	(140.7)	(217.3)	(563.1)
NYISO	(1,558.3)	(1,124.8)	(1,425.5)	(705.0)	(443.0)	(806.3)	(6,062.9)
HUDS	(204.6)	(91.7)	(164.3)	(97.9)	(11.2)	(103.1)	(672.8)
LIND	(227.9)	(199.4)	(226.6)	(137.2)	(142.6)	(141.5)	(1,075.3)
NEPT	(464.5)	(436.9)	(496.3)	(344.5)	(411.8)	(409.0)	(2,563.0)
NYIS	(661.2)	(396.8)	(538.3)	(125.4)	122.5	(152.6)	(1,751.9)
TVA	52.5	96.0	8.1	39.9	(51.0)	(88.9)	56.7
Total	(2,678.7)	(2,198.9)	(1,854.3)	(2,360.4)	(3,037.8)	(3,637.1)	(15,767.1)

11 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 June, 2019

	Jan	Feb	Mar	Apr	May	Jun	Total
CPLE	161.9	144.3	165.6	55.3	83.1	71.0	681.2
CPLW	0.0	0.0	0.3	0.0	0.0	0.0	0.3
DUK	299.5	402.5	293.4	188.3	162.9	145.3	1,491.9
LGEE	113.4	101.6	93.3	48.5	114.3	21.0	492.1
MISO	665.3	290.4	468.2	113.6	93.0	51.1	1,681.7
ALTE	38.7	19.1	71.2	25.1	4.1	7.2	165.5
ALTW	0.1	0.6	0.0	0.0	0.0	0.0	0.6
AMIL	334.0	139.1	172.3	19.9	54.9	4.0	724.1
CIN	31.0	24.9	43.3	9.8	9.4	15.1	133.3
CWLP	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	14.7
MEC	19.2	17.1	24.1	21.7	19.7	16.4	118.4
MECS	231.4	77.7	152.0	23.9	3.2	4.9	493.0
NIPS	0.5	4.2	0.0	0.0	0.0	0.0	4.7
WEC	6.4	4.8	1.5	13.0	0.3	1.1	27.3
NYISO	163.0	125.9	125.3	141.0	237.1	168.9	961.2
HUDS	0.0	0.0	0.0	0.0	0.0	0.0	0.1
LIND	0.0	0.7	0.1	1.7	8.8	1.7	13.0
NEPT	0.0	0.0	0.0	0.0	0.0	0.0	0.1
NYIS	163.0	125.2	125.2	139.3	228.3	167.1	948.1
TVA	104.3	144.6	62.4	96.9	37.7	40.6	486.5
Total	1,507.5	1,209.2	1,208.5	643.7	728.0	497.9	5,794.8

Table 9-5 Real-time scheduled gross export volume by interface (GWh): January through June, 2019

	Jan	Feb	Mar	Apr	May	Jun	Total
CPLE	115.3	42.0	84.9	55.0	54.7	56.1	408.1
CPLW	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	824.9
LGEE	90.4	71.1	98.3	60.4	105.8	83.2	509.2
MISO	1,900.7	1,858.7	1,224.6	1,878.4	2,728.6	2,775.0	12,365.8
ALTE	260.1	332.9	123.6	278.6	357.3	367.2	1,719.5
ALTW	5.4	0.0	4.6	0.0	57.6	21.0	88.6
AMIL	17.9	33.0	14.6	11.6	50.3	36.3	163.7
CIN	824.0	851.1	531.7	858.3	1,267.8	1,199.5	5,532.5
CWLP	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	640.8
MEC	555.3	452.3	424.5	456.2	488.7	470.9	2,847.9
MECS	101.9	87.9	38.8	93.9	185.8	255.2	763.4
NIPS	4.8	0.3	0.3	0.0	13.8	0.0	19.1
WEC	90.8	63.4	24.4	52.4	141.0	218.4	590.3
NYISO	1,721.3	1,250.6	1,550.8	846.0	680.1	975.2	7,024.1
HUDS	204.6	91.7	164.3	97.9	11.2	103.1	672.9
LIND	228.0	200.0	226.7	138.9	151.4	143.3	1,088.3
NEPT	464.5	436.9	496.3	344.5	411.8	409.0	2,563.0
NYIS	824.2	522.0	663.5	264.7	105.7	319.7	2,699.9
TVA	51.8	48.6	54.3	57.0	88.6	129.4	429.8
Total	4,186.1	3,408.1	3,062.8	3,004.1	3,765.8	4,135.0	21,561.9

Real-Time Interface Pricing Point Imports and Exports

Interfaces differ from interface pricing points. An interface is a point of interconnection between PJM and a neighboring balancing authority which market participants may designate as a path on which scheduled imports or exports will flow.[12] An interface pricing point defines the price at which transactions are priced, and is based on the path of the actual, physical transfer of energy. While a market participant designates a scheduled path from a generation control area (GCA) to a load control area (LCA), this path reflects the scheduled path as defined by the transmission reservations only, and may not reflect how the energy actually flows from the GCA to LCA. For example, the import transmission path from LG&E Energy, L.L.C. (LGEE), through MISO and into PJM would show the transfer of power into PJM at the PJM/MISO Interface based on the scheduled path of the transaction. However,

12 There are multiple paths between any generation and load balancing authority. Market participants select the path based on transmission service availability and the transmission costs for moving energy from generation to load and interface prices.

the physical flow of energy does not enter the PJM footprint at the PJM/MISO Interface, but enters PJM at the southern boundary. For this reason, PJM prices an import with the GCA of LGEE at the SouthIMP interface pricing point rather than the MISO pricing point.

Interfaces differ from interface pricing points. The challenge is to create interface prices, composed of external pricing points, which accurately represent the locational price impact of flows between PJM and external sources of energy and that reflect the underlying economic fundamentals across balancing authority borders.[13]

Transactions can be scheduled to an interface based on a contract transmission path, but pricing points are developed and applied based on the estimated electrical impact of the external power source on PJM tie lines, regardless of the contract transmission path.[14] PJM establishes prices for transactions with external balancing authorities by assigning interface pricing points to individual balancing authorities based on the generation control area and load control area as specified on the NERC Tag. Dynamic interface pricing calculations use actual system conditions to determine a set of weights for each external pricing point in an interface price definition. The weights are designed so that the interface price reflects actual system conditions. However, the weights are an approximation given the complexity of the transmission network outside PJM and the dynamic nature of power flows. Table 9-19 presents the interface pricing points used in the first six 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 of all balancing authorities in the Western Interconnection, only Nevada Power Company (NEVP) is mapped to the SouthIMP interface pricing point. The MMU recommends that PJM review these mappings, at least annually, to reflect the fact that changes to the system topology can affect the impact of external power sources on PJM.

The interface pricing method implies that the weighting factors reflect the actual system flows in a dynamic manner. In fact, the weightings are static, and are modified by PJM only occasionally.[15] The MMU recommends that PJM monitor, and adjust as necessary, the weights applied to the components of the interfaces to ensure that the interface prices reflect ongoing changes in system conditions.

The contract transmission path only reflects the path of energy into or out of PJM to one neighboring balancing authority. The NERC Tag requires the complete path to be specified from the generation control area (GCA) to the load control area (LCA), but participants do not always do so. The NERC Tag path is used by PJM to determine the interface pricing point that PJM assigns to the transaction. This approach will correctly identify the interface pricing point only if the market participant provides the complete path in the Tag. This approach will not correctly identify the interface pricing point if the market participant breaks the transaction into portions, each with a separate Tag. The breaking of transactions into portions can be a way to manipulate markets and the result of such behavior can be incorrect and noncompetitive pricing of transactions.

There are several pricing points mapped to the region south of PJM. The SouthIMP and SouthEXP pricing points serve as the default pricing point for transactions at the southern border of PJM. The CPLEEXP, CPLEIMP, DUKEXP, DUKIMP, NCMPAEXP and NCMPAIMP were also established to account for various special agreements with neighboring balancing areas, and PJM continued to use the Southwest pricing point for certain grandfathered transactions which have since expired.[16]

In the Real-Time Energy Market, in the first six months of 2019, there were net scheduled exports at nine of PJM's 17 interface pricing points eligible for real-time transactions.[17] The top three net exporting interface pricing points in the Real-Time Energy Market accounted for 80.6 percent of the total net scheduled exports: PJM/MISO with 59.1 percent, PJM/NEPTUNE with 12.6

13 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.

14 See "Interface Pricing Point Assignment Methodology," (August 28, 2014) <http://www.pjm.com/~/media/etools/exschedule/interface-pricing-point-assignment-methodology.ashx>. PJM periodically updates these definitions on its website.

15 On June 1, 2015, PJM began using a dynamic weighting factor in the calculation for the Ontario Interface Pricing Point.

16 Use of the Southwest pricing point for grandfathered transactions is not appropriate, and the MMU recommends that no further such agreements be entered into.

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

percent and PJM/SouthEXP with 8.8 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 29.9 percent of the total net PJM scheduled exports in the Real-Time Energy Market.

In the Real-Time Energy Market, in the first six 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 86.2 percent of the total net scheduled imports: PJM/SouthIMP with 71.1 percent and PJM/NCMPAIMP with 15.1 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.[18]

Table 9-6 Real-time scheduled net interchange volume by interface pricing point (GWh): January through June, 2019

	Jan	Feb	Mar	Apr	May	Jun	Total
IMO	193.2	86.2	82.4	7.8	8.5	4.6	382.6
MISO	(1,858.3)	(1,798.4)	(1,089.5)	(1,817.4)	(2,691.6)	(2,731.2)	(11,986.5)
NORTHWEST	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)	(6,067.6)
HUDSONTP	(204.6)	(91.7)	(164.3)	(97.9)	(11.2)	(103.1)	(672.8)
LINDENVFT	(227.9)	(199.4)	(226.6)	(137.2)	(142.6)	(141.5)	(1,075.3)
NEPTUNE	(464.5)	(436.9)	(496.3)	(344.5)	(411.8)	(409.0)	(2,563.0)
NYIS	(662.3)	(396.8)	(538.3)	(127.7)	121.2	(152.7)	(1,756.5)
Southern Imports	1,110.8	948.9	883.8	442.0	453.5	285.7	4,124.6
CPLEIMP	0.0	1.0	0.5	0.1	0.2	0.0	1.7
DUKIMP	40.2	42.7	69.0	38.0	37.5	12.0	239.4
NCMPAIMP	149.6	145.5	107.9	71.2	91.6	114.2	680.0
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHIMP	921.0	759.7	706.4	332.6	324.2	159.4	3,203.4
Southern Exports	(565.1)	(310.7)	(305.5)	(285.5)	(363.8)	(389.8)	(2,220.3)
CPLEEXP	(71.4)	(9.3)	(23.1)	(25.0)	(19.3)	(13.5)	(161.6)
DUKEXP	(137.8)	(86.6)	(10.1)	(37.9)	(1.9)	(0.3)	(274.6)
NCMPAEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	(0.1)	(1.3)	0.0	(1.4)
SOUTHWEST	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)	(1,782.7)
Total	(2,678.7)	(2,198.9)	(1,854.3)	(2,360.4)	(3,037.8)	(3,637.1)	(15,767.1)

18 In the Real-Time Energy Market, three PJM interface pricing points had a net interchange of zero (Northwest, Southwest and NCMPAEXP).

Table 9-7 Real-time scheduled gross import volume by interface pricing point (GWh): January through June, 2019

	Jan	Feb	Mar	Apr	May	Jun	Total
IMO	196.6	88.0	83.2	9.3	8.5	6.6	392.2
MISO	38.1	46.5	116.1	53.7	30.3	36.8	321.5
NORTHWEST	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	956.5
HUDSONTP	0.0	0.0	0.0	0.0	0.0	0.0	0.1
LINDENVFT	0.0	0.7	0.1	1.7	8.8	1.7	13.0
NEPTUNE	0.0	0.0	0.0	0.0	0.0	0.0	0.1
NYIS	161.9	125.2	125.2	137.1	226.9	167.1	943.4
Southern Imports	1,110.8	948.9	883.8	442.0	453.5	285.7	4,124.6
CPLEIMP	0.0	1.0	0.5	0.1	0.2	0.0	1.7
DUKIMP	40.2	42.7	69.0	38.0	37.5	12.0	239.4
NCMPAIMP	149.6	145.5	107.9	71.2	91.6	114.2	680.0
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHIMP	921.0	759.7	706.4	332.6	324.2	159.4	3,203.4
Southern Exports	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CPLEEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	1,507.5	1,209.2	1,208.5	643.7	728.0	497.9	5,794.8

Table 9-8 Real-time scheduled gross export volume by interface pricing point (GWh): January through June, 2019

	Jan	Feb	Mar	Apr	May	Jun	Total
IMO	3.4	1.8	0.9	1.5	0.0	2.0	9.6
MISO	1,896.4	1,844.9	1,205.6	1,871.1	2,722.0	2,768.0	12,307.9
NORTHWEST	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	7,024.1
HUDSONTP	204.6	91.7	164.3	97.9	11.2	103.1	672.9
LINDENVFT	228.0	200.0	226.7	138.9	151.4	143.3	1,088.3
NEPTUNE	464.5	436.9	496.3	344.5	411.8	409.0	2,563.0
NYIS	824.2	522.0	663.5	264.7	105.7	319.7	2,699.9
Southern Imports	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CPLEIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Southern Exports	565.1	310.7	305.5	285.5	363.8	389.8	2,220.3
CPLEEXP	71.4	9.3	23.1	25.0	19.3	13.5	161.6
DUKEXP	137.8	86.6	10.1	37.9	1.9	0.3	274.6
NCMPAEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.1	1.3	0.0	1.4
SOUTHWEST	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	1,782.7
Total	4,186.1	3,408.1	3,062.8	3,004.1	3,765.8	4,135.0	21,561.9

Day-Ahead Interface Imports and Exports

In the Day-Ahead Energy Market, as in the Real-Time Energy Market, scheduled imports and exports are determined by the scheduled path, which is the transmission path a market participant selects from the original source to the final sink. Entering external energy transactions in the Day-Ahead Energy Market requires fewer steps than in the Real-Time Energy Market. Market participants need to acquire a valid, willing to pay congestion (WPC) OASIS reservation to prove that their day-ahead schedule could be supported in the Real-Time Energy Market.[19] Day-ahead energy market schedules need to be cleared through the day-ahead energy market process in order to become an approved schedule. The day-ahead energy market transactions are financially binding, but will not physically flow unless they are also submitted in the Real-Time Energy Market. In the Day-Ahead Energy Market, a market participant

19 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.[20]

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 six 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 six 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 66.0 percent of the total net scheduled exports: PJM/ MidAmerican Energy Company (MEC) with 23.8 percent, PJM/Neptune (NEPT) with 21.9 percent and PJM/Cinergy (CIN) with 20.3 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 40.4 percent of the total net PJM scheduled exports in the Day-Ahead Energy Market. In the first six 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 57.6 percent of the total net PJM exports in the Day-Ahead Energy Market.

In the Day-Ahead Energy Market, in the first six 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/CPLE[21] with 51.0 percent and PJM/Duke Energy Corp. (DUK) with 49.0 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 six 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.[22]

20 See the *2010 State of the Market Report for PJM*, Volume 2, Section 4, "Interchange Transactions," for details.

21 The Progress Energy Carolinas (PEC) LMP is defined as the Carolina Power and Light (East) (CPLE) pricing point.

22 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 June, 2019

	Jan	Feb	Mar	Apr	May	Jun	Total
CPLE	159.7	130.7	88.9	20.6	83.2	55.5	538.5
CPLW	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	516.8
LGEE	0.0	0.0	0.0	0.0	(48.4)	(0.0)	(48.5)
MISO	(1,270.9)	(1,187.1)	(757.2)	(1,156.1)	(1,187.0)	(1,207.4)	(6,765.8)
ALTE	(198.1)	(220.9)	(65.7)	(170.8)	(232.3)	(245.6)	(1,133.5)
ALTW	(3.9)	0.0	0.0	0.0	(46.6)	(23.5)	(74.0)
AMIL	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)	(2,386.1)
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MEC	(525.0)	(443.0)	(398.5)	(468.2)	(487.9)	(469.9)	(2,792.5)
MECS	(34.7)	(54.1)	0.3	(15.4)	(20.3)	(26.3)	(150.5)
NIPS	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)	(229.3)
NYISO	(1,227.8)	(835.5)	(1,089.0)	(540.2)	(421.3)	(637.9)	(4,751.7)
HUDS	(106.9)	(38.3)	(49.1)	(37.3)	(4.9)	(35.2)	(271.8)
LIND	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)	(2,576.1)
NYIS	(663.8)	(355.9)	(541.0)	(150.4)	0.7	(193.4)	(1,903.8)
TVA	(15.0)	(15.5)	(34.5)	(22.7)	(42.1)	(57.5)	(187.3)
Total without Up To Congestion	(2,249.9)	(1,745.7)	(1,699.8)	(1,605.0)	(1,597.8)	(1,799.6)	(10,697.8)
Up To Congestion	2,376.2	1,131.3	2,930.3	1,681.5	1,740.5	619.8	10,479.5
Total	126.3	(614.4)	1,230.4	76.4	142.7	(1,179.8)	(218.3)

Table 9-10 Day-ahead scheduled gross import volume by interface (GWh): January through June, 2019

	Jan	Feb	Mar	Apr	May	Jun	Total
CPLE	207.7	159.5	142.5	52.9	106.6	86.7	755.9
CPLW	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	599.5
LGEE	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	163.5
ALTE	3.7	3.4	33.6	4.5	1.1	0.0	46.3
ALTW	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
CIN	4.4	3.5	10.7	1.1	1.6	3.6	24.9
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MEC	1.7	0.0	0.0	1.1	0.0	0.0	2.8
MECS	47.1	31.4	7.0	1.4	0.3	2.3	89.5
NIPS	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
NYISO	37.2	19.4	0.2	8.8	49.6	24.7	139.9
HUDS	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
NEPT	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	139.9
TVA	0.0	0.0	0.0	4.6	0.5	8.0	13.1
Total without Up To Congestion	405.8	379.0	287.4	183.0	207.4	209.2	1,671.9
Up To Congestion	4,365.8	3,552.0	5,600.3	4,317.6	4,188.1	3,690.4	25,714.2
Total	4,771.6	3,931.0	5,887.7	4,500.6	4,395.5	3,899.6	27,386.1

Table 9-11 Day-ahead scheduled gross export volume by interface (GWh): January through June, 2019

	Jan	Feb	Mar	Apr	May	Jun	Total
CPLE	48.0	28.9	53.6	32.3	23.4	31.2	217.4
CPLW	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	82.7
LGEE	0.0	0.0	0.0	0.0	48.4	0.0	48.5
MISO	1,327.8	1,225.5	808.5	1,164.2	1,190.0	1,213.3	6,929.3
ALTE	201.8	224.3	99.3	175.3	233.4	245.6	1,179.7
ALTW	3.9	0.0	0.0	0.0	46.6	23.5	74.0
AMIL	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	2,411.0
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MEC	526.7	443.0	398.5	469.3	487.9	469.9	2,795.3
MECS	81.8	85.5	6.7	16.7	20.6	28.7	239.9
NIPS	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	229.3
NYISO	1,264.9	854.9	1,089.3	549.0	470.9	662.6	4,891.6
HUDS	106.9	38.3	49.1	37.3	4.9	35.2	271.8
LIND	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	2,576.1
NYIS	700.9	375.3	541.2	159.3	48.9	218.1	2,043.7
TVA	15.0	15.5	34.5	27.4	42.5	65.5	200.3
Total without Up To Congestion	2,655.7	2,124.7	1,987.3	1,788.1	1,805.2	2,008.7	12,369.7
Up To Congestion	1,989.6	2,420.7	2,670.0	2,636.1	2,447.6	3,070.7	15,234.7
Total	4,645.3	4,545.4	4,657.3	4,424.2	4,252.8	5,079.4	27,604.4

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 six months of 2019, up to congestion transactions accounted for 93.9 percent of all scheduled import MW transactions and 55.2 percent of all scheduled export MW transactions in the Day-Ahead Energy Market. The day-ahead net scheduled interchange in the first six 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 six 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 six months of 2019, the day-ahead net scheduled interchange at the NIPSCO interface pricing point was -6,143.2 GWh (Table 9-12). Table 9-13 shows that all -6,143.2 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 six 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 76.4 percent of the total net scheduled exports: PJM/NIPSCO with 47.7 percent, PJM/MISO with 13.5 percent and PJM/SouthEXP with 15.3 percent of the net scheduled export volume. The four separate interface pricing points that connect PJM to the NYISO (PJM/NYIS, PJM/NEPTUNE, PJM/HUDSONTP and PJM/LINDENVFT) together represented 21.8 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 six 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 90.1 percent of the total net scheduled imports: PJM/NORTHWEST with 49.1 percent, PJM/SouthImp with 34.2 percent and PJM/NCMPAIMP with 6.9 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 3.8 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.

In the Day-Ahead Energy Market, in the first six 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 94.7 percent of the total net up to congestion scheduled exports: PJM/NIPSCO with 74.6 percent and PJM/SouthEXP with 20.1 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 5.3 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 six 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: PJM/NORTHWEST with 47.7 percent, PJM/SouthIMP with 22.0 percent and PJM/MISO with 12.9 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 15.2 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 June, 2019

	Jan	Feb	Mar	Apr	May	Jun	Total
IMO	120.3	82.9	51.3	32.5	54.7	150.1	491.8
MISO	(405.0)	(801.4)	232.2	(428.0)	(136.2)	(195.8)	(1,734.3)
NIPSCO	(524.1)	(412.7)	(1,318.9)	(1,253.0)	(1,303.6)	(1,330.9)	(6,143.2)
NORTHWEST	1,323.3	(117.7)	1,739.0	1,137.7	977.9	1,158.8	6,219.0
NYISO	(1,126.4)	(632.1)	(641.4)	(13.6)	306.6	(221.2)	(2,328.1)
HUDSONTP	(218.7)	(288.3)	(75.0)	(92.3)	30.2	(49.0)	(693.1)
LINDENVFT	99.2	0.5	118.8	117.8	89.3	56.5	482.0
NEPTUNE	(308.0)	(184.3)	(224.1)	(150.8)	(91.2)	(191.3)	(1,149.7)
NYIS	(698.8)	(160.1)	(461.0)	111.7	278.3	(37.4)	(967.3)
Southern Imports	939.8	1,448.3	1,377.0	809.1	624.1	282.3	5,480.7
CPLEIMP	53.3	23.6	28.2	1.0	1.7	0.6	108.4
DUKIMP	26.8	51.6	29.3	35.8	9.3	13.8	166.5
NCMPAIMP	180.7	176.8	140.2	98.6	128.0	149.6	873.9
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHIMP	679.1	1,196.3	1,179.2	673.8	485.2	118.3	4,331.9
Southern Exports	(201.6)	(181.6)	(208.8)	(208.3)	(380.8)	(1,023.2)	(2,204.2)
CPLEEXP	(45.1)	(27.1)	(50.8)	(37.6)	(21.8)	(29.9)	(212.3)
DUKEXP	0.0	0.0	0.0	(8.4)	(5.1)	(1.0)	(14.5)
NCMPAEXP	0.0	0.0	0.0	0.0	(0.6)	0.0	(0.6)
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEXP	(156.4)	(154.6)	(158.0)	(162.3)	(353.3)	(992.2)	(1,976.7)
Total	126.3	(614.4)	1,230.4	76.4	142.7	(1,179.8)	(218.3)

Table 9-13 Up to congestion scheduled net interchange volume by interface pricing point (GWh): January through June, 2019

	Jan	Feb	Mar	Apr	May	Jun	Total
IMO	74.4	49.9	43.3	31.1	54.4	147.8	400.7
MISO	431.1	(6.9)	610.7	268.1	566.2	552.4	2,421.5
NIPSCO	(524.1)	(412.7)	(1,318.9)	(1,253.0)	(1,303.6)	(1,330.9)	(6,143.2)
NORTHWEST	1,812.5	315.9	2,124.9	1,599.1	1,458.6	1,620.3	8,931.3
NYISO	92.9	195.4	447.7	526.6	732.2	416.8	2,411.6
HUDSONTP	(120.4)	(258.6)	(27.1)	(55.0)	35.2	(13.8)	(439.6)
LINDENVFT	99.2	0.5	118.8	117.8	89.3	56.5	482.0
NEPTUNE	149.1	257.1	274.8	201.5	325.8	218.0	1,426.3
NYIS	(35.0)	196.5	81.1	262.2	281.9	156.1	942.8
Southern Imports	628.0	1,127.0	1,141.1	643.0	469.1	103.7	4,112.0
CPLEIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHIMP	628.0	1,127.0	1,141.1	643.0	469.1	103.7	4,112.0
Southern Exports	(138.5)	(137.3)	(118.5)	(133.4)	(236.5)	(890.3)	(1,654.5)
CPLEEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEXP	(138.5)	(137.3)	(118.5)	(133.4)	(236.5)	(890.3)	(1,654.5)
Total Interfaces	2,376.2	1,131.3	2,930.3	1,681.5	1,740.5	619.8	10,479.5
INTERNAL	9,708.1	9,029.3	10,124.5	9,316.8	8,678.5	7,500.9	54,358.1
Total	12,084.3	10,160.6	13,054.8	10,998.2	10,419.0	8,120.6	64,837.6

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 9-14 Day-ahead scheduled gross import volume by interface pricing point (GWh): January through June, 2019

	Jan	Feb	Mar	Apr	May	Jun	Total
IMO	152.0	135.3	80.3	95.8	80.5	188.1	732.0
MISO	863.4	515.5	1,137.6	840.0	949.5	894.5	5,200.3
NIPSCO	112.2	133.2	156.6	103.1	111.4	108.9	725.4
NORTHWEST	2,074.1	969.4	2,320.0	1,818.3	1,580.8	1,746.0	10,508.5
NYISO	630.1	729.4	816.3	834.3	1,049.2	679.8	4,739.1
HUDSONTP	43.1	43.7	80.1	43.7	118.4	40.5	369.5
LINDENVFT	154.0	103.2	173.2	170.5	186.0	108.0	894.8
NEPTUNE	207.3	293.3	309.0	257.1	365.2	264.2	1,696.1
NYIS	225.8	289.3	254.0	362.9	379.6	267.1	1,778.6
Southern Imports	939.8	1,448.3	1,377.0	809.1	624.1	282.3	5,480.7
CPLEIMP	53.3	23.6	28.2	1.0	1.7	0.6	108.4
DUKIMP	26.8	51.6	29.3	35.8	9.3	13.8	166.5
NCMPAIMP	180.7	176.8	140.2	98.6	128.0	149.6	873.9
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHIMP	679.1	1,196.3	1,179.2	673.8	485.2	118.3	4,331.9
Southern Exports	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CPLEEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	4,771.6	3,931.0	5,887.7	4,500.6	4,395.5	3,899.6	27,386.1

Table 9-15 Up to congestion scheduled gross import volume by interface pricing point (GWh): January through June, 2019

	Jan	Feb	Mar	Apr	May	Jun	Total
IMO	104.9	102.3	71.2	94.5	80.2	185.7	638.6
MISO	853.6	510.1	1,095.4	833.3	946.8	890.9	5,130.1
NIPSCO	112.2	133.2	156.6	103.1	111.4	108.9	725.4
NORTHWEST	2,074.1	969.4	2,320.0	1,818.3	1,580.8	1,746.0	10,508.5
NYISO	593.0	710.0	816.0	825.4	999.8	655.2	4,599.5
HUDSONTP	43.1	43.7	80.1	43.7	118.4	40.5	369.5
LINDENVFT	154.0	103.2	173.2	170.5	186.0	108.0	894.8
NEPTUNE	207.3	293.3	309.0	257.1	365.2	264.2	1,696.1
NYIS	188.7	269.9	253.7	354.0	330.2	242.5	1,638.9
Southern Imports	628.0	1,127.0	1,141.1	643.0	469.1	103.7	4,112.0
CPLEIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHIMP	628.0	1,127.0	1,141.1	643.0	469.1	103.7	4,112.0
Southern Exports	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CPLEEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Interfaces	4,365.8	3,552.0	5,600.3	4,317.6	4,188.1	3,690.4	25,714.2

Table 9-16 Day-ahead scheduled gross export volume by interface pricing point (GWh): January through June, 2019

	Jan	Feb	Mar	Apr	May	Jun	Total
IMO	31.7	52.4	29.0	63.4	25.8	37.9	240.2
MISO	1,268.4	1,316.9	905.4	1,268.0	1,085.7	1,090.3	6,934.6
NIPSCO	636.4	545.9	1,475.5	1,356.1	1,415.0	1,439.8	6,868.6
NORTHWEST	750.8	1,087.1	581.0	680.6	603.0	587.2	4,289.6
NYISO	1,756.6	1,361.5	1,457.6	847.9	742.6	901.0	7,067.2
HUDSONTP	261.9	332.0	155.0	136.0	88.2	89.5	1,062.6
LINDENVFT	54.8	102.7	54.4	52.7	96.7	51.5	412.8
NEPTUNE	515.3	477.5	533.2	408.0	456.4	455.5	2,845.9
NYIS	924.6	449.3	715.0	251.1	101.3	304.5	2,745.9
Southern Imports	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CPLEIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Southern Exports	201.6	181.6	208.8	208.3	380.8	1,023.2	2,204.2
CPLEEXP	45.1	27.1	50.8	37.6	21.8	29.9	212.3
DUKEXP	0.0	0.0	0.0	8.4	5.1	1.0	14.5
NCMPAEXP	0.0	0.0	0.0	0.0	0.6	0.0	0.6
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEXP	156.4	154.6	158.0	162.3	353.3	992.2	1,976.7
Total	4,645.3	4,545.4	4,657.3	4,424.2	4,252.8	5,079.4	27,604.4

Table 9-17 Up to congestion scheduled gross export volume by interface pricing point (GWh): January through June, 2019

	Jan	Feb	Mar	Apr	May	Jun	Total
IMO	30.5	52.4	27.9	63.4	25.8	37.9	237.9
MISO	422.5	517.0	484.7	565.2	380.6	338.5	2,708.5
NIPSCO	636.4	545.9	1,475.5	1,356.1	1,415.0	1,439.8	6,868.6
NORTHWEST	261.6	653.5	195.1	219.2	122.2	125.7	1,577.2
NYISO	500.1	514.6	368.4	298.8	267.6	238.4	2,187.9
HUDSONTP	163.5	302.3	107.1	98.7	83.2	54.3	809.1
LINDENVFT	54.8	102.7	54.4	52.7	96.7	51.5	412.8
NEPTUNE	58.2	36.2	34.2	55.6	39.4	46.2	269.8
NYIS	223.7	73.4	172.6	91.8	48.3	86.3	696.1
Southern Imports	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CPLEIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Southern Exports	138.5	137.3	118.5	133.4	236.5	890.3	1,654.5
CPLEEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEXP	138.5	137.3	118.5	133.4	236.5	890.3	1,654.5
Total Interfaces	1,989.6	2,420.7	2,670.0	2,636.1	2,447.6	3,070.7	15,234.7

Table 9-18 Active scheduling interfaces: January through June, 2019[24]

	Jan	Feb	Mar	Apr	May	Jun
ALTE	Active	Active	Active	Active	Active	Active
ALTW	Active	Active	Active	Active	Active	Active
AMIL	Active	Active	Active	Active	Active	Active
CIN	Active	Active	Active	Active	Active	Active
CPLE	Active	Active	Active	Active	Active	Active
CPLW	Active	Active	Active	Active	Active	Active
CWLP	Active	Active	Active	Active	Active	Active
DUK	Active	Active	Active	Active	Active	Active
HUDS	Active	Active	Active	Active	Active	Active
IPL	Active	Active	Active	Active	Active	Active
LGEE	Active	Active	Active	Active	Active	Active
LIND	Active	Active	Active	Active	Active	Active
MEC	Active	Active	Active	Active	Active	Active
MECS	Active	Active	Active	Active	Active	Active
NEPT	Active	Active	Active	Active	Active	Active
NIPS	Active	Active	Active	Active	Active	Active
NYIS	Active	Active	Active	Active	Active	Active
TVA	Active	Active	Active	Active	Active	Active
WEC	Active	Active	Active	Active	Active	Active

Figure 9-3 PJM's footprint and its external scheduling interfaces

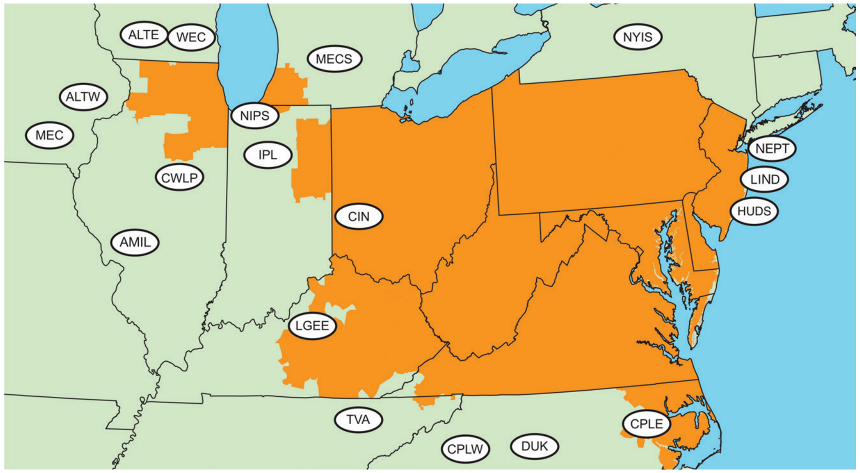


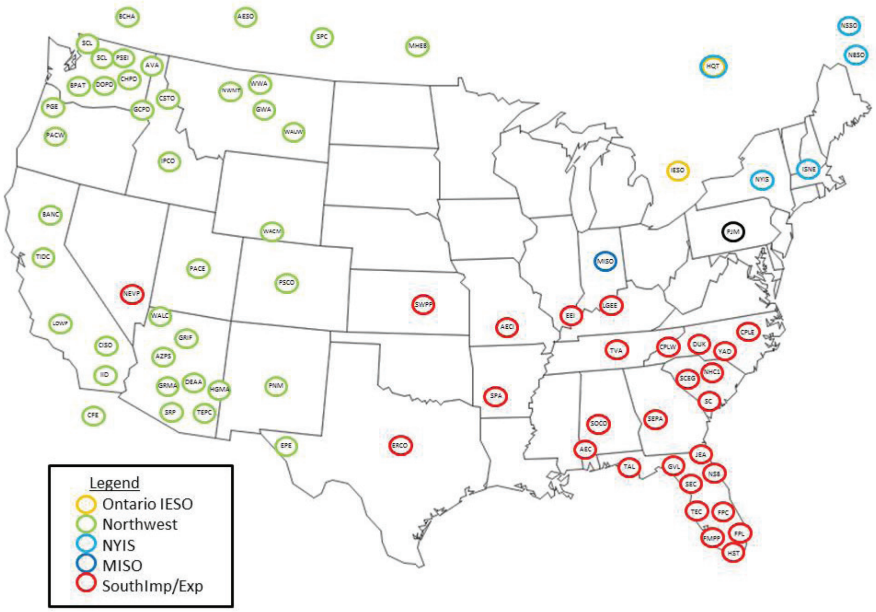
Table 9-19 Active scheduled interface pricing points: January through June, 2019[25]

	Jan	Feb	Mar	Apr	May	Jun
CPLEEXP	Active	Active	Active	Active	Active	Active
CPLEIMP	Active	Active	Active	Active	Active	Active
DUKEXP	Active	Active	Active	Active	Active	Active
DUKIMP	Active	Active	Active	Active	Active	Active
HUDSONTP	Active	Active	Active	Active	Active	Active
LINDENVFT	Active	Active	Active	Active	Active	Active
MISO	Active	Active	Active	Active	Active	Active
NCMPAEXP	Active	Active	Active	Active	Active	Active
NCMPAIMP	Active	Active	Active	Active	Active	Active
NEPTUNE	Active	Active	Active	Active	Active	Active
NIPSCO	Active	Active	Active	Active	Active	Active
Northwest	Active	Active	Active	Active	Active	Active
NYIS	Active	Active	Active	Active	Active	Active
Ontario IESO	Active	Active	Active	Active	Active	Active
Southeast	Active	Active	Active	Active	Active	Active
SOUTHEXP	Active	Active	Active	Active	Active	Active
SOUTHIMP	Active	Active	Active	Active	Active	Active
Southwest	Active	Active	Active	Active	Active	Active

24 On July 2, 2012, Duke Energy Corp. (DUK) completed a merger with Progress Energy Inc. (CPLE and CPLW). As of June 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.

25 The NIPSCO interface pricing point is valid only in the Day-Ahead Energy Market.

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 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 six months of 2019, there were net scheduled flows of 924 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.

26 See the *2012 State of the Market Report for PJM*, Volume 2, Section 8, "Interchange Transactions," for a more detailed discussion.

In the first six months of 2019, net scheduled interchange was -15,767 GWh and net actual interchange was -15,770 GWh, a difference of 3 GWh. In the first six months of 2018, net scheduled interchange was -4,537 GWh and net actual interchange was -4,572 GWh, a difference of 35 GWh. This difference is inadvertent interchange. PJM attempts to minimize the amount of accumulated inadvertent interchange by continually monitoring and correcting for inadvertent interchange. PJM can reduce the accumulation of inadvertent interchange using unilateral or bilateral paybacks.[27]

Table 9-20 shows that in the first six 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 -5,658 GWh of net actual interchange, a difference of 5,643 GWh.

Table 9-20 Net scheduled and actual PJM flows by interface (GWh): January through June, 2019

	Actual	Net Scheduled	Difference (GWh)
CPLE	398	273	125
CPLW	(322)	0	(323)
DUK	930	667	263
LGEE	1,768	(17)	1,785
MISO	(15,693)	(10,684)	(5,009)
ALTE	(1,657)	(1,554)	(103)
ALTW	(1,182)	(88)	(1,094)
AMIL	(1,579)	560	(2,139)
CIN	(3,647)	(5,399)	1,752
CWLP	(56)	0	(56)
IPL	(784)	(626)	(158)
MEC	(3,134)	(2,729)	(405)
MECS	(96)	(270)	174
NIPS	(5,658)	(14)	(5,643)
WEC	2,099	(563)	2,662
NYISO	(6,020)	(6,063)	43
HUDS	(673)	(673)	0
LIND	(1,075)	(1,075)	0
NEPT	(2,563)	(2,563)	0
NYIS	(1,709)	(1,752)	43
TVA	3,170	57	3,114
Total	(15,770)	(15,767)	(3)

27 See PJM. "PJM Manual 12: Balancing Operations," Rev. 39 (February 21, 2019).

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.

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

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.

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 (13,858 GWh) and the total southern export actual flows (-7,914 GWh) for 5,944 GWh of net imports. The net scheduled flows from the southern region are determined by summing the total southern import scheduled flows (4,125 GWh) and the total southern export scheduled flows (-2,220 GWh) for 1,904 GWh of net imports. In the first six months of 2019, the loop flows at the southern region were the difference between the southern region net scheduled flows (1,904 GW) and the southern region net actual flows (5,944 GWh) for a total of 4,039 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 June, 2019

	Actual	Net Scheduled	Difference (GWh)
IMO	0	383	(383)
MISO	(15,693)	(11,986)	(3,707)
NORTHWEST	0	0	0
NYISO	(6,020)	(6,068)	47
HUDSONTP	(673)	(673)	0
LINDENVFT	(1,075)	(1,075)	0
NEPTUNE	(2,563)	(2,563)	0
NYIS	(1,709)	(1,757)	47
Southern Imports	13,858	4,125	9,733
CPLEIMP	0	2	(2)
DUKIMP	0	239	(239)
NCMPAIMP	0	680	(680)
SOUTHEAST	0	0	0
SOUTHWEST	0	0	0
SOUTHIMP	13,858	3,203	10,654
Southern Exports	(7,914)	(2,220)	(5,694)
CPLEEXP	0	(162)	162
DUKEXP	0	(275)	275
NCMPAEXP	0	0	0
SOUTHEAST	0	(1)	1
SOUTHWEST	0	0	0
SOUTHEXP	(7,914)	(1,783)	(6,131)
Total	(15,770)	(15,767)	(3)

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 378 of the 383 GWh (98.7 percent) of gross scheduled transactions that were mapped to the IMO interface pricing point were scheduled as imports through MISO, and 5 of the 383 GWh (1.3 percent) were scheduled as imports through the NYISO.

Table 9-22 shows that in the first six months of 2019, the SouthIMP interface pricing point had the largest loop flows of any interface pricing point with 3,203 GWh of net scheduled interchange and 13,858 GWh of net actual interchange, a difference of 10,654 GWh.

Table 9-22 PJM flows by interface pricing point (GWh) (Adjusted for IMO Scheduled Interfaces): January through June, 2019

	Actual	Net Scheduled	Difference (GWh)
MISO	(15,693)	(11,609)	(4,085)
NORTHWEST	0	0	0
NYISO	(6,020)	(6,063)	43
HUDSONTP	(673)	(673)	0
LINDENVFT	(1,075)	(1,075)	0
NEPTUNE	(2,563)	(2,563)	0
NYIS	(1,709)	(1,752)	43
Southern Imports	13,858	4,125	9,733
CPLEIMP	0	2	(2)
DUKIMP	0	239	(239)
NCMPAIMP	0	680	(680)
SOUTHEAST	0	0	0
SOUTHWEST	0	0	0
SOUTHIMP	13,858	3,203	10,654
Southern Exports	(7,914)	(2,220)	(5,694)
CPLEEXP	0	(162)	162
DUKEXP	0	(275)	275
NCMPAEXP	0	0	0
SOUTHEAST	0	(1)	1
SOUTHWEST	0	0	0
SOUTHEXP	(7,914)	(1,783)	(6,131)
Total	(15,770)	(15,767)	(3)

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 six 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 (25 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 (-5,402 GWh).

Table 9-23 Net scheduled and actual flows by interface and interface pricing point (GWh): January through June, 2019

Interface	Interface Pricing Point	Actual	Net Scheduled	Difference (GWh)	Interface	Interface Pricing Point	Actual	Net Scheduled	Difference (GWh)
ALTE		(1,657)	(1,554)	(103)	IPL		(784)	(626)	(158)
	IMO	0	69	(69)		IMO	0	5	(5)
	MISO	(1,657)	(1,625)	(33)		MISO	(784)	(627)	(157)
	SOUTHEXP	0	(2)	2		SOUTHEXP	0	(4)	4
	SOUTHIMP	0	4	(4)		SOUTHIMP	0	0	(0)
ALTW		(1,182)	(88)	(1,094)	LGEE		1,768	(17)	1,785
	MISO	(1,182)	(83)	(1,098)		SOUTHEXP	(3,525)	(509)	(3,016)
	SOUTHEXP	0	(5)	5		SOUTHIMP	5,293	492	4,801
AMIL		(1,579)	560	(2,139)	LIND		(1,075)	(1,075)	0
	MISO	(1,579)	(158)	(1,420)		LINDENVFT	(1,075)	(1,075)	0
	SOUTHEXP	0	(1)	1	MEC		(3,134)	(2,729)	(405)
	SOUTHIMP	0	720	(720)		MISO	(3,134)	(2,732)	(402)
CIN		(3,647)	(5,399)	1,752		SOUTHEXP	0	(0)	0
	IMO	0	1	(1)		SOUTHIMP	0	3	(3)
	MISO	(3,647)	(5,402)	1,755	MECS		(96)	(270)	174
	SOUTHEXP	0	(27)	27		IMO	0	303	(303)
	SOUTHIMP	0	28	(28)		MISO	(96)	(751)	655
CPLE		398	273	125		SOUTHEXP	0	(9)	9
	CPLEEXP	0	(159)	159		SOUTHIMP	0	186	(186)
	CPLEIMP	0	2	(2)	NEPT		(2,563)	(2,563)	0
	DUKEXP	0	(7)	7		NEPTUNE	(2,563)	(2,563)	0
	DUKIMP	0	35	(35)	NIPS		(5,658)	(14)	(5,643)
	NCMPAIMP	0	391	(391)		MISO	(5,658)	(19)	(5,639)
	SOUTHEXP	(1,582)	(241)	(1,341)		SOUTHIMP	0	5	(5)
	SOUTHIMP	1,980	253	1,726	NYIS		(1,709)	(1,752)	43
	SOUTHEAST	0	(1)	1		IMO	0	5	(5)
CPLW		(322)	0	(323)		NYIS	(1,709)	(1,757)	47
	SOUTHEXP	(388)	(0)	(387)	TVA		3,170	57	3,114
	SOUTHIMP	65	0	65		SOUTHEXP	(1,878)	(430)	(1,449)
CWLP		(56)	0	(56)		SOUTHIMP	5,049	486	4,562
	MISO	(56)	0	(56)	WEC		2,099	(563)	2,662
DUK		930	667	263		MISO	2,099	(589)	2,688
	CPLEEXP	0	(3)	3		SOUTHEXP	0	(1)	1
	DUKEXP	0	(267)	267		SOUTHIMP	0	27	(27)
	DUKIMP	0	204	(204)	Grand Total		(15,770)	(15,767)	(3)
	NCMPAIMP	0	289	(289)					
	SOUTHEXP	(542)	(555)	13					
	SOUTHIMP	1,471	999	472					
HUDS		(673)	(673)	0					
	HUDSONTP	(673)	(673)	0					

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 six 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 (303 GWh). In the first six 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 June, 2019

Interface Pricing Point	Interface	Actual	Net Scheduled	Difference (GWh)	Interface Pricing Point	Interface	Actual	Net Scheduled	Difference (GWh)
CPLEEXP		0	(162)	162	NEPTUNE		(2,563)	(2,563)	0
	CPLE	0	(159)	159		NEPT	(2,563)	(2,563)	0
	DUK	0	(3)	3	NYIS		(1,709)	(1,757)	47
CPLEIMP		0	2	(2)		NYIS	(1,709)	(1,757)	47
	CPLE	0	2	(2)	SOUTHEAST		0	(1)	1
DUKEXP		0	(275)	275		CPLE	0	(1)	1
	CPLE	0	(7)	7	SOUTHEXP		(7,914)	(1,783)	(6,131)
	DUK	0	(267)	267		ALTE	0	(2)	2
DUKIMP		0	239	(239)		ALTW	0	(5)	5
	CPLE	0	35	(35)		AMIL	0	(1)	1
	DUK	0	204	(204)		CIN	0	(27)	27
HUDSONTP		(673)	(673)	0		CPLE	(1,582)	(241)	(1,341)
	HUDS	(673)	(673)	0		CPLW	(388)	(0)	(387)
IMO		0	383	(383)		DUK	(542)	(555)	13
	ALTE	0	69	(69)		IPL	0	(4)	4
	CIN	0	1	(1)		LGEE	(3,525)	(509)	(3,016)
	IPL	0	5	(5)		MEC	0	(0)	0
	MECS	0	303	(303)		MECS	0	(9)	9
	NYIS	0	5	(5)		TVA	(1,878)	(430)	(1,449)
LINDENVFT		(1,075)	(1,075)	0		WEC	0	(1)	1
	LIND	(1,075)	(1,075)	0	SOUTHIMP		13,858	3,203	10,654
MISO		(15,693)	(11,986)	(3,707)		ALTE	0	4	(4)
	ALTE	(1,657)	(1,625)	(33)		AMIL	0	720	(720)
	ALTW	(1,182)	(83)	(1,098)		CIN	0	28	(28)
	AMIL	(1,579)	(158)	(1,420)		CPLE	1,980	253	1,726
	CIN	(3,647)	(5,402)	1,755		CPLW	65	0	65
	CWLP	(56)	0	(56)		DUK	1,471	999	472
	IPL	(784)	(627)	(157)		IPL	0	0	(0)
	MEC	(3,134)	(2,732)	(402)		LGEE	5,293	492	4,801
	MECS	(96)	(751)	655		MEC	0	3	(3)
	NIPS	(5,658)	(19)	(5,639)		MECS	0	186	(186)
	WEC	2,099	(589)	2,688		NIPS	0	5	(5)
NCMPAIMP		0	680	(680)		TVA	5,049	486	4,562
	CPLE	0	391	(391)		WEC	0	27	(27)
	DUK	0	289	(289)	Grand Total		(15,770)	(15,767)	(3)

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.

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).

Area Control Error (ACE) Data

Area Control Error (ACE) data provides information about how well each balancing authority is matching their generation with their load. This information, combined with the scheduled and actual interchange values will show whether an individual balancing authority is pushing on or leaning on the interconnection, contributing to loop flows.

NERC makes real-time ACE graphs available on their Reliability Coordinator Information System (RCIS) website. This information is presented only in graphical form, and the underlying data is not available for analysis.

Market Flow Impact Data

In addition to interchange transactions, internal dispatch can also affect flows on balancing authorities' tie lines. The impact of internal dispatch on tie lines is called market flow. Market flow data are imported in the IDC, but there is only limited historical data, as only market flow data related to TLR levels 3 or higher are required to be made available via a Congestion Management Report (CMR). The remaining data are deleted.

There is currently a project in development through the NERC Operating Reliability Subcommittee (ORS) called the Market Flow Impact Tool. The purpose of this tool is to make visible the impacts of dispatch on loop flows. The MMU supports the development of this tool, 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 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

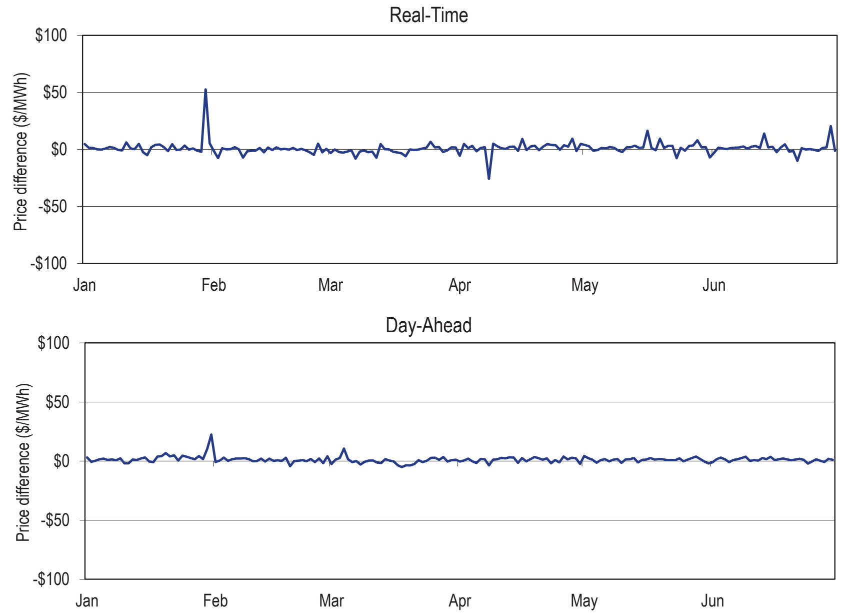
In the first six months of 2019, the direction of flow was consistent with price differentials in 62.2 percent of the hours. Table 9-25 shows the number of hours and average hourly price differences between the PJM/MISO Interface and the MISO/PJM Interface based on LMP differences and flow direction. 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 June, 2019

LMP Difference	Flow Direction	Number of Hours	Average Hourly Price Difference
MISO/PJM LMP > PJM/MISO LMP	Total Hours	2,704	$5.10
	Consistent Flow (PJM to MISO)	2,702	$5.10
	Inconsistent Flow (MISO to PJM)	2	$7.38
	No Flow	0	$0.00
PJM/MISO LMP > MISO/PJM LMP	Total Hours	1,639	$5.91
	Consistent Flow (MISO to PJM)	1	$18.83
	Inconsistent Flow (PJM to MISO)	1,638	$5.90
	No Flow	0	$0.00

31 See "LMP Aggregate Definitions" (June 1, 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>.

Figure 9-5 Price differences (MISO/PJM Interface minus PJM/MISO Interface): January through June, 2019



Distribution and Prices of Hourly Flows at the PJM/MISO Interface

In the first six months of 2019, the direction of hourly energy flows was consistent with PJM and MISO interface price differentials in 2,703 hours (62.2 percent of all hours), and was inconsistent with price differentials in 1,640 hours (37.8 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 1,640 hours where flows were in a direction inconsistent with price differences, 1,201 of those hours (73.2 percent) had a price difference greater than or equal to $1.00 and 383 of those hours (23.4 percent) had a price difference greater than or equal to $5.00. The largest price difference with such flows was $589.40. Of the 2,703 hours where flows were consistent with price differences, 2,162 of those hours

(80.0 percent) had a price difference greater than or equal to $1.00 and 537 of all such hours (19.9 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 June, 2019

Price Difference Range (Greater Than or Equal To)	Inconsistent Hours	Percent of Inconsistent Hours	Consistent Hours	Percent of Consistent Hours
$0.00	1,640	100.0%	2,703	100.0%
$1.00	1,201	73.2%	2,162	80.0%
$5.00	383	23.4%	537	19.9%
$10.00	205	12.5%	253	9.4%
$15.00	123	7.5%	141	5.2%
$20.00	87	5.3%	91	3.4%
$25.00	55	3.4%	64	2.4%
$50.00	21	1.3%	25	0.9%
$75.00	13	0.8%	13	0.5%
$100.00	9	0.5%	9	0.3%
$200.00	2	0.1%	3	0.1%
$300.00	1	0.1%	3	0.1%
$400.00	1	0.1%	2	0.1%
$500.00	1	0.1%	2	0.1%

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 six 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 59.8 percent of the hours in the first six 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 on a daily hourly average basis. There are a number of relevant measures

32 See the *2012 State of the Market Report for PJM*, Volume 2, Section 8, "Interchange Transactions," for a more detailed discussion.

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 June, 2019[33]

LMP Difference	Flow Direction	Number of Hours	Average Hourly Price Difference
NYIS/PJM proxy bus LBMP > PJM/NYIS LMP	Total Hours	2,187	$8.43
	Consistent Flow (PJM to NYIS)	1,758	$8.59
	Inconsistent Flow (NYIS to PJM)	429	$7.78
	No Flow	0	$0.00
PJM/NYIS LMP > NYIS/PJM proxy bus LBMP	Total Hours	2,156	$9.71
	Consistent Flow (NYIS to PJM)	839	$7.27
	Inconsistent Flow (PJM to NYIS)	1,317	$11.26
	No Flow	0	$0.00

Figure 9-6 Price differences (NY/PJM proxy - PJM/NYIS Interface): January through June, 2019

33 The NYISO Locational Based Marginal Price (LBMP) is the equivalent term to PJM's Locational Marginal Price (LMP).

Distribution and Prices of Hourly Flows at the PJM/NYISO Interface

In the first six months of 2019, the direction of hourly energy flows was consistent with PJM/NYISO and NYISO/PJM price differences in 2,597 hours (59.8 percent of all hours), and was inconsistent with price differences in 1,746 hours (40.2 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 1,746 hours where flows were in a direction inconsistent with price differences, 1,518 of those hours (86.9 percent) had a price difference greater than or equal to $1.00 and 797 of all those hours (45.6 percent) had a price difference greater than or equal to $5.00. The largest price difference with such flows was $461.20. Of the 2,597 hours where flows were consistent with price differences, 2,315 of those hours (89.1 percent) had a price difference greater than or equal to $1.00 and 1,187 of all such hours (45.7 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 June, 2019

Price Difference Range (Greater Than or Equal To)	Inconsistent Hours	Percent of Inconsistent Hours	Consistent Hours	Percent of Consistent Hours
$0.00	1,746	100.0%	2,597	100.0%
$1.00	1,518	86.9%	2,315	89.1%
$5.00	797	45.6%	1,187	45.7%
$10.00	415	23.8%	521	20.1%
$15.00	250	14.3%	278	10.7%
$20.00	180	10.3%	170	6.5%
$25.00	148	8.5%	121	4.7%
$50.00	66	3.8%	44	1.7%
$75.00	38	2.2%	25	1.0%
$100.00	17	1.0%	13	0.5%
$200.00	3	0.2%	5	0.2%
$300.00	2	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 June, 2019[34]

		Real-Time		Day-Ahead	
	Description	NYISO	MISO	NYISO	MISO
Average Interval Price	PJM Price at ISO Border	$26.05	$24.72	$26.46	$25.19
	ISO Price at PJM Border	$25.46	$25.66	$26.74	$26.38
	Difference at Border (PJM-ISO)	$0.59	($0.94)	($0.28)	($1.19)
	Average Absolute Value of Interval Difference at Border	$39.86	$38.33	$3.78	$2.84
	Sign Changes per Day	43.8	43.7	2.8	3.3
Standard Deviation	PJM Price at ISO Border	$32.83	$30.16	$12.23	$7.46
	ISO Price at PJM Border	$29.34	$26.15	$13.30	$8.23
	Difference at Border (PJM-ISO)	$41.44	$38.88	$5.24	$3.61

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 72.9 percent of the hours in the first six 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 June, 2019

LMP Difference	Flow Direction	Number of Hours	Average Hourly Price Difference
NYIS/Neptune Bus LBMP > PJM/NEPT LMP	Total Hours	3,170	$12.75
	Consistent Flow (PJM to NYIS)	3,165	$12.75
	Inconsistent Flow (NYIS to PJM)	0	$0.00
	No Flow	5	$11.20
PJM/NEPT LMP > NYIS/Neptune Bus LBMP	Total Hours	1,173	$9.08
	Consistent Flow (NYIS to PJM)	0	$0.00
	Inconsistent Flow (PJM to NYIS)	1,173	$9.08
	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 June 30, 2019, the rate for the nonfirm service released by default was $10 per MWh. The primary rights holder remains obligated to pay for the released service unless a second transmission customer acquires the released service.

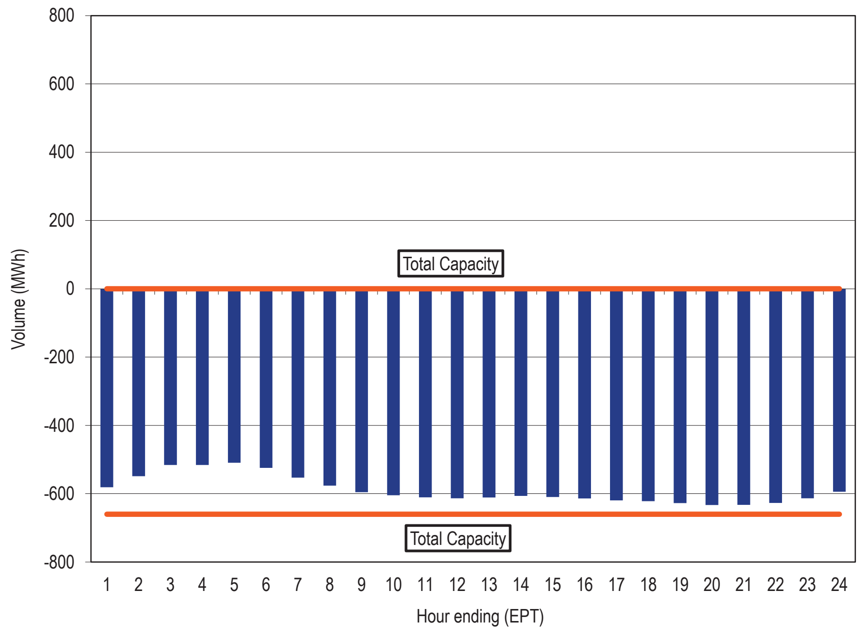
Table 9-31 shows the percent of scheduled interchange across the Neptune Line by the primary rights holder since commercial operations began in July, 2007. Table 9-31 shows that in the first six months of 2019, the primary rights holder was responsible for 100 percent of the scheduled interchange across the Neptune Line in all months. Figure 9-7 shows the hourly average flow across the Neptune Line for the first six months of 2019.

Table 9-31 Percent of scheduled interchange across the Neptune Line by primary rights holder: July 2007 through June 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%	
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%	
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%	
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 June, 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 67.9 percent of the hours in the first six 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 June, 2019

LMP Difference	Flow Direction	Number of Hours	Average Hourly Price Difference
NYIS/Linden Bus LBMP > PJM/LIND LMP	Total Hours	3,034	$9.54
	Consistent Flow (PJM to NYIS)	2,947	$9.45
	Inconsistent Flow (NYIS to PJM)	0	$0.00
	No Flow	87	$12.68
PJM/LIND LMP > NYIS/Linden Bus LBMP	Total Hours	1,309	$12.92
	Consistent Flow (NYIS to PJM)	0	$0.00
	Inconsistent Flow (PJM to NYIS)	1,281	$12.79
	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.

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>.

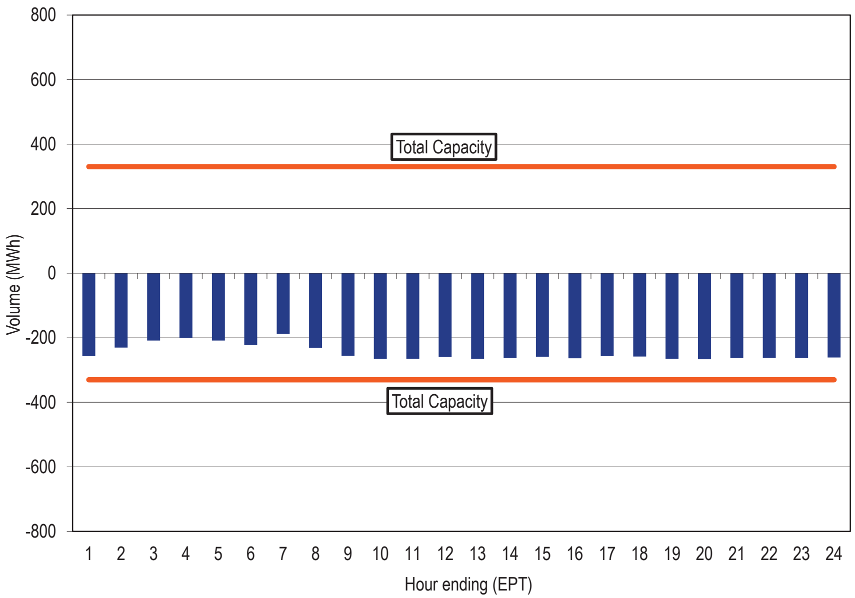
On June 30, 2019, the rate for the nonfirm service released by default was $6.00 per MWh. The primary rights holder remains obligated to pay for the released service unless a second transmission customer acquires the released service.

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 six 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 six months of 2019.

Table 9-33 Percent of scheduled interchange across the Linden VFT Line by primary rights holder: November 2009 through June 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%	
August	NA	100.00%	100.00%	100.00%	100.00%	82.46%	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%	
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 June, 2019[39]



Hudson Direct Current (DC) Merchant Transmission Line

The Hudson direct current (DC) Line is a bidirectional merchant 230 kV transmission line, with a capacity of 673 MW, providing a direct connection between PJM (Public Service Electric and Gas Company's (PSE&G) Bergen 230 kV Switching Station located in Ridgefield, New Jersey) and NYISO (Consolidated Edison's (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 65.6 percent of the hours in the first six 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 June, 2019

LMP Difference	Flow Direction	Number of Hours	Average Hourly Price Difference
NYIS/Hudson Bus LBMP > PJM/HUDS LMP	Total Hours	2,925	$9.58
	Consistent Flow (PJM to NYIS)	2,850	$9.63
	Inconsistent Flow (NYIS to PJM)	0	$0.00
	No Flow	75	$7.74
PJM/HUDS LMP > NYIS/Hudson Bus LBMP	Total Hours	1,418	$10.91
	Consistent Flow (NYIS to PJM)	0	$0.00
	Inconsistent Flow (PJM to NYIS)	1,383	$11.06
	No Flow	35	$4.92

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 June 30, 2019, the rate for the nonfirm service released by default was $10

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.

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>.

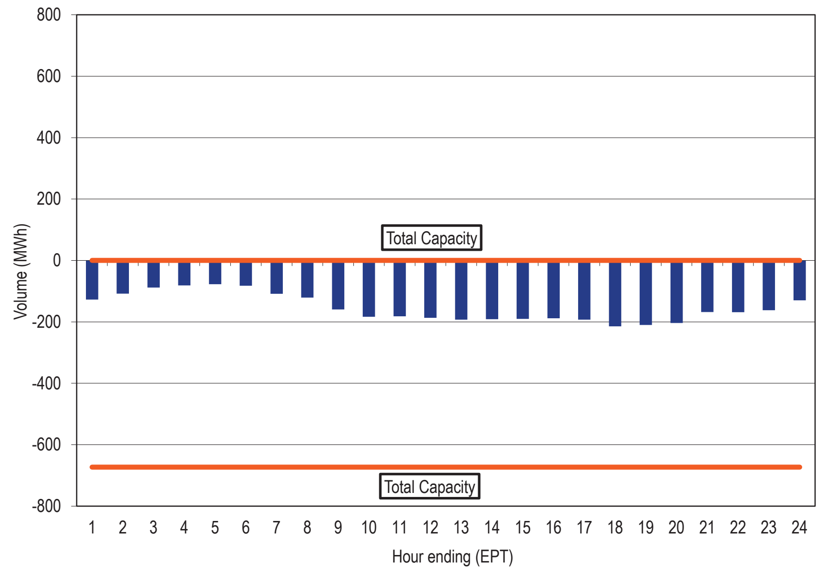
per MWh. The primary rights holder remains obligated to pay for the released service unless a second transmission customer acquires the released service.

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 six 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 six months of 2019.

Table 9-35 Percent of scheduled interchange across the Hudson Line by primary rights holder: May 2013 through June 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%	
August	100.00%	75.17%	65.48%	NA	NA	19.24%	
September	100.00%	75.31%	78.73%	NA	NA	22.90%	
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 June, 2019



Interchange Activity During High Load Hours

The PJM metered system peak load during the first six months of 2019 was 134,060 MW in the HE 0700 on January 31, 2019. PJM was under a cold 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 but two hours on January 31, 2019 (HE 0400 and HE 0600), with average hourly scheduled exports of 1,143 MW. During HE 0700 on January 31, 2019, PJM had net scheduled exports of 1,077 MW and net metered actual exports of 1,668 MW. Net transaction exports during this time were consistent with the price differences between PJM and MISO, but were inconsistent with price differences between PJM and the NYISO interfaces (NYIS, Neptune, Linden and Hudson). During the month of January 2019, PJM was a net scheduled exporter of energy in 740 of the 744 hours. During January 2019, the average hourly scheduled interchange was -3,600 MW (representing 3.7 percent of the average hourly load of 97,319 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

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>.

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 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 six months of 2019, PJM added 16 flowgates and deleted eight flowgates, leaving 145 flowgates eligible for M2M coordination as of June 30, 2019. As of January 1, 2019, MISO had 239 flowgates eligible for M2M coordination. In the first six months of 2019, MISO added 41 flowgates and deleted 65 flowgates, leaving 215 flowgates eligible for M2M coordination as of June 30, 2019.

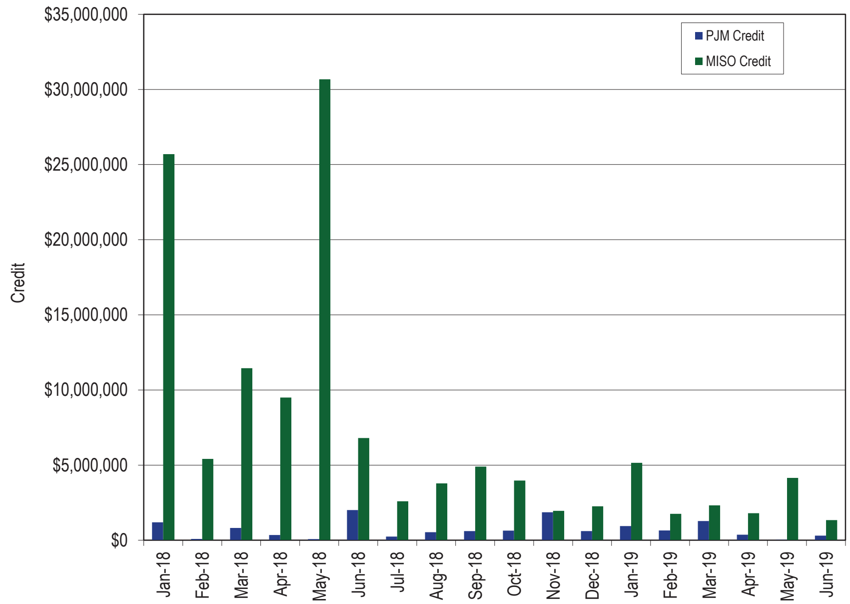
The firm flow entitlement (FFE) represents the amount of historic 2004 flow that each RTO had created on each RCF used in the market to market settlement process. The FFE establishes the amount of market flow that each RTO is permitted to create on the RCF before incurring redispatch costs during the 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 non-monitoring 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 six 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.

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>.
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>.

Figure 9-10 PJM/MISO credits for coordinated congestion management: January 2018 through June 2019[49]



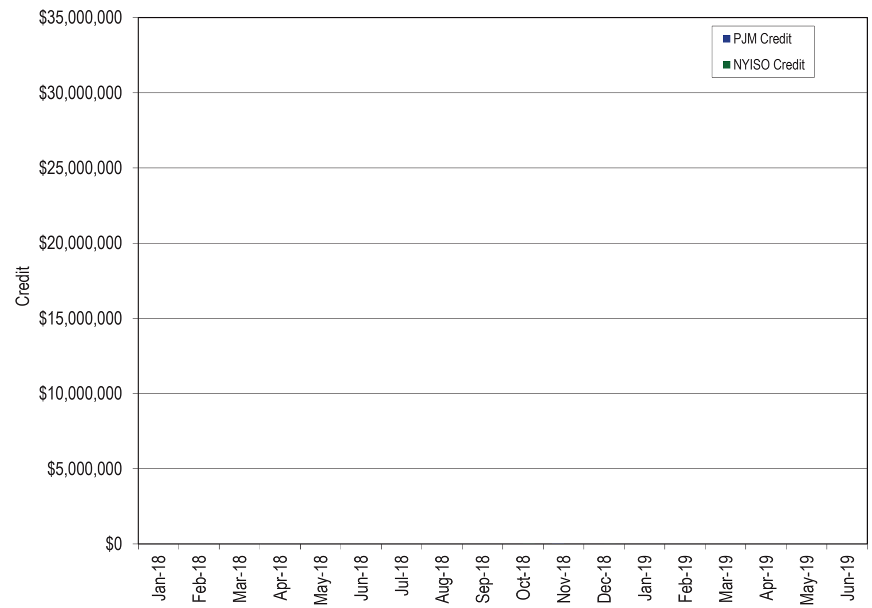
PJM and New York Independent System Operator Joint Operating Agreement (JOA)[50]

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 six 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 six 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 June 2019[52]

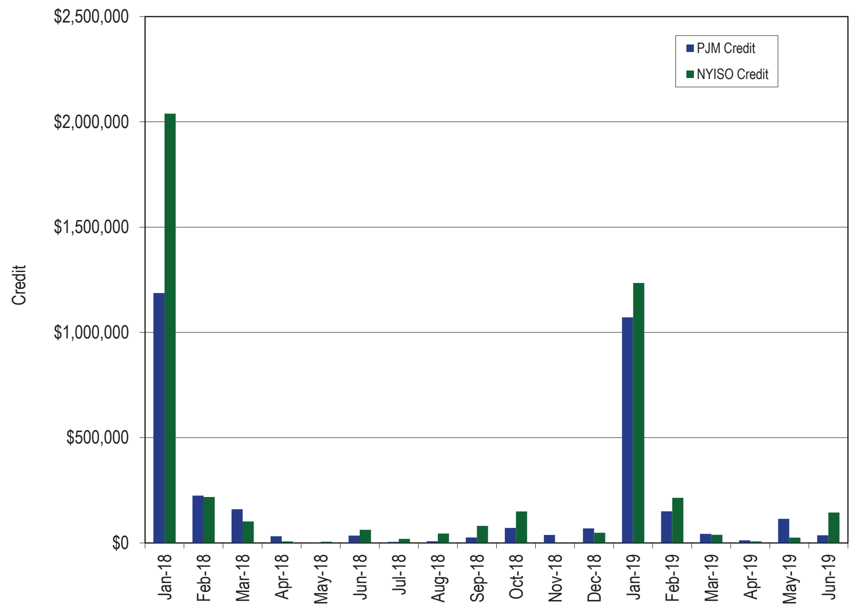


49 The totals represented in this figure represent the settlements as of the time of this report and may not include adjustments or resettlements.
50 See "New York Independent System Operator, Inc., Joint Operating Agreement with PJM Interconnection, L.L.C." (June 21, 2017) <http://www.pjm.com/~/media/documents/agreements/nyiso-joa.ashx>.
51 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.

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 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 six 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.

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>.

Figure 9-12 PJM/NYISO credits for coordinated congestion management (PARs): January 2018 through June 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 six months of 2019.

PJM and Duke Energy Progress, Inc. Joint Operating Agreement[56]

On September 9, 2005, the FERC approved a JOA between PJM and Progress Energy Carolinas, Inc. (PEC), with an effective date of July 30, 2005. As part of this agreement, both parties agreed to develop a formal congestion management protocol (CMP). On February 2, 2010, PJM and PEC filed a revision to the JOA to include a CMP.[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).

The PJM/DEP JOA states that the Marginal Cost Proxy Method (MCPM) will be used in the determination of the CPLEIMP and CPLEEXP interface price. Section 2.6A (2) of the PJM Tariff describes the process of calculating the interface price under the MCPM. Under the MCPM, PJM compares the individual bus LMP (as calculated by PJM) for each DEP generator in the PJM model with a telemetered output greater than zero MW to the marginal cost for that generator.

For the CPLEIMP price (imports to PJM), PJM uses the lowest LMP of any generator bus in the DEP balancing authority area, with an output greater than zero MW that has an LMP less than its marginal cost for each five minute interval. If no generator with an output greater than zero MW has an LMP less than its marginal cost, then the import price is the average of the bus LMPs for the set of generators in the DEP area with an output greater than zero MW that PJM determines to be the marginal units in the DEP area for that five minute interval. PJM determines the marginal units in the DEP area by summing the output of the units serving load in the DEP area in ascending order by the units' marginal costs until the sum equals the real-time load in the DEP area. Units in the DEP area with marginal costs at or above that of the last unit included in the sum are the marginal units for the DEP area for that interval.

PJM calculates the CPLEEXP price for exports from PJM to DEP as the highest LMP of any generator bus in the DEP area with an output greater than zero MW (excluding nuclear and hydro units) that has an LMP greater than its marginal cost in the 5 minute interval.[58] If no generator with an output greater than zero MW has an LMP greater than its marginal cost, then the export price will be the average of the bus LMPs for the set of generators with an output greater than zero MW that PJM determines to the be marginal units in the same manner as described for the CPLEIMP interface price. The hourly integrated import and export prices are the average of all of the 5 minute intervals in each hour.

The MCPM calculation is based on the DEP units modeled in the PJM market that have an output greater than zero, and only uses the units whose output exceeds the reported DEP real-time load. When new units are added to the DEP footprint, and existing units in the DEP footprint retire, PJM does not have complete data to calculate the interface price. These new units can impact the interface price in several ways. By not having the additional units modeled, these units cannot be considered to be marginal units, and therefore cannot set price. For the import price, if the PJM calculated LMP of one of the new units were to be lower than any currently modeled unit, then PJM's CPLEIMP pricing point would be lower, and PJM would pay less for imports. If the PJM calculated LMP of one of the new units were to be higher than any currently modeled unit, then PJM's CPLEEXP pricing point would be higher, and PJM would receive more for exports.

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 The MMU has objected to the omission of nuclear and hydro units from the calculation. This omission is not included in the definition of the MCPM interface pricing method in the PJM Tariff, but is included as a special condition in the PJM/DEP JOA. The MMU does not believe it is appropriate to exclude these units from the calculation as these units could be considered marginal and affect the prices.

Not maintaining a current set of units in the DEP footprint in PJM's network model limits PJM's ability to recognize which units are marginal and it is often not possible to calculate the CPLEIMP and CPLEEXP interface prices using the MCPM. By not maintaining a complete set of units in the DEP footprint, the reported output of the modeled units are often insufficient to cover the reported real-time load, and therefore no units are considered marginal. When this occurs, the MMU believes that the CPLEIMP and CPLEEXP pricing points should revert to the SOUTHIMP and SOUTHEXP interface prices, but this has not happened. When this occurs, PJM uses the high-low interface pricing method as described in Section 2.6A (1) of the PJM Tariff. The MMU does not believe that this is appropriate, and does not see the basis for this approach in either the PJM Tariff or the PJM/DEP JOA.

On July 2, 2012, Duke Energy and Progress Energy Inc. completed a merger. While the individual companies planned to operate separately for a period of time, they have a joint dispatch agreement, and a joint open access transmission tariff.[59] On October 3, 2014, Duke Energy Progress (DEP) and PJM submitted revisions to the JOA to include a new Appendix B, update references to DEP's current legal name, and incorporate other revisions.[60] The MMU submitted a protest to this filing noting that the existing JOA depends on the specific characteristics of PEC as a standalone company, and the assumptions reflected in the current JOA no longer apply under the DEP joint dispatch agreement.[61] As noted in the 2010 filing, "the terms and conditions of the bilateral agreement among PEC and PJM are grounded in an appreciation of their systems as they exist at the time of the effective date of the JOA, but they fully expect that evolving circumstances, protocols and requirements will require that they negotiate, in good faith, a response to such changes."[62] The joint dispatch agreement changed the unique operational relationship that existed when the congestion management protocol was established. However, the merged company has not engaged in discussions with PJM as to whether the congestion management protocol that was "tailored to their [PJM and PEC] unique operational relationship" is still appropriate, or whether the congestion management protocol needs to be revised. The existing JOA does not apply to the merged company and should be terminated.

Article 14 of the JOA provides details of the PJM/DEP congestion management agreement (CMA). The purpose of the CMA is to allow "DEP to quickly respond to the LMP values sent by PJM to DEP. This quick response will help manage the congestion on the PJM transmission system by maintaining flows within established limits and stabilizing PJM LMP values, and will help reduce the need to use the TLR process to relieve the congestion by maintaining power flows within established reliability limits." Congestion is managed by using a dynamic schedule between CPLE and PJM. DEP responds to the dynamic pricing signal sent by PJM by increasing generation, which creates energy flow in the direction from CPLE to PJM or by decreasing generation, which creates energy flow in the direction from PJM to CPLE. The dynamic schedule calls for more DEP generation when the DEP marginal cost of online generation is less than the CPLE LMP, and it calls for less DEP generation when the DEP marginal cost exceeds the CPLE LMP. The economic energy flow on the dynamic schedule reduces congestion.

The amount of congestion relief is limited by the amount of energy that can flow on the dynamic schedule. Several factors determine this limit, including: the physical limitations of DEP's units; ATC limits on the transmission path between CPLE and PJM; the actual confirmed transmission acquired in advance by DEP. Section 14.4.1 of the JOA states that:

> The transmission service used on the DEP transmission system to support the process described in this Article will be a non-firm point to point reservation from DEP to PJM made by DEP. The Dynamic Schedule will be limited to the point to point reservation. The transmission service used on the PJM transmission system will be network secondary service.

In the first six months of 2019, DEP acquired the required transmission service in only 55 of the 4,343 hours (0.1 percent of all hours), with an average capacity of approximately 211 MW. At most, DEP could have increased their

59 See "Duke Energy Carolinas, LLC, Carolina Power & Light tariff filing," Docket No. ER12-1338-000 (July 12, 2012) and "Duke Energy Carolinas, LLC, Carolina Power & Light Joint Dispatch Agreement filing," Docket No. ER12-1343-000 (July 11, 2012).

60 See *Duke Energy Progress, Inc. and PJM Interconnection, L.L.C*, Docket No. ER15-29-000 (October 3, 2014).

61 See Protest and Motion for Rehearing of the Independent Market Monitor for PJM in Docket No. ER15-29-000 (October 24, 2014).

62 Joint Motion for Leave to Answer and Answer of PJM Interconnection, L.C.C. and Progress Energy Carolinas, Inc., Docket No. ER10-713-000 (March 10, 2010) at 2. Section 3.3 of the PJM-Progress JOA.

generation to help manage constraints via a sale of power to PJM 0.1 percent of the time in the first six months of 2019, and the maximum redispatch would have been only 211 MW, on average.

A CMA that can only be used in 0.1 percent of all hours is not an effective approach to congestion management. For that reason and based on the significant flaws in the agreement, the MMU has recommended that PJM immediately provide the required 12-month notice to DEP to unilaterally terminate the Joint Operating Agreement. On May 20, 2019, PJM and DEP submitted revisions to the JOA to delete Article 14.[63] 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. As of June 30, 2019, the Commission has not ruled on the filing.

PJM and VACAR South Reliability Coordination Agreement[64]

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 six months of 2019.

Balancing Authority Operations Coordination Agreement between Wisconsin Electric Power Company (WEC) and PJM Interconnection, LLC[65]

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 six months of 2019.

Northeastern ISO-Regional Transmission Organization Planning Coordination Protocol[66]

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 six 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.

The PJM/DEP JOA allows for the CPLEIMP and CPLEEXP interface pricing points to be calculated using the Marginal Cost Proxy Pricing method.[67] 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 six months of 2019. The values shown in Table 9-37 are the average LMP over only the hours in the first six 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 -$0.04 with Duke to $0.26 with PEC. This means that under the specific interface pricing agreements, transactions

63 See *PJM Interconnection, L.L.C*, Docket No. ER19-1905-000 (May 20, 2019).
64 See "PJM-VACAR South RC Agreement" (November 7, 2014) <http://www.pjm.com/~/media/documents/agreements/executed-pjm-vacar-rc-agreement.ashx>.
65 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>.
66 See "Northeastern ISO/RTO Planning Coordination Protocol" (December 8, 2004) <http://www.pjm.com/~/media/documents/agreements/northeastern-iso-rto-planning-coordination-protocol.ashx>.
67 See *PJM Interconnection, L.L.C*, Docket No. ER10-2710-000 (September 17, 2010).

settling at the Duke interface price would receive, on average, $0.04 less for importing energy into PJM than if they were to receive the SouthIMP pricing point. In the first six months of 2019, market participants received $10,946 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 $0.44 with Duke to $1.71 with PEC.[68] This means that under the specific interface pricing agreements, transactions settling at the PEC interface price would pay, on average, $1.71 more for exporting energy from PJM than they would have if they were to pay the SouthEXP pricing point. In the first six months of 2019, market participants paid $335,854 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 June, 2019

	Import LMP	Export LMP	SOUTHIMP	SOUTHEXP	Difference IMP LMP - SOUTHIMP	Difference EXP LMP - SOUTHEXP
Duke	$27.85	$27.37	$27.89	$26.93	($0.04)	$0.44
PEC	$27.23	$32.29	$26.97	$30.57	$0.26	$1.71
NCMPA	$25.12	NA	$25.00	NA	$0.12	NA

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 six months of 2019. The values shown in Table 9-38 are the average LMP over only the hours in the first six 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 $0.38 with NCMPA to $0.49 with PEC. This means that under the specific interface pricing agreements, transactions settling at the PEC interface price would receive, on average, $0.49 more for importing energy into PJM than if they were to receive the SouthIMP pricing point. In the first six months of 2019, market participants received $62,963 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 -$0.14 with Duke to $0.91 with PEC. This means that under the specific interface pricing agreements, transactions settling at the PEC interface price would pay, on average, $0.91 more for exporting energy from PJM than if they were to pay the SouthEXP pricing point. In the first six months of 2019, market participants paid $209,885 more for exporting energy using this pricing point than they would have if they were to have paid the SouthEXP pricing point.

Table 9-38 Day-ahead LMP comparison for Duke, PEC and NCMPA: January through June, 2019

	Import LMP	Export LMP	SOUTHIMP	SOUTHEXP	Difference IMP LMP - SOUTHIMP	Difference EXP LMP - SOUTHEXP
Duke	$30.91	$27.09	$30.47	$27.22	$0.44	($0.14)
PEC	$28.28	$30.60	$27.79	$29.69	$0.49	$0.91
NCMPA	$26.22	$23.30	$25.84	$22.99	$0.38	$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. In the case of the DEP JOA for example, the merger between Progress and Duke has resulted in a single, combined entity where one part of that entity (Duke Energy Progress) is engaged in congestion management with PJM while the other part of the entity (Duke) is not.

Interchange Transaction Issues

Hudson Transmission Partners (HTP) and Linden VFT Requests to Convert Firm Transmission Withdrawal Rights (FTWR) to NonFirm Transmission Withdrawal Rights (NFTWR)

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

68 The Progress Energy Carolinas (PEC) LMP is defined as the Carolina Power and Light (East) (CPLE) pricing point.

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.[69]

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.[70] 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.[71] [72] 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.[73]

69 155 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).

70 See *PJM Interconnection, L.L.C*, Docket No. ER17-2267-000 (August 9, 2017).

71 161 FERC ¶ 62,242 (2017).

72 161 FERC ¶ 62,264 (2017).

73 See *PJM Interconnection, L.L.C.*, Docket No. ER18-680-000 (January 19, 2018).

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 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.[74]

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 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. 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

74 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>.

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.

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.[75] 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 six months of 2018 to two in the first six months of 2019.[76] The number of different flowgates for which PJM declared a TLR 3a or higher was three in the first six months of 2018 and one in the first six months of 2019. The total MWh of transactions curtailed decreased by 74.3 percent from 5,832 MWh in the first six months of 2018 to 1,499 MWh in the first six months of 2019.

The number of MISO issued TLRs of level 3a or higher decreased from 35 in the first six months of 2018 to 20 in the first six months of 2019. The number of different flowgates for which MISO declared a TLR 3a decreased from 17 in the first six months of 2018 to 14 in the first six months of 2019. The total MWh of transaction curtailments decreased by 39.3 percent from 24,579 MWh in the first six months of 2018 to 14,909 MWh in the first six months of 2019.

The number of NYISO issued TLRs of level 3a or higher increased from one in the first six months of 2018 to eight in the first six months of 2019. The number of different flowgates for which NYISO declared a TLR 3a or higher increased from one in the first six months of 2018 to two in the first six months of 2019. The total MWh of transaction curtailments increased by 957.0 percent from 1,428 MWh in the first six months of 2018 to 15,092 MWh in the first six months of 2019.

75 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.

76 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.

Table 9-39 PJM, MISO, and NYISO TLR procedures: January 2016 through June 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

Table 9-40 Number of TLRs by TLR level by reliability coordinator: January through June, 2019[77]

Year	Reliability Coordinator	3a	3b	4	5a	5b	6	Total
2019	MISO	6	4	0	3	6	0	19
	NYIS	8	0	0	0	0	0	8
	ONT	7	1	0	0	0	0	8
	PJM	1	1	0	0	0	0	2
	SOCO	0	0	0	0	0	0	0
	SWPP	7	2	0	14	6	0	29
	TVA	6	9	0	3	3	0	21
	VACS	2	1	0	0	0	0	3
Total		37	18	0	20	15	0	90

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.[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.

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.[79]

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.[80]

77 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.

78 See the *2012 State of the Market Report for PJM*, Volume 2, Section 8, "Interchange Transactions," for a more detailed discussion.

79 See the *2019 Quarterly State of the Market Report for PJM: January through June*, Section 13: FTRs and ARRs, "FTR Forfeitures" for more information on up to congestion transaction impacts on FTRs.

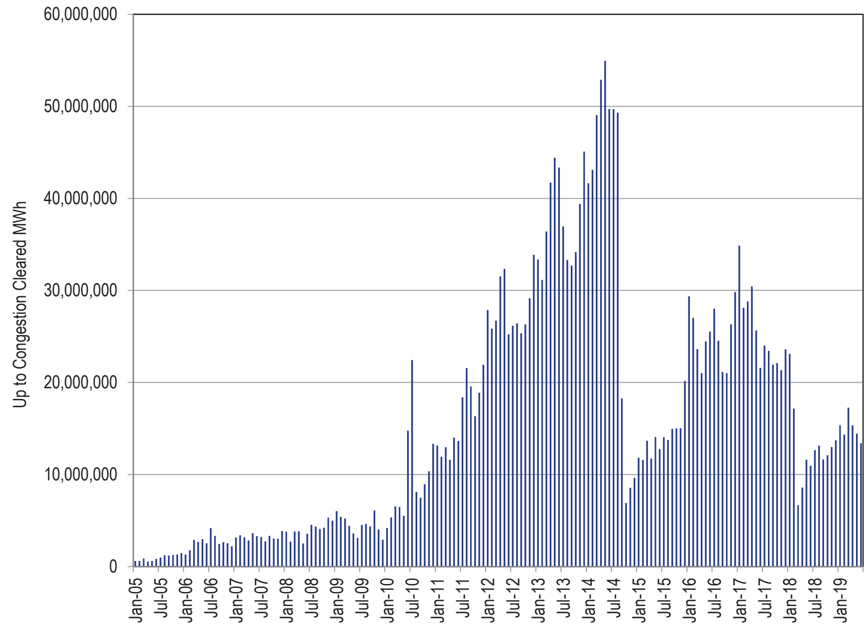
80 148 FERC ¶ 61,144 (2014).

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..."[81]

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.[82] As a result, market participants reduced up to congestion trading effective February 22, 2018.

The average number of up to congestion bids submitted in the Day-Ahead Energy Market decreased by 37.0 percent, from 76,114 bids per day in the first six months of 2018 to 47,989 bids per day in the first six months of 2019. The average cleared volume of up to congestion bids submitted in the Day-Ahead Energy Market increased by 15.4 percent, from 431,553 MWh per day in the first six months of 2018, to 497,987 MWh per day in the first six months of 2019.

Figure 9-13 Monthly up to congestion cleared bids in MWh: January 2005 through June 2019



81 16 U.S.C. § 824e.
82 162 FERC ¶ 61,139 (2018).

Table 9-41 Monthly volume of cleared and submitted up to congestion bids: January 2018 through June 2019

	Bid MW					Bid Volume				
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
TOTAL	166,580,211	77,708,713	43,739,684	502,838,852	790,867,459	6,526,016	2,296,544	911,398	22,521,612	32,255,570

	Cleared MW					Cleared Volume				
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
TOTAL	57,432,117	23,165,857	12,245,926	151,679,802	244,523,701	2,871,155	1,008,924	368,830	9,898,697	14,147,606

In the first six months of 2019, the cleared MW volume of up to congestion transactions was comprised of 22.8 percent imports, 11.2 percent exports, 5.7 percent wheeling transactions and 60.3 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.[83]

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 six months of 2019, of the 383 GWh of the gross scheduled transactions between PJM and IESO, 378 GWh (98.7 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.[84]

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.[85] The evaluation is based on the forward-looking prices as determined by PJM's intermediate term security constrained economic dispatch tool (ITSCED) and the NYISO's real-time commitment (RTC) tool. PJM shares its PJM/NYISO interface price ITSCED results with the NYISO. The NYISO compares the PJM/NYISO interface price with its RTC calculated NYISO/PJM interface price. If the PJM and NYISO interface price spread is greater than the market participant's CTS bid, the transaction is approved. If the PJM and NYISO interface price spread is less than the CTS bid, the transaction is denied.

The ITSCED application runs approximately every five minutes and each run produces forecast LMPs for the intervals approximately 30 minutes, 45 minutes, 90 minutes and 135 minutes ahead. Therefore, for each 15 minute interval, the various ITSCED solutions will produce 12 forecasted PJM/NYIS interface prices. To evaluate the accuracy of ITSCED forecasts, the forecasted PJM/NYIS interface price for each 15 minute interval from ITSCED was compared to the actual real-time interface LMP for the first six 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 44.9 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 6.6 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 $70.54 when the price difference was greater than $20.00, and $361.14 when the price difference was greater than -$20.00.

83 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>.

84 On October 1, 2013, a sub-group of PJM's Market Implementation Committee started stakeholder discussions to address this inconsistency in market pricing.

85 PJM and the NYISO implemented CTS on November 4, 2014. 146 FERC ¶ 61,096 (2014).

Table 9-42 Differences between forecast and actual PJM/NYIS interface prices: January through June, 2019

Range of Price Differences	Percent of All Intervals	Average Price Difference
> $20	2.9%	$70.54
$10 to $20	3.4%	$13.83
$5 to $10	5.8%	$6.99
$0 to $5	44.9%	$1.52
$0 to -$5	33.9%	$1.39
-$5 to -$10	3.2%	$6.92
-$10 to -$20	2.1%	$14.36
< -$20	3.7%	$361.14

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 79.7 percent of all intervals, the average price difference between the ITSCED forecasted LMP and the actual real-time interface LMP fell within +/- $5.00 of the actual PJM/NYIS interface real-time LMP, compared to 79.0 percent in the 135 minute ahead ITSCED results.

Table 9-43 Differences between forecast and actual PJM/NYIS interface prices: January through June, 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%	$64.72	1.8%	$63.24	2.2%	$62.31	2.5%	$63.88
$10 to $20	2.3%	$13.79	2.8%	$13.63	3.0%	$13.92	3.4%	$13.63
$5 to $10	4.0%	$7.05	4.4%	$7.09	5.5%	$6.90	6.3%	$6.92
$0 to $5	30.8%	$1.54	32.0%	$1.56	46.5%	$1.53	47.7%	$1.54
$0 to -$5	48.1%	$1.63	47.9%	$1.58	32.7%	$1.40	32.0%	$1.36
-$5 to -$10	5.1%	$6.89	4.5%	$6.88	3.5%	$6.92	3.1%	$6.96
-$10 to -$20	3.4%	$14.43	2.9%	$14.26	2.3%	$14.38	1.8%	$14.50
< -$20	4.8%	$397.69	3.7%	$232.19	4.2%	$444.54	3.2%	$258.29

In 5.7 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 $63.88 when the price difference was greater than $20.00, and $258.29 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 June, 2019

Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	YTD Avg
~ 30 Minutes Prior to Real-Time	> $20	5.7%	2.7%	1.4%	2.3%	1.3%	1.4%	2.5%
	$10 to $20	2.7%	2.1%	2.8%	5.6%	3.9%	3.3%	3.4%
	$5 to $10	4.5%	3.6%	6.5%	10.4%	7.2%	5.6%	6.3%
	$0 to $5	37.7%	45.1%	46.1%	46.9%	54.2%	56.3%	47.7%
	$0 to -$5	35.7%	36.9%	33.8%	27.0%	28.6%	30.1%	32.0%
	-$5 to -$10	4.4%	3.2%	3.8%	3.1%	2.0%	1.9%	3.1%
	-$10 to -$20	3.0%	2.2%	1.8%	2.1%	1.3%	0.7%	1.8%
	< -$20	6.4%	4.2%	3.8%	2.6%	1.5%	0.7%	3.2%
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	YTD Avg
~ 45 Minutes Prior to Real-Time	> $20	5.1%	2.4%	1.0%	1.6%	1.4%	1.5%	2.2%
	$10 to $20	3.3%	1.6%	2.1%	4.4%	3.4%	2.9%	3.0%
	$5 to $10	3.4%	3.5%	5.4%	9.1%	6.5%	5.4%	5.5%
	$0 to $5	37.5%	44.1%	43.5%	45.4%	53.0%	55.8%	46.5%
	$0 to -$5	36.3%	37.0%	34.1%	28.5%	30.2%	30.5%	32.7%
	-$5 to -$10	4.4%	3.3%	5.0%	3.9%	2.4%	2.3%	3.5%
	-$10 to -$20	3.5%	2.9%	2.1%	2.8%	1.6%	1.0%	2.3%
	< -$20	6.6%	5.2%	6.9%	4.2%	1.4%	0.7%	4.2%
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	YTD Avg
~ 90 Minutes Prior to Real-Time	> $20	4.6%	1.3%	2.0%	1.7%	0.5%	0.9%	1.8%
	$10 to $20	2.9%	1.5%	3.2%	4.2%	2.2%	2.6%	2.8%
	$5 to $10	3.9%	2.3%	5.9%	6.5%	4.0%	4.0%	4.4%
	$0 to $5	25.8%	29.3%	35.9%	32.8%	34.1%	34.1%	32.0%
	$0 to -$5	44.6%	53.2%	42.4%	45.8%	50.5%	51.4%	47.9%
	-$5 to -$10	6.3%	4.2%	4.9%	3.9%	4.0%	3.4%	4.5%
	-$10 to -$20	4.5%	3.3%	1.9%	2.2%	2.8%	2.6%	2.9%
	< -$20	7.5%	4.9%	3.9%	3.0%	2.0%	1.0%	3.7%
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	YTD Avg
~ 135 Minutes Prior to Real-Time	> $20	4.4%	1.0%	1.4%	1.3%	0.6%	0.8%	1.6%
	$10 to $20	2.8%	1.2%	2.0%	3.4%	1.9%	2.4%	2.3%
	$5 to $10	3.7%	2.3%	4.8%	5.1%	3.8%	4.0%	4.0%
	$0 to $5	24.6%	27.5%	34.6%	30.7%	33.4%	34.1%	30.8%
	$0 to -$5	45.8%	54.0%	42.3%	46.1%	50.2%	51.0%	48.1%
	-$5 to -$10	6.2%	4.1%	5.8%	5.4%	5.0%	3.8%	5.1%
	-$10 to -$20	4.7%	3.6%	2.2%	3.4%	3.4%	2.9%	3.4%
	< -$20	7.8%	6.3%	6.9%	4.6%	1.9%	1.1%	4.8%

Table 9-45 Monthly differences between forecast and actual PJM/NYIS interface prices (average price difference): January through June, 2019

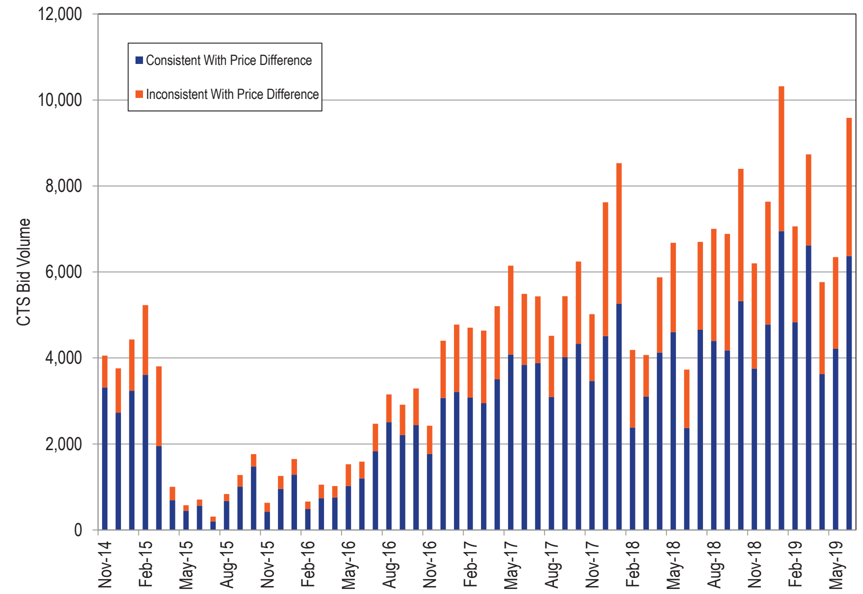
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	YTD Avg
~ 30 Minutes Prior to Real-Time	> $20	$79.73	$90.51	$45.45	$39.96	$34.12	$37.01	$63.88
	$10 to $20	$13.95	$13.81	$13.64	$13.53	$13.52	$13.53	$13.63
	$5 to $10	$7.12	$6.73	$7.02	$6.78	$6.92	$7.00	$6.92
	$0 to $5	$1.44	$1.41	$1.54	$1.80	$1.54	$1.48	$1.54
	$0 to -$5	$1.40	$1.32	$1.45	$1.44	$1.30	$1.24	$1.36
	-$5 to -$10	$6.93	$7.15	$6.99	$7.01	$6.82	$6.78	$6.96
	-$10 to -$20	$14.75	$14.47	$14.03	$14.31	$14.65	$14.95	$14.50
	< -$20	$109.20	$169.71	$436.84	$676.44	$43.90	$64.36	$258.29
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	YTD Avg
~ 45 Minutes Prior to Real-Time	> $20	$78.44	$85.72	$37.73	$40.42	$36.28	$37.89	$62.31
	$10 to $20	$14.51	$15.06	$13.50	$13.61	$13.80	$13.54	$13.92
	$5 to $10	$7.16	$6.86	$6.91	$6.81	$6.81	$7.01	$6.90
	$0 to $5	$1.43	$1.38	$1.47	$1.75	$1.59	$1.52	$1.53
	$0 to -$5	$1.41	$1.37	$1.47	$1.55	$1.33	$1.25	$1.40
	-$5 to -$10	$6.93	$6.99	$6.96	$7.00	$6.77	$6.73	$6.92
	-$10 to -$20	$14.46	$13.97	$14.09	$14.43	$14.56	$15.31	$14.38
	< -$20	$104.35	$272.98	$701.93	$961.94	$44.48	$57.99	$444.54
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	YTD Avg
~ 90 Minutes Prior to Real-Time	> $20	$86.98	$63.07	$44.96	$43.09	$39.41	$30.17	$63.24
	$10 to $20	$13.73	$12.83	$13.44	$13.64	$14.22	$13.68	$13.63
	$5 to $10	$7.15	$7.24	$7.13	$7.10	$7.04	$6.94	$7.09
	$0 to $5	$1.52	$1.43	$1.52	$1.84	$1.67	$1.37	$1.56
	$0 to -$5	$1.54	$1.53	$1.55	$1.71	$1.64	$1.53	$1.58
	-$5 to -$10	$6.82	$6.84	$6.97	$7.07	$6.93	$6.67	$6.88
	-$10 to -$20	$15.06	$14.30	$13.86	$13.31	$14.59	$13.48	$14.26
	< -$20	$102.51	$154.46	$440.43	$593.65	$42.14	$53.40	$232.19
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	YTD Avg
~ 135 Minutes Prior to Real-Time	> $20	$87.42	$64.44	$43.97	$43.47	$38.50	$31.51	$64.72
	$10 to $20	$13.68	$12.62	$13.88	$13.70	$14.16	$14.23	$13.79
	$5 to $10	$7.24	$7.05	$7.03	$6.96	$7.02	$7.05	$7.05
	$0 to $5	$1.43	$1.41	$1.59	$1.82	$1.61	$1.36	$1.54
	$0 to -$5	$1.61	$1.58	$1.59	$1.72	$1.69	$1.57	$1.63
	-$5 to -$10	$6.89	$6.99	$7.12	$6.71	$6.83	$6.72	$6.89
	-$10 to -$20	$15.07	$14.32	$14.31	$14.03	$14.67	$13.74	$14.43
	< -$20	$99.93	$241.48	$695.65	$895.06	$42.47	$47.23	$397.69

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 June 30, 2019, 244,714 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 78,624 (32.1 percent) of the intervals was inconsistent with the differences in real-time PJM/NYISO and NYISO/PJM prices. For example, if a market participant submits a CTS transaction from NYISO to PJM with a spread bid of $5.00, and NYISO's forecasted PJM interface price was at least $5.00 lower than PJM's forecasted NYISO interface price, the transaction would be approved. For 32.1 percent of the approved transactions, the actual, real-time price differentials were in the opposite direction of the forecast differential. The actual, real-time price differentials meant that the transactions would have been economic in the opposite direction. For 67.9 percent of the intervals, the forecast price differentials were consistent with real-time PJM/NYISO and NYISO/PJM price differences. Figure 9-14 shows the monthly volume of cleared PJM/NYIS CTS bids. Figure 9-14 also shows the percent of cleared bids that resulted in flows consistent and inconsistent with price differences.

Figure 9-14 Monthly cleared PJM/NYIS CTS bid volume: November 4, 2014 through June 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 six 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 44.7 percent of all intervals. In those intervals, the average price difference between the ITSCED forecasted LMP and the actual real-time LMP was $1.58. In 5.6 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 $57.40 when the price difference was greater than $20.00, and $387.19 when the price difference was greater than -$20.00.

Table 9-46 Differences between forecast and actual PJM/MISO interface prices: January through June, 2019

Range of Price Differences	Percent of All Intervals	Average Price Difference
> $20	2.4%	$57.40
$10 to $20	3.5%	$13.85
$5 to $10	6.4%	$6.99
$0 to $5	44.7%	$1.58
$0 to -$5	34.5%	$1.42
-$5 to -$10	3.2%	$6.96
-$10 to -$20	2.1%	$14.21
< -$20	3.2%	$387.19

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 80.4 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/MISO interface real-time LMP, compared to 80.5 percent in the 135 minute ahead ITSCED results.

Table 9-47 Differences between forecast and actual PJM/MISO interface prices: January through June, 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	1.0%	$42.28	1.1%	$41.68	1.6%	$44.06	1.6%	$41.72
$10 to $20	1.8%	$13.80	2.0%	$13.76	3.5%	$13.64	3.5%	$13.62
$5 to $10	4.0%	$7.05	3.9%	$6.98	7.0%	$6.94	7.1%	$7.00
$0 to $5	28.8%	$1.55	29.7%	$1.53	48.6%	$1.63	49.5%	$1.62
$0 to -$5	51.7%	$1.68	51.1%	$1.66	31.8%	$1.34	30.9%	$1.34
-$5 to -$10	5.5%	$6.89	5.3%	$6.91	2.7%	$6.99	2.6%	$7.04
-$10 to -$20	3.4%	$13.97	3.3%	$14.08	1.8%	$14.24	1.8%	$14.31
< -$20	3.8%	$382.83	3.7%	$334.61	3.0%	$403.32	3.0%	$363.53

In 4.6 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 $41.72 when the price difference was greater than $20.00, and $363.53 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 June, 2019

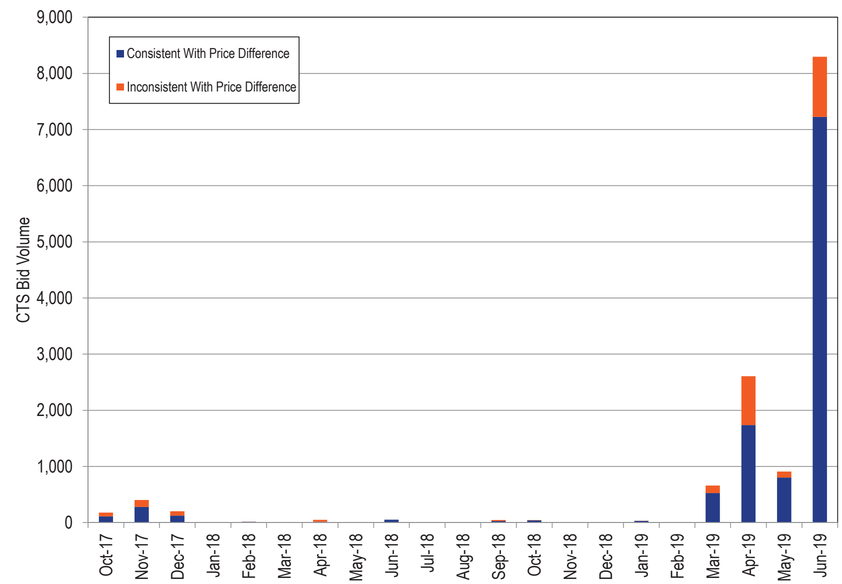
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	YTD Avg
~ 30 Minutes Prior to Real-Time	> $20	2.7%	1.6%	0.9%	1.8%	0.9%	1.7%	1.6%
	$10 to $20	2.2%	2.3%	2.3%	6.4%	5.1%	2.9%	3.5%
	$5 to $10	3.5%	5.6%	7.2%	8.8%	11.4%	6.2%	7.1%
	$0 to $5	45.3%	45.9%	48.3%	48.1%	52.2%	56.9%	49.5%
	$0 to -$5	39.8%	34.5%	31.9%	26.1%	25.0%	28.5%	30.9%
	-$5 to -$10	3.1%	2.9%	3.3%	2.5%	2.4%	1.6%	2.6%
	-$10 to -$20	1.8%	2.4%	1.8%	2.4%	1.4%	0.9%	1.8%
	< -$20	1.8%	4.8%	4.4%	4.1%	1.6%	1.4%	3.0%
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	YTD Avg
~ 45 Minutes Prior to Real-Time	> $20	2.4%	1.7%	0.9%	2.0%	1.1%	1.6%	1.6%
	$10 to $20	2.4%	2.4%	2.1%	5.5%	5.3%	3.2%	3.5%
	$5 to $10	3.3%	5.5%	6.7%	9.1%	10.5%	6.6%	7.0%
	$0 to $5	45.0%	44.8%	47.1%	46.8%	52.2%	55.3%	48.6%
	$0 to -$5	40.2%	35.5%	32.9%	27.5%	25.4%	29.3%	31.8%
	-$5 to -$10	3.4%	3.1%	3.1%	2.9%	2.1%	1.7%	2.7%
	-$10 to -$20	1.6%	2.5%	2.3%	2.2%	1.8%	0.8%	1.8%
	< -$20	1.8%	4.4%	4.9%	4.0%	1.6%	1.5%	3.0%
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	YTD Avg
~ 90 Minutes Prior to Real-Time	> $20	1.8%	0.6%	1.5%	1.1%	0.3%	1.0%	1.1%
	$10 to $20	1.9%	1.7%	1.9%	3.5%	1.0%	1.7%	2.0%
	$5 to $10	2.9%	3.1%	5.1%	4.6%	4.0%	3.8%	3.9%
	$0 to $5	27.5%	26.6%	36.4%	31.1%	27.5%	28.8%	29.7%
	$0 to -$5	55.1%	54.4%	43.3%	46.4%	51.9%	55.5%	51.1%
	-$5 to -$10	5.2%	5.1%	4.4%	5.5%	7.2%	4.4%	5.3%
	-$10 to -$20	3.2%	3.2%	2.3%	3.1%	5.3%	2.9%	3.3%
	< -$20	2.4%	5.2%	5.0%	4.8%	2.9%	1.8%	3.7%
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	YTD Avg
~ 135 Minutes Prior to Real-Time	> $20	1.9%	0.7%	1.2%	1.1%	0.3%	1.0%	1.0%
	$10 to $20	1.8%	1.4%	1.9%	3.3%	1.0%	1.7%	1.8%
	$5 to $10	2.8%	2.9%	5.2%	4.4%	4.1%	4.4%	4.0%
	$0 to $5	26.6%	25.6%	35.2%	30.3%	27.0%	27.5%	28.8%
	$0 to -$5	55.8%	55.5%	43.7%	46.9%	52.0%	56.6%	51.7%
	-$5 to -$10	5.0%	5.5%	4.9%	6.0%	7.3%	4.0%	5.5%
	-$10 to -$20	3.4%	3.1%	2.5%	3.3%	5.2%	3.0%	3.4%
	< -$20	2.6%	5.3%	5.4%	4.6%	3.1%	1.8%	3.8%

Table 9-49 Monthly differences between forecast and actual PJM/MISO interface prices (average price difference): January through June, 2019

Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	YTD Avg
~ 30 Minutes Prior to Real-Time	> $20	$44.69	$44.07	$47.98	$41.73	$29.97	$37.87	$41.72
	$10 to $20	$14.36	$13.27	$13.39	$13.90	$13.48	$13.14	$13.62
	$5 to $10	$7.17	$6.92	$7.02	$6.81	$7.07	$7.07	$7.00
	$0 to $5	$1.34	$1.55	$1.62	$1.79	$1.85	$1.56	$1.62
	$0 to -$5	$1.21	$1.36	$1.42	$1.42	$1.45	$1.21	$1.34
	-$5 to -$10	$7.24	$6.97	$6.85	$7.11	$6.95	$7.18	$7.04
	-$10 to -$20	$14.22	$14.22	$14.16	$14.28	$14.68	$14.54	$14.31
	< -$20	$77.60	$179.96	$604.25	$648.50	$66.87	$68.61	$363.53
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	YTD Avg
~ 45 Minutes Prior to Real-Time	> $20	$50.71	$43.83	$43.20	$44.99	$32.36	$41.70	$44.06
	$10 to $20	$15.00	$13.44	$13.46	$13.66	$13.31	$13.42	$13.64
	$5 to $10	$7.12	$6.95	$6.88	$6.86	$7.01	$6.93	$6.94
	$0 to $5	$1.32	$1.56	$1.66	$1.80	$1.86	$1.55	$1.63
	$0 to -$5	$1.23	$1.36	$1.42	$1.51	$1.39	$1.22	$1.34
	-$5 to -$10	$7.08	$7.00	$6.79	$7.10	$6.91	$7.12	$6.99
	-$10 to -$20	$14.69	$14.48	$13.83	$14.05	$14.28	$14.28	$14.24
	< -$20	$64.73	$181.49	$677.95	$700.70	$72.16	$76.31	$403.32
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	YTD Avg
~ 90 Minutes Prior to Real-Time	> $20	$48.58	$42.18	$41.28	$43.68	$37.74	$28.77	$41.68
	$10 to $20	$14.66	$13.20	$13.75	$13.79	$13.32	$13.49	$13.76
	$5 to $10	$7.08	$6.79	$6.98	$6.91	$6.87	$7.26	$6.98
	$0 to $5	$1.29	$1.48	$1.61	$1.80	$1.62	$1.35	$1.53
	$0 to -$5	$1.47	$1.64	$1.60	$1.77	$1.80	$1.70	$1.66
	-$5 to -$10	$7.06	$6.71	$6.87	$6.97	$7.03	$6.69	$6.91
	-$10 to -$20	$15.20	$14.00	$13.97	$13.59	$13.89	$13.89	$14.08
	< -$20	$73.77	$209.99	$476.22	$722.26	$61.64	$63.52	$334.61
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	YTD Avg
~ 135 Minutes Prior to Real-Time	> $20	$50.44	$43.01	$41.85	$40.18	$38.26	$29.77	$42.28
	$10 to $20	$13.48	$12.92	$14.08	$14.33	$13.58	$13.60	$13.80
	$5 to $10	$7.27	$7.11	$6.94	$6.99	$6.86	$7.21	$7.05
	$0 to $5	$1.29	$1.59	$1.60	$1.83	$1.60	$1.36	$1.55
	$0 to -$5	$1.51	$1.62	$1.64	$1.80	$1.81	$1.71	$1.68
	-$5 to -$10	$7.06	$6.62	$6.79	$6.92	$7.12	$6.66	$6.89
	-$10 to -$20	$14.89	$13.95	$13.92	$13.69	$13.65	$13.82	$13.97
	< -$20	$61.97	$236.83	$723.62	$671.91	$59.92	$64.08	$382.83

CTS transactions were evaluated for each interval. From October 3, 2017, through June 30, 2019, 13,499 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 2,519 (18.7 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 18.7 percent of the approved transactions, the actual, real-time price differentials were in the opposite direction of the forecast differential. The actual, real-time price differentials meant that the transactions would have been economic in the opposite direction. For 81.3 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 June 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 June 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	
Aug	$731,539	$37	$0	$0	$0	$0	$0	$0	$0	
Sep	$119,162	$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

Prior to April 1, 2007, PJM did not limit nonfirm service imports that were willing to pay congestion, including spot imports, secondary network service imports and bilateral imports using nonfirm point-to-point service. Spot market imports, nonfirm point to point and network services that are willing to pay congestion, all termed willing to pay congestion (WPC), were part of the PJM LMP energy market design implemented on April 1, 1998. Under this approach, market participants could offer energy into or bid to buy from the PJM spot market at the border/interface as price takers without restrictions based on estimated available transmission capability (ATC). Price and PJM system conditions, rather than ATC, were the only limits on interchange.

However, PJM has interpreted its JOA with MISO to require restrictions on spot imports and exports although MISO has not implemented a corresponding restriction.[86] The result is that the availability of spot import service is limited by ATC and not all spot transactions are approved. Spot import service (a network service) is provided at no charge to the market participant offering into the PJM spot market.

86 See OASIS "Modifications to the Practices of Non-Firm and Spot Market Import Service" (April 20, 2007) <http://www.pjm.com/~/media/etools/oasis/wpc-white-paper.ashx>.

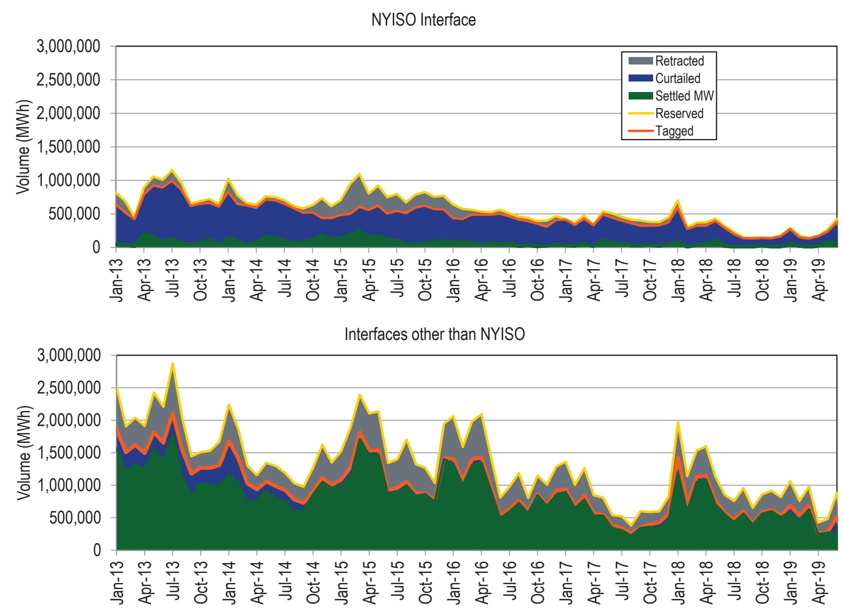
The spot import rules provide incentives to hoard spot import capability. In response to market participant complaints regarding the inability to acquire spot import service after this rule change on April 1, 2007, changes were made to the spot import service effective May 1, 2008.[87] These changes limited spot imports to only hourly reservations and caused spot import service to expire if not associated with a valid NERC Tag within two hours when reserved the day prior to the scheduled flow or within 30 minutes when reserved on the day of the scheduled flow.

These changes did not fully resolve the issue. In the *2008 State of the Market Report for PJM*, the MMU recommended that PJM reconsider whether a new approach to limiting spot import service is required or whether a return to the prior policy with an explicit system of managing related congestion is preferable. PJM and the MMU jointly addressed this issue through the stakeholder process, recommending that all unused spot import service be retracted if not tagged within 30 minutes from the queue time of the reservations intraday, and two hours when queued the day prior. On June 23, 2009, PJM implemented the new business rules.

Figure 9-16 shows the spot import service use for the NYISO Interface, and for all other interfaces, from January 1, 2013 through June 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.

87 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 9-16 Spot import service use: January 2013 through June 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.[88] 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.

88 The minimum duration for a real-time dispatchable transaction was modified to 15 minutes as per FERC Order No. 764.

Interchange Cap During Emergency Conditions

An interchange cap is a limit on the level of interchange permitted for nondispatchable energy using spot import or hourly point-to-point transmission. An interchange cap is a nonmarket intervention which should be a temporary solution and should be replaced with a market-based solution as soon as possible. Since the approval of this process on October 30, 2014, PJM has not yet needed to implement an interchange cap.

The purpose of the interchange cap is to help ensure that actual interchange more closely meets operators' expectations of interchange levels when internal PJM resources, e.g. CTs or demand response, were dispatched to meet the peak load. Once these resources have been called on, PJM must honor their minimum operating constraints regardless of whether additional interchange then materializes. Therefore any interchange received in excess of what was expected can have a suppressive effect on energy and reserve pricing and result in increased uplift.

PJM will notify market participants of the possible use of the interchange cap the day before. The interchange cap will be implemented for the forecasted peak and surrounding hours during emergency conditions.

The interchange cap will limit the acceptance of spot import and hourly nonfirm point to point interchange (imports and exports) not submitted as real-time with price transactions once net interchange has reached the interchange cap value. Spot imports and hourly nonfirm point to point transactions submitted prior to the implementation of the interchange cap will not be limited. In addition, schedules with firm or network designated transmission service will not be limited either, regardless of whether net interchange is at or above the cap.

The calculation of the interchange cap is based on the operator expectation of interchange at the time the cap is calculated plus an additional margin. The margin is set at 700 MW, which is half of the largest contingency on the system. The additional margin also allows interchange to adjust to the loss of a unit or deviation between actual load and forecasted load. The interchange cap is based on the maximum sustainable interchange from PJM reliability studies.

45 Minute Schedule Duration Rule

PJM limits the change in interchange volumes on 15 minute intervals. These changes are referred to as ramp. The purpose of imposing a ramp limit is to help ensure the reliable operation of the PJM system. The 1,000 MW ramp limit per 15 minute interval was based on the availability of ramping capability by generators in the PJM system. The limit is consistent with the view that the available generation in the PJM system can only move 1,000 MW over any 15 minute period 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.[89] [90] On April 17, 2014, FERC issued its order which found that PJM's 45 minute duration rule was inconsistent with Order No. 764.[91]

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.[92]

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.[93] On July 15, 2010, MISO submitted revisions to the MISO Tariff to implement criteria for identifying and allocating the costs of MVPs.[94] On December 16, 2010, the Commission accepted the proposed MVP charge for export and wheel-through transactions, except for transactions that sink in PJM.[95] 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

89 Order No. 764, 139 FERC ¶ 61,246 (2012), *order on reh'g*, Order No. 764-A, 141 FERC ¶ 61231 (2012).
90 Order No. 764 at P 51.
91 *See Id.* at P 12.
92 *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>.
93 See MISO. MTEP "Multi Value Project Portfolio Analysis," <https://cdn.misoenergy.org/2011%20MVP%20Portfolio%20Analysis%20Full%20Report117059.pdf>.
94 See Midwest Independent Transmission Operator Inc. filing, Docket No. ER10-1791-000 (July 15, 2010).
95 133 FERC ¶ 61,221 (2010); *order on reh'g*, 137 FERC ¶ 61,074 (2011).

Order and MVP Rehearing Order.[96] 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.[97] 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.[98]

On July 13, 2016, FERC issued an order permitting MISO to collect charges associated with MVPs for all transactions sinking in PJM, effective immediately.[99] 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."[100]

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.[101] It is not clear whether the MUR charge has affected interchange volumes from MISO into PJM.

Table 9-51 MISO projected multi value project usage rate: 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

96 Illinois Commerce Commission, et al. v. FERC, 721 F.3d 764, 778–780 (7th Cir. 2013).
97 *Id.* at 780.
98 *Id.* at 779.
99 156 FERC ¶ 61,034 (2016).
100 *Id.* at P 55.
101 See MISO, "Schedule 26A Indicative Annual Charges," (August 29, 2016) <https://cdn.misoenergy.org/Schedule%2026A%20Indicative%20Annual%20Charges106365.xlsx>.

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 six 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 4.9 percent of cleared hours in the first six 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 208 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 87.5 percent of the hours in the first six months of 2019.
- Participant behavior in the PJM Regulation Market was evaluated as competitive for the first six 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 six months of 2019, the average primary reserve requirement was 2,445.7 MW in the RTO Zone and 2,418.3 MW in the MAD Subzone.

Tier 1 Synchronized Reserve

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

Tier 1 synchronized reserve is 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 six months of 2019, there was an average hourly supply of 2,108.7 MW of tier 1 available in the RTO Zone. In the first six months of 2019, there was an average hourly supply of 1,552.9 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. 37 (Dec. 10, 2018).

of $50 per MWh in addition to LMP.[4] This is the Synchronized Energy Premium Price.

There were no spinning events 10 minutes or longer in the first six months of 2019.

- **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 $1,094,766 in the first six 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, that have an obligation to respond, that have penalties for failure to respond, and that must be dispatched in order to satisfy the synchronized reserve requirement.

When the synchronized reserve requirement cannot be met with tier 1 synchronized reserve, PJM uses a market to satisfy the balance of the requirement with tier 2 synchronized reserve. The Tier 2 Synchronized Reserve Market includes the PJM RTO Reserve Zone and a subzone, the Mid-Atlantic Dominion Reserve Subzone (MAD).

Market Structure

- **Supply.** In the first six months 2019, the supply of offered and eligible tier 2 synchronized reserve was 29,234.4 MW in the RTO Zone of which 5,427.5 MW was located in the MAD Subzone.
- **Demand.** The average hourly synchronized reserve requirement was 1,694.4 MW in the RTO Reserve Zone and 1,676.5 MW for the Mid-Atlantic Dominion Reserve Subzone. The hourly average cleared tier 2 synchronized reserve was 264.1 MW in the MAD Subzone and 534.0 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 six months 2019.

  The average HHI for tier 2 synchronized reserve in the RTO Zone was 5622 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.

4 See PJM. "Manual 11: Energy & Ancillary Services Market Operations,"§ 4.2.10 Settlements, Rev. 106 (May 30, 2019).

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 six months of 2019 was $2.58 per MW, a decrease of $3.48 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 $2.64 per MW in the first six months of 2019, a decrease of $3.76 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 six months of 2019, the average hourly supply of eligible nonsynchronized reserve was 3,879.1 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.[5] 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 1,770.4 MW of nonsynchronized reserve in the first six months of 2019.
- **Market Concentration.** The MMU calculates that the three pivotal supplier test would have been failed in 59.8 percent of hours in the first six 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 $0.13 per MW in the first six months of 2019. The price cleared above $0.00 in 0.8 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.[6] If DASR units are on an outage in real time or cleared DASR MW are not available, the DASR payment is not made.

5 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," § $b.2.2 Non-Synchronized Reserve Zones and Levels, Rev. 106 (May 30, 2019). "Because Synchronized Reserve may be utilized to meet the Primary Reserve requirement, there is no explicit requirement for non-synchronized reserves."

6 See PJM, "Manual 11: Energy & Ancillary Services Market Operations," § 11.2.7 Day-Ahead Scheduling Reserve Performance, Rev. 106 (May 30, 2019).

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 six months of 2019, the average available hourly DASR was 44,532.7 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 six months of 2019 was 5,115.5 MW. This is a reduction from the 5,534.0 hourly MW in 2018.
- **Concentration.** In the first six months of 2019, the DASR Market did not fail the three pivotal supplier test in any hour.

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 six months of 2019, a daily average of 39.6 percent of units offered above $0.00. A daily average of 16.5 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 six months of 2019.

Market Performance

- **Price.** In the first six months of 2019, the weighted average DASR price for all hours when the DASRMCP was above $0.00 was $1.14.

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 function (MBF). Correctly implemented, the MBF would be the marginal rate of technical substitution (MRTS) between RegA and RegD, holding the level of regulation service constant. The current market design is critically flawed as it has not properly implemented the MBF as an MRTS between RegA and RegD resource MW and the MBF has not been consistently applied in the optimization, clearing and settlement of the Regulation Market.

Market Structure

- **Supply.** In the first six months of 2019, the average hourly eligible supply of regulation for nonramp hours was 1,096.2 performance adjusted MW (821.9 effective MW). This was an increase of 7.6 performance adjusted MW (a decrease of 28.8 effective MW) from the first six months of 2018, when the average hourly eligible supply of regulation was 1,088.7 performance adjusted MW (850.7 effective MW). In the first six months of 2019, the average hourly eligible supply of regulation for ramp hours was 1,384.8 performance adjusted MW (1,137.1 effective MW). This was an increase of 5.5 performance adjusted MW (a decrease of 30.9 effective MW) from the first six months of 2018, when the average hourly eligible supply of regulation was 1,379.2 performance adjusted MW (1,168.0 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 470.3 hourly average performance adjusted actual MW in the first six months of 2019. This is a decrease of 16.1 performance adjusted actual MW from the first six months of 2018, when the average hourly total regulation cleared performance adjusted actual MW for nonramp hours were 486.4 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 717.0 hourly average performance adjusted actual MW in the first six months of 2019. This is an increase of 29.5 performance adjusted actual MW from the first six months of 2018, where the average hourly regulation cleared MW for ramp hours were 746.6 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 1.93 in the first six months of 2019. This is an increase of 4.5 percent from the first six months of 2018, when the ratio was 1.85. The ratio of the average hourly eligible supply of regulation to average hourly regulation demand (performance adjusted cleared MW) for nonramp hours was 2.33 in the first six months of 2019. This is an increase of 4.0 percent from the first six months of 2018, when the ratio was 2.24.

- **Market Concentration.** In the first six months of 2019, the three pivotal supplier test was failed in 87.5 percent of hours. In the first six months of 2019, the effective MW weighted average HHI of RegA resources was 2475 which is highly concentrated and the weighted average HHI of RegD resources was 1300 which is moderately concentrated.[7] The weighted average HHI of all resources was 1024, which is moderately concentrated.

Market Conduct

- **Offers.** Daily regulation offer prices are submitted for each unit by the unit owner. Owners are required to submit a cost-based offer and may submit a price-based offer. Offers include both a capability offer and a performance offer. Owners must specify which signal type the unit will be following, RegA or RegD.[8] In the first six months of 2019, there were 187 resources following the RegA signal and 58 resources following the RegD signal.

Market Performance

- **Price and Cost.** The weighted average clearing price for regulation was $13.85 per MW of regulation in the first six months of 2019. This is a decrease of $19.11 per MW, or 58.0 percent, from the weighted average clearing price of $32.97 per MW in the first six months of 2018. The weighted average cost of regulation in the first six months of 2019 was $18.12 per MW of regulation. This is a decrease of $22.64 per MW, or 55.6 percent, from the weighted average cost of $40.76 per MW in the first six 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 Function.** The marginal benefit factor (MBF) is intended to measure the operational substitutability of RegD resources for RegA resources. The marginal benefit factor function is incorrectly defined and applied in the PJM market clearing. Correctly defined, the MBF function represents the Marginal Rate of Technical Substitution (MRTS) between RegA and RegD. Correctly implemented, the MBF would be consistently applied in the Regulation Market clearing and settlement. The current incorrect and inconsistent implementation of the MBF

7 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.

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

function has resulted in the PJM Regulation Market over procuring RegD relative to RegA in most hours and in a consistently inefficient market signal to participants regarding the value of RegD to the market in every hour. This over procurement 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.[9] The MMU and PJM filed requests for rehearing.[10]

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).[11]

In the first six months of 2019, total black start charges were $32.21 million, including $32.10 million in revenue requirement charges and $0.114 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 six months of 2019 ranged from $0.04 per MW-day in the DLCO Zone (total charges were $22,609) to $4.07 per MW-day in the PENELEC Zone (total charges were $2,206,364).

9 162 FERC ¶ 61,295.
10 FERC Docket No. ER18-87-002.
11 OATT Schedule 1 § 1.3BB.

Reactive

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

Reactive capability revenue requirements are based on FERC approved filings that permit recovery based on a cost of service approach.[12] 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 six months of 2019, total reactive charges were $175.00 million, a 2.9 percent increase from $170.04 million in the first six months of 2018. Reactive capability revenue requirement charges increased from $159.32 million in the first six months of 2018 to $174.55 million in the first six months of 2019 and reactive service charges decreased from $10.72 million in the first six months of 2018 to $0.45 million in 2019. Total reactive service charges in the first six months of 2019 ranged from $0 in the RECO and OVEC Zones, which have no generating units, to $24.10 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.[13] PJM filed revisions in compliance with Order No. 842 that substantively incorporated the pro forma agreements into its market rules.[14]

12 OATT Schedule 2.
13 See 157 FERC ¶ 61,122 (2016).
14 See 164 FERC ¶ 61,224 (2018).

Ancillary Services Costs per MWh of Load: January through June, 1999 through 2019

Table 10-4 shows PJM ancillary services costs for the first six months, 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 June, 1999 through 2019[15] [16]

Year (Jan-Jun)	Regulation	Scheduling, Dispatch and System Control	Reactive	Synchronized Reserve	Total
1999	$0.08	$0.23	$0.27	$0.00	$0.58
2000	$0.26	$0.32	$0.33	$0.00	$0.91
2001	$0.50	$0.73	$0.22	$0.00	$1.45
2002	$0.31	$0.81	$0.19	$0.00	$1.31
2003	$0.57	$1.06	$0.24	$0.16	$2.03
2004	$0.53	$1.07	$0.26	$0.16	$2.02
2005	$0.58	$0.80	$0.27	$0.11	$1.76
2006	$0.48	$0.74	$0.29	$0.08	$1.59
2007	$0.61	$0.71	$0.27	$0.09	$1.68
2008	$0.73	$0.52	$0.34	$0.08	$1.67
2009	$0.38	$0.32	$0.36	$0.04	$1.10
2010	$0.34	$0.36	$0.37	$0.06	$1.13
2011	$0.33	$0.36	$0.40	$0.10	$1.19
2012	$0.20	$0.43	$0.47	$0.03	$1.13
2013	$0.26	$0.43	$0.65	$0.03	$1.37
2014	$0.46	$0.43	$0.42	$0.20	$1.51
2015	$0.29	$0.42	$0.37	$0.14	$1.22
2016	$0.11	$0.43	$0.39	$0.05	$0.98
2017	$0.13	$0.49	$0.43	$0.06	$1.11
2018	$0.24	$0.47	$0.44	$0.08	$1.23
2019	$0.11	$0.46	$0.47	$0.04	$1.08

15 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.
16 Reactive totals include FERC approved rates for reactive capability.

Recommendations

- The MMU recommends that the Regulation Market be modified to incorporate a consistent application of the marginal benefit factor (MBF) throughout the optimization, assignment and settlement process. The MBF should be defined as the Marginal Rate of Technical Substitution (MRTS) between RegA and RegD. (Priority: High. First reported 2012. Status: Not adopted. FERC rejected, pending rehearing request before FERC.[17])
- 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.[18] FERC rejected, pending rehearing request before FERC.[19])
- 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.[20])
- 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.[21])
- 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.[22])

17 FERC Docket No. ER18-87.
18 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.
19 FERC Docket No. ER18-87.
20 *Id.*
21 *Id.*
22 *Id.*

- 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 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.)

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.[23]

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.

23 Order No. 755, 137 FERC ¶ 61,064 at PP 197–200 (2011).

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.[24] 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.[25] The MMU and PJM separately filed requests for rehearing.[26]

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 were no spinning events 10 minutes or longer in the first six months of 2019. 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

24 18 CFR § 385,211 (2017).
25 162 FERC ¶ 61,295 (2018).
26 The MMU filed its request for rehearing on April 27, 2018, and PJM filed its request for rehearing on April 30, 2018.

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 $1.1 million in the first six 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.[27] The NERC requirement is 100 percent compliance and status must be reported quarterly. PJM implements this contingency reserve requirement using primary reserves.[28] 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.

PJM can, for conservative operations, raise the primary and synchronized reserve requirement when grid maintenance or outages change the largest contingency or in cases of hot weather or cold weather alerts.[29] Such additional reserves are committed as part of the hourly (ASO) and five minute (RTSCED) processes. In the first six months of 2019, the average five minute interval primary reserve requirement for the RTO Zone was 2,447.5 MW. The average five minute interval primary reserve requirement in the MAD Subzone was 2,421.6 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

27 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."
28 See PJM "Manual 10: Pre-Scheduling Operations," § 3.1.1 Day-ahead Scheduling (Operating) Reserve, Rev. 37 (Dec. 10, 2018).
29 See Temporary Changes to the Synchronized Reserve Requirements at <https://messages.pjm.com/messages/pages/public/messages.jsf>.

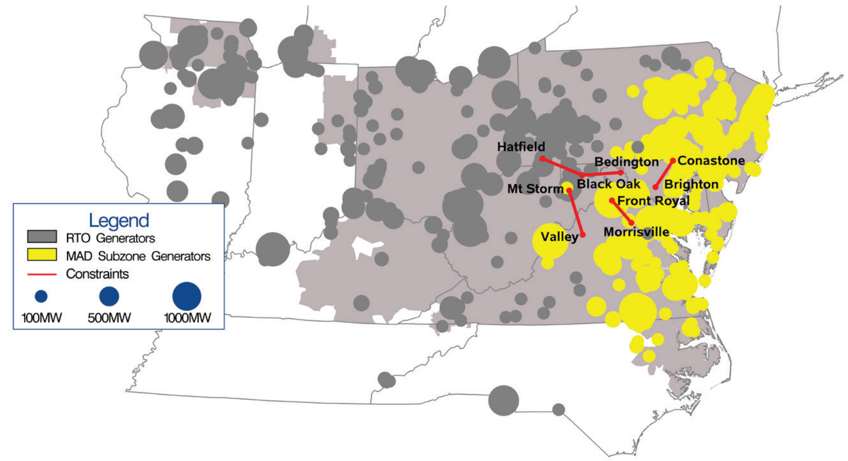
are estimated against average requirement levels before and after the periods of increase.

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 (1,350MW), Synchronized Reserve (1,000MW)
4-Mar-19	5-Mar-19	24	Primary Reserve (220MW), Synchronized Reserve (150MW)
29-Apr-19	3-May-19	61	Primary Reserve (65MW), Synchronized Reserve (50MW)
7-May-19	7-May-19	6	Primary Reserve (280MW), Synchronrized Reserve (230MW)
6-Jun-19	6-Jun-19	5	Primary Reserve (600MW), Synchronized Reserve (400MW)
11-Jun-19	11-Jun-19	5	Primary Reserve (600MW), Synchronized Reserve (300MW)
17-Jun-19	19-Jun-19	24	Primary Reserve (220MW), Synchronized Reserve (150MW)

Transmission constraints limit the deliverability of reserves within the RTO, requiring the definition of the Mid-Atlantic Dominion (MAD) Subzone (Figure 10-1).[30] 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).[31] 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 synchronized reserves.[32] In the first six months of 2019, the five minute average synchronized reserve requirement in the RTO Zone was 1,695.1 MW. The five minute average synchronized reserve requirement in the MAD Subzone was 1,677.9 MW. The synchronized reserve requirement is calculated every five minutes.

30 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. 106 (May 30, 2019).

31 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>.

32 "PJM Manual 13: Emergency Operations," Rev 70 (May 30, 2019) p. 18.

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 984.7 MW of tier 1 was identified by the RT SCED market solution as available in the first six months of 2019 (Table 10-7).[33] 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 11.6 percent of intervals in the first six months of 2019. In the RTO Zone, an average of 2,108.7 MW of tier 1 was available (Table 10-7) fully satisfying the synchronized reserve requirement in 60.8 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.[34]

After tier 1 is estimated, the remainder of the synchronized reserve requirement is met by tier 2. In the RTO Zone, there were 29,179.4 MW of tier 2 synchronized reserve offered daily. Of this, 5,427.5 MW were located in the MAD Subzone (Figure 10-10) and available to meet the average MAD tier 2 hourly demand of 266.8 MW (Table 10-6).

In the MAD Subzone, there was an average of 3,055.4 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 3,884.6 MW supply was available to meet the average interval demand of 1,765.8 MW (Table 10-6).

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 June 2019.

Table 10-6 Average hourly reserves used to satisfy the primary reserve requirement, MAD Subzone: January 2018 through June 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	Average	1,552.9	266.0	1,504.3	3,057.3

33 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.

34 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 4.2 PJM Synchronized Reserve Market Business Rules, Rev. 106 (May 30, 2019).

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 June 2019.

Table 10-7 Average monthly reserves used to satisfy the primary reserve requirement, RTO Zone: January 2018 through June 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	Average	2,117.2	528.9	1,767.8	4,413.9

Supply and Demand

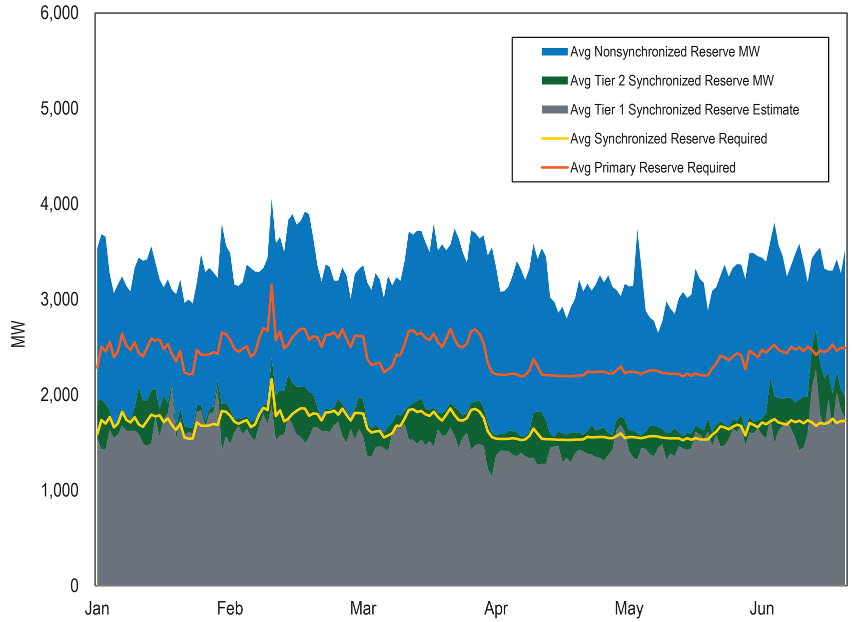
The market solution software relevant to reserves consists of: the Ancillary Services Optimizer (ASO) solving hourly; the intermediate term security constrained economic dispatch market solution (IT SCED); and the real-time (short term) security constrained economic dispatch market solution (RT SCED).

All market solutions determine the actual primary reserves required each hour as one hundred and fifty percent of the largest contingency based on generation and transmission resources. Of this, synchronized reserves must be one hundred percent of the largest contingency. The ASO solves each hour one hour ahead. It first assigns self-scheduled synchronized reserves and then estimates the amount of tier 1 synchronized reserves available. The ASO clears inflexible tier 2 synchronized reserve and identifies flexible synchronized reserve sufficient to meet the remaining synchronized reserve requirement.

IT SCED runs at 15 minute intervals and jointly optimizes energy and reserves given the ASO's inflexible unit commitments. IT SCED estimates available tier 1 synchronized reserve and can commit additional reserves (flexibly or inflexibly) if needed. RT SCED runs at five minute intervals and produces load forecasts up to 20 minutes ahead. The RT SCED estimates the available tier 1, provides a real-time ancillary services solution and can commit additional flexible tier 2 resources if needed.

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 up to the synchronized reserve is filled with tier 2 synchronized reserve (blue area). After synchronized reserve is assigned, the primary reserve requirement is filled by jointly optimizing synchronized reserve and nonsynchronized reserve (light blue area). Since nonsynchronized reserve is priced lower than or equal to synchronized reserve, almost all primary reserve above the synchronized reserve requirement is filled by nonsynchronized reserve.

Figure 10-2 Mid-Atlantic Dominion subzone primary reserve MW by source (Daily Averages): January through June, 2019



The solution method is the same for the RTO Reserve Zone.[35] 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 June, 2019

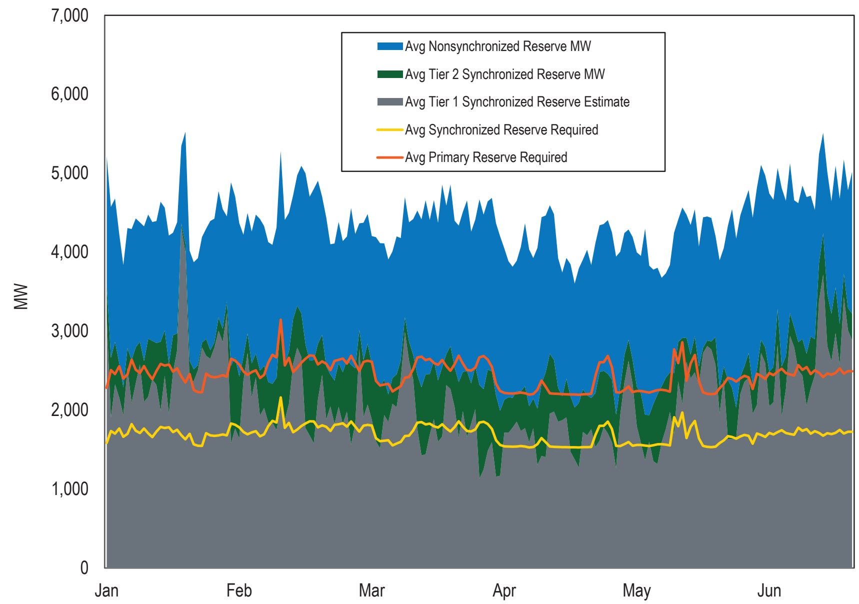


Figure 10-2 shows that within the MAD Subzone, Tier 1, Tier 2 from MAD, and Tier 2 from the RTO are all essential to satisfying the synchronized reserve requirement. Figure 10-3 shows that tier 1 synchronized reserve remains the major contributor to satisfying the synchronized reserve requirement in the RTO Zone.

35 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.

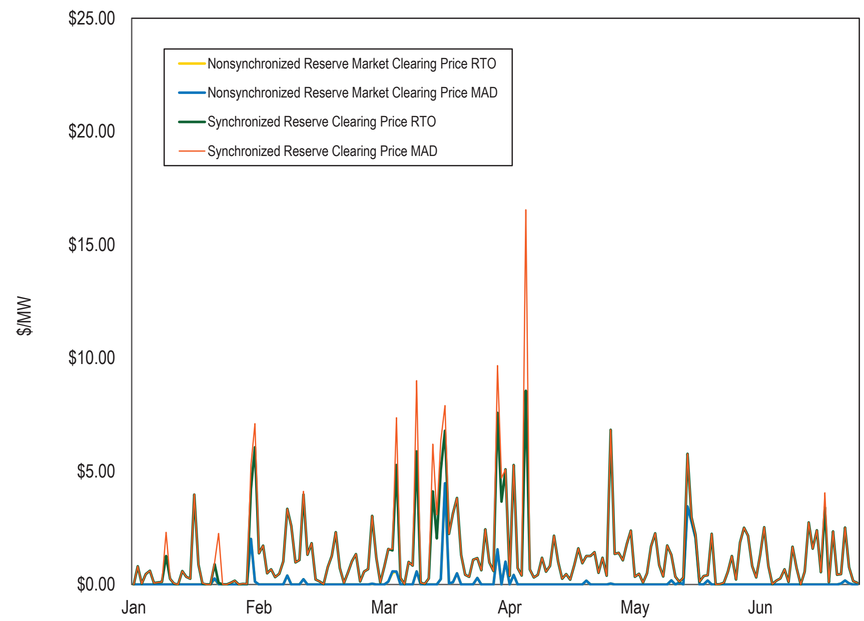
Price and Cost

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 six months of 2019.

Figure 10-4 Daily average market clearing prices ($/MW) for synchronized reserve and nonsynchronized reserve: January through June, 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 six months 2019 was 39.0 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 $18.03 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 $4.26 per MW.

Table 10-8 Primary reserve requirement components, RTO Reserve Zone: January through June, 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	1,647	$82,354	NA	$50.00
Tier 1 Synchronized Reserve Estimated	0.9%	60,712	$1,094,766	$0.00	$18.03
Tier 2 Synchronized Reserve Scheduled	27.7%	1,827,781	$7,780,861	$2.66	$4.26
Non Synchronized Reserve Scheduled	71.4%	4,711,432	$5,091,757	$0.13	$1.09
Primary Reserve (total of above)	100.0%	6,601,572	$14,049,738	$0.83	$2.13

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.[36] 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.

36 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 4.2.1 Synchronized Reserve Market Eligibility, Rev. 106 (May 30, 2019).

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 r ate, 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.[37] 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, 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 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.[38] 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.[39]

37 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>.

38 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," § 4.2.1 Synchronized Reserve Market Eligibility, Rev. 106 (May 30, 2019).

39 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," § 4.2.1 Synchronized Reserve Market Eligibility, Rev. 106 (May 30, 2019).

In the first six months of 2019, the market solutions estimated tier 1 MW from an average of 151 units that could contribute ramp in a spinning event. In the RTO Reserve Zone, the average interval estimated tier 1 synchronized reserve was 2,117.2 MW (Table 10-9). In 60.8 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 six months of 2019, the average estimated tier 1 synchronized reserve was 1,552.9 MW in the MAD Subzone and 564.9 MW were available from the RTO (Table 10-9). In 11.6 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.

Table 10-9 Monthly average interval market solutions for tier 1 synchronized reserve (MW): January 2018 through June 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	1,270.7	379.9	1,648.5	2,528.7
2019	Feb	999.9	629.9	1,629.9	2,056.8
2019	Mar	935.7	601.0	1,535.9	1,948.4
2019	Apr	666.1	702.7	1,368.8	1,593.4
2019	May	879.1	570.1	1,449.2	2,003.4
2019	Jun	1,159.8	510.0	1,669.8	2,522.5
2019	Average	1,068.8	536.9	1,604.8	2,178.0

Demand

There is no required amount of tier 1 synchronized reserve.

The ancillary services market solution treats the cost of estimated tier 1 synchronized reserve as $0, even when the nonsynchronized reserve market clearing price is above $0. As a result, the optimization cannot 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.

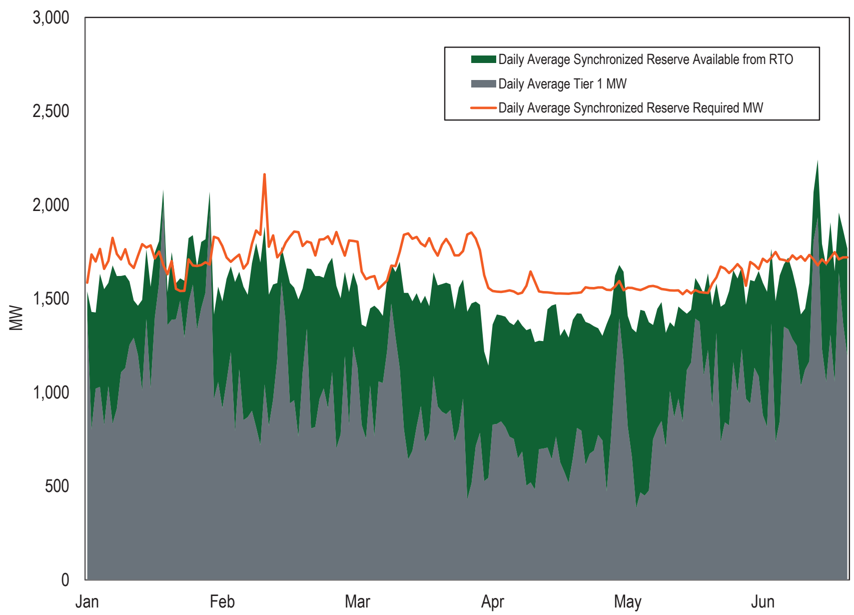
Supply and Demand

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 (gray area of Figure 10-5) as well as the synchronized reserve MW estimated to be available within the MAD Subzone from the RTO Zone (green area of Figure 10-5) up to the synchronized reserve requirement. If the total tier 1 synchronized reserve is less than the synchronized reserve requirement, the remainder of the synchronized reserve requirement is filled with tier 2 synchronized reserve (white area below the synchronized reserve required line in Figure 10-5).

Figure 10-5 Daily average tier 1 synchronized reserve supply (MW) in the MAD Subzone: January through June, 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.[40] 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.

40 See PJM. "Manual 11: Energy & Ancillary Services Market Operations,"§ 4.2.10 Settlements, Rev. 106 (May 30, 2019).

In the first six months of 2019, tier 1 synchronized reserve spinning event response credits of $82,354 were paid for six spinning events covering 12 intervals. The average tier 1 response over the six spinning events was 269.1 MWh (Table 10-10).

Table 10-10 Tier 1 synchronized reserve event response costs: January 2018 through June 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		1,646.9	$82,354	269.0	60,712.6	$1,094,766	523.4

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 10-12). However, the shortage pricing tariff changes (October 1, 2012) modified the pricing of tier 1 so that tier 1 synchronized reserve is paid the tier 2 synchronized reserve market clearing price whenever the nonsynchronized reserve market clearing price rises above zero. The rationale for this change was and is unclear, but it has had a significant impact on the cost of tier 1 synchronized reserves (Table 10-11). The nonsynchronized reserve market clearing price was above $0.00 in 92 hours in the first six months of 2019. For those 92 hours, tier 1 synchronized reserve resources were paid a weighted average synchronized reserve market clearing price of $23.25 per MW and earned $1,094,766 in credits.

Table 10-11 Price of tier 1 synchronized reserve attributable to a nonsynchronized reserve price above zero: January 2018 through June 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		92	$23.25	60,712.2	$1,094,766	523.4

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 2018, 67.2 percent of the DGP adjusted market solution's estimated tier 1 MW actually responded during synchronized reserve events of 10 minutes or longer while 32.8 percent of DGP adjusted tier 1 estimated MW did not respond during spinning events. For all tier 1 units, 76.1 percent of responded with 100 percent of their T1 capability and 9.9 percent of DGP estimated T1 units did not respond at all (zero percent). The remaining 14.0 percent responded with less than their full DGP estimated tier 1 MW. 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 six months of 2019, tier 1 synchronized reserve was paid $82,354 for responding to synchronized reserve events. During the same time period, tier 1 synchronized reserve was paid a windfall of $1,094,766 simply because the NSRMCP was greater than $0.00 in 40 hours. Table 10-10 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.[41] Tier 1 should be compensated only

41 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.

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 10-12.

Table 10-12 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 10-13.

Table 10-13 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 1 Estimate Bias

PJM's ASO market solution software allows the operator to bias the inflexible tier 2 synchronized reserve solution by forcing the software to assume a different tier 1 MW value than it actually estimates. PJM no longer allows dispatchers to use tier 1 biasing in the intermediate and real-time SCED solutions, but tier 1 biasing is used in the hour ahead reserve market solution, ASO. Biasing means manually modifying (decreasing or increasing) the tier 1 synchronized reserve estimate of the market solution. This forces the market clearing engine to clear more or less tier 2 synchronized reserve and nonsynchronized reserve to satisfy the synchronized reserve and primary reserve requirements than would have cleared under the market solution. Negative biasing is the primary form of biasing actually used although sometimes the solution is biased positively (Table 10-14). Table 10-14 shows RTO Zone ASO tier 1 estimate biasing for the January 2018 through June 2019 period.

Table 10-14 RTO zone ASO tier 1 estimate biasing: January 2018 through June 2019

Year	Month	Number of Hours Biased Negatively	Average Negative Bias (MW)	Number of Hours Biased Positively	Average Positive Bias (MW)
2018	Jan	209	(851.9)	0	NA
2018	Feb	85	(558.8)	0	NA
2018	Mar	72	(477.8)	0	NA
2018	Apr	232	(510.6)	0	NA
2018	May	114	(394.1)	4	237.5
2018	Jun	95	(534.5)	3	733.3
2018	Jul	46	(1,716.3)	2	1,600.0
2018	Aug	139	(591.4)	0	NA
2018	Sep	92	(886.2)	2	325.0
2018	Oct	84	(547.6)	0	NA
2018	Nov	40	(666.3)	3	566.7
2018	Dec	20	(1,112.5)	0	NA
2018		1,228	(737.3)	14	692.5
2019	Jan	9	(888.9)	0	NA
2019	Feb	4	(688.0)	0	NA
2019	Mar	17	(1,644.1)	0	NA
2019	Apr	6	(1,966.7)	0	NA
2019	May	0	NA	0	NA
2019	Jun	0	NA	0	NA
2019		36	(1,296.9)	0	NA

Tier 1 biasing is not mentioned in the PJM manuals and does not appear to be defined in any public document. PJM dispatchers use tier 1 biasing to compensate for uncertainty in short-term load forecasting and uncertainty about expected generator performance, which result in uncertainty about the accuracy of the market solution's tier 1 estimate. The purpose of tier 1 estimate biasing is to modify the demand for tier 2 and therefore the market results both for tier 2 synchronized reserve and for nonsynchronized reserve. Biasing the tier 1 estimate forces the market solution to clear more or less tier 2 than actual demand and thus artificially affects the price for tier 2 reserves. The MMU recommends that PJM be more explicit and transparent about why tier 1 biasing is used in defining demand in the Tier 2 Synchronized Reserve Market. The MMU recommends that PJM define rules for estimating tier 1 MW, define rules for the use and amount of tier 1 biasing and identify the rule based reasons for each instance of biasing.

Tier 2 Synchronized Reserve Market

Synchronized reserve is provided by generators or demand response resources synchronized to the grid and capable of increasing output or decreasing load within 10 minutes. Synchronized reserve consists of tier 1 and tier 2 synchronized reserves. When the synchronized reserve requirement cannot be met by tier 1 synchronized reserve, PJM clears a market to satisfy the requirement with tier 2 synchronized reserve. Tier 2 synchronized reserve is provided by online resources, either synchronized to the grid but not producing energy, or dispatched to provide synchronized reserve at an operating point below their economic dispatch point. Tier 2 synchronized reserve is also provided by demand resources that have offered to reduce load in the event of an synchronized reserve event. Tier 2 synchronized reserves are committed to be available in the event of a synchronized reserve event. Tier 2 resources have a must offer requirement. Tier 2 resources are scheduled by the ASO 60 minutes before the operating hour, are committed to provide synchronized reserve for the entire hour, and are paid the higher of the SRMCP or their offer price plus lost opportunity cost (LOC). Demand response resources are paid the clearing price (SRMCP).

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.[42]

In the first six months of 2019, the Mid Atlantic Dominion (MAD) Reserve Subzone averaged 5,427.6 MW of tier 2 synchronized reserve offers, and the RTO Reserve Zone averaged 29,179.4 MW of tier 2 synchronized reserve offers (Figure 10-10).

The supply of tier 2 synchronized reserve offered in the first six 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.

42 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 4.2.1 Synchronized Reserve Market Eligibility, Rev. 106 (May 30, 2019).

The largest portion of cleared tier 2 synchronized reserve in the first six months of 2019 was from CTs, 57.5 percent (Figure 10-6). Although demand resources are limited to 33 percent of the total synchronized reserve requirement, the amount of tier 2 synchronized reserve required in any hour is often much less than the full synchronized reserve requirement because so much of it is met with tier 1 synchronized reserve. This means that in many hours demand resources make up considerably more than 33 percent of the cleared Tier 2 MW. DR MW were 20.9 percent of cleared tier 2 synchronized reserve in the first six months of 2019, combined cycle units were 9.1 percent and hydro resources were 7.8 percent.

Figure 10-6 Cleared tier 2 synchronized reserve average MW per hour by unit type, RTO Zone: January 2016 through June 2019

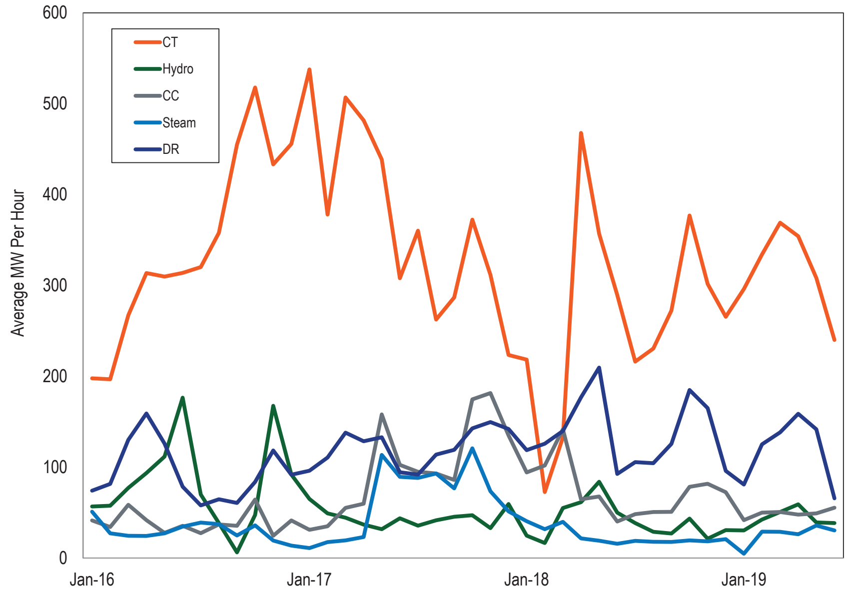
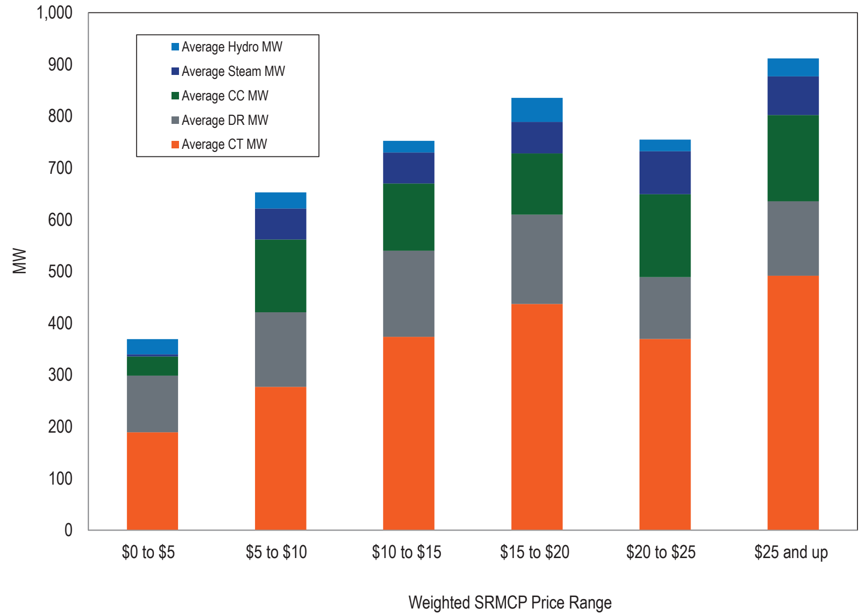


Figure 10-7 provides the average hourly cleared tier 2 MW by unit type by tier 2 clearing price range (SRMCP).

Figure 10-7 Average hourly tier 2 MW by unit type by weighted SRMCP range: January through June, 2019



Demand

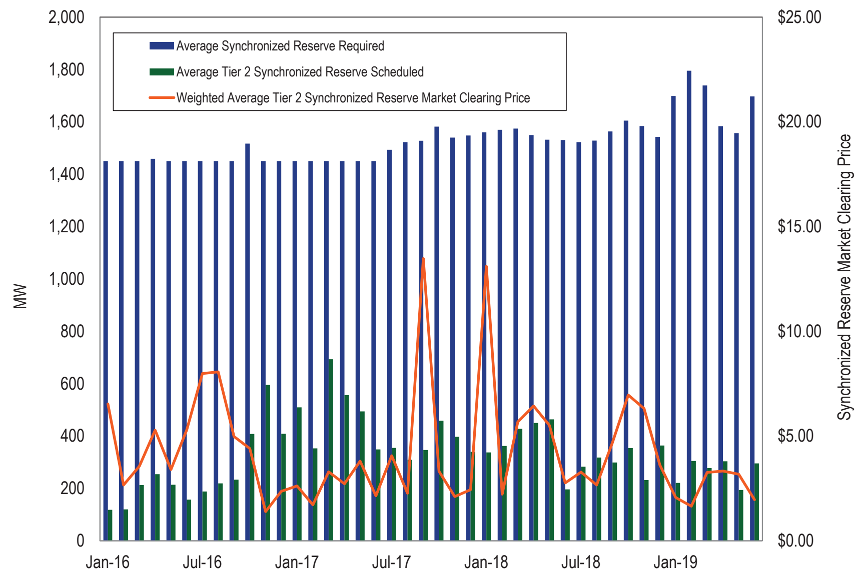
On July 12, 2017, PJM adopted a dynamic synchronized reserve requirement set equal to 100 percent of the most severe single contingency (MSSC), determined in each five minute interval by RT SCED. There are two circumstances in which PJM may alter the synchronized reserve requirement from its 100 percent of the largest contingency value. 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.[43]

In the first six months of 2019, the average synchronized reserve requirement per interval in the RTO Zone was 1,695.1 MW and the average synchronized reserve requirement in the MAD Subzone was 1,677.9 MW. These averages include temporary increases to the synchronized reserve requirement.

The RTO Reserve Zone purchased an interval average of 527.1 MW of tier 2 synchronized reserves in the first six months of 2019. Of this, an average of 266.8 MW cleared within the MAD Subzone.

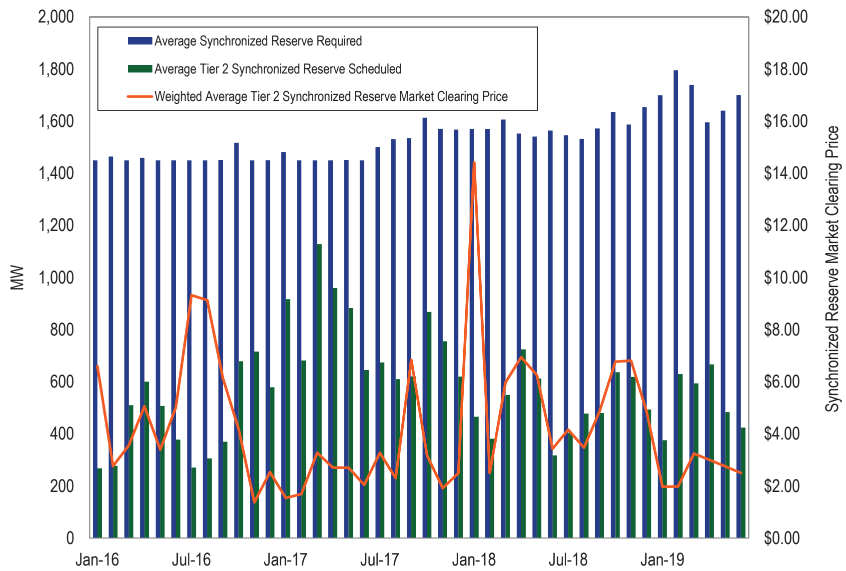
Figure 10-8 and Figure 10-9 show the average monthly synchronized reserve required and the average monthly tier 2 synchronized reserve MW scheduled (PJM scheduled plus self scheduled) from January 2016 through June 2019, for the RTO Reserve Zone and MAD Reserve Subzone. There were 16 intervals of shortage in the first six months 2019. There were 6 spinning events in the first six months of 2019, all less than 10 minutes.

Figure 10-8 MAD hourly average tier 2 synchronized reserve scheduled MW: January 2016 through June 2019



43 PJM "Manual 11: Energy & Ancillary Services Market Operations," § 4.2.2 Synchronized Reserve Requirement Determination, Rev. 106 (May 30, 2019).

Figure 10-9 RTO hourly average tier 2 synchronized reserve scheduled MW: January 2016 through June 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 six months of 2019 was 4196, which is defined as highly concentrated. In 66.0 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 six months of 2019 was 5622, which is defined as highly concentrated. In 95.1 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 2.5 percent of all tier 2 synchronized reserve in the first six months of 2019. In the RTO Zone, flexible synchronized reserve assigned was 13.3 percent of all tier 2 synchronized reserve during the same period.

In the first six months of 2019, 3.1 percent of hours would have failed the three pivotal supplier test in the MAD Subzone for all cleared hours of the inflexible Synchronized Reserve Market in the hour ahead market (Table 10-15) and 2.9 percent of hours would have failed the three pivotal supplier test in the RTO Zone during the same time period.

Table 10-15 Three pivotal supplier test results for the RTO Zone and MAD Subzone: January 2018 through June 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	0.0%	0.0%
2019	Average	3.1%	2.9%

The market structure results indicate that the RTO Zone and Mid-Atlantic Dominion Subzone Tier 2 Synchronized Reserve Markets are not structurally competitive.

Market Behavior

Offers

Daily cost-based offers are submitted for each unit by the unit owner. For generators the offer must include 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.[44] 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.[45]

Figure 10-10 shows the daily average of hourly offered tier 2 synchronized reserve MW for both the RTO Synchronized Reserve Zone and the Mid-Atlantic Dominion Synchronized Reserve Subzone. In the first six months of 2019, the ratio of eligible tier 2 synchronized reserve to synchronized reserve required in the Mid-Atlantic Dominion Subzone was 3.2 averaged over all hours. For the RTO Synchronized Reserve Zone the ratio was 17.2.

PJM has a tier 2 synchronized reserve must offer requirement for all generation that is online, nonemergency, and physically able to operate with an output less than dictated by economic dispatch. Tier 2 synchronized reserve offers are made on a daily basis with hourly updates permitted. Daily offers can be changed as a result of maintenance status or physical limitations only and are required regardless of online/offline state.[46] 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 10-10). Changes to the hourly offer status are only permitted when resources are physically unable to provide tier 2. Changes to hourly eligibility levels are the result of online status, minimum/maximum runtimes, minimum notification times, maintenance status and grid conditions including constraints. However, resource operators can make their units unavailable for an hour or block of hours without having to provide a reason.

44 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 4.2.1 Synchronized Reserve Market Eligibility Rev. 106 (May 30, 2019).

45 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 4.2.1 Synchronized Reserve Market Eligibility Rev. 106 (May 30, 2019).

46 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…").

Figure 10-10 Tier 2 synchronized reserve hourly offer and eligible volume (MW): January through June, 2019

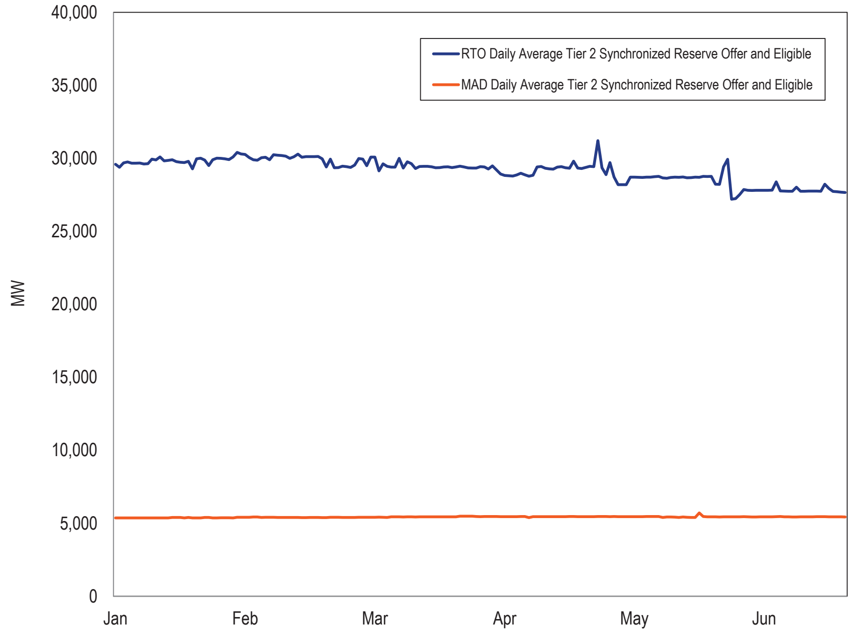
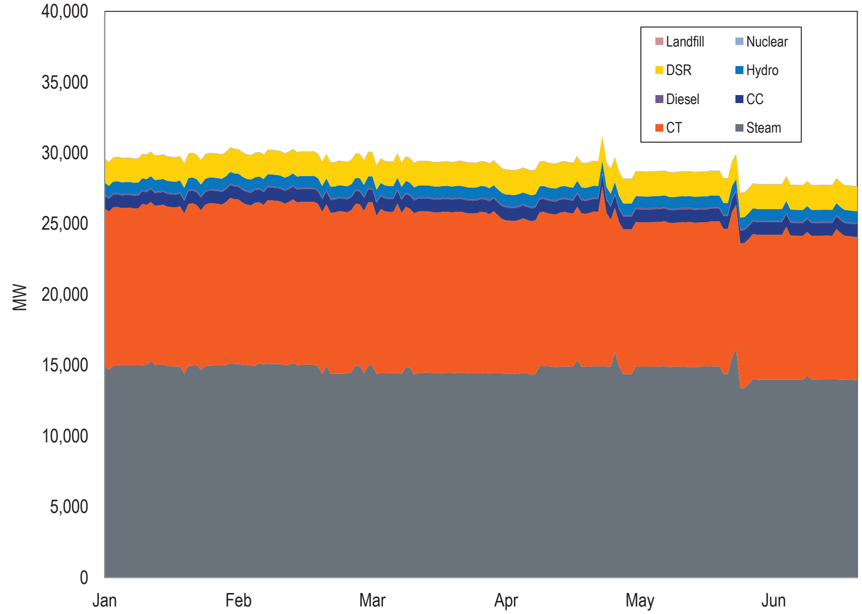


Figure 10-11 RTO daily tier 2 synchronized reserve offers by unit type (MW): January through June, 2019



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.[47]

Figure 10-11 shows average full RTO daily offer MW volume by unit type in the first 6 months of 2019.

47 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 hours where total tier 1 MW synchronized reserve MW is less than the synchronized reserve requirement, PJM must clear a Tier 2 Synchronized Reserve Market for synchronized reserves.

In the first six months of 2019, there was enough tier 1 synchronized reserve plus self-scheduled tier 2 reserve to cover the full requirement in 11.6 percent of intervals when the market solution solved. For the first six months of 2019, the MAD tier 2 market cleared an average of 266.8 MW at a weighted average clearing price of $2.59 compared to $6.06 in the same period of 2018 (Table 10-16).

In the first six months of 2019, the Tier 2 Synchronized Reserve Market for the RTO Zone cleared an average of 527.1 MW at a weighted average price of $2.64 compared to $6.40 in the same period of 2018 (Table 10-17).

In 99.1 percent of cleared hours, the synchronized reserve market clearing price was the same for both the MAD Subzone and the RTO Zone. In the 0.8 percent of hours when the price diverged, the average clearing price was $48.87 in the MAD Subzone, and $30.13 in the RTO Zone.

Supply, performance, and demand are reflected in the price of synchronized reserve. (Figure 10-8 and Figure 10-9).

Table 10-16 MAD Subzone, average SRMCP and average scheduled, tier 1 estimated and demand response MW: January 2018 through June 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	$2.07	134.1	1,650.6	26.5
2019	Feb	$1.65	180.9	1,629.9	32.4
2019	Mar	$3.26	197.3	1,536.7	44.9
2019	Apr	$3.33	168.7	1,368.8	59.5
2019	May	$3.18	105.4	1,449.2	48.4
2019	Jun	$1.96	170.5	1,669.8	23.9
2019	Average	$2.58	159.5	1,550.8	39.3

Table 10-17 RTO zone average SRMCP and average scheduled, tier 1 estimated and demand response MW: January 2018 through June 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	$1.97	270.9	2,540.4	72.9
2019	Feb	$1.98	459.3	2,060.9	118.2
2019	Mar	$3.25	476.3	1,965.2	136.5
2019	Apr	$3.00	499.2	1,593.8	157.8
2019	May	$2.75	364.9	2,022.4	134.1
2019	Jun	$2.50	305.6	2,520.3	53.9
2019	Average	$2.58	396.0	2,117.2	112.2

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 one hundred percent, the more the market price reflects the full cost of tier 2 synchronized reserve. A price to cost ratio close to one hundred percent is an indicator of an efficient synchronized reserve market design.

In the first six months of 2019, the price to cost (including self scheduled) ratio of the RTO Zone Tier 2 Synchronized Reserve Market averaged 38.9 percent (Table 10-18); the price to cost ratio of the MAD Subzone (Table 10-19) averaged 49.0 percent.

Table 10-18 RTO Zone tier 2 synchronized reserve MW, credits, price, and cost: January 2018 through June 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		1,827,781	$4,997,380	$7,780,861	$2.66	$6.84	38.9%

Table 10-19 MAD Subzone tier 2 synchronized reserve MW, credits, price, and cost: January 2018 through June 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		836,370	$4,249,737	$2.46	$5.02	49.0%

Compliance

The MMU has identified and quantified the actual performance of scheduled tier 2 synchronized reserve resources when called on to deliver during synchronized reserve events since 2011.[48] 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.[49] 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

48 See *2011 State of the Market Report for PJM*, Vol. 2, Section 9, "Ancillary Services," at 250.
49 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 4.2.10 Settlements Rev. 106 (May 30, 2019).

failure of a scheduled tier 2 resource to perform during any synchronized reserve event lasting 10 minutes or longer.

In the first six months of 2019, there were six spinning events and all of them were less 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. In the first six months of 2019, there were no spinning events of 10 minutes or longer.

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.[50]

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 six of the most heavily scheduled resources in the tier 2 synchronized reserve market, the MMU concludes that under the

50 See PJM "Manual 28: Operating Agreement Accounting,"§ 6.3 Charges for Synchronized Reserve, Rev. 81 (Oct. 25, 2018).

current penalty structure completely unresponsive resources would be paid for providing reserves (Table 10-20). The analysis covered the period from the April 1, 2018, introduction of five minute pricing, 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 10-20 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 event greater 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.[51] 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 10-21 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 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 10-21 Synchronized reserve events 10 minutes or longer, tier 2 response compliance, RTO Reserve Zone: January 2018 through June 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%

History of Synchronized Reserve Events

Synchronized reserve is designed to provide relief for disturbances.[52] [53] 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 non-disturbance reason is that it reduces the amount of synchronized reserve available for a disturbance. Disturbances are unpredictable. Synchronized reserve has a requirement to sustain its output for only up to 30 minutes. When the need is for reserve extending past 30 minutes, secondary reserve is the appropriate source of the response. The use of synchronized reserve is an expensive solution during an hour when the hour ahead market solution and reserve dispatch indicated no shortage of primary reserve. PJM's primary reserve levels have been sufficient to recover from disturbances and should remain available in the absence of disturbance.

51 See *id.* at 98.

52 *2013 State of the Market Report for PJM*, Appendix F – PJM's DCS Performance, at 451–452.

53 See PJM "Manual 12: Balancing Operations," Rev. 39 (Feb. 21, 2019) § 4.1.2 Loading Reserves.

From January 1, 2010, through June 30, 2019, PJM experienced 232 synchronized reserve events (Table 10-22), approximately 2.1 events per month. During this period, synchronized reserve events had an average duration of 11.6 minutes.

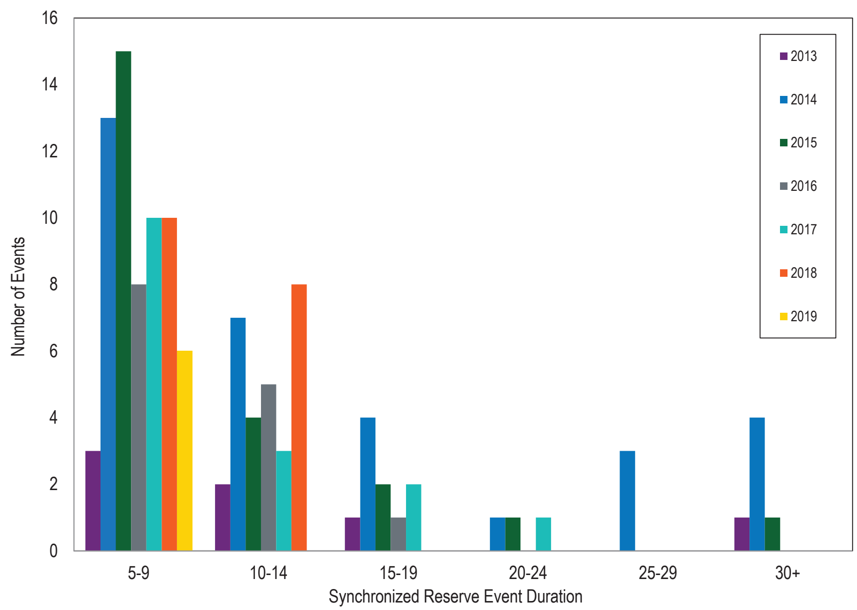
Table 10-22 Synchronized reserve events: January 2010 through June 2019

Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)
FEB-18-2010 13:27	Mid-Atlantic	19	JAN-11-2011 15:10	Mid-Atlantic	6	JAN-03-2012 16:51	RFC	9	JAN-22-2013 08:34	RTO	8	JAN-06-2014 22:01	RTO	68
MAR-18-2010 11:02	RFC	27	FEB-02-2011 01:21	RFC	5	JAN-06-2012 23:25	RFC	8	JAN-25-2013 15:01	RTO	19	JAN-07-2014 02:20	RTO	25
MAR-23-2010 20:14	RFC	13	FEB-08-2011 22:41	Mid-Atlantic	11	JAN-23-2012 15:02	Mid-Atlantic	8	FEB-09-2013 22:55	RTO	10	JAN-07-2014 04:18	RTO	34
APR-11-2010 13:12	RFC	9	FEB-09-2011 11:40	Mid-Atlantic	16	MAR-02-2012 19:54	RFC	9	FEB-17-2013 23:10	RTO	13	JAN-07-2014 11:27	RTO	11
APR-28-2010 15:09	Mid-Atlantic	8	FEB-13-2011 15:35	Mid-Atlantic	14	MAR-08-2012 17:04	RFC	6	APR-17-2013 01:11	RTO	11	JAN-07-2014 13:20	RTO	41
MAY-11-2010 19:57	Mid-Atlantic	9	FEB-24-2011 11:35	Mid-Atlantic	14	MAR-19-2012 10:14	RFC	10	APR-17-2013 20:01	RTO	9	JAN-10-2014 16:46	RTO	12
MAY-15-2010 03:03	RFC	6	FEB-25-2011 14:12	RFC	10	APR-16-2012 00:20	Mid-Atlantic	9	MAY-07-2013 17:33	RTO	8	JAN-21-2014 18:52	RTO	6
MAY-28-2010 04:06	Mid-Atlantic	5	MAR-30-2011 19:13	RFC	12	APR-16-2012 11:18	RFC	8	JUN-05-2013 18:54	RTO	20	JAN-22-2014 02:26	RTO	7
JUN-15-2010 00:46	RFC	34	APR-02-2011 13:13	Mid-Atlantic	11	APR-19-2012 11:54	RFC	16	JUN-08-2013 15:19	RTO	9	JAN-22-2014 22:54	RTO	8
JUN-19-2010 23:49	Mid-Atlantic	9	APR-11-2011 00:28	RFC	6	APR-20-2012 11:08	Mid-Atlantic	7	JUN-12-2013 17:35	RTO	10	JAN-25-2014 05:22	RTO	10
JUN-24-2010 00:56	RFC	15	APR-16-2011 22:51	RFC	9	JUN-20-2012 13:35	RFC	7	JUN-30-2013 01:22	RTO	10	JAN-26-2014 17:11	RTO	6
JUN-27-2010 19:33	Mid-Atlantic	15	APR-21-2011 20:02	Mid-Atlantic	6	JUN-26-2012 17:51	RFC	7	JUL-03-2013 20:40	RTO	13	JAN-31-2014 15:05	RTO	13
JUL-07-2010 15:20	RFC	8	APR-27-2011 01:22	RFC	8	JUL-23-2012 21:45	RFC	18	JUL-15-2013 18:43	RTO	29	FEB-02-2014 14:03	Dominion	8
JUL-16-2010 20:45	Mid-Atlantic	19	MAY-02-2011 00:05	Mid-Atlantic	21	AUG-03-2012 12:44	RFC	10	JUL-28-2013 14:20	RTO	10	FEB-08-2014 06:05	Dominion	18
AUG-11-2010 19:09	RFC	17	MAY-12-2011 19:39	RFC	9	SEP-08-2012 04:34	RFC	12	SEP-10-2013 19:48	RTO	68	FEB-22-2014 23:05	RTO	7
AUG-13-2010 23:19	RFC	6	MAY-26-2011 17:17	Mid-Atlantic	20	SEP-27-2012 17:19	Mid-Atlantic	7	OCT-28-2013 10:44	RTO	33	MAR-01-2014 05:18	RTO	26
AUG-16-2010 07:08	RFC	17	MAY-27-2011 12:51	RFC	6	OCT-17-2012 10:48	RTO	10	DEC-01-2013 11:17	RTO	9	MAR-05-2014 21:25	RTO	8
AUG-16-2010 19:39	Mid-Atlantic	11	MAY-29-2011 09:04	RFC	7	OCT-23-2012 22:29	RTO	19	DEC-07-2013 19:44	RTO	7	MAR-13-2014 20:39	RTO	8
SEP-15-2010 11:20	RFC	13	MAY-31-2011 16:36	RFC	27	OCT-30-2012 05:12	RTO	14				MAR-27-2014 10:37	RTO	56
SEP-22-2010 15:28	Mid-Atlantic	24	JUN-03-2011 14:23	RFC	7	NOV-25-2012 16:32	RTO	12				APR-14-2014 01:16	RTO	10
OCT-05-2010 17:20	RFC	10	JUN-06-2011 22:02	Mid-Atlantic	9	DEC-16-2012 07:01	RTO	9				APR-25-2014 17:33	RTO	6
OCT-16-2010 03:22	Mid-Atlantic	10	JUN-23-2011 23:26	RFC	8	DEC-21-2012 05:51	RTO	7				MAY-01-2014 14:18	RTO	13
OCT-16-2010 03:25	RFCNonMA	7	JUN-26-2011 22:03	Mid-Atlantic	10	DEC-21-2012 10:29	RTO	5				MAY-03-2014 17:11	RTO	13
OCT-27-2010 10:35	RFC	7	JUL-10-2011 11:20	RFC	10							MAY-14-2014 01:36	RTO	5
OCT-27-2010 12:50	Mid-Atlantic	10	JUL-28-2011 18:49	RFC	12							JUL-08-2014 03:07	RTO	9
NOV-26-2010 14:24	RFC	13	AUG-02-2011 01:08	RFC	6							JUL-25-2014 19:19	RTO	7
NOV-27-2010 11:34	RFC	8	AUG-18-2011 06:45	Mid-Atlantic	6							SEP-06-2014 13:32	RTO	18
DEC-08-2010 01:19	RFC	11	AUG-19-2011 14:49	RFC	5							SEP-20-2014 23:42	RTO	14
DEC-09-2010 20:07	RFC	5	AUG-23-2011 17:52	RFC	7							SEP-29-2014 10:08	RTO	15
DEC-14-2010 12:02	Mid-Atlantic	24	SEP-24-2011 15:48	RFC	8							OCT-20-2014 06:35	RTO	15
DEC-16-2010 18:40	Mid-Atlantic	20	SEP-27-2011 14:20	RFC	7							OCT-23-2014 11:03	RTO	27
DEC-17-2010 22:09	Mid-Atlantic	6	SEP-27-2011 16:47	RFC	9							NOV-01-2014 06:50	RTO	9
DEC-29-2010 19:01	Mid-Atlantic	15	OCT-30-2011 22:39	Mid-Atlantic	10							NOV-08-2014 02:08	RTO	8
			DEC-15-2011 14:35	Mid-Atlantic	8							NOV-22-2014 05:27	RTO	21
			DEC-21-2011 14:26	RFC	18							NOV-22-2014 08:19	RTO	10
												DEC-10-2014 18:58	RTO	8
												DEC-31-2014 21:42	RTO	12

Table 10-22 Synchronized reserve events: January 2010 through June 2019 (continued)

Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)
JAN-07-2015 22:36	RTO	8	JAN-18-2016 17:58	RTO	12	JAN-08-2017 03:21	RTO	7	JAN-01-2018 02:41	RTO	7	JAN-22-2019 22:30	RTO	8
FEB-24-2015 02:51	RTO	5	FEB-08-2016 15:05	RTO	10	JAN-09-2017 19:24	RTO	9	JAN-03-2018 03:00	RTO	13	JAN-31-2019 01:26	RTO	5
FEB-26-2015 15:20	RTO	6	FEB-28-2016 18:29	RTO	8	JAN-10-2017 13:05	MAD	9	JAN-07-2018 14:15	RTO	9	JAN-31-2019 09:26	RTO	9
MAR-03-2015 17:02	RTO	11	APR-14-2016 20:09	RTO	10	JAN-15-2017 20:13	RTO	8	APR-12-2018 13:28	RTO	10	FEB-25-2019 00:25	RTO	9
MAR-16-2015 10:25	RTO	24	MAY-11-2016 15:55	RTO	6	JAN-23-2017 09:08	RTO	7	JUN-04-2018 10:22	RTO	6	MAR-03-2019 12:31	RTO	9
MAR-17-2015 23:34	RTO	17	JUN-01-2016 09:01	RTO	5	FEB-13-2017 18:30	RTO	7	JUN-29-2018 15:21	RTO	9	MAR-06-2019 22:06	RTO	9
MAR-23-2015 23:44	RTO	15	JUL-06-2016 00:40	RTO	5	FEB-14-2017 00:11	RTO	6	JUN-30-2018 09:46	RTO	11			
APR-06-2015 14:23	RTO	8	JUL-28-2016 13:28	RTO	15	FEB-15-2017 06:37	RTO	6	JUL-04-2018 10:56	RTO	7			
APR-07-2015 17:11	RTO	31	AUG-31-2016 19:29	RTO	8	MAR-23-2017 06:48	RTO	24	JUL-10-2018 15:45	RTO	13			
APR-15-2015 08:14	RTO	8	SEP-09-2016 19:11	RTO	6	APR-08-2017 11:53	RTO	10	JUL-23-2018 09:02	RTO	8			
APR-25-2015 03:21	RTO	9	SEP-11-2016 19:30	RTO	9	MAY-08-2017 04:18	RTO	10	JUL-23-2018 15:43	RTO	6			
JUL-30-2015 14:04	RTO	10	OCT-12-2016 08:21	RTO	5	JUN-08-2017 03:39	RTO	10	JUL-24-2018 16:17	RTO	7			
AUG-05-2015 19:47	RTO	7	OCT-12-2016 14:40	RTO	7	JUN-20-2017 05:38	RTO	9	AUG-12-2018 11:06	RTO	11			
AUG-19-2015 16:47	RTO	9	NOV-04-2016 17:13	RTO	11	SEP-04-2017 20:18	MAD	15	SEP-13-2018 09:47	RTO	7			
SEP-05-2015 01:16	RTO	7	DEC-03-2016 00:11	RTO	7	SEP-07-2017 09:16	RTO	9	SEP-14-2018 13:24	RTO	7			
SEP-10-2015 10:12	RTO	8	DEC-31-2016 05:10	RTO	12	SEP-21-2017 14:15	RTO	16	SEP-26-2018 19:08	RTO	8			
SEP-29-2015 00:58	Mid-Atlantic	11							SEP-30-2018 11:29	RTO	11			
NOV-12-2015 16:42	RTO	8							OCT-30-2018 10:40	RTO	11			
NOV-21-2015 17:17	RTO	8												
DEC-04-2015 22:41	RTO	7												
DEC-24-2015 17:42	RTO	8												

Figure 10-12 Synchronized reserve events duration distribution curve: January 2013 through June 2019



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.[54]

The average scheduled nonsynchronized reserve in the RTO Zone in the first six months 2019 was 1,770.4 MW. The average scheduled nonsynchronized reserve in the MAD Subzone for primary reserve in the first six months 2019 was 1,505.6 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).

54 See PJM "Manual 11: Energy and Ancillary Services Market Operations," § 4.2.2 Synchronized Reserve Requirement Determination, Rev. 106 (May 30, 2019).

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 can start in 10 minutes or less, and diesels.[55] In the first six months of 2019, an average of 1,782.5 MW of nonsynchronized reserve was scheduled hourly out of 3,879.1 eligible MW as part of the primary reserve requirement in the RTO Zone.

In the first six months of 2019, CTs provided 86.2 percent of scheduled nonsynchronized reserve and hydro resources provided 13.8 percent.

Market Concentration

The supply of nonsynchronized reserves in the Mid-Atlantic Dominion Subzone and the RTO Zone was highly concentrated in the first six months of 2019.

55 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 4b.2 Non-Synchronized Reserve Market Business Rules, Rev. 106 (May 30, 2019).

Table 10-23 Nonsynchronized reserve market pivotal supplier test: January 2018 through June 2019

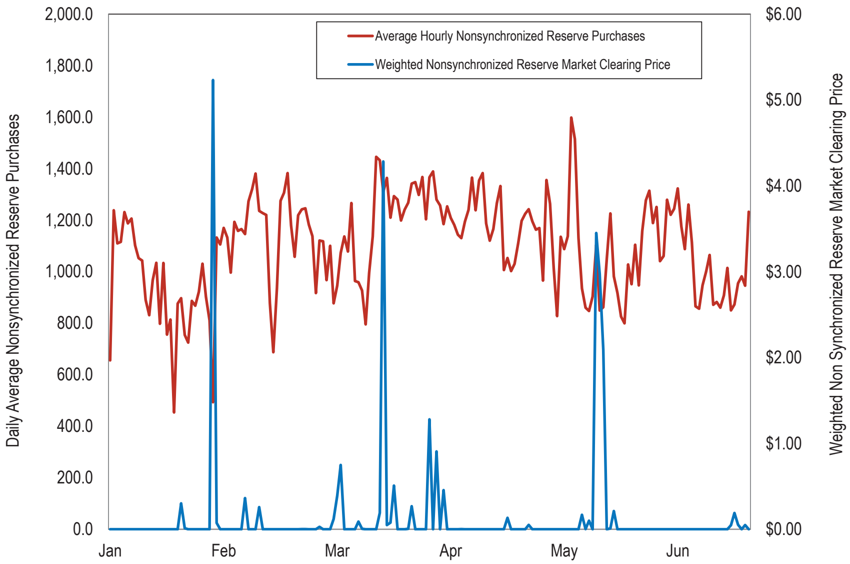
Year	Month	Non Synchronized Reserve Three Pivotal Supplier Hours
2018	Jan	87.2%
2018	Feb	88.0%
2018	Mar	93.5%
2018	Apr	16.0%
2018	May	6.9%
2018	Jun	58.0%
2018	Jul	76.8%
2018	Aug	55.9%
2018	Sep	16.7%
2018	Oct	12.1%
2018	Nov	5.2%
2018	Dec	21.5%
2018	Average	44.8%
2019	Jan	64.3%
2019	Feb	81.0%
2019	Mar	53.2%
2019	Apr	62.9%
2019	May	53.2%
2019	Jun	44.4%
2019	Average	59.8%

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 10-13 shows the daily average nonsynchronized reserve market clearing price (NSRMCP) and average scheduled MW for the RTO Zone. In the first six months of 2019, the average nonsynchronized market clearing price was $0.14 per MW. The hourly average nonsynchronized reserve scheduled was 1,095.2 MW. The market cleared at a price greater than $0 in 0.8 percent of all intervals. The maximum interval clearing price was $310.53 per MW over two consecutive intervals on March 19, 2019. The high clearing prices were a result of high LOC.

Figure 10-13 Daily average RTO Zone nonsynchronized reserve market clearing price and MW purchased: January through June 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.[56]

The full cost of nonsynchronized reserve including payments for the clearing price and uplift costs is calculated and compared to the price (Table 10-24). The closer the price to cost ratio comes to one, the more the market price reflects the full cost of nonsynchronized reserve.

In the first six months 2019, the price to cost ratio for the RTO Zone was 12.5 percent.

Resources that are not synchronized to the grid are generally off because it is not economic for them to produce energy. A resource scheduled for nonsynchronized reserve is obligated to remain unsynchronized even if its LMP changes and it becomes economic to start. In that case, the unit has a positive LOC.

Both nonsynchronized reserve markets cleared at a price above $0 in 0.8 percent of hours.

56 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 2.16 Minimum Capacity Emergency in Day-ahead Market, Rev. 106 (May 30, 2019).

Table 10-24 RTO zone nonsynchronized reserve MW, charges, price, and cost: 2018 through June 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	$1.17	13.3%
RTO Zone	2019	Feb	777,009	$549,304	$0.02	$0.71	3.1%
RTO Zone	2019	Mar	865,531	$1,209,490	$0.22	$1.40	15.6%
RTO Zone	2019	Apr	870,167	$1,441,716	$0.09	$1.66	5.7%
RTO Zone	2019	May	779,072	$624,877	$0.29	$0.80	36.5%
RTO Zone	2019	Jun	727,972	$458,230	$0.01	$0.63	1.7%
RTO Zone	2019	Total	4,711,432	$5,091,757	$0.13	$1.06	12.5%

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.[57]

Market Structure

Supply

DASR is offered by both generation and demand resources. 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 six months of 2019, the average available hourly DASR was 44,532.7 MW, a 15.3 percent increase from the same time period in 2018. The DASR hourly MW purchased averaged 5,352.1 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.[58] 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.

Of the 5,352.1 MW average hourly DASR cleared in the first six months 2019, 82.7 percent was from CTs, 5.8 percent was from steam, 7.8 percent was from hydro, and 3.3 percent was CCs.

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.[59] The RFC and Dominion secondary reserve requirements are

57 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 10.5 Aggregation for Economic and Emergency Demand Resources, Rev. 106 (May 30, 2019).

58 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 11.2.2 Day-Ahead Scheduling Reserve Market Eligibility, Rev. 106 (May 30, 2019).

59 See PJM "Manual 13: Emergency Operations," § 2.2 Reserve Requirements, Rev. 70 (May 30, 2019).

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 will be 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.

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."[60] The amount of additional DASR MW that may be required is the Adjusted Fixed Demand (AFD) determined by a Seasonal Conditional Demand (SCD) factor.[61] 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. PJM Dispatch may also schedule additional Day-Ahead Scheduling Reserves as deemed necessary for conservative operations.[62] 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.[63] The result is substantial discretion for PJM to increase the demand for DASR under a variety of circumstances. PJM invoked adjusted fixed demand on 7 days during the first six months 2019 and 18 of the twenty hours with highest DASR market clearing price during the first six months of 2019 were 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 10-25.

Table 10-25 DASR market three pivotal supplier test results and number of hours with DASRMCP above $0: January 2018 through June 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	21	1.4%
2019	Mar	24	0.0%
2019	Apr	15	0.0%
2019	May	43	0.0%
2019	Jun	72	0.0%
2019	Average	35	0.5%

60 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>.
61 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 11.2.1 Day-Ahead Scheduling Reserve Market Reserve Requirement, Rev. 106 (May 30, 2019).
62 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 11.2.1 Day-Ahead Scheduling Reserve Market Reserve Requirement, Rev. 106 (May 30, 2019).
63 See PJM "Manual 13: Emergency Operations," § 3.2 Conservative Operations, Rev. 70, (May 30, 2019).

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.[64] 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 six 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. In the first six months of 2019, 16.5 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 six months of 2019, the DASR Market cleared at a price above $0.00 in 4.9 percent of hours. The weighted average DASR price for all hours was $0.08. The average cleared MW in all hours was 5,115.5 MW. The average cleared MW in all hours when the DASRMCP was above $0.00 was 7,717.4 MW. The highest DASR price was $16.97 on June 28, 2019.

The introduction of Adjusted Fixed Demand (AFD) on March 1, 2015, created a bifurcated market (Table 10-27). In 2015, PJM added AFD to the normal 5.93 percent of forecast load in 367 hours. In 2016, PJM added AFD to the normal 5.7 percent of forecast load in 522 hours. In 2017, PJM added AFD to the normal 5.52 percent of forecast load in 336 hours. In 2018, PJM added AFD to the normal 5.28 percent in 598 hours. In the first six months of 2019, PJM added AFD to the normal 5.29 percent in 168 hours. The difference in market clearing price, MW cleared, obligation incurred, and charges to PJM load are substantial. Table 10-26 shows the differences in price and MW between AFD hours and non-AFD hours.

64 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 11.2.2 Day-Ahead Scheduling Reserve Market Eligibility, Rev. 106 (May 30, 2019).

Table 10-26 Impact of Adjusted Fixed Demand on DASR prices and demand: January through June, 2019

Metric	Year	Number Hours	Weighted Day-Ahead Scheduling Reserve Market Clearing Price (DASRMCP)	Average Hourly Total DASR MW
All Hours	Jan-Jun 2019	4,344	$0.08	5,115.5
All Hours when DASRMCP > $0	Jan-Jun 2019	208	$1.14	7,717.4
All Hours when AFD is used	Jan-Jun 2019	168	$0.94	10,165.4

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 10-27) shows that the use of AFD for 598 hours in 2018, and 208 hours in the first six months of 2019 significantly increased the cost of DASR. Table 10-27 shows that the cost increase was a result of a substantial increase in DASR MW cleared.

Table 10-27 DASR Market, regular hours vs. adjusted fixed demand hours: January 2018 through June 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	4,409	NA	$38	NA
2019	May	43	NA	$0.02	NA	79,257	NA	4,545	NA	$77	NA
2019	Jun	30	42	$0.03	$1.72	85,713	105,502	5,138	11,076	$139	$19,030
2019		126	82	$0.01	$0.73	85,493	113,000	4,928	10,265	$54	$7,908

Table 10-28 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 six months of 2019.

Table 10-28 DASR Market all hours of DASR market clearing price greater than $0: January 2018 through June 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 Charges
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	4,224,642	97,612	$182,645
2019	Feb	22	$0.31	111,730	3,657,625	85,339	$67,211
2019	Mar	24	$0.26	105,987	3,657,007	0	$31,569
2019	Apr	15	$0.39	90,323	3,174,292	0	$27,293
2019	May	43	$0.28	98,135	3,381,168	0	$57,282
2019	Jun	72	$2.12	117,694	4,127,133	251,804	$1,460,362
2019	Total	208	$0.66	107,849	22,221,867	434,754	$1,826,362

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. DASR prices have been low in 2019.

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.[65] 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

65 Order No. 755, 137 FERC ¶ 61,064 at P 2 (2011).

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 output and the regulation signal; and precision, the difference between the regulation response and the regulation requested.[66] Performance scores are reported on an hourly basis for each resource.

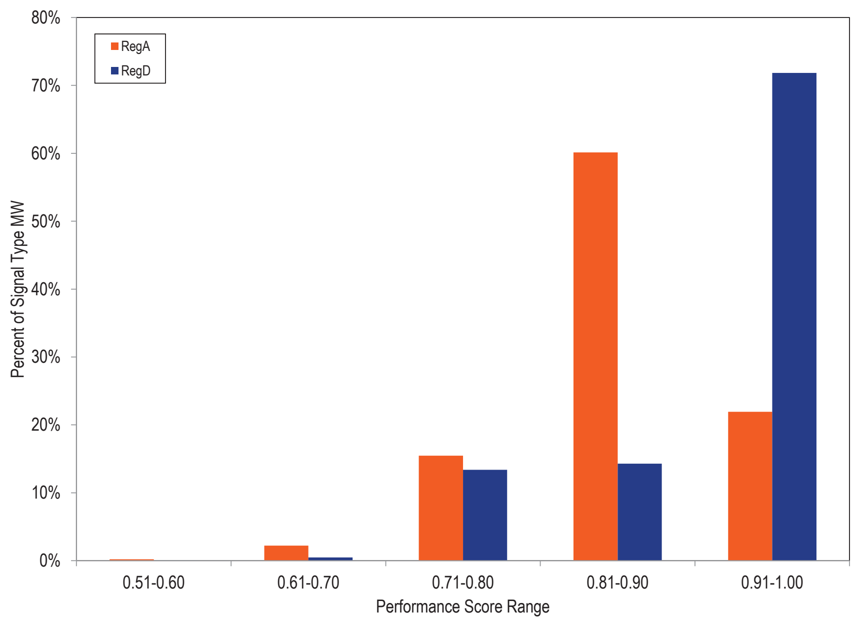
Table 10-29 and Figure 10-14 show the average performance score by resource type and the signal followed in the first six months of 2019. In these figures, the MW used are actual MW and the performance score is the hourly performance score of the regulation resource.[67] Each category (color bar) is based on the percentage of the full performance score distribution for each resource (or signal) type. As Figure 10-14 shows, 71.8 percent of RegD resources had average performance scores within the 0.91-1.00 range, and 21.9 percent of RegA resources had average performance scores within that range, in the first six months of 2019. These scores are higher than the scores for both product types in the first six months of 2018, where 44.1 percent of RegD resources had average performance scores within the 0.91-1.00 range, and 18.8 percent of RegA resources had average performance scores within that range.

66 PJM "Manual 12: Balancing Operations," § 4.5.6 Performance Score Calculation, Rev. 39 (Feb. 21, 2019).
67 Except where explicitly referred to as effective MW or effective regulation MW, MW means actual MW unadjusted for either MBF or performance factor.

Table 10-29 Hourly average performance score by unit type: January through June, 2019

		Performance Score Range				
		51-60	61-70	71-80	81-90	91-100
RegA	Battery	-	-	-	-	-
	CT	-	0.1%	25.7%	43.7%	30.5%
	Diesel	-	-	-	-	100.0%
	DSR	-	12.1%	28.7%	55.1%	4.1%
	Hydro	-	-	0.5%	32.4%	67.1%
	Steam	0.3%	3.0%	20.1%	69.3%	7.3%
RegD	Battery	-	0.1%	12.4%	11.5%	76.0%
	CT	-	1.5%	98.5%	-	-
	Diesel	-	-	5.5%	94.5%	-
	DSR	-	-	26.6%	24.1%	49.3%
	Hydro	-	10.8%	-	42.1%	47.1%
	Steam	-	-	-	-	-

Figure 10-14 Hourly average performance score by regulation signal type: January through June, 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 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 six 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, Reg D 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 the 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.[68] Both PJM and the MMU have filed requests for rehearing.[69]

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

68 162 FERC ¶ 61,295 (2018).
69 See FERC Docket No. ER18-87-002.

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 10-30). 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 10-30 Seasonal regulation requirement definitions[70]

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 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

70 See PJM. "Regulation Requirement Definition," <http://www.pjm.com/~/media/markets-ops/ancillary/regulation-requirement-definition.ashx>.

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.[71]

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.

71 The MBF, as used in this report, refers to PJM's incorrectly calculated MBF and not the MBF equivalent to the MRTS.

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.[72]

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 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.[73] 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.

72 18 CFR § 385.211 (2017)
73 145 FERC ¶ 61,011 (2013).

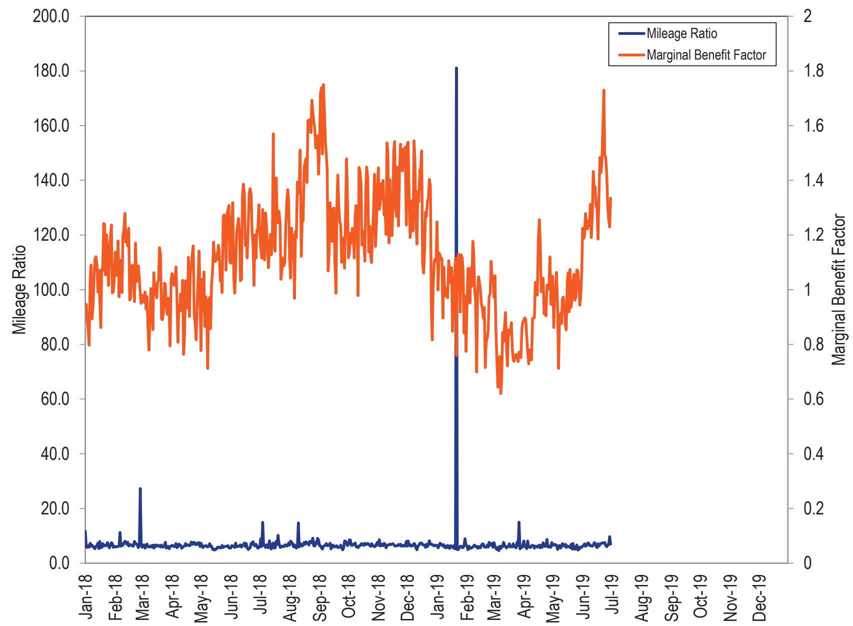
If the MBF were consistently applied, every resource would receive the same clearing price per marginal effective MW. But the MBF is not consistently applied and resources do not receive the same clearing price per marginal effective MW.

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.

Figure 10-15 shows the daily average MBF and the mileage ratio. The weighted average mileage ratio increased from 6.53 in the first six months of 2018, to 7.31 in the first six months of 2019 (an increase of 11.9 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 10-15 Daily average MBF and mileage ratio: January 2018 through June 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 10-31 shows RegD resource payments on a performance adjusted MW basis and RegA resource payments on a performance adjusted MW basis by month, from January 1, 2018, through June 30, 2019. In 2018, RegD resources earned 32.8 percent more per performance adjusted MW than RegA resources. In the first six months of 2019, RegD resources earned 39.0 percent more per performance adjusted MW than RegA resources.

Table 10-31 Average monthly price paid per performance adjusted MW of RegD and RegA: January 2018 through June 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%
Average		$18.07	$13.00	39.0%

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 six months of 2018 (1.06), however, RegD resources were still overpaid on average versus if they had been paid on a per effective MW basis. In the first six months of 2019, the average MBF was equal to 1.01.

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 10-32. Table 10-32 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 one in 2018 (1.06), while the average daily mileage ratio was 6.53, resulting in RegD resources being paid $20.4 million more than they would have been if the MBF were correctly implemented. In the first six months of 2019, the MBF averaged 1.01, while the average daily mileage ratio was 7.31, resulting in RegD resources being paid $3.20 million more than they would have been if the MBF were correctly implemented.

Table 10-32 Average monthly price paid per effective MW of RegD and RegA under mileage and MBF based settlement: January 2018 through June 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
Yearly		$17.88	$13.58	$13.58	31.7%	$3,204,232

Figure 10-16 shows, for January 2018 through June 2019, the maximum, minimum and average MBF, by month. The average MBF in the first six months of 2018 was 1.06. The average MBF in the first six months of 2019 was 1.01.

Figure 10-16 Maximum, minimum, and average PJM calculated MBF by month: January 2018 through June 2019

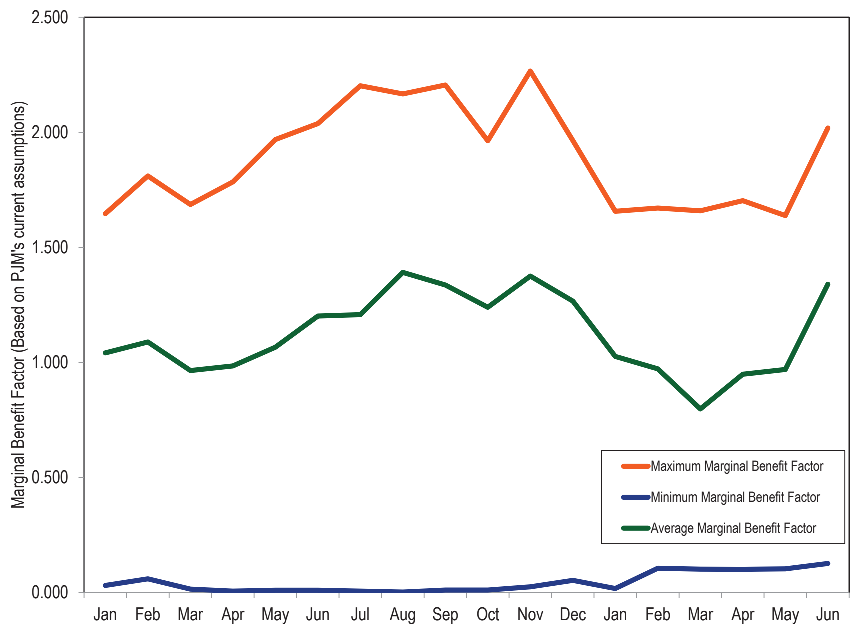


Table 10-33 shows actual and effective MW that were eligible and cleared during the first six months of 2018 and 2019.

Table 10-33 Actual and effective RegD MW eligible and cleared: January through June, 2018 and 2019

	RegD MW		
	2018 (Jan-Jun)	2019 (Jan-Jun)	Change
Actual Eligible	269.3	343.1	27.4%
Effective Eligible	289.6	316.9	9.4%
Actual Cleared	163.1	173.6	6.5%
Effective Cleared	277.0	303.4	9.5%

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.[74]

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.

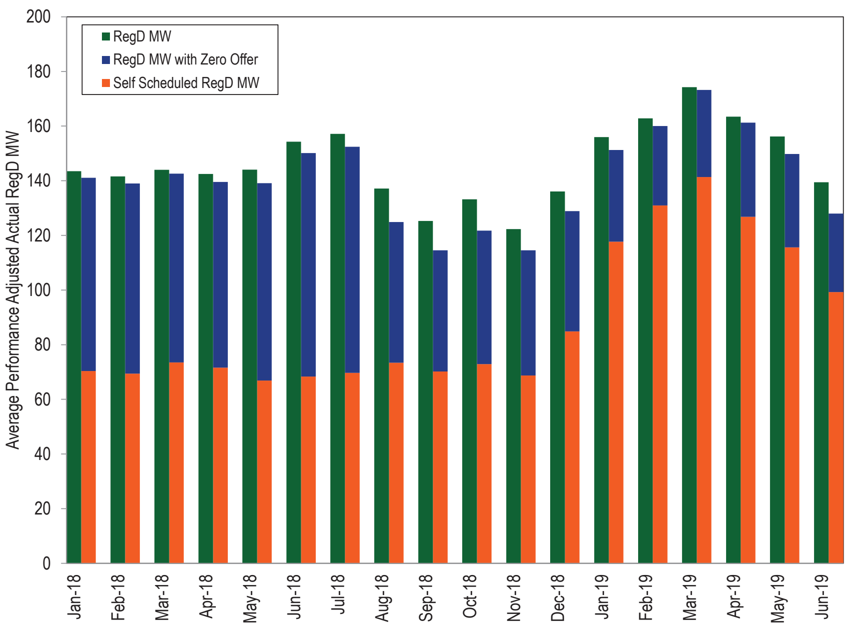
Figure 10-17 shows, by month, the proportion of cleared RegD MW with an effective price of $0.00 from January 1, 2018, through June 30, 2019. In the first six months of 2019, 96.8 percent of all RegD MW clearing the market had an effective offer of $0.00. In the first six months of 2018, 97.9 percent of all cleared RegD MW had an effective cost of $0.00. In the first six months of 2019, 76.6 percent of all RegD offers were self scheduled, compared to 48.3 percent of all RegD offers in the first six months of 2018.

The increase 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

74 See "Regulation Market Review," Operating Committee meeting (May 5, 2015) <http://www.pjm.com/~/media/committees-groups/committees/oc/20150505/20150505-item-17-regulation-market-review.ashx>.

MW, market participants that offer at zero instead of self scheduling run the risk of not clearing the market. The total level of RegD cleared in the market increased 9.5 percent in the first six months of 2019 compared to the first six months of 2018.

Figure 10-17 Average cleared RegD MW and average cleared RegD with an effective price of $0.00 by month: January 2018 through June 2019



Price Spikes

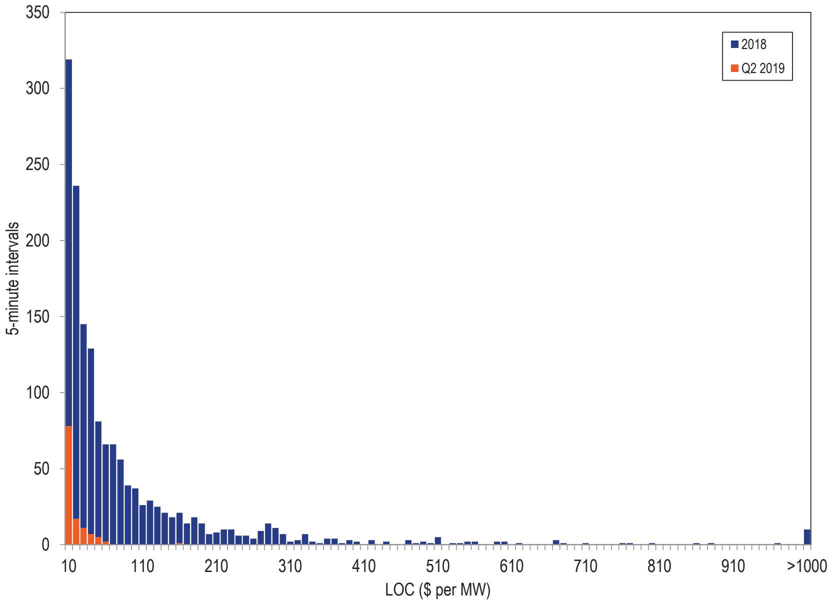
Beginning in 2018, extreme price spikes were identified in the regulation market. The price spikes were caused by a combination of the inconsistent application of the MBF in the market design and the discrepancy between the hour ahead estimated LOC and the actual realized within hour LOC.

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.[75] This change reduced the amount and frequency of the price spikes, but 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 10-18 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 six months of 2019.

75 See 166 FERC ¶ 61,040 (2019).

Figure 10-18 LOC distribution in each five-minute interval with a RegD marginal unit and an LOC greater than zero: 2018 and January through June, 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. Bit, 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 10-34 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 six months of 2019.[76] 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 six months of 2019, the average hourly eligible supply of regulation for nonramp hours was 1,096.2 actual MW (821.9 effective MW). This was an increase of 7.6 actual MW (a decrease of 28.8 effective MW) from the first six months of 2018, when the average hourly eligible supply of regulation was 1,088.7 actual MW (850.7 effective MW). In the first six months of 2019, the average hourly eligible supply of regulation for ramp hours was 1,384.8 actual MW (1,137.1 effective MW). This was an increase of 5.5 actual MW (a decrease of 30.9 effective MW) from the first six months of 2018, when the average hourly eligible supply of regulation was 1,379.2 actual MW (1,168.0 effective MW).

76 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 1.93 in the first six months of 2019. This is an increase of 4.5 percent from the first six months of 2018, when the ratio was 1.85. The ratio of the average hourly eligible supply of regulation to average hourly regulation demand (actual cleared MW) for nonramp hours was 2.33 in the first six months of 2019. This is an increase of 4.0 percent from the first six months of 2018, when the ratio was 2.24.

Table 10-34 PJM regulation capability, daily offer and hourly eligible: January through June, 2019[77 78]

			By Resource Type		By Signal Type	
		All Regulation	Generating Resources	Demand Resources	RegA Following Resources	RegD Following Resources
Capability MW	Daily	11,087.6	11,054.4	33.2	10,702.3	657.7
Offered MW	Daily	7,763.4	7,737.6	25.8	7,349.1	414.3
Actual Eligible MW	Ramp	1,384.8	1,358.1	26.7	1,025.1	359.7
	Nonramp	1,096.2	1,072.3	24.0	769.1	327.1
Effective Eligible MW	Ramp	1,137.1	1,106.3	30.7	774.7	362.4
	Nonramp	821.9	800.5	21.4	549.2	272.7
Actual Cleared MW	Ramp	717.7	699.9	17.8	538.6	179.0
	Nonramp	470.9	455.8	15.1	302.6	168.3
Effective Cleared MW	Ramp	799.9	769.8	30.2	461.3	338.6
	Nonramp	528.0	507.2	20.8	258.7	269.3

Table 10-35 provides the settled regulation MW by source unit type, the total settled regulation MW provided by all resources, and the percent of settled regulation provided by unit type. In Table 10-35 the MW have been adjusted by the performance score since this adjustment forms the basis of payment for units providing regulation. Total regulation performance adjusted settled MW decreased 3.4 percent from 2,297,462.1 MW in the first six months of 2018 to 2,218,756.1 MW in the first six months of 2019. The average proportion of regulation provided by battery units had the largest increase (3.1 percent), providing 23.3 percent of regulation in the first six months of 2018 and 26.4 percent of regulation in the first six months of 2019. Coal units had the largest decrease in average proportion of regulation provided (2.1 percent), decreasing from 8.8 percent in the first six months of 2018, to 6.7 percent in

77 Average Daily Offer MW excludes units that have offers but are unavailable for the day.

78 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.

the first six months of 2019. The total regulation credits in the first six months of 2019 were $39,478,168, down 57.1 percent from $92,054,668 in the first six months of 2018.

Table 10-35 PJM regulation by source: January through June, 2018 and 2019[79]

	2018 (Jan-Jun)				2019 (Jan-Jun)			
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	535,900	23.3%	$21,171,150	24	586,764	26.4%	$10,772,506
Coal	37	202,136	8.8%	$13,129,940	19	149,388	6.7%	$4,139,996
Hydro	28	419,231	18.2%	$16,622,250	24	402,697	18.1%	$8,224,977
Natural Gas	168	1,096,317	47.7%	$39,494,364	146	1,018,212	45.9%	$15,175,723
DR	30	43,879	1.9%	$1,636,965	26	61,694	2.8%	$1,164,966
Total	286	2,297,462.1	100.0%	$92,054,668	239	2,218,756.1	100.0%	$39,478,168

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 10-36).

Table 10-36 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	27	66.1
2016	2	39.7
2017	3	2.5
2018	30	900.8
2019	34	1,459.5
Total	98	2,483.1

The supply of regulation can be affected by regulating units retiring from service. If all units that are requesting retirement through the end of the first six 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 10-30).

Table 10-37 shows the average hourly required regulation by month and the ratio of supply to demand for both actual and effective MW, for ramp and nonramp hours. The average hourly required regulation by month is an average of the ramp and nonramp hours in the month.

The nonramp regulation requirement of 525.0 effective MW was provided by a combination of RegA and RegD resources equal to 470.3 hourly average

79 Biomass data have been added to the natural gas category for confidentiality purposes.

performance adjusted actual MW in the first six months of 2019. This is a decrease of 16.1 performance adjusted actual MW from the first six months of 2018, when the average hourly total regulation cleared performance adjusted actual MW for nonramp hours were 486.4 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 717.0 hourly average performance adjusted actual MW in the first six months of 2019. This is a decrease of 29.5 performance adjusted actual MW from the first six months of 2018, where the average hourly regulation cleared MW for ramp hours were 746.6 performance adjusted actual MW.

Table 10-37 Required regulation and ratio of supply to requirement: January through June, 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
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

Market Concentration

In the first six months of 2019, the effective MW weighted average HHI of RegA resources was 2475 which is highly concentrated and the weighted average HHI of RegD resources was 1300 which is also highly concentrated.[80] The weighted average HHI of all resources was 1024, which is moderately concentrated. The HHI of RegA resources and the HHI of RegD resources are higher than the HHI for all resources because different owners have large market shares in the RegA and RegD markets.

Table 10-38 includes a monthly summary of three pivotal supplier (TPS) results. In the first six months of 2019, 87.5 percent of hours had three or fewer pivotal suppliers. The MMU concludes that the PJM Regulation Market in the first six months of 2019 was characterized by structural market power.

Table 10-38 Regulation market monthly three pivotal supplier results: January 2017 through June 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%	
Aug	88.0%	79.6%	
Sep	82.6%	78.6%	
Oct	68.1%	82.1%	
Nov	72.5%	78.2%	
Dec	79.3%	74.2%	
Average	85.7%	81.7%	87.5%

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.[81] 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.[82]

80 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.

81 See "PJM Manual 11: Energy & Ancillary Services Market Operations," § 3.2.1 Regulation Market Eligibility, Rev. 106 (May 30, 2019).
82 Id. at 3.2.2, at p 62.

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.[83]

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.[84]

All LSEs are required to provide regulation in proportion to their load share. LSEs can purchase regulation in the regulation market, purchase regulation from other providers bilaterally, or self schedule regulation to satisfy their obligation (Table 10-40).[85] Figure 10-19 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.[86]

83 See "PJM Manual 15: Cost Development Guidelines," § 7.8 Regulation Cost, Rev. 32 (May 13, 2019).
84 See "PJM Manual 11: Energy & Ancillary Services Market Operations," § 3.2.1 Regulation Market Eligibility, Rev. 106 (May 30, 2019).
85 See "PJM Manual 28: Operating Agreement Accounting," § 4.1Regulation Accounting Overview, Rev. 81 (Oct. 25, 2018).
86 See "PJM Manual 11: Energy & Ancillary Services Market Operations," § 3.2.1 Regulation Market Eligibility, Rev. 106 (May 30, 2019).

Self scheduled regulation comprised an average of 45.3 percent during ramp hours and 60.4 percent during nonramp hours in the first six months of 2019.

Figure 10-19 Nonramp and ramp regulation levels: January 2018 through June 2019[87]

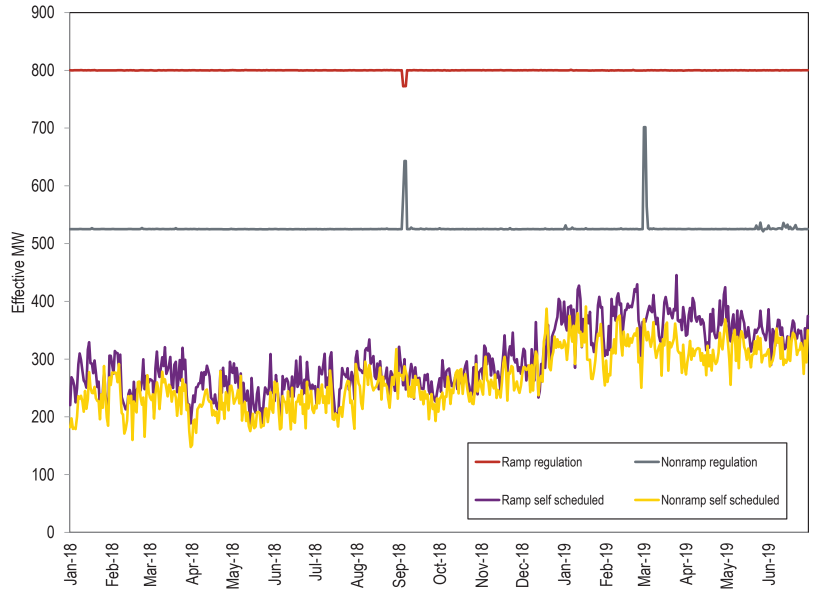


Table 10-39 shows the role of RegD resources in the regulation market. RegD resources are both a growing proportion of the market (10.9 percent of the total effective MW at the start of the performance based regulation market design in October 2012 and 41.4 percent of the total effective MW in June 2019) and a growing proportion of resources that self schedule (25.0 percent of all self scheduled MW in October 2012 and 62.1 percent of all self scheduled MW in June 2019). In the first six months of 2019, the average RegD percentage of total self scheduled MW was 66.5 percent, an increase of 12.7 percent from the first six months of 2018, when the average was 53.8 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.

87 The effective MW increases during the nonramp hours of September 2018 and March 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 10-39 RegD self scheduled regulation by month: October 2012 through June 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 Average		226.2	321.7	339.8	662.1	66.5%	45.9%

Increased self scheduled regulation lowers the requirement for cleared regulation, resulting in fewer MW cleared in the market and lower clearing prices. Of the LSEs' obligation to provide regulation in the first six months of 2019, 49.8 percent was purchased in the PJM market, 45.0 percent was self scheduled, and 5.2 percent was purchased bilaterally (Table 10-40). Table 10-41 shows the total regulation by source including spot market regulation, self scheduled regulation, and bilateral regulation for the first six months of each year from 2012 to 2019. Table 10-40 and Table 10-41 are based on settled (purchased) MW.

Table 10-40 Regulation sources: spot market, self scheduled, bilateral purchases: January 2018 through June 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%	155,554.8	40.3%	19,950.0	5.2%	385,581.8
Total		1,085,870.9	49.8%	980,559.5	45.0%	114,334.0	5.2%	2,180,764.4

Table 10-41 Regulation sources: January through June, 2012 through 2019

Jan-Jun	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	3,065,069.1	76.0%	847,576.2	21.0%	122,641.0	3.0%	4,035,286.2
2013	1,740,438.6	64.9%	849,955.3	31.7%	92,120.0	3.4%	2,682,513.9
2014	1,370,386.4	57.9%	889,917.5	37.6%	106,365.5	4.5%	2,366,669.4
2015	1,282,300.1	55.7%	894,595.8	38.8%	126,408.6	5.5%	2,303,304.4
2016	1,139,515.1	48.5%	1,086,532.7	46.3%	122,808.5	5.2%	2,348,856.3
2017	1,176,249.8	52.2%	948,195.8	42.1%	128,534.5	5.7%	2,252,980.1
2018	1,390,856.8	61.6%	757,440.3	33.5%	110,201.5	4.9%	2,258,498.6
2019	1,085,870.9	49.8%	980,559.5	45.0%	114,334.0	5.2%	2,180,764.4

In the first six months of 2019, DR provided an average of 17.8 MW of regulation per hour during ramp hours (11.8 MW of regulation per hour during ramp hours in the first six months of 2018), and an average of 15.1 MW of regulation per hour during nonramp hours (10.5 MW of regulation per hour during off peak hours in the first six months of 2018). Generating units supplied an average of 699.9 MW of regulation per hour during ramp hours in the first six months of 2019 (735.0 MW of regulation per hour during ramp hours in the first six months of 2018), and an average of 455.8 MW per hour during nonramp hours in the first six months of 2019 (476.0 MW of regulation per hour during nonramp hours in the first six months of 2018).

Market Performance

Price

Table 10-45 shows the regulation price and regulation cost per MW for the first six months of each year from 2009 through 2019. The weighted average RMCP for the first six months of 2019 was $13.85 per MW. This is a decrease of $19.11 per MW, or 58.0 percent, from the weighted average RMCP of $32.97 per MW in the first six months of 2018. This decrease in the regulation clearing price was the result of a decrease in energy prices in the first six months of 2019 and the related decrease in the opportunity cost component of RMCP.

Figure 10-20 shows the daily weighted average regulation market clearing price and the opportunity cost component for the PJM Regulation Market on a performance adjusted MW basis. This data is based on actual five minute interval operational data. The increase in January was the result of increases in energy prices and the corresponding increase in the opportunity cost component of the RMCP.

Figure 10-20 illustrates that the opportunity cost (blue line) is the largest component of the clearing price.

Figure 10-20 Regulation market-clearing price, opportunity cost and offer price components (Dollars per MW): January through June, 2019

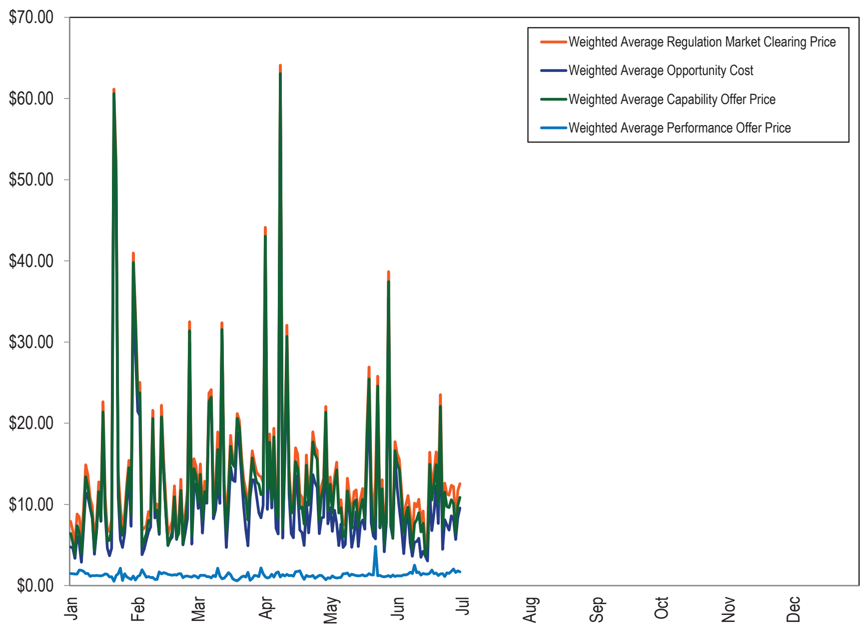


Table 10-42 shows the capability and performance components of the monthly average regulation prices. These components differ from the components of the marginal unit's offers in Figure 10-20 because the performance component of the settlement price for each hour is determined from the average of the highest performance offers in each five minute interval, calculated independent of the marginal unit's offers in those intervals.

Table 10-42 PJM regulation market monthly component of price (Dollars per MW): January through June, 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
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 10-43. Total scheduled regulation is based on settled performance adjusted MW. The total of all regulation charges for the first six months of 2019 was $39.5 million, compared to $92.0 million for the first six months of 2018.

Table 10-43 Total regulation charges: January 2018 through June 2019

Year	Month	Scheduled Regulation (MW)	Total Regulation Charges ($)	Weighted Average Regulation Market Price ($/MW)	Cost of Regulation ($/MW)	Price as Percent of Cost
2017	Jan	395,801.8	$6,867,859	$14.08	$17.35	81.2%
2017	Feb	356,168.1	$5,351,147	$11.12	$15.02	74.0%
2017	Mar	375,627.5	$8,604,989	$16.32	$22.91	71.2%
2017	Apr	371,527.5	$9,057,296	$16.21	$24.38	66.5%
2017	May	367,839.9	$8,949,242	$18.85	$24.33	77.5%
2017	Jun	386,015.3	$7,729,571	$13.85	$20.02	69.1%
2017	Jul	406,828.4	$8,698,583	$15.66	$21.38	73.3%
2017	Aug	403,294.0	$8,396,208	$13.70	$20.82	65.8%
2017	Sep	354,990.9	$10,511,205	$21.98	$29.61	74.2%
2017	Oct	365,994.1	$8,807,785	$16.96	$24.07	70.5%
2017	Nov	351,119.3	$7,994,687	$16.65	$22.77	73.1%
2017	Dec	395,432.9	$13,406,934	$26.06	$33.90	76.9%
Yearly		4,554,652.8	$145,465,939	$25.33	$31.94	79.3%
2018	Jan	397,789.2	$39,129,936	$80.83	$98.37	82.2%
2018	Feb	358,045.5	$6,260,199	$12.81	$17.48	73.2%
2018	Mar	374,137.6	$10,735,239	$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	369,122.0	$10,333,629	$20.81	$28.00	74.3%
2018	Nov	358,139.5	$7,528,217	$15.28	$21.02	72.7%
2018	Dec	390,797.7	$7,118,344	$13.39	$18.21	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	$7,527,395	$16.96	$21.70	78.2%
2019	May	357,340.1	$6,108,491	$12.90	$17.09	75.5%
2019	Jun	385,581.8	$5,746,043	$11.37	$14.90	76.3%
Year to date		2,180,764.4	$39,510,954	$13.85	$18.12	76.5%

The capability, performance, and opportunity cost components of the cost of regulation are shown in Table 10-44. Total scheduled regulation is based on settled performance adjusted MW. In the first six months of 2019, the average total cost of regulation was $18.12 per MW, 55.6 percent lower than $40.76 in the first six months of 2018. In the first six months of 2019, the monthly average capability component cost of regulation was $13.06, 59.2 percent lower than $32.02 in the first six months of 2018. In the first six months of 2019, the monthly average performance component cost of regulation was $2.70, 24.0 percent lower than $3.56 in the first six months of 2018.

Table 10-44 Components of regulation cost: January 2018 through June 2019

Year	Month	Scheduled Regulation (MW)	Cost of Regulation Capability ($/MW)	Cost of Regulation Performance ($/MW)	Opportunity Cost ($/MW)	Total Cost ($/MW)
2018	Jan	397,789.2	$80.32	$3.76	$14.29	$98.37
	Feb	358,045.5	$11.17	$4.47	$1.84	$17.48
	Mar	374,137.6	$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	369,122.0	$19.20	$4.99	$3.81	$28.00
	Nov	358,139.5	$14.20	$3.36	$3.46	$21.02
	Dec	390,797.7	$12.31	$3.29	$2.61	$18.21
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	$2.36	$17.09
	Jun	385,581.8	$10.35	$3.10	$1.45	$14.90
Year to date		2,180,764.4	$13.06	$2.70	$2.35	$18.12

Table 10-45 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 six months of 2019 was 76.5 percent, a 5.5 percent decrease from 80.9 percent in the first six months of 2018.

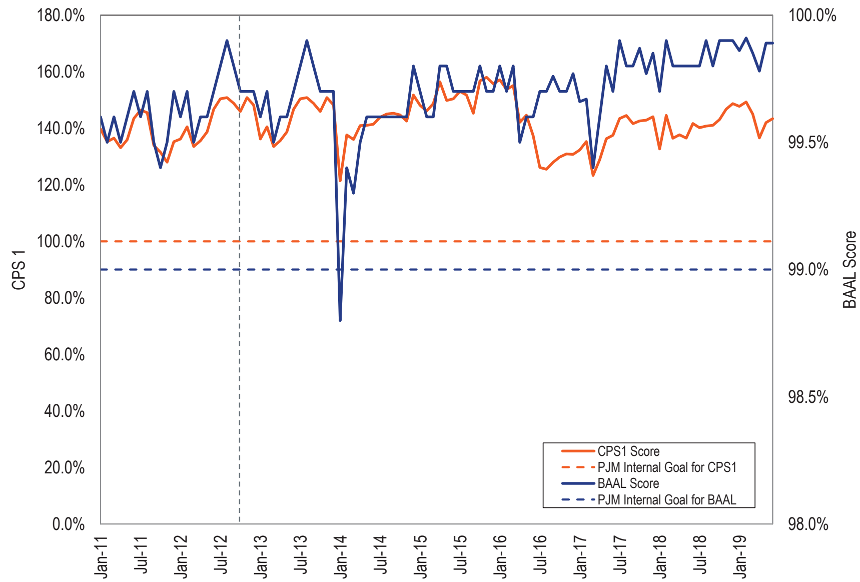
Table 10-45 Comparison of average price and cost for PJM regulation: January through June, 2009 through 2019

Jan-Jun	Weighted Regulation Market Price	Weighted Regulation Market Cost	Regulation Price as Percent Cost
2009	$25.23	$33.82	74.6%
2010	$18.33	$31.43	58.3%
2011	$15.31	$31.00	49.4%
2012	$13.89	$18.34	75.7%
2013	$32.04	$37.04	86.5%
2014	$62.71	$75.97	82.5%
2015	$40.94	$49.57	82.6%
2016	$15.90	$18.30	86.9%
2017	$15.08	$20.67	73.0%
2018	$32.97	$40.76	80.9%
2019	$13.85	$18.12	76.5%

Performance Standards

PJM's performance as measured by CPS1 and BAAL standards is shown in Figure 10-21 for every month from January 2011 through June 2019 with the dashed vertical line marking the date (October 1, 2012) of the implementation of the Performance Based Regulation Market design.[88] The horizontal dashed lines represent PJM internal goals for CPS1 and BAAL performance. While PJM did not meet its internal goal for BAAL performance in January 2014, PJM remained in compliance with the applicable NERC standards.

Figure 10-21 PJM monthly CPS1 and BAAL performance: January 2011 through June 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,

88 See *2018 State of the Market Report for PJM*, Appendix F: Ancillary Services.

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.[89] [90] 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 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.[91]

In the first six months of 2019, total black start charges were $32.211 million, a decrease of $1.292 million (-3.9 percent) from the same six month period in 2018. Operating reserve charges for black start service decreased from $0.138 million in the first six months of 2018 to $0.114 million in the first six months of 2019. Table 10-46 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.

89 See PJM. "RTO-Wide Five-Year Selection Process Request for Proposal for Black Start Service," (July 1, 2013).
90 RFPs issued can be found on the PJM website. See PJM. <http://www.pjm.com/markets-and-operations/ancillary-services.aspx>.
91 OATT Schedule 6A (paras. 25, 26 and 27 outline how charges are to be applied).

Table 10-46 Black start revenue requirement charges: January through June, 2010 through 2019

Jan-Jun	Revenue Requirement Charges	Operating Reserve Charges	Total
2010	$5,481,206	$0	$5,481,206
2011	$5,968,676	$0	$5,968,676
2012	$7,873,702	$0	$7,873,702
2013	$10,584,683	$48,075,584	$58,660,267
2014	$10,874,608	$14,339,174	$25,213,781
2015	$23,348,866	$5,036,053	$28,384,918
2016	$33,778,388	$168,645	$33,947,033
2017	$35,617,856	$146,223	$35,764,079
2018	$33,363,810	$138,852	$33,502,661
2019	$32,096,367	$114,444	$32,210,811

Black start zonal charges in the first six months of 2019 ranged from $0.04 per MW-day in the DLCO Zone (total charges were $22,609) to $4.07 per MW-day in the PENELEC Zone (total charges were $2,206,364). For each zone, Table 10-47 shows black start charges, the sum of monthly zonal peak loads multiplied by the number of days of the month in which the peak load occurred, and black start rates (calculated as charges per MW-day). For black start service, point to point transmission customers paid on average $1.06 per MW-day of reserve capacity during the first six months of 2019.

Table 10-47 Black start zonal charges for network transmission use: January through June, 2018 and 2019[92]

	Jan-Jun 2018						Jan-Jun 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	$1,382,456	$14,031	$1,396,487	2,541	181	$3.04	$1,343,031	$8,011	$1,351,043	2,591	181	$2.88
AEP	$8,810,415	$39,193	$8,849,608	21,647	181	$2.26	$8,657,226	$21,783	$8,679,009	22,739	181	$2.11
APS	$1,948,578	$3,945	$1,952,523	8,755	181	$1.23	$1,957,637	$1,102	$1,958,740	9,342	181	$1.16
ATSI	$1,527,398	$934	$1,528,332	12,052	181	$0.70	$2,587,089	$1,482	$2,588,571	12,825	181	$1.12
BGE	$838,685	$3,371	$842,056	6,448	181	$0.72	$196,125	$846	$196,971	6,627	181	$0.16
ComEd	$2,417,164	$13,815	$2,430,979	20,351	181	$0.66	$2,103,306	$12,470	$2,115,776	21,349	181	$0.55
DAY	$128,749	$2,330	$131,079	3,225	181	$0.22	$103,072	$1,176	$104,248	3,337	181	$0.17
DEOK	$520,538	$0	$520,538	5,036	181	$0.57	$175,928	$0	$175,928	5,195	181	$0.19
DLCO	$25,579	$0	$25,579	2,682	181	$0.05	$22,609	$0	$22,609	2,795	181	$0.04
Dominion	$2,160,777	$9,576	$2,170,353	19,661	181	$0.61	$1,773,298	$19,300	$1,792,598	21,232	181	$0.47
DPL	$1,140,358	$5,752	$1,146,111	3,813	181	$1.66	$1,111,941	$3,339	$1,115,280	4,002	181	$1.54
EKPC	$204,382	$844	$205,226	2,860	181	$0.40	$166,257	$1,964	$168,222	3,431	181	$0.27
JCPL	$3,432,220	$9,035	$3,441,255	5,721	181	$3.32	$3,385,513	$7,186	$3,392,699	5,977	181	$3.14
Met-Ed	$320,680	$19,180	$339,860	2,897	181	$0.65	$235,450	$14,235	$249,685	3,028	181	$0.46
OVEC	$0	$0	$0	NA	181	NA	$0	$0	$0	NA	181	NA
PECO	$830,728	$2,460	$833,188	8,141	181	$0.57	$679,184	$3,169	$682,353	8,608	181	$0.44
PENELEC	$2,287,099	$0	$2,287,099	2,890	181	$4.37	$2,205,080	$1,284	$2,206,364	2,997	181	$4.07
Pepco	$1,269,548	$8,179	$1,277,726	6,097	181	$1.16	$1,236,354	$7,525	$1,243,879	6,412	181	$1.07
PPL	$608,728	$0	$608,728	7,401	181	$0.45	$569,196	$0	$569,196	7,681	181	$0.41
PSEG	$2,106,297	$861	$2,107,159	9,567	181	$1.22	$2,091,019	$4,526	$2,095,545	9,978	181	$1.16
RECO	$0	$0	$0	NA	181	NA	$0	$0	$0	NA	181	NA
(Imp/Exp/Wheels)	$1,403,430	$5,346	$1,408,777	6,678	181	$1.17	$1,497,052	$5,043	$1,502,096	7,868	181	$1.05
Total	$33,363,810	$138,852	$33,502,661	158,463		$1.17	$32,096,367	$114,444	$32,210,811	168,014		$1.06

Table 10-48 provides a revenue requirement estimate by zone for the 2019/2020, 2020/2021 and 2021/2022 delivery years.[93] 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.

92 Peak load for each zone is used to calculate the black start rate per MW day.
93 The System Restoration Strategy Task Force requested that the MMU provide estimated black start revenue requirements.

Table 10-48 Black start zonal revenue requirement estimate: 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.[94]

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 10-22 illustrates that the size of the oil tank does not change with the addition of the black start unit. Figure 10-23 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.

94 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 10-22 Oil tank MTSL not changed from addition of black start generator

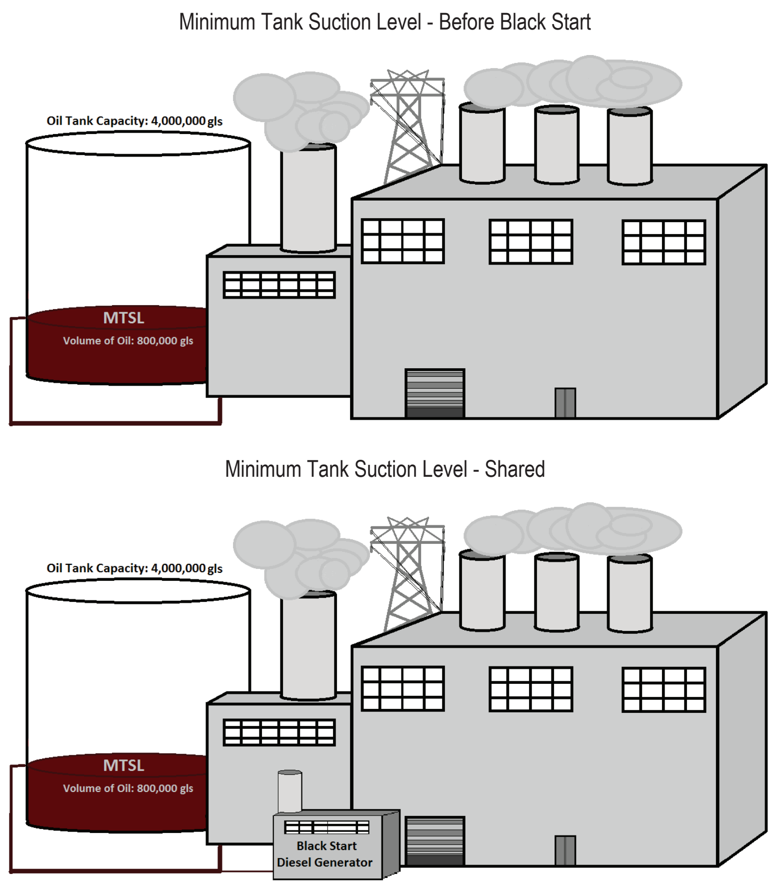
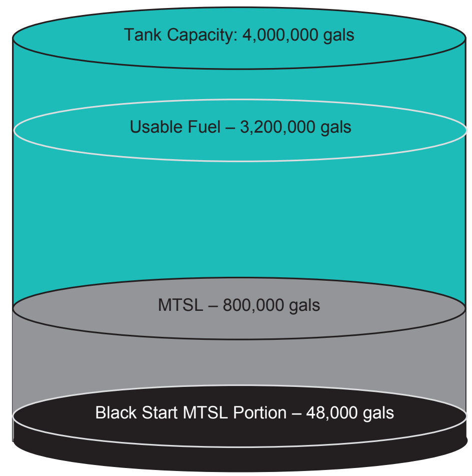


Figure 10-23 Oil tank black start MTSL portion



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.[95]

Any reactive service provided operationally that involves a MW reduction outside of its normal operating range or a startup for reactive power will be logged by PJM operators and awarded uplift or LOC credits.

Reactive Service, Reactive Supply and Voltage Control are provided by generation and other sources of reactive power (such as static VAR

95 See "PJM Manual 27: Open Access Transmission Tariff Accounting,"§ 3.2 Reactive Supply and Voltage Control Credits, Rev. 90, (Dec. 6, 2018).

compensators and capacitor banks).[96] 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.[97] 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.[98]

In 2016, the FERC began to reexamine its policies on reactive compensation.[99] 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.[100] 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.[101] 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.[102] The Commission has recently extended the interconnection service requirement to have reactive capability to wind and solar units, which previously had been exempt.[103] 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.

96 OATT Schedule 2.

97 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).

98 OATT Schedule 2.

99 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).

100 See 88 FERC ¶ 61,141 (1999).

101 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.").

102 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).

103 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.[104] The only FERC proceeding that has provided an opportunity for the MMU to raise its concerns at hearing has been *Panda Stonewall LLC.*[105] The initial decision issued in that case sidesteps the issues identified by the MMU.[106] 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."[107] Typically this has meant reliance on manufacturers' specified nameplate power factor.[108] More recently, the Commission has, in the *Wabash* Orders, required that "reactive power revenue requirement filings must include reactive power test reports."[109] 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.[110]

The Commission has identified a significant issue.[111] 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.[112] 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.

104 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.
105 See Docket No. EL17-1821.
106 167 FERC ¶ 63,010 (April 26, 2019).
107 *AEP mimeo* at 31.
108 See, e.g., *id.*
109 154 FERC ¶ 61,246 at P 28 (2016); see also 154 FERC ¶ 61,246 at P 29 (*Wabash* Orders).
110 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.").
111 154 FERC ¶ 61,246 at P 28 (2016); see also 154 FERC ¶ 61,246 at P 29.
112 *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.[113] 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. Fleet rates can 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 revenue offset is defined as a fixed number in the OATT and is currently set equal at $2,199/MW-year.[114] 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.[115] Participants have not been properly including reactive revenues in capacity market offers, and the MMU has notified participants of its compliance concerns. The identification of revenues for reactive capability on a unit specific basis is necessary for the calculation of accurate avoidable cost rate offers and is needed to avoid disputes that could interfere with the orderly administration of RPM auctions. The MMU has sought to address this issue through participation in proceedings at FERC concerning reactive capability rates for PJM units.[116]

Losses

The estimated capability costs also include estimated heating losses relative to MVAR output.[117] Heating losses are variable costs and not fixed costs and should not be included in the definition of reactive capability costs.[118] 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

113 See OATT Attachment DD § 5.10(a)(iv).
114 *See* OATT Attachment DD § 5.10(a)(v).
115 See OATT Attachment DD §§ 6.4, 6.8(d).
116 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.
117 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).
118 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.

not be included in the cost of reactive capability. The production of reactive power slightly reduces the MWh output of the generator as the generator follows its D-curve. The value of this heating loss component is generally estimated based on estimated operation and associated estimated losses and estimated market prices, treated as a fixed cost, and included in the cost of reactive capability. Losses are minimal and occur during normal operations and should not be treated as a fixed cost. Losses can be better and more accurately accounted for as a variable cost based on actual unit operations and market conditions.

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.[119] 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.[120] 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.[121] Fleet rates should be eliminated. Compensation should be based on unit specific costs. Fleet rates make it almost impossible to monitor whether compensation for reactive capability is based on actual unit specific performance and costs.

Reactive Costs

In the first six months of 2019, total reactive charges were $175.0 million, a 2.9 percent increase from the $170.3 million for the first six months of 2018. Reactive capability revenue requirement charges increased from $159.3 million in the first six months 2018 to $174.6 million in 2019 and reactive service charges decreased from $10.3 million in the first six months of 2018 to $0.450 million in the first six months of 2019. All $0.450 million in the first six months of 2019 were paid for reactive service provided by 21 units in 56 hours in specific locations.

Table 10-49 shows reactive service charges in the first six months of 2018 and 2019, reactive capability revenue requirement 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 revenue requirement charges show charges to each zone for reactive capability.

Table 10-49 Reactive zonal charges for network transmission use: January through June, 2018 and 2019

	Jan-Jun 2018			Jan-Jun 2019		
Zone	Reactive Service Charges	Reactive Capability Revenue Requirement Charges	Total Charges	Reactive Service Charges	Reactive Capability Revenue Requirement Charges	Total Charges
AECO	$0	$2,363,319	$2,363,319	$0	$2,350,115	$2,350,115
AEP	$775,231	$20,328,423	$21,103,654	$3,517	$24,094,285	$24,097,801
APS	$0	$7,780,164	$7,780,164	$14,903	$7,861,649	$7,876,553
ATSI	$0	$10,719,414	$10,719,414	$697	$13,152,305	$13,153,001
BGE	$0	$4,138,290	$4,138,290	$0	$3,753,690	$3,753,690
ComEd	$9,142,938	$19,155,124	$28,298,062	$0	$20,269,438	$20,269,438
DAY	$0	$2,676,604	$2,676,604	$0	$1,410,097	$1,410,097
DEOK	$0	$3,700,108	$3,700,108	$0	$5,109,564	$5,109,564
Dominion	$22,293	$19,111,875	$19,134,167	$182,436	$19,196,193	$19,378,630
DPL	$257,310	$5,829,925	$6,087,235	$110,010	$5,696,005	$5,806,015
DLCO	$0	$391,399	$391,399	$0	$389,212	$389,212
EKPC	$166,357	$1,097,882	$1,264,239	$0	$1,091,748	$1,091,748
JCPL	$0	$4,793,749	$4,793,749	$0	$3,653,816	$3,653,816
Met-Ed	$0	$2,321,908	$2,321,908	$1,093	$2,599,221	$2,600,314
OVEC	$0	$0	$0	$0	$0	$0
PECO	$0	$11,369,085	$11,369,085	$0	$11,284,501	$11,284,501
PENELEC	$354,393	$5,986,959	$6,341,352	$137,908	$6,446,976	$6,584,884
Pepco	$0	$4,257,546	$4,257,546	$0	$5,680,511	$5,680,511
PPL	$0	$12,261,444	$12,261,444	$0	$17,927,316	$17,927,316
PSEG	$0	$13,589,118	$13,589,118	$0	$13,872,920	$13,872,920
RECO	$0	$0	$0	$0	$0	$0
(Imp/Exp/Wheels)	$0	$7,447,529	$7,447,529	$0	$8,712,819	$8,712,819
Total	$10,718,521	$159,319,863	$170,038,385	$450,564	$174,552,382	$175,002,946

119 See, e.g., OATT Schedule 2; 114 FERC ¶ 61,318 (2006).
120 See 149 FERC ¶ 61,132 (2014); 151 FERC ¶ 61,224 (2015); OATT Schedule 2.
121 *Id.*

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.[122] 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).

PJM filed revisions in compliance with Order No. 842 that substantively incorporated the pro forma agreements into its market rules.[123]

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. 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.

122 157 FERC ¶ 61,122 (2016).
123 See 164 FERC ¶ 61,224 (2018).

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 costs plus net explicit congestion costs plus net inadvertent congestion charges. The net implicit congestion costs are the load congestion payments less generation congestion credits. This section refers to total energy costs and total marginal loss costs in the same way. As with congestion, total energy costs are more precisely termed net energy costs and total marginal loss costs are more precisely termed net marginal loss costs. Ignoring interchange, total generation MWh must be greater than total load MWh in any hour in order to provide for losses. Since the hourly integrated energy component of LMP is the same for every bus within every hour, the net energy bill is negative (ignoring net interchange), with more generation credits than load payments in every hour.[4]

Local congestion is calculated on a constraint specific basis. This constraint based congestion is the total congestion payments by 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 capability of transmission facilities, the offers and geographic distribution of

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 six months of 2019 were calculated as of July 16, 2019, and are subject to change, based on continued PJM billing updates.

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 $642.5 million or 71.7 percent, from $896.6 million in the first six months of 2018 to $254.1 million in the first six months of 2019.
- **Day-Ahead Congestion.** Day-ahead congestion costs decreased by $605.0 million or 66.0 percent, from $916.5 million in the first six months of 2018 to $311.5 million in the first six months of 2019.
- **Balancing Congestion.** Negative balancing congestion costs increased by $37.5 million or 188.6 percent, from -$19.9 million in the first six months of 2018 to -$57.4 million in the first six months of 2019. Balancing explicit costs decreased by $40.9 million or 364.9 percent, from $11.2 million in the first six months of 2018 to -$29.7 million in the first six months of 2019.
- **Real-Time Congestion.** Real-time congestion costs decreased by $749.1 million or 71.8 percent, from $1,042.9 million in the first six months of 2018 to $293.8 million in the first six months of 2019.
- **Monthly Congestion.** Monthly total congestion costs in the first six 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 Siegfried Transformer, the AP South Interface, the East Interface, and the CPL - DOM 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 six 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 36.5 percent from 81,854 congestion event hours in the first six months of 2018 to 51,990 congestion event hours in the first six months of 2019. The majority (94.2 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]

  Real-time congestion frequency decreased by 35.6 percent from 12,867 congestion event hours in the first six months of 2018 to 8,287 congestion event hours in the first six 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 six months of 2019. With $40.7 million in total congestion costs, it accounted for 16.0 percent of the total PJM congestion costs in the first six 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 six months of 2019 and -$2.6 million of balancing congestion in the first six months of 2019. None of the closed loop interfaces was binding in the first six months of 2019 or 2018.
- **Zonal Congestion.** AEP had the largest zonal congestion costs among all control zones in the first six months of 2019. AEP had $38.8 million in zonal congestion costs, comprised of $48.0 million in zonal day-ahead congestion costs and -$9.2 million in zonal balancing congestion costs. The Conastone - Peach Bottom Line, the AP South Interface, the East Interface, the Hazard Transformer, and the Conastone - Northwest Line contributed $13.7 million, or 35.2 percent of the AEP zonal congestion costs.

5 162 FERC ¶ 61,139

Marginal Loss Cost

- **Total Marginal Loss Costs.** Total marginal loss costs decreased by $198.3 million or 38.0 percent, from $521.4 million in the first six months of 2018 to $323.1 million in the first six months of 2019. The loss MWh in PJM decreased by 230.1 GWh or 3.0 percent, from 7,657.9 GWh in the first six months of 2018 to 7,427.8 GWh in the first six months of 2019. The loss component of real-time LMP in the first six months of 2019 was $0.02, compared to $0.02 in the first six months of 2018.
- **Monthly Total Marginal Loss Costs.** Monthly total marginal loss costs in the first six 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 $184.6 million or 34.5 percent, from $534.4 million in the first six months of 2018 to $349.7 million in the first six months of 2019.
- **Balancing Marginal Loss Costs.** Negative balancing marginal loss costs increased by $13.7 million or 105.9 percent, from -$12.9 million in the first six months of 2018 to -$26.6 million in the first six months of 2019.
- **Total Marginal Loss Surplus.** The total marginal loss surplus decreased in the first six months of 2019 by $71.4 million or 40.7 percent, from $175.6 million in the first six months of 2018, to $104.2 million in the first six months of 2019.

Energy Cost

- **Total Energy Costs.** Total energy costs increased by $126.2 million or 36.6 percent, from -$345.2 million in the first six months of 2018 to -$218.9 million in the first six months of 2019.
- **Day-Ahead Energy Costs.** Day-ahead energy costs increased by $112.4 million or 29.6 percent, from -$380.4 million in the first six months of 2018 to -$268.0 million in the first six months of 2019.
- **Balancing Energy Costs.** Balancing energy costs increased by $17.4 million or 57.2 percent, from $30.3 million in the first six months of 2018 to $47.7 million in the first six months of 2019.
- **Monthly Total Energy Costs.** Monthly total energy costs in the first six months of 2019 ranged from -$59.3 million in January to -$25.7 million in April.

Conclusion

Congestion is defined to be the total congestion payments by load in excess of the total congestion credits received by generation. The level and distribution of congestion reflects the underlying characteristics of the power system, including the nature and capability of transmission facilities, the offers and geographic distribution of generation facilities, the level and geographic distribution of incremental bids and offers and the geographic and temporal distribution of load.

Total congestion in the first six months of 2019 decreased significantly from the first six 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, following the FERC decision to allocate some of the surplus to load, the offset was 92.1 percent.

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 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

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.

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 implicit balancing congestion.

Prior to April 1, 2018, implicit balancing congestion costs 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 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 netting of zonal and aggregate deviations decreased the allocation of negative balancing charges to load deviations and increased the allocation to real-time load plus real-time exports.

Table 11-1 shows the total implicit balancing congestion costs that would have resulted from applying either the pre or post April 1, 2018 settlement rules for the first six months of 2017, 2018 and 2019. Table 11-1 also shows the actual total implicit balancing congestion costs for the first six months of 2017, 2018 and 2019 based on the methods in place at the time.[8] The only difference is that the actual implicit balancing congestion in 2018 reflects the fact that in the first quarter of 2018 the implicit balancing congestion cost was calculated under the pre April 1, 2018, settlement rule and in the second quarter of 2018, the implicit balancing congestion cost was 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 six 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 costs to increase by $3.60 million (14.9 percent) in the first six months of 2019, and would have caused such costs to increase by $1.4 million (9.1 percent) in the first six months of 2017 and to increase by $11.3 million (38.9 percent) in the first six months of 2018.

8 In 2017, the actual total balancing congestion costs were calculated using old method. In 2018, the actual total balancing congestion costs were calculated using the old method in the first quarter and using the new method in the second quarter. In 2019, the actual total balancing congestion costs were calculated using the new method.

Table 11-1 Total balancing implicit congestion cost ($M) (old method and new method): January through June, 2017 through 2019

	Balancing ($ Milllion)								
	Old Method			New Method			Actual		
(Jan - Jun)	Load Payments	Generation Credits	Total Implicit	Load Payments	Generation Credits	Total Implicit	Load Payments	Generation Credits	Total Implicit
2017	$6.1	$21.5	($15.4)	$5.0	$21.8	($16.8)	$6.1	$21.5	($15.4)
2018	$17.2	$46.1	($28.9)	$3.3	$43.5	($40.2)	$14.7	$45.8	($31.1)
2019	$5.2	$29.3	($24.1)	$0.2	$28.0	($27.7)	$0.2	$28.0	($27.7)

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.[9] 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.[10] 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 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 June, 2008 through 2019.[11]

The load-weighted average real-time LMP decreased $14.95 or 35.2 percent from $42.44 in the first six months of 2018 to $27.49 in the first six months of 2019. The load-weighted, average real-time congestion component decreased by $0.02 from $0.04 in the first six months of 2018 to $0.02 in the first six months of 2019. The load-weighted average real-time loss component in the first six months of 2019 was $0.02 compared to $0.02 in the first six months of 2018. The load-weighted, average real-time energy component decreased

9 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>.

10 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.

11 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.

by $14.92 or 35.2 percent from $42.37 in the first six months of 2018 to $27.45 in the first six months of 2019.

Table 11-2 PJM real-time, load-weighted average LMP components (Dollars per MWh): January through June, 2008 through 2019[12]

(Jan - Jun)	Real-Time LMP	Energy Component	Congestion Component	Loss Component
2008	$74.77	$74.66	$0.07	$0.05
2009	$42.48	$42.40	$0.05	$0.03
2010	$45.75	$45.65	$0.06	$0.04
2011	$48.47	$48.40	$0.05	$0.03
2012	$31.21	$31.17	$0.04	$0.01
2013	$37.96	$37.92	$0.02	$0.02
2014	$69.92	$69.95	($0.06)	$0.02
2015	$42.30	$42.24	$0.03	$0.02
2016	$27.09	$27.04	$0.03	$0.01
2017	$29.81	$29.78	$0.02	$0.01
2018	$42.44	$42.37	$0.04	$0.02
2019	$27.49	$27.45	$0.02	$0.02

Table 11-3 shows the PJM day-ahead, load-weighted average LMP components for January through June, 2008 through 2019.[13] The load-weighted average day-ahead LMP decreased $12.99, or 31.7 percent, from $40.96 in the first six months of 2018 to $27.97 in the first six months of 2019. The load-weighted, average congestion component decreased $0.05 from $0.11 in the first six months of 2018 to $0.06 in the first six months of 2019. The load-weighted, average loss component was -$0.01 in the first six months of 2018 and -$0.01 in the first six months of 2019. The load-weighted average energy component decreased $12.94, or 31.7 percent, from $40.86 in the first six months of 2018 to $27.92 in the first six months of 2019.

Table 11-3 PJM day-ahead, load-weighted average LMP components (Dollars per MWh): January through June, 2008 through 2019

(Jan - Jun)	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
2008	$73.71	$74.10	($0.16)	($0.23)
2009	$42.21	$42.47	($0.14)	($0.12)
2010	$46.12	$46.04	$0.08	($0.00)
2011	$47.12	$47.32	($0.10)	($0.11)
2012	$31.84	$31.76	$0.10	($0.02)
2013	$38.23	$38.14	$0.09	$0.00
2014	$70.66	$70.37	$0.30	($0.01)
2015	$43.26	$42.95	$0.33	($0.02)
2016	$27.33	$27.22	$0.12	($0.01)
2017	$30.02	$30.02	$0.02	($0.02)
2018	$40.96	$40.86	$0.11	($0.01)
2019	$27.97	$27.92	$0.06	($0.01)

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 June 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		
Aug	$38.64	$25.11		
Sep	$36.83	$26.29		
Oct	$35.27	$26.11		
Nov	$37.64	$26.58		
Dec	$34.60	$24.19		
Avg	$41.15	$24.71	$28.81	$21.79

12 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.

13 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.

Zonal Components

The real-time components of LMP for each control zone are presented in Table 11-5 for January through June, 2018 and 2019. In the first six months of 2019, BGE had the highest real-time congestion component of all control zones, $1.70, and PPL had the lowest real-time congestion component, -$1.73.

Table 11-5 Zonal and PJM real-time, load-weighted average LMP components (Dollars per MWh): January through June, 2018 and 2019

	2018 (Jan - Jun)				2019 (Jan - Jun)			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AECO	$40.49	$41.77	($2.32)	$1.05	$26.96	$27.27	($0.66)	$0.35
AEP	$41.23	$42.27	($0.38)	($0.67)	$27.65	$27.44	$0.39	($0.17)
APS	$44.74	$42.73	$1.69	$0.33	$27.89	$27.58	$0.22	$0.09
ATSI	$43.91	$41.20	$2.36	$0.35	$27.74	$27.29	$0.12	$0.33
BGE	$52.10	$43.65	$6.80	$1.65	$30.33	$27.70	$1.70	$0.93
ComEd	$29.33	$40.90	($9.15)	($2.42)	$24.97	$27.17	($1.15)	($1.05)
DAY	$41.76	$41.92	($0.67)	$0.51	$28.67	$27.48	$0.37	$0.81
DEOK	$43.29	$42.06	$2.40	($1.17)	$27.46	$27.37	$0.35	($0.26)
DLCO	$43.94	$41.46	$2.52	($0.03)	$27.15	$27.22	$0.03	($0.09)
Dominion	$51.20	$44.06	$6.43	$0.71	$28.93	$27.60	$1.03	$0.31
DPL	$47.15	$44.07	$0.78	$2.31	$28.29	$27.81	($0.28)	$0.77
EKPC	$38.69	$44.90	($4.57)	($1.63)	$27.64	$27.99	$0.06	($0.41)
JCPL	$41.37	$42.06	($1.73)	$1.04	$27.04	$27.44	($0.69)	$0.30
Met-Ed	$41.10	$42.22	($1.85)	$0.72	$27.45	$27.55	($0.13)	$0.03
OVEC	NA	NA	NA	NA	$26.31	$27.02	$0.14	($0.85)
PECO	$41.24	$42.37	($1.91)	$0.78	$26.53	$27.44	($0.96)	$0.05
PENELEC	$41.30	$41.48	($0.63)	$0.45	$26.78	$27.38	($0.64)	$0.04
Pepco	$50.27	$43.35	$5.79	$1.13	$29.35	$27.64	$1.08	$0.63
PPL	$40.39	$42.62	($2.67)	$0.44	$25.71	$27.65	($1.73)	($0.21)
PSEG	$40.93	$41.46	($1.54)	$1.01	$27.34	$27.22	($0.09)	$0.21
RECO	$40.42	$41.41	($1.86)	$0.86	$27.11	$27.19	($0.21)	$0.12
PJM	$42.44	$42.37	$0.04	$0.02	$27.49	$27.45	$0.02	$0.02

The day-ahead components of LMP for each control zone are presented in Table 11-6 for January through June, 2018 and 2019. In the first six months of 2019, BGE had the highest day-ahead congestion component of all control zones, $2.28, and PPL had the lowest day-ahead congestion component, -$1.83.

Table 11-6 Zonal and PJM day-ahead, load-weighted average LMP components (Dollars per MWh): January through June, 2018 and 2019

	2018 (Jan - Jun)				2019 (Jan - Jun)			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AECO	$39.91	$40.45	($1.05)	$0.51	$26.98	$27.81	($1.05)	$0.21
AEP	$39.55	$40.89	($0.84)	($0.50)	$28.19	$27.99	$0.35	($0.15)
APS	$42.73	$40.87	$1.61	$0.25	$28.55	$28.05	$0.42	$0.08
ATSI	$40.80	$39.82	$0.55	$0.43	$28.55	$27.78	$0.37	$0.40
BGE	$49.72	$41.71	$6.68	$1.33	$31.18	$28.10	$2.28	$0.80
ComEd	$28.48	$39.60	($9.15)	($1.97)	$25.23	$27.61	($1.46)	($0.92)
DAY	$40.39	$40.58	($0.83)	$0.64	$29.19	$27.93	$0.47	$0.79
DEOK	$42.98	$40.50	$3.20	($0.72)	$28.27	$27.89	$0.58	($0.20)
DLCO	$40.90	$40.08	$0.82	($0.00)	$27.85	$27.69	$0.24	($0.08)
Dominion	$49.61	$42.45	$6.45	$0.70	$30.05	$28.13	$1.68	$0.23
DPL	$46.11	$42.49	$2.07	$1.55	$28.27	$28.30	($0.56)	$0.53
EKPC	$37.37	$43.52	($4.75)	($1.40)	$28.02	$28.56	($0.06)	($0.49)
JCPL	$40.47	$40.62	($0.75)	$0.60	$26.81	$27.90	($1.30)	$0.21
Met-Ed	$40.04	$40.48	($0.64)	$0.21	$27.08	$27.95	($0.76)	($0.11)
OVEC	NA	NA	NA	NA	$29.38	$30.13	$0.12	($0.87)
PECO	$40.26	$40.65	($0.72)	$0.33	$26.28	$27.88	($1.51)	($0.09)
PENELEC	$39.93	$40.62	($0.89)	$0.20	$28.06	$28.21	($0.29)	$0.13
Pepco	$48.47	$41.67	$5.76	$1.04	$30.48	$28.16	$1.73	$0.59
PPL	$39.57	$40.83	($1.19)	($0.07)	$25.85	$28.04	($1.83)	($0.37)
PSEG	$41.27	$40.40	$0.16	$0.71	$27.27	$27.74	($0.63)	$0.15
RECO	$40.51	$40.26	($0.37)	$0.63	$27.86	$27.92	($0.18)	$0.11
PJM	$40.96	$40.86	$0.11	($0.01)	$27.97	$27.92	$0.06	($0.01)

Hub Components

The real-time components of LMP for each hub are presented in Table 11-7 for January through June, 2018 and 2019.[14]

Table 11-7 Hub real-time, average LMP components (Dollars per MWh): January through June, 2018 and 2019

	2018 (Jan - Jun)				2019 (Jan - Jun)			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AEP Gen Hub	$34.55	$38.76	($2.55)	($1.66)	$25.71	$26.38	$0.16	($0.83)
AEP-DAY Hub	$36.12	$38.76	($1.85)	($0.79)	$26.53	$26.38	$0.37	($0.22)
ATSI Gen Hub	$39.11	$38.76	$0.76	($0.41)	$26.44	$26.38	$0.18	($0.11)
Chicago Gen Hub	$27.39	$38.76	($8.65)	($2.72)	$23.87	$26.38	($1.20)	($1.31)
Chicago Hub	$27.96	$38.76	($8.60)	($2.19)	$24.32	$26.38	($1.12)	($0.94)
Dominion Hub	$44.52	$38.76	$5.45	$0.31	$27.18	$26.38	$0.74	$0.06
Eastern Hub	$39.76	$38.76	($0.62)	$1.62	$26.19	$26.38	($0.76)	$0.58
N Illinois Hub	$27.75	$38.76	($8.62)	($2.39)	$24.14	$26.38	($1.15)	($1.09)
New Jersey Hub	$37.47	$38.76	($2.10)	$0.81	$25.95	$26.38	($0.60)	$0.18
Ohio Hub	$35.70	$38.76	($2.22)	($0.83)	$26.60	$26.38	$0.41	($0.19)
West Interface Hub	$41.99	$38.76	$3.65	($0.42)	$26.54	$26.38	$0.37	($0.21)
Western Hub	$40.52	$38.76	$1.57	$0.19	$26.63	$26.38	$0.26	($0.01)

The day-ahead components of LMP for each hub are presented in Table 11-8 for January through June, 2018 and 2019.

Table 11-8 Hub day-ahead, average LMP components (Dollars per MWh): January through June, 2018 and 2019

	2018 (Jan - Jun)				2019 (Jan - Jun)			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AEP Gen Hub	$34.00	$37.83	($2.40)	($1.42)	$26.17	$26.82	$0.14	($0.79)
AEP-DAY Hub	$35.55	$37.83	($1.67)	($0.61)	$27.01	$26.82	$0.37	($0.19)
ATSI Gen Hub	$37.25	$37.83	($0.35)	($0.22)	$27.24	$26.82	$0.42	($0.00)
Chicago Gen Hub	$26.66	$37.83	($8.86)	($2.31)	$24.22	$26.82	($1.41)	($1.19)
Chicago Hub	$27.23	$37.83	($8.82)	($1.77)	$24.62	$26.82	($1.39)	($0.81)
Dominion Hub	$43.42	$37.83	$5.20	$0.39	$28.03	$26.82	$1.23	($0.03)
Eastern Hub	$39.56	$37.83	$0.58	$1.16	$26.31	$26.82	($0.95)	$0.44
N Illinois Hub	$26.99	$37.83	($8.83)	($2.00)	$24.42	$26.82	($1.42)	($0.98)
New Jersey Hub	$37.61	$37.83	($0.70)	$0.48	$25.93	$26.82	($1.00)	$0.12
Ohio Hub	$35.23	$37.83	($1.95)	($0.64)	$27.04	$26.82	$0.38	($0.16)
West Interface Hub	$40.37	$37.83	$2.83	($0.29)	$27.27	$26.82	$0.62	($0.17)
Western Hub	$39.36	$37.83	$1.44	$0.10	$27.43	$26.82	$0.58	$0.02

14 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 implicit congestion costs plus explicit congestion costs. Implicit congestion costs equal congestion payments minus congestion credits. Explicit congestion costs are the net congestion costs associated with 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.[15] 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 costs 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.

Total congestion costs are equal to the net implicit congestion bill plus net explicit congestion costs plus net inadvertent congestion charges, incurred in both the Day-Ahead Energy Market and the balancing energy market.

Total congestion costs equal congestion payments netted against congestion credits on an hourly basis, by billing organization, and summed for the given period. Congestion payments are made by withdrawals and congestion credits are paid to injections. Withdrawals are generically referred to as load and injections are generically referred to as generation.

Congestion payments and congestion credits are calculated for both the Day-Ahead and balancing energy markets.

- **Day-Ahead Load Congestion Payments.** Day-ahead load congestion payments are calculated for all cleared demand, decrement bids and day-ahead energy market sale transactions. Day-ahead load congestion payments are calculated using MW and the load bus CLMP, the decrement bid CLMP or the CLMP at the source of the sale transaction, as applicable.
- **Day-Ahead Generation Congestion Credits.** Day-ahead generation congestion credits are calculated for all cleared generation, increment offers and day-ahead energy market purchase transactions. Day-ahead generation congestion credits are calculated using MW and the generator bus CLMP, the increment offer's CLMP or the CLMP at the sink of the purchase transaction, as applicable.
- **Balancing Load Congestion Payments.** Balancing load congestion payments are calculated for all deviations between a PJM member's real-time load and energy sale transactions and their day-ahead cleared demand, decrement bids and energy sale transactions. Balancing load congestion payments are calculated using MW deviations and the real-time CLMP for each bus where a deviation exists.
- **Balancing Generation Congestion Credits.** Balancing generation congestion credits are calculated for all deviations between a PJM member's real-time generation and energy purchase transactions and the day-ahead cleared generation, increment offers and energy purchase transactions. Balancing generation congestion credits are calculated using MW deviations and the real-time CLMP for each bus where a deviation exists.
- **Explicit Congestion Costs.** Explicit congestion costs are the net congestion costs associated with point to point energy transactions. These costs equal the product of the transacted MW and CLMP differences between sources (origins) and sinks (destinations) in the Day-Ahead Energy Market. Balancing energy market explicit congestion costs equal the product of the deviations between the real-time and day-ahead transacted MW and the differences between the real-time CLMP at the transactions' sources

15 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.

and sinks. Explicit congestion costs are calculated for internal purchase, import and export transaction, and up to congestion transactions (UTCs.)

- **Inadvertent Congestion Charges.** Inadvertent congestion charges are congestion charges resulting from the differences between the net actual energy flow and the net scheduled energy flow into or out of the PJM control area each hour. This inadvertent interchange of energy may be positive or negative, where positive interchange typically results in a charge while negative interchange typically results in a credit. Inadvertent congestion charges are common costs, not directly attributable to specific participants that are distributed on a load ratio basis.[16]

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 consequently load payments and generation credits can be both positive and negative. Total congestion costs, when positive, measure the total congestion payment by a participant group and when negative, measure the total congestion credit paid to a participant group. Load congestion payments, when positive, measure the total congestion payment by load and when negative, measure the total congestion credit paid by load. Generation congestion credits, when negative, measure the total congestion payment by generation and when positive, measure the total congestion credit paid to generation. Explicit congestion costs, when positive, measure the congestion payment by a PJM member and when negative, measure the congestion credit paid to a PJM member. Explicit congestion costs are calculated for up to congestion transactions (UTCs).

The accounting definitions can be misleading. Load pays for congestion. Generation does not pay for 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 for congestion.

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.[17]

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

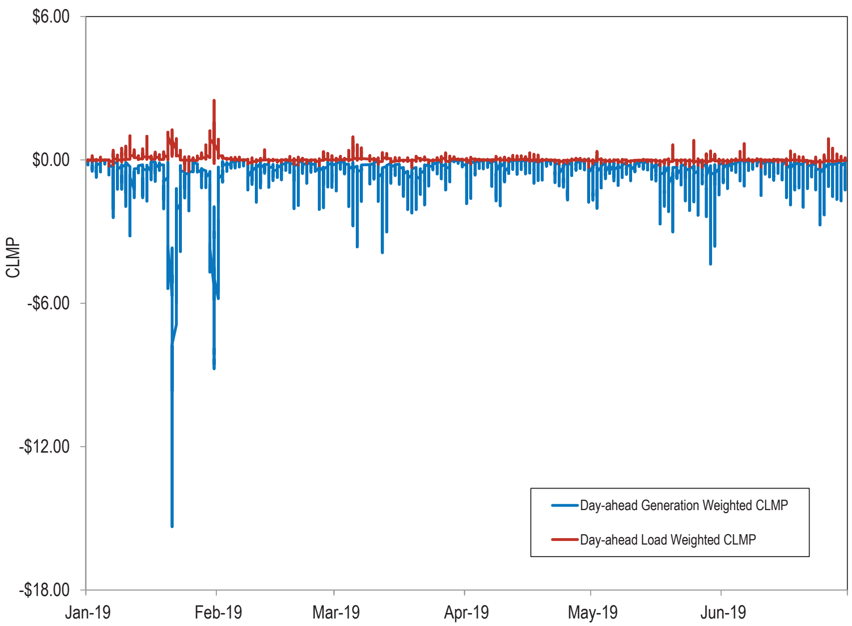
16 PJM Operating Agreement Schedule 1 §3.7.

17 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>.

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 six months of 2019, day-ahead generation weighted CLMPs were generally negative and day-ahead load weighted CLMPs were generally equal to or slightly greater than zero. Figure 11-1 also shows that in the first six 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 June, 2019



Total Congestion

Total congestion costs in PJM in the first six months of 2019 were $254.1 million, which were comprised of load congestion payments of $100.6 million, generation credits of -$160.3 million and explicit congestion of -$6.8 million. Total congestion is the difference between what load pays for energy and what generation is paid for energy.

Table 11-9 shows total congestion for January through June, 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.[18 19]

Table 11-9 Total PJM congestion component costs (Dollars (Millions)): January through June, 2008 through 2019

	Congestion Costs (Millions)			
(Jan - Jun)	Congestion Cost	Percent Change	Total PJM Billing	Percent of PJM Billing
2008	$1,166	NA	$16,549	7.0%
2009	$408	(65.0%)	$13,457	3.0%
2010	$644	57.8%	$16,314	3.9%
2011	$570	(11.5%)	$18,685	3.1%
2012	$263	(53.8%)	$13,991	1.9%
2013	$306	16.3%	$15,571	2.0%
2014	$1,442	371.3%	$31,060	4.6%
2015	$919	(36.3%)	$23,390	3.9%
2016	$479	(47.8%)	$18,290	2.6%
2017	$286	(40.4%)	$18,960	1.5%
2018	$897	214.0%	$25,780	3.5%
2019	$254	(71.7%)	$20,070	1.3%

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

18 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>.
19 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>.

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 June, 2008 through 2019. Table 11-11 and Table 11-12 show that the decrease in balancing explicit costs was the result of the decrease in balancing explicit costs incurred by up to congestion transactions (UTCs) in the first six months of 2019 from the first six 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 11-10 shows that the balancing explicit costs 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 June, 2008 through 2019

	Congestion Costs (Millions)									
	Day-Ahead				Balancing					
(Jan - Jun)	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
2008	$727.6	($589.4)	$86.7	$1,403.8	($102.4)	$68.2	($67.1)	($237.7)	$0.0	$1,166.1
2009	$159.3	($299.4)	$63.1	$521.7	($17.0)	($2.4)	($99.0)	($113.6)	$0.0	$408.2
2010	$151.5	($544.1)	$38.1	$733.8	($7.3)	$18.6	($63.9)	($89.8)	($0.0)	$644.0
2011	$256.0	($420.3)	$25.6	$701.9	$31.1	$56.0	($107.0)	($131.9)	$0.0	$570.0
2012	$56.8	($267.4)	$65.4	$389.6	($5.0)	$19.5	($101.8)	($126.4)	$0.0	$263.3
2013	$133.2	($306.1)	$87.8	$527.1	($8.4)	$90.4	($122.3)	($221.1)	($0.0)	$306.0
2014	$392.5	($1,353.6)	($54.1)	$1,691.9	$64.4	$219.9	($94.2)	($249.7)	$0.0	$1,442.3
2015	$428.5	($655.2)	$9.5	$1,093.2	$10.7	$68.8	($116.5)	($174.6)	$0.0	$918.6
2016	$201.9	($293.4)	$18.7	$514.0	$0.4	$11.5	($23.7)	($34.8)	$0.0	$479.1
2017	$47.1	($246.0)	$3.8	$296.8	$6.1	$21.5	$4.1	($11.3)	$0.0	$285.5
2018	$211.8	($745.0)	($40.3)	$916.5	$14.7	$45.8	$11.2	($19.9)	$0.0	$896.6
2019	$100.4	($188.3)	$22.9	$311.5	$0.2	$28.0	($29.7)	($57.4)	$0.0	$254.1

Table 11-11 and Table 11-12 show the total congestion charges and credits for each transaction type in the first six months of 2019 and 2018. Table 11-11 shows that in the first six months of 2019 DECs paid $6.7 million in congestion charges in the day-ahead market, were paid $7.5 million in congestion credits in the balancing energy market, resulting in a net payment of $0.8 million in total congestion credits. In the first six months of 2019, INCs paid $8.3 million in congestion charges in the day-ahead market, were paid $12.7 million in congestion credits in the balancing energy market resulting in a net payment of $4.4 million in total congestion credits. In the first six months of 2019, up to congestion (UTCs) paid $22.7 million in congestion charges in the day-ahead market, were paid $29.9 million in congestion credits in the balancing market resulting in a total payment of $7.2 million in total congestion credits.

Table 11-11 Total PJM congestion credits and charges by transaction type by market (Dollars (Millions)): January through June, 2019

	Congestion Costs (Millions)									
	Day-Ahead				Balancing					
Transaction Type	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
DEC	$6.7	$0.0	$0.0	$6.7	($7.5)	$0.0	$0.0	($7.5)	$0.0	($0.8)
Demand	$18.2	$0.0	$0.0	$18.2	$8.1	$0.0	$0.0	$8.1	$0.0	$26.3
Demand Response	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Explicit Congestion Only	$0.0	$0.0	$0.5	$0.5	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.4
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	($8.3)	$0.0	($0.2)	($8.5)	($0.0)	$0.0	$0.7	$0.7	$0.0	($7.8)
Generation	$0.0	($263.9)	$0.0	$263.9	$0.0	$17.8	$0.0	($17.8)	$0.0	$246.1
Import	$0.0	$0.2	$0.0	($0.2)	$0.0	($2.2)	($0.2)	$2.0	$0.0	$1.9
INC	$0.0	($8.3)	$0.0	$8.3	$0.0	$12.7	$0.0	($12.7)	$0.0	($4.4)
Internal Bilateral	$83.8	$83.7	($0.0)	$0.0	($0.3)	($0.3)	$0.0	($0.0)	$0.0	($0.0)
Up to Congestion	$0.0	$0.0	$22.7	$22.7	$0.0	$0.0	($29.9)	($29.9)	$0.0	($7.2)
Wheel In	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.2)	($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	$100.4	($188.3)	$22.9	$311.5	$0.2	$28.0	($29.7)	($57.4)	$0.0	$254.1

Table 11-12 Total PJM congestion credits and charges by transaction type by market (Dollars (Millions)): January through June, 2018

	Congestion Costs (Millions)									
	Day-Ahead				Balancing					
Transaction Type	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
DEC	$12.2	$0.0	$0.0	$12.2	($16.2)	$0.0	$0.0	($16.2)	$0.0	($3.9)
Demand	$32.9	$0.0	$0.0	$32.9	$38.3	$0.0	$0.0	$38.3	$0.0	$71.1
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	($0.6)	($0.6)	$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	($39.1)	$0.0	($0.8)	($40.0)	($9.8)	$0.0	($3.7)	($13.5)	$0.0	($53.4)
Generation	$0.0	($928.8)	$0.0	$928.8	$0.0	$58.9	$0.0	($58.9)	$0.0	$869.9
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	($6.1)	$0.0	$6.1	$0.0	($39.7)	($3.0)	$36.7	$0.0	$42.8
INC	$0.0	($16.3)	$0.0	$16.3	$0.0	$24.1	$0.0	($24.1)	$0.0	($7.8)
Internal Bilateral	$205.8	$206.2	$0.4	($0.0)	$3.1	$3.1	$0.0	($0.0)	$0.0	($0.0)
Up to Congestion	$0.0	$0.0	($40.1)	($40.1)	$0.0	$0.0	$18.8	$18.8	$0.0	($21.3)
Wheel In	$0.0	$0.0	$0.0	$0.0	$0.0	($0.6)	($0.4)	$0.2	$0.0	$0.2
Wheel Out	$0.0	$0.0	$0.0	$0.0	($0.6)	$0.0	$0.0	($0.6)	$0.0	($0.6)
Total	$211.8	($745.0)	($40.3)	$916.5	$14.7	$45.8	$11.2	($19.9)	$0.0	$896.6

Table 11-13 shows the change in total congestion credits and charges incurred by transaction type from the first six months of 2018 to the first six months of 2019. Total congestion credits incurred by generation decreased by $623.8 million, and total congestion charges incurred by demand decreased by $44.9 million. The total congestion payments to up to congestion transactions (UTCs) decreased by $14.1 million, from $21.3 million in the first six months of 2018 to $7.2 million in the first six months of 2019. Total day-ahead congestion payments to UTCs decreased by $62.8 million from $40.1 million in the first six months of 2018 to -$22.7 million in the first six months of 2019. Over the same period balancing congestion payments to UTCs increased by $48.8 million, from -$18.8 million in the first six months of 2018 to $29.9 million in the first six months of 2019.

Table 11-13 Change in total PJM congestion credits and charges by transaction type by market: January through June, 2018 to 2019 (Dollars (Millions))

	Change in Congestion Costs (Millions)									
	Day-Ahead				Balancing					
Transaction Type	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
DEC	($5.5)	$0.0	$0.0	($5.5)	$8.6	$0.0	$0.0	$8.6	$0.0	$3.1
Demand	($14.7)	$0.0	$0.0	($14.7)	($30.1)	$0.0	$0.0	($30.1)	$0.0	($44.9)
Demand Response	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Explicit Congestion Only	$0.0	$0.0	($0.3)	($0.3)	$0.0	$0.0	$0.5	$0.5	$0.0	$0.2
Explicit Congestion and Loss Only	$0.0	$0.0	($0.1)	($0.1)	$0.0	$0.0	$0.0	$0.0	$0.0	($0.1)
Export	$30.9	$0.0	$0.6	$31.5	$9.8	$0.0	$4.3	$14.1	$0.0	$45.6
Generation	$0.0	$664.9	$0.0	($664.9)	$0.0	($41.1)	$0.0	$41.1	$0.0	($623.8)
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	$6.3	$0.0	($6.3)	$0.0	$37.4	$2.8	($34.7)	$0.0	($40.9)
INC	$0.0	$8.1	$0.0	($8.1)	$0.0	($11.4)	$0.0	$11.4	$0.0	$3.3
Internal Bilateral	($122.1)	($122.5)	($0.4)	$0.0	($3.4)	($3.4)	($0.0)	$0.0	$0.0	$0.0
Up to Congestion	$0.0	$0.0	$62.8	$62.8	$0.0	$0.0	($48.8)	($48.8)	$0.0	$14.1
Wheel In	$0.0	$0.0	$0.0	$0.0	$0.0	$0.6	$0.2	($0.4)	$0.0	($0.4)
Wheel Out	$0.0	$0.0	$0.0	$0.0	$0.6	$0.0	$0.0	$0.6	$0.0	$0.6
Total	($111.4)	$556.8	$63.2	($605.0)	($14.5)	($17.8)	($40.9)	($37.5)	$0.0	($642.5)

Zonal Congestion

Zonal congestion is calculated on a constraint specific basis. Constraint based congestion includes all energy charges or credits incurred to serve zonal load. Constraint based congestion is the congestion paid by the 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 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 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, 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 six months of 2019. Table 11-15 shows the congestion costs by zone for the first six months of 2018.

Table 11-14 Day-ahead and balancing congestion by zone (Dollars (Millions)): January through June, 2019

Congestion Costs (Millions)									
	Day-Ahead				Balancing				
Control Zone	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total
AECO	$2.6	($2.0)	$0.5	$5.1	$0.0	$0.4	($0.3)	($0.7)	$4.4
AEP	$17.0	($27.0)	$4.0	$48.0	$0.1	$4.5	($4.8)	($9.2)	$38.8
APS	$9.7	($11.6)	$1.0	$22.2	$0.1	$1.7	($1.9)	($3.5)	$18.7
ATSI	$6.4	($13.1)	$1.4	$20.9	($0.0)	$2.1	($2.5)	($4.6)	$16.3
BGE	$4.5	($6.6)	$0.5	$11.6	($0.1)	$1.2	($1.3)	($2.6)	$9.0
ComEd	$7.4	($25.0)	$5.5	$37.9	$0.0	$3.0	($2.4)	($5.4)	$32.5
DAY	$1.9	($3.0)	$0.4	$5.4	$0.0	$0.6	($0.7)	($1.2)	$4.1
DEOK	$3.3	($4.4)	$0.7	$8.4	$0.0	$0.9	($1.0)	($1.9)	$6.5
DLCO	$1.0	($1.8)	$0.2	$3.0	$0.0	$0.4	($0.5)	($0.9)	$2.1
Dominion	$12.5	($21.6)	$1.8	$35.8	$0.3	$3.6	($3.8)	($7.2)	$28.6
DPL	$6.4	($5.2)	$1.2	$12.8	($0.1)	$0.9	($0.8)	($1.8)	$11.0
EKPC	$1.5	($2.5)	$0.3	$4.3	$0.0	$0.5	($0.5)	($0.9)	$3.3
EXT	$0.2	($0.0)	$0.1	$0.3	($0.2)	$0.2	($1.1)	($1.6)	($1.3)
JCPL	$2.5	($7.4)	$0.5	$10.4	$0.1	$0.8	($0.8)	($1.6)	$8.8
Met-Ed	$2.6	($4.6)	$0.3	$7.5	($0.1)	$0.7	($0.7)	($1.5)	$6.0
OVEC	($0.0)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.1	$0.1	$0.1
PECO	$2.7	($12.8)	$0.8	$16.3	$0.1	$1.6	($1.5)	($2.9)	$13.4
PENELEC	$4.4	($4.6)	$0.5	$9.5	($0.1)	$0.7	($0.6)	($1.4)	$8.1
Pepco	$3.9	($5.9)	$0.5	$10.3	$0.1	$1.0	($1.1)	($2.1)	$8.2
PPL	$5.3	($13.8)	$1.5	$20.6	$0.1	$1.4	($1.5)	($2.9)	$17.7
PSEG	$4.5	($14.8)	$1.0	$20.3	($0.0)	$1.7	($1.5)	($3.2)	$17.1
RECO	$0.2	($0.5)	$0.1	$0.8	($0.0)	$0.0	($0.3)	($0.4)	$0.5
Total	$100.4	($188.3)	$22.9	$311.5	$0.2	$28.0	($29.7)	($57.4)	$254.1

Table 11-15 Day-ahead and balancing congestion by zone (Dollars (Millions)): January through June, 2018

Congestion Costs (Millions)									
	Day-Ahead				Balancing				
Control Zone	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total
AECO	$1.9	($9.1)	($0.5)	$10.6	$0.2	$0.5	$0.1	($0.2)	$10.4
AEP	$47.5	($121.6)	($5.4)	$163.7	$2.1	$6.9	$1.2	($3.5)	$160.2
APS	$14.0	($40.6)	($2.6)	$52.0	$1.0	$2.3	$0.8	($0.6)	$51.4
ATSI	$15.1	($53.6)	($3.1)	$65.7	$1.0	$2.4	$0.1	($1.3)	$64.3
BGE	$10.9	($26.0)	($2.0)	$35.0	$0.7	$1.7	$0.7	($0.4)	$34.6
ComEd	$3.9	($106.9)	($1.9)	$108.9	$1.6	$5.6	$0.6	($3.3)	$105.5
DAY	$3.6	($16.3)	($0.9)	$19.0	$0.3	$0.7	$0.1	($0.3)	$18.7
DEOK	$4.7	($30.7)	($1.3)	$34.1	$0.5	$1.0	$0.2	($0.3)	$33.7
DLCO	$2.2	($9.6)	($0.6)	$11.2	$0.3	$0.5	($0.0)	($0.3)	$10.9
Dominion	$40.3	($81.2)	($6.1)	$115.4	$2.9	$6.4	$2.6	($0.9)	$114.5
DPL	$19.7	($19.5)	($0.0)	$39.1	$0.0	$0.9	($0.3)	($1.1)	$38.0
EKPC	$3.8	($14.7)	($1.0)	$17.6	$0.4	$0.7	$0.3	$0.0	$17.6
EXT	$0.1	($0.4)	$0.5	$1.0	$0.0	$5.7	$0.9	($4.7)	($3.8)
JCPL	$4.6	($23.1)	($1.4)	$26.3	$0.4	$1.0	$0.3	($0.3)	$26.0
Met-Ed	$3.3	($19.8)	($1.1)	$22.0	$0.3	$1.3	$0.3	($0.7)	$21.3
PECO	$7.2	($39.2)	($2.9)	$43.4	$0.7	$1.9	$0.7	($0.5)	$42.9
PENELEC	$0.3	($22.0)	($1.3)	$20.9	$0.2	$0.8	$0.3	($0.3)	$20.6
Pepco	$12.0	($22.7)	($1.9)	$32.8	$0.6	$1.5	$0.7	($0.2)	$32.5
PPL	$9.1	($42.7)	($4.0)	$47.8	$0.8	$1.9	$1.1	($0.0)	$47.8
PSEG	$7.4	($44.1)	($2.7)	$48.8	$0.7	$2.0	$0.5	($0.8)	$48.0
RECO	$0.3	($1.2)	($0.1)	$1.4	$0.0	$0.1	($0.0)	($0.1)	$1.4
Total	$211.8	($745.0)	($40.3)	$916.5	$14.7	$45.8	$11.2	($19.9)	$896.6

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 six months of 2019.

Table 11-16 Constraint based total day-ahead and total balancing congestion assigned by zone and special case logic (Dollars (Millions)): January through June, 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	$5.1	$5.1	($0.0)	$0.0	$0.0	$0.0	($0.0)	($0.7)	($0.7)	$4.4
AEP	$0.0	($0.0)	$0.0	$1.2	($0.0)	$46.9	$48.0	($0.0)	($0.3)	$0.0	$0.0	($0.1)	($8.8)	($9.2)	$38.8
APS	$0.0	($0.0)	$0.0	$0.0	($0.0)	$22.3	$22.2	$0.0	($0.0)	$0.0	($0.0)	$0.0	($3.5)	($3.5)	$18.7
ATSI	$0.0	$0.0	$0.0	$0.0	$0.0	$20.9	$20.9	$0.0	($0.2)	$0.0	$0.0	$0.0	($4.4)	($4.6)	$16.3
BGE	$0.0	($0.0)	$0.0	$0.1	$0.0	$11.5	$11.6	($0.0)	$0.0	$0.0	$0.0	($0.0)	($2.6)	($2.6)	$9.0
ComEd	$0.0	($0.0)	$0.0	$1.3	($0.0)	$36.6	$37.9	$0.0	($0.1)	$0.0	($0.0)	($0.0)	($5.2)	($5.4)	$32.5
DAY	$0.0	$0.0	$0.0	$0.0	$0.0	$5.3	$5.4	$0.0	($0.1)	$0.0	$0.0	$0.0	($1.2)	($1.2)	$4.1
DEOK	$0.0	$0.0	$0.0	$0.0	$0.0	$8.4	$8.4	$0.0	($0.1)	$0.0	($0.0)	($0.0)	($1.9)	($1.9)	$6.5
DLCO	$0.0	($0.0)	$0.0	$0.0	$0.0	$3.0	$3.0	$0.0	($0.0)	$0.0	$0.0	$0.0	($0.9)	($0.9)	$2.1
Dominion	$0.0	$0.0	$0.0	$0.0	($0.0)	$35.8	$35.8	$0.0	$0.0	$0.0	($0.0)	($0.0)	($7.2)	($7.2)	$28.6
DPL	$0.0	($0.0)	$0.0	$0.0	$0.0	$12.8	$12.8	($0.0)	$0.0	$0.0	$0.0	($0.1)	($1.8)	($1.8)	$11.0
EKPC	$0.0	$0.0	$0.0	$0.0	($0.0)	$4.3	$4.3	$0.0	($0.0)	$0.0	$0.0	($0.0)	($0.9)	($0.9)	$3.3
EXT	$0.0	($0.1)	$0.0	$0.2	$0.1	$0.0	$0.3	($0.0)	($1.4)	$0.0	$0.0	($0.2)	$0.0	($1.6)	($1.3)
JCPL	($0.0)	($0.0)	$0.0	$0.0	$0.0	$10.4	$10.4	$0.0	($0.1)	$0.0	$0.0	($0.0)	($1.5)	($1.6)	$8.8
Met-Ed	$0.0	$0.0	$0.0	$0.2	($0.0)	$7.3	$7.5	$0.0	$0.0	$0.0	($0.1)	$0.0	($1.4)	($1.5)	$6.0
OVEC	$0.0	($0.0)	$0.0	$0.1	($0.0)	$0.0	$0.0	$0.0	$0.1	$0.0	$0.0	$0.0	($0.0)	$0.1	$0.1
PECO	($0.0)	$0.0	$0.0	$0.0	($0.0)	$16.2	$16.3	($0.0)	($0.1)	$0.0	($0.0)	$0.0	($2.8)	($2.9)	$13.4
PENELEC	$0.0	($0.1)	$0.0	$0.2	($0.0)	$9.4	$9.5	$0.0	($0.0)	$0.0	($0.1)	$0.0	($1.4)	($1.4)	$8.1
Pepco	$0.0	($0.0)	$0.0	($0.0)	$0.0	$10.3	$10.3	$0.0	($0.0)	$0.0	$0.0	$0.0	($2.1)	($2.1)	$8.2
PPL	$0.0	($0.0)	$0.0	$0.1	($0.0)	$20.5	$20.6	($0.0)	($0.1)	$0.0	$0.0	$0.0	($2.8)	($2.9)	$17.7
PSEG	($0.0)	$0.1	$0.0	$0.0	($0.0)	$20.3	$20.3	$0.0	($0.0)	$0.0	$0.0	$0.0	($3.2)	($3.2)	$17.1
RECO	$0.0	$0.0	$0.0	$0.0	$0.0	$0.8	$0.8	$0.0	($0.3)	$0.0	$0.0	($0.0)	($0.1)	($0.4)	$0.5
Total	$0.0	($0.2)	$0.0	$3.4	$0.1	$308.2	$311.5	($0.0)	($2.6)	$0.0	($0.2)	($0.3)	($54.3)	($57.4)	$254.1

Table 11-17 Constraint Based total day-ahead and total balancing congestion assigned by zone and special case logic (Dollars (Millions)): January through June, 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	$10.1	$10.6	$0.0	($0.0)	$0.0	$0.0	($0.0)	($0.1)	($0.2)	$10.4
AEP	$0.3	$0.0	$0.0	$0.5	$0.0	$162.8	$163.7	$0.0	($2.1)	$0.0	$0.0	$0.0	($1.4)	($3.5)	$160.2
APS	$0.0	($0.3)	$0.0	$0.0	($0.0)	$52.3	$52.0	$0.0	($0.1)	$0.0	$0.0	($0.0)	($0.5)	($0.6)	$51.4
ATSI	$0.0	$0.5	$0.0	$0.2	$0.0	$65.0	$65.7	$0.0	($0.1)	$0.0	$0.0	($0.0)	($1.2)	($1.3)	$64.3
BGE	$0.0	$0.0	$0.0	$0.0	$0.0	$35.0	$35.0	$0.0	($0.1)	$0.0	($0.0)	($0.0)	($0.3)	($0.4)	$34.6
ComEd	$1.4	($1.0)	$0.0	$4.1	($0.0)	$104.3	$108.9	($0.0)	($1.9)	$0.0	$0.3	$0.3	($2.1)	($3.3)	$105.5
DAY	$0.0	$0.1	$0.0	$0.0	$0.0	$18.9	$19.0	$0.0	($0.2)	$0.0	$0.0	$0.2	($0.3)	($0.3)	$18.7
DEOK	$0.2	$0.2	$0.0	$2.0	$0.0	$31.8	$34.1	$0.0	$0.1	$0.0	$0.0	$0.2	($0.6)	($0.3)	$33.7
DLCO	$0.0	$0.0	$0.0	$0.0	($0.0)	$11.2	$11.2	$0.0	($0.0)	$0.0	$0.0	$0.0	($0.2)	($0.3)	$10.9
Dominion	$0.0	$0.2	$0.0	$0.2	$0.0	$115.0	$115.4	$0.0	($0.0)	$0.0	($0.0)	$0.0	($0.9)	($0.9)	$114.5
DPL	$0.0	$0.6	$0.0	$0.3	$0.0	$38.2	$39.1	$0.0	($0.1)	$0.0	$0.0	($0.0)	($1.0)	($1.1)	$38.0
EKPC	$0.0	$0.0	$0.0	$0.0	$0.0	$17.6	$17.6	$0.0	($0.0)	$0.0	$0.0	$0.1	($0.1)	$0.0	$17.6
EXT	$0.0	$0.1	$0.0	$0.5	$0.3	$0.0	$1.0	$0.0	($3.8)	$0.0	$0.0	($1.0)	$0.0	($4.7)	($3.8)
JCPL	$0.0	$0.7	$0.0	($0.0)	$0.0	$25.5	$26.3	$0.0	$0.0	$0.0	$0.0	$0.0	($0.3)	($0.3)	$26.0
Met-Ed	$0.0	$0.2	$0.0	$3.0	$0.0	$18.8	$22.0	$0.0	($0.0)	$0.0	($0.5)	$0.0	($0.1)	($0.7)	$21.3
PECO	$0.0	($0.7)	$0.0	$0.4	($0.0)	$43.7	$43.4	$0.0	($0.1)	$0.0	$0.0	$0.0	($0.4)	($0.5)	$42.9
PENELEC	$0.3	$0.1	$0.0	$0.7	($0.0)	$19.7	$20.9	$0.0	$0.1	$0.0	($0.0)	$0.0	($0.5)	($0.3)	$20.6
Pepco	$0.0	$0.1	$0.0	$0.0	$0.0	$32.6	$32.8	$0.0	$0.1	$0.0	$0.0	($0.0)	($0.3)	($0.2)	$32.5
PPL	($0.0)	($2.0)	$0.0	$0.8	($0.0)	$49.0	$47.8	$0.0	$0.1	$0.0	$0.0	$0.0	($0.1)	($0.0)	$47.8
PSEG	$0.0	($0.3)	$0.0	$0.7	($0.0)	$48.4	$48.8	$0.0	($0.0)	$0.0	$0.0	($0.1)	($0.7)	($0.8)	$48.0
RECO	$0.0	$0.0	$0.0	$0.0	$0.0	$1.4	$1.4	$0.0	($0.0)	$0.0	$0.0	$0.0	($0.0)	($0.1)	$1.4
Total	$2.3	($1.2)	$0.0	$13.9	$0.3	$901.2	$916.5	($0.0)	($8.2)	$0.0	($0.2)	($0.3)	($11.2)	($19.9)	$896.6

Monthly Congestion

Table 11-18 shows day-ahead, balancing and inadvertent congestion costs by month for 2018 and the first six months of 2019.

Table 11-18 Monthly PJM congestion costs by market (Dollars (Millions)): January 2018 through June 2019

	Congestion Costs (Millions)							
	2018				2019			
	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand 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				
Aug	$69.2	($3.5)	$0.0	$65.7				
Sep	$95.2	($6.3)	($0.0)	$88.9				
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	$311.5	($57.4)	$0.0	$254.1

Figure 11-2 shows PJM monthly total congestion cost for January 1, 2008 through June 30, 2019.

Figure 11-2 PJM monthly total congestion cost (Dollars (Millions)): January 2008 through June 2019

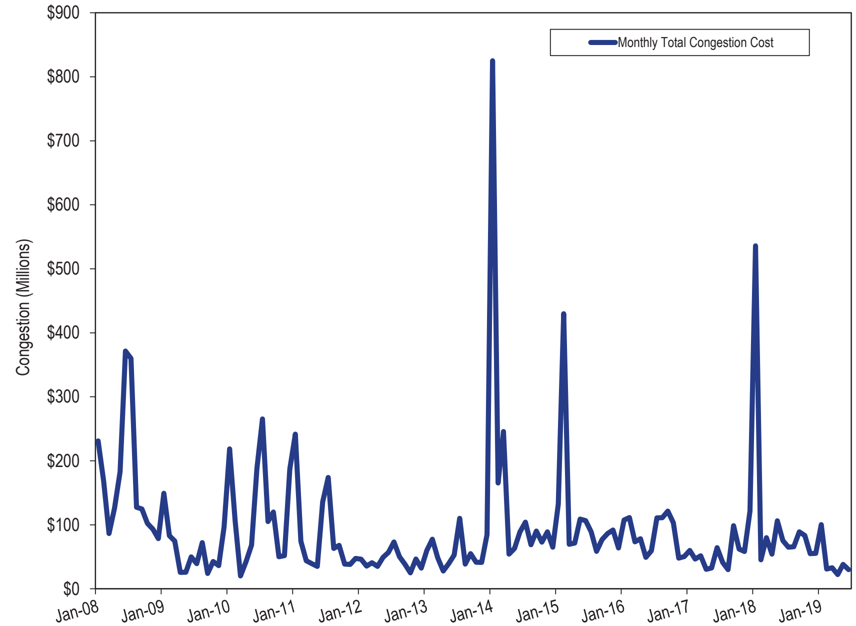


Table 11-19 shows monthly total congestion credits and charges for each virtual transaction type in 2018 and the first six months of 2019. Virtual transaction congestion charges, when positive, are the total congestion charges to the virtual transactions and when negative, are the total congestion credits to the virtual transactions. The negative totals in Table 11-19 show that virtuals were paid, in net, congestion credits in the first six months of 2019 and in the first six months of 2018. More than half the total payment to virtuals went to UTCs in the first six months of 2018 and in the first six months of 2019.

Table 11-19 Monthly PJM congestion charges by virtual transaction type and by market (Dollars (Millions)): January 2018 through June 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)
	Total	$6.7	($7.5)	($0.8)	$8.3	($12.7)	($4.4)	$22.7	($29.9)	($7.2)	($12.5)

Congested Facilities

A congestion event exists when a unit or units must be dispatched out of merit order to control for the potential impact of a contingency on a monitored facility or to control an actual overload. A congestion event hour exists when a specific facility is constrained for one or more five-minute intervals within an hour. A congestion event hour differs from a constrained hour, which is any hour during which one or more facilities are congested. Thus, if two facilities are constrained during an hour, the result is two congestion event hours and one constrained hour. Constraints are often simultaneous, so the number of congestion event hours usually exceeds the number of constrained hours and the number of congestion event hours usually exceeds the number of hours in a year.

In order to have a consistent metric for real-time and day-ahead congestion frequency, real-time congestion frequency is measured using the convention that an hour is constrained if any of its component five-minute intervals is constrained. This is consistent with the way in which PJM reports real-time congestion. In the first six months of 2019, there were 51,990 day-ahead, congestion event hours compared to 81,854 day-ahead congestion event hours in the first six months of 2018. Of the day-ahead congestion event hours in the first six months of 2019, only 3,189 (6.1 percent) were also constrained in the Real-Time Energy Market. In the first six months of 2019, there were 8,287 real-time, congestion event hours compared to 12,867 real-time, congestion event hours in the first six months of 2018. Of the real-time congestion event hours in the first six months of 2019, 3,263 (39.4 percent) were also constrained in the Day-Ahead Energy Market.

The top five constraints by congestion costs contributed $88.6 million, or 34.9 percent, of the total PJM congestion costs in the first six months of 2019. The top five constraints were the Conastone - Peach Bottom Line, the Siegfried Transformer, the AP South Interface, the East Interface, and the CPL - DOM Interface.

The change in the location of the top 10 constraints between the first six months of 2018 and the first six 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.[20]

Real-time, congestion event hours decreased on transformers, flowgates, interfaces and lines in the first six months of 2019.

20 162 FERC ¶ 61,139.

Day-ahead congestion costs decreased on all types of facilities in the first six months of 2019 compared to the first six months of 2018. Day-ahead negative generation credits decreased on all types of facilities in the first six months of 2019 compared to the first six months of 2018.

Balancing congestion costs decreased on all types of facilities except lines in the first six months of 2019 compared to the first six months of 2018 (Table 11-21). Table 11-20 provides congestion event hour subtotals and congestion cost subtotals comparing the first six months of 2019 results by facility type: line, transformer, interface, flowgate and unclassified facilities.[21] [22]

Table 11-20 Congestion summary (By facility type): January through June, 2019

	Congestion Costs (Millions)										
	Day-Ahead				Balancing					Event Hours	
Type	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day-Ahead	Real-Time
Flowgate	($7.9)	($41.0)	$3.1	$36.3	$0.7	$2.3	($20.2)	($21.8)	$14.5	5,799	2,373
Interface	$7.3	($32.8)	$0.1	$40.2	$1.1	$4.1	$0.7	($2.3)	$37.9	639	130
Line	$81.7	($70.9)	$15.3	$167.9	($0.8)	$12.5	($7.1)	($20.3)	$147.5	32,473	4,533
Transformer	$15.2	($30.1)	$3.0	$48.4	($1.8)	$5.8	($1.7)	($9.3)	$39.1	10,182	656
Other	$4.0	($13.4)	$1.2	$18.7	$0.8	$3.2	($1.0)	($3.4)	$15.3	2,897	595
Unclassified	$0.0	($0.0)	$0.0	$0.1	$0.1	$0.1	($0.3)	($0.3)	($0.2)	NA	NA
Total	$100.4	($188.3)	$22.9	$311.5	$0.2	$28.0	($29.7)	($57.4)	$254.1	51,990	8,287

Table 11-21 Congestion summary (By facility type): January through June, 2018

	Congestion Costs (Millions)										
	Day-Ahead				Balancing					Event Hours	
Type	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day-Ahead	Real-Time
Flowgate	($39.6)	($245.6)	($37.6)	$168.4	($0.5)	$4.6	$6.2	$1.1	$169.4	12,857	3,445
Interface	$60.1	($161.4)	($13.7)	$207.8	$15.2	$22.8	$11.1	$3.5	$211.3	1,951	373
Line	$126.5	($245.8)	$8.8	$381.1	($3.4)	$18.3	($4.7)	($26.4)	$354.8	43,813	7,631
Transformer	$52.0	($87.9)	$1.1	$141.0	($0.5)	$0.8	$3.5	$2.2	$143.2	20,213	1,009
Other	$12.7	($4.2)	$1.0	$17.9	$3.0	($1.6)	($4.7)	($0.0)	$17.9	3,020	409
Unclassified	$0.1	($0.1)	$0.1	$0.3	$0.9	$0.9	($0.3)	($0.3)	$0.0	NA	NA
Total	$211.8	($745.0)	($40.3)	$916.5	$14.7	$45.8	$11.2	($19.9)	$896.6	81,854	12,867

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 six months of 2019, there were 51,990 congestion event hours in the Day-Ahead Energy Market. Of those day-ahead congestion event hours, only 3,189 (6.1

21 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.
22 The term flowgate refers to MISO reciprocal coordinated flowgates and NYISO M2M flowgates.

percent) were also constrained in the Real-Time Energy Market. In the first six months of 2018, of the 81,854 day-ahead congestion event hours, only 6,423 (7.8 percent) were binding in the Real-Time Energy Market.[23]

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 six months of 2019, of the 8,287 congestion event hours in the Real-Time Energy Market, 3,263 (39.4 percent) were also constrained in the Day-Ahead Energy Market. In the first six months of 2018, of the 12,867 real-time congestion event hours, 6,482 (50.4 percent) were also in the Day-Ahead Energy Market.

Table 11-22 Congestion event hours (day-ahead against real-time): January through June, 2018 and 2019

	Congestion Event Hours					
	2018 (Jan - Jun)			2019 (Jan - Jun)		
Type	Day-Ahead Constrained	Corresponding Real-Time Constrained	Percent	Day-Ahead Constrained	Corresponding Real-Time Constrained	Percent
Flowgate	12,857	1,538	12.0%	5,799	451	7.8%
Interface	1,951	238	12.2%	639	27	4.2%
Line	43,813	4,014	9.2%	32,473	2,136	6.6%
Transformer	20,213	405	2.0%	10,182	343	3.4%
Other	3,020	228	7.5%	2,897	232	8.0%
Total	81,854	6,423	7.8%	51,990	3,189	6.1%

Table 11-23 Congestion event hours (real-time against day-ahead): January through June, 2018 and 2019

	Congestion Event Hours					
	2018 (Jan - Jun)			2019 (Jan - Jun)		
Type	Real-Time Constrained	Corresponding Day-Ahead Constrained	Percent	Real-Time Constrained	Corresponding Day-Ahead Constrained	Percent
Flowgate	3,445	1,538	44.6%	2,373	450	19.0%
Interface	373	263	70.5%	130	31	23.8%
Line	7,631	4,047	53.0%	4,533	2,192	48.4%
Transformer	1,009	406	40.2%	656	344	52.4%
Other	409	228	55.7%	595	246	41.3%
Total	12,867	6,482	50.4%	8,287	3,263	39.4%

23 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 11-24 shows congestion costs by facility voltage class for the first six months of 2019. Congestion costs in the first six months of 2019 decreased for all facilities except 69 kV facilities compared to the first six months of 2018.

Table 11-24 Congestion summary (By facility voltage): January through June, 2019

	Congestion Costs (Millions)										
	Day-Ahead				Balancing					Event Hours	
Voltage (kV)	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day-Ahead	Real-Time
765	($0.1)	($0.7)	$0.6	$1.2	($0.1)	$0.2	($0.2)	($0.5)	$0.7	171	46
500	$43.1	($38.7)	$0.1	$81.9	$2.0	$6.4	($1.2)	($5.7)	$76.2	2,907	1,450
345	($2.7)	($32.8)	$5.5	$35.6	$0.6	$0.8	($4.6)	($4.8)	$30.8	5,949	561
230	$34.0	($50.1)	$3.5	$87.5	($2.2)	$10.1	($4.1)	($16.4)	$71.1	7,067	1,980
212	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	114	0
161	($0.2)	($4.6)	($0.1)	$4.3	($0.2)	$0.1	($0.3)	($0.6)	$3.7	1,041	107
138	$11.0	($43.8)	$9.8	$64.5	$0.1	$3.1	($17.9)	($20.8)	$43.7	15,888	2,988
115	$5.7	($12.3)	$0.5	$18.5	($0.5)	$5.9	($0.7)	($7.1)	$11.3	5,059	725
69	$9.2	($5.4)	$2.9	$17.6	$0.4	$1.2	($0.3)	($1.1)	$16.5	12,583	430
35	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	17	0
34	$0.3	$0.1	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	620	0
13	$0.1	$0.0	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	490	0
12	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	84	0
Unclassified	$0.0	($0.0)	$0.0	$0.1	$0.1	$0.1	($0.3)	($0.3)	($0.2)	NA	NA
Total	$100.4	($188.3)	$22.9	$311.5	$0.2	$28.0	($29.7)	($57.4)	$254.1	51,990	8,287

Table 11-25 Congestion summary (By facility voltage): January through June, 2018

	Congestion Costs (Millions)										
	Day-Ahead				Balancing					Event Hours	
Voltage (kV)	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day-Ahead	Real-Time
765	$0.6	($1.3)	$0.1	$2.1	$0.7	$0.3	($0.0)	$0.4	$2.4	94	21
500	$65.3	($168.7)	($13.3)	$220.7	$14.5	$19.8	$11.9	$6.6	$227.2	2,714	556
345	$23.3	($191.0)	($5.2)	$209.1	($1.0)	($3.3)	($2.3)	$0.0	$209.1	14,998	1,540
230	$127.4	($26.1)	$2.9	$156.4	$0.0	$5.7	$0.2	($5.5)	$150.9	14,217	3,639
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	215	49
138	($16.0)	($310.3)	($22.8)	$271.5	($0.2)	$19.6	$2.3	($17.6)	$253.9	31,554	5,484
115	$1.6	($40.7)	($3.7)	$38.6	$0.1	$3.9	($0.2)	($4.0)	$34.6	8,413	1,217
69	$8.6	($2.1)	$1.5	$12.1	($0.4)	($0.6)	($0.7)	($0.5)	$11.6	7,013	358
34	$0.1	$0.0	$0.3	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	1,768	3
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	($0.0)	($0.1)	($0.0)	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	NA	NA
Total	$211.6	($745.0)	($40.4)	$916.3	$13.8	$44.9	$11.5	($19.6)	$896.6	81,854	12,867

Constraint Duration

Table 11-26 lists the constraints for January through June, 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 six months of 2018 to the first six 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 six 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 six months of 2018 to the first six months of 2019.

Table 11-26 Top 25 constraints with frequent occurrence: January through June, 2018 and 2019

			Event Hours						Percent of Annual Hours					
			Day-Ahead			Real-Time			Day-Ahead			Real-Time		
			(Jan - Jun)			(Jan - Jun)			(Jan - Jun)			(Jan - Jun)		
No.	Constraint	Type	2018	2019	Change	2018	2019	Change	2018	2019	Change	2018	2019	Change
1	Conastone - Peach Bottom	Line	352	2,159	1,807	125	1,188	1,063	8%	50%	42%	3%	27%	24%
2	Monroe - Vineland	Line	545	2,641	2,096	29	78	49	13%	61%	48%	1%	2%	1%
3	Berwick - Koonsville	Line	358	2,666	2,308	0	2	2	8%	61%	53%	0%	0%	0%
4	Easton - Emuni	Line	1,874	1,814	(60)	2	9	7	43%	42%	(1%)	0%	0%	0%
5	Face Rock	Other	402	1,653	1,251	0	0	0	9%	38%	29%	0%	0%	0%
6	Marquis - Dept of Energy	Line	118	1,494	1,376	0	0	0	3%	34%	32%	0%	0%	0%
7	Gardners - Texas Eastern	Line	1,829	1,028	(801)	292	92	(200)	42%	24%	(18%)	7%	2%	(5%)
8	Munster	Flowgate	0	709	709	0	169	169	0%	16%	16%	0%	4%	4%
9	Siegfried	Trf	2	560	558	9	310	301	0%	13%	13%	0%	7%	7%
10	Marblehead	Flowgate	202	551	349	335	260	(75)	5%	13%	8%	8%	6%	(2%)
11	Graceton - Safe Harbor	Line	2,889	605	(2,284)	1,755	205	(1,550)	67%	14%	(53%)	40%	5%	(36%)
12	Lenox - North Meshoppen	Line	27	425	398	1	350	349	1%	10%	9%	0%	8%	8%
13	East Towanda - Hillside	Line	199	454	255	2	290	288	5%	10%	6%	0%	7%	7%
14	Goodland - Reynolds	Flowgate	36	103	67	8	608	600	1%	2%	2%	0%	14%	14%
15	Palisades - Argenta	Flowgate	0	618	618	0	69	69	0%	14%	14%	0%	2%	2%
16	New Castle	Trf	195	686	491	0	0	0	4%	16%	11%	0%	0%	0%
17	Roxana - Praxair	Flowgate	497	512	15	263	131	(132)	11%	12%	0%	6%	3%	(3%)
18	Hazard	Trf	140	624	484	17	0	(17)	3%	14%	11%	0%	0%	(0%)
19	Tristate	Trf	0	597	597	0	23	23	0%	14%	14%	0%	1%	1%
20	New Carlisle - Olive	Line	109	579	470	0	0	0	3%	13%	11%	0%	0%	0%
21	Preston - Tanyard	Line	244	579	335	4	0	(4)	6%	13%	8%	0%	0%	(0%)
22	Tanners Creek - Miami Fort	Flowgate	958	562	(396)	0	0	0	22%	13%	(9%)	0%	0%	0%
23	Vermilion - Tilton	Flowgate	148	546	398	0	0	0	3%	13%	9%	0%	0%	0%
24	Mountain	Trf	379	499	120	0	0	0	9%	11%	3%	0%	0%	0%
25	Emilie - Falls	Line	751	393	(358)	149	95	(54)	17%	9%	(8%)	3%	2%	(1%)

Table 11-27 Top 25 constraints with largest year to year change in occurrence: January through June, 2018 and 2019

			Event Hours						Percent of Annual Hours					
			Day-Ahead			Real-Time			Day-Ahead			Real-Time		
			(Jan - Jun)			(Jan - Jun)			(Jan - Jun)			(Jan - Jun)		
No.	Constraint	Type	2018	2019	Change	2018	2019	Change	2018	2019	Change	2018	2019	Change
1	Graceton - Safe Harbor	Line	2,889	605	(2,284)	1,755	205	(1,550)	67%	14%	(53%)	40%	5%	(36%)
2	Conastone - Peach Bottom	Line	352	2,159	1,807	125	1,188	1,063	8%	50%	42%	3%	27%	24%
3	Berwick - Koonsville	Line	358	2,666	2,308	0	2	2	8%	61%	53%	0%	0%	0%
4	Monroe - Vineland	Line	545	2,641	2,096	29	78	49	13%	61%	48%	1%	2%	1%
5	Quad Cities	Trf	2,026	312	(1,714)	0	0	0	47%	7%	(39%)	0%	0%	0%
6	Lakeview - Greenfield	Line	1,303	36	(1,267)	321	13	(308)	30%	1%	(29%)	7%	0%	(7%)
7	Brokaw - Leroy	Flowgate	1,232	0	(1,232)	261	0	(261)	28%	0%	(28%)	6%	0%	(6%)
8	Marquis - Dept of Energy	Line	118	1,494	1,376	0	0	0	3%	34%	32%	0%	0%	0%
9	Olive	Other	1,327	0	(1,327)	0	0	0	31%	0%	(31%)	0%	0%	0%
10	Face Rock	Other	402	1,653	1,251	0	0	0	9%	38%	29%	0%	0%	0%
11	Newton	Flowgate	858	0	(858)	367	0	(367)	20%	0%	(20%)	8%	0%	(8%)
12	Flint Lake - Luchtman Road	Flowgate	865	0	(865)	354	0	(354)	20%	0%	(20%)	8%	0%	(8%)
13	Zion	Line	1,193	0	(1,193)	0	0	0	27%	0%	(27%)	0%	0%	0%
14	Waukegan	Trf	1,083	19	(1,064)	0	0	0	25%	0%	(24%)	0%	0%	0%
15	Cedar Grove Sub - Roseland	Line	1,198	179	(1,019)	54	15	(39)	28%	4%	(23%)	1%	0%	(1%)
16	Gardners - Texas Eastern	Line	1,829	1,028	(801)	292	92	(200)	42%	24%	(18%)	7%	2%	(5%)
17	Pleasant Prairie - Zion	Flowgate	1,011	117	(894)	60	0	(60)	23%	3%	(21%)	1%	0%	(1%)
18	Canton - South Troy	Line	949	0	(949)	0	0	0	22%	0%	(22%)	0%	0%	0%
19	Person - Sedge Hill	Line	814	17	(797)	136	10	(126)	19%	0%	(18%)	3%	0%	(3%)
20	Monroe - Lallendorf	Flowgate	945	62	(883)	0	0	0	22%	1%	(20%)	0%	0%	0%
21	Munster	Flowgate	0	709	709	0	169	169	0%	16%	16%	0%	4%	4%
22	Siegfried	Trf	2	560	558	9	310	301	0%	13%	13%	0%	7%	7%
23	Lenox - North Meshoppen	Line	27	425	398	1	350	349	1%	10%	9%	0%	8%	8%
24	Halifax - Roanoke Rapids	Line	741	0	(741)	0	0	0	17%	0%	(17%)	0%	0%	0%
25	AEP - DOM	Int	604	23	(581)	150	0	(150)	14%	1%	(13%)	3%	0%	(3%)

Constraint Costs

Table 11-28 and Table 11-29 show the top constraints affecting congestion costs by facility for the first six months of 2019 and 2018. The Conastone - Peach Bottom Line was the largest contributor to congestion costs in the first six months of 2019, with $40.7 million in total congestion costs and 16.0 percent of the total PJM congestion costs in the first six months of 2019.

Table 11-28 Top 25 constraints affecting PJM congestion costs (By facility): January through June, 2019[24]

				Congestion Costs (Millions)									Percent of Total PJM Congestion Costs
				Day-Ahead				Balancing					
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	2019 (Jan - Jun)
1	Conastone - Peach Bottom	Line	500	$36.5	($4.0)	($0.1)	$40.3	$0.9	$2.0	$1.4	$0.4	$40.7	16.0%
2	Siegfried	Transformer	PPL	$6.8	($13.7)	$0.4	$20.9	($1.6)	$5.2	($0.1)	($6.8)	$14.1	5.5%
3	AP South	Interface	500	$8.3	($5.5)	($0.2)	$13.6	$0.2	$0.1	$0.1	$0.1	$13.8	5.4%
4	East	Interface	500	($5.9)	($20.2)	$0.1	$14.4	$0.9	$4.0	$0.9	($2.2)	$12.2	4.8%
5	CPL - DOM	Interface	500	$3.5	($4.2)	$0.1	$7.8	$0.0	$0.0	$0.0	$0.0	$7.8	3.1%
6	Face Rock	Other	PPL	$0.0	($8.0)	$0.7	$8.7	$0.9	$1.6	($0.2)	($0.9)	$7.8	3.1%
7	Palisades - Argenta	Flowgate	MISO	($0.3)	($7.3)	$0.6	$7.6	$0.1	($0.3)	($0.6)	($0.3)	$7.3	2.9%
8	Tanners Creek - Miami Fort	Flowgate	MISO	($2.3)	($8.9)	$0.3	$6.9	$0.0	$0.0	$0.0	$0.0	$6.9	2.7%
9	Conastone - Northwest	Line	BGE	$4.6	($1.8)	$0.4	$6.8	($0.0)	($0.1)	($0.3)	($0.2)	$6.7	2.6%
10	Pleasant View - Ashburn	Line	Dominion	$4.7	($1.2)	$0.3	$6.2	$0.4	$0.9	($0.2)	($0.7)	$5.5	2.2%
11	Graceton - Safe Harbor	Line	BGE	$5.4	$0.0	$0.1	$5.5	$0.2	$0.4	$0.1	($0.1)	$5.4	2.1%
12	Bagley - Graceton	Line	BGE	$3.4	($1.0)	$0.1	$4.5	$0.0	$0.1	($0.0)	($0.0)	$4.5	1.8%
13	Cedar Grove Sub - Roseland	Line	PSEG	($0.0)	($4.6)	($0.3)	$4.2	($0.0)	$0.1	$0.0	($0.1)	$4.1	1.6%
14	Gardners - Texas Eastern	Line	Met-Ed	($0.4)	($5.4)	$0.2	$5.3	($0.8)	$0.3	($0.3)	($1.5)	$3.8	1.5%
15	Cloverdale	Transformer	AEP	$1.5	($1.8)	$0.3	$3.6	$0.0	($0.2)	($0.1)	$0.1	$3.7	1.5%
16	Siegfried	Other	PPL	$0.0	($5.0)	$0.5	$5.6	($0.3)	$1.1	($0.6)	($2.0)	$3.5	1.4%
17	Blooming Grove - Paupack	Line	PPL	$1.2	($2.3)	($0.0)	$3.5	$0.0	$0.0	$0.0	$0.0	$3.5	1.4%
18	Nottingham	Other	PECO	$4.1	$0.6	($0.1)	$3.3	$0.0	$0.0	$0.0	$0.0	$3.3	1.3%
19	Munster	Flowgate	MISO	($0.1)	($2.0)	($0.3)	$1.6	$0.3	($0.2)	($5.1)	($4.6)	($3.0)	(1.2%)
20	Greentown	Flowgate	MISO	($0.1)	($0.8)	($0.0)	$0.6	($0.5)	$0.3	($2.8)	($3.6)	($3.0)	(1.2%)
21	Monroe - Vineland	Line	AECO	$3.3	$1.2	$0.5	$2.7	($0.1)	($0.0)	$0.0	($0.1)	$2.6	1.0%
22	Wescosville	Transformer	PPL	$1.8	($1.0)	($0.0)	$2.7	($0.1)	$0.1	$0.0	($0.2)	$2.5	1.0%
23	Hazard	Transformer	AEP	$0.3	($2.2)	$0.0	$2.5	$0.0	$0.0	$0.0	$0.0	$2.5	1.0%
24	Krendale - Shanorma	Line	APS	($2.1)	($4.3)	$0.3	$2.5	$0.0	$0.0	$0.0	$0.0	$2.5	1.0%
25	Volunteer - Phipps Bend	Flowgate	TVA	($0.2)	($0.9)	$0.0	$0.7	($0.1)	$0.3	($2.8)	($3.2)	($2.5)	(1.0%)
	Top 25 Total			$74.0	($104.4)	$3.8	$182.2	$0.5	$15.7	($10.7)	($25.9)	$156.3	61.5%
	All Other Constraints			$26.4	($83.8)	$19.1	$129.3	($0.3)	$12.3	($18.9)	($31.5)	$97.8	38.5%
	Total			$100.4	($188.3)	$22.9	$311.5	$0.2	$28.0	($29.7)	($57.4)	$254.1	100.0%

24 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 June, 2018[25]

				Congestion Costs (Millions)									Percent of Total PJM Congestion Costs
				Day-Ahead				Balancing					
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	2018 (Jan - Jun)
1	AEP - DOM	Interface	500	$54.5	($66.2)	($5.1)	$115.6	$13.4	$18.7	$9.0	$3.8	$119.4	13.3%
2	Cloverdale	Transformer	AEP	$46.0	($40.9)	($0.8)	$86.1	($1.6)	$0.6	$3.6	$1.4	$87.5	9.8%
3	Graceton - Safe Harbor	Line	BGE	$86.9	$29.2	$2.3	$60.1	($0.1)	$4.4	($1.5)	($5.9)	$54.1	6.0%
4	Tanners Creek - Miami Fort	Flowgate	MISO	($13.7)	($64.7)	($3.5)	$47.5	$0.0	$0.0	$0.0	$0.0	$47.5	5.3%
5	5004/5005 Interface	Interface	500	($15.4)	($54.3)	($4.4)	$34.6	$0.8	$1.7	$2.1	$1.1	$35.7	4.0%
6	Batesville - Hubble	Flowgate	MISO	($10.4)	($43.6)	($9.4)	$23.8	($0.5)	($2.1)	$0.3	$1.9	$25.8	2.9%
7	Lakeview - Greenfield	Line	ATSI	($19.5)	($55.4)	($1.6)	$34.3	($1.4)	$8.9	$0.5	($9.8)	$24.5	2.7%
8	Bedington - Black Oak	Interface	500	$9.3	($13.5)	($1.4)	$21.4	$0.6	$0.7	$0.6	$0.5	$21.8	2.4%
9	Capitol Hill - Chemical	Line	AEP	$11.9	($5.0)	$0.5	$17.4	$0.8	($0.8)	($0.1)	$1.5	$18.9	2.1%
10	AP South	Interface	500	$11.2	($7.9)	($1.4)	$17.7	$0.0	$0.1	($0.0)	($0.1)	$17.6	2.0%
11	Person - Sedge Hill	Line	Dominion	$16.9	$2.3	$1.7	$16.3	($0.2)	($0.9)	($1.0)	($0.4)	$15.9	1.8%
12	Gardners - Texas Eastern	Line	Met-Ed	($5.7)	($20.1)	($0.1)	$14.4	$0.2	($0.1)	$0.4	$0.8	$15.1	1.7%
13	Northport - Albion	Flowgate	MISO	($2.3)	($18.4)	($3.8)	$12.3	($0.2)	($1.1)	$1.3	$2.2	$14.5	1.6%
14	Brokaw - Leroy	Flowgate	MISO	$0.8	($12.3)	($4.4)	$8.6	$0.5	($1.3)	$3.0	$4.8	$13.5	1.5%
15	Nottingham	Other	PECO	$12.3	$0.3	$0.3	$12.3	$0.0	$0.0	$0.0	$0.0	$12.3	1.4%
16	Tanners Creek - Miami Fort	Line	AEP	($2.2)	($10.0)	($0.4)	$7.4	($0.8)	($1.8)	$2.9	$3.9	$11.3	1.3%
17	Monroe - Lallendorf	Flowgate	MISO	($1.4)	($11.7)	($0.4)	$9.9	$0.0	$0.0	$0.0	$0.0	$9.9	1.1%
18	Maple - Jackson	Line	ATSI	($8.0)	($17.6)	$1.2	$10.8	$0.1	$0.5	($0.9)	($1.2)	$9.5	1.1%
19	Conastone - Northwest	Line	BGE	$8.0	($1.0)	($0.7)	$8.3	($0.8)	($0.4)	$1.4	$0.9	$9.2	1.0%
20	Flint Lake - Luchtman Road	Flowgate	MISO	$0.3	($10.4)	($4.9)	$5.7	($0.2)	($1.4)	$1.8	$3.1	$8.7	1.0%
21	Conastone - Peach Bottom	Line	500	$7.9	$0.3	$0.1	$7.8	$0.2	$0.1	($0.2)	($0.2)	$7.6	0.9%
22	Olive	Flowgate	MISO	$0.2	($6.6)	$0.3	$7.0	$0.0	$0.0	$0.0	$0.0	$7.0	0.8%
23	Cedar Grove Sub - Roseland	Line	PSEG	($1.2)	($7.3)	$0.7	$6.8	($0.1)	$0.3	$0.4	$0.0	$6.8	0.8%
24	Emilie - Falls	Line	PECO	$1.5	($4.4)	$0.1	$6.0	$0.3	$0.4	$0.4	$0.4	$6.4	0.7%
25	Pleasant View - Ashburn	Line	Dominion	$5.3	($1.4)	($0.4)	$6.3	$0.0	$0.0	$0.0	$0.0	$6.3	0.7%
	Top 25 Total			$193.4	($440.4)	($35.3)	$598.5	$11.1	$26.6	$24.0	$8.6	$607.1	67.7%
	All Other Constraints			$18.4	($304.6)	($5.0)	$318.0	$3.5	$19.2	($12.8)	($28.4)	$289.5	32.3%
	Total			$211.8	($745.0)	($40.3)	$916.5	$14.7	$45.8	$11.2	($19.9)	$896.6	100.0%

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 six months of 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 six 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 six months of 2019.

25 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 Location of the top 10 constraints by PJM total congestion costs: January through June, 2019

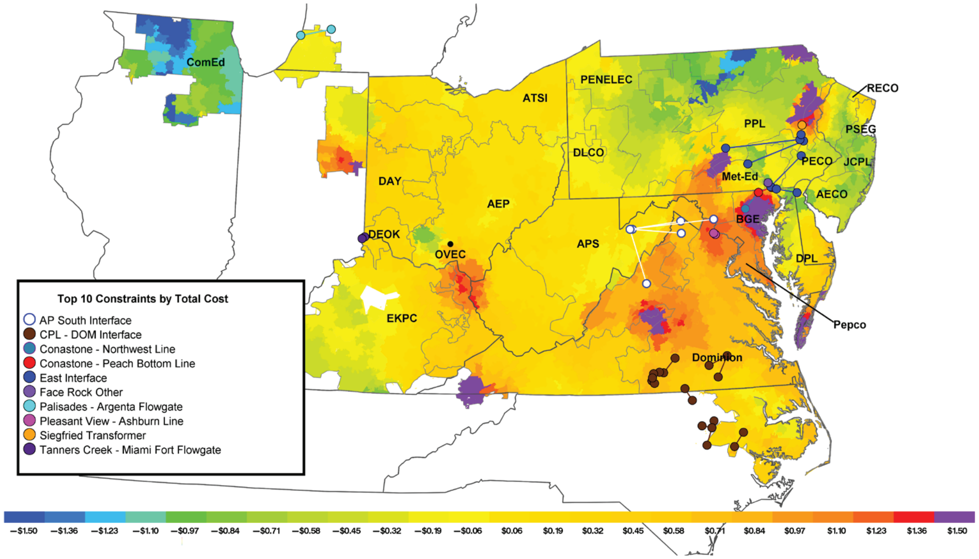


Figure 11-4 Location of the top 10 constraints by PJM balancing congestion costs: January through June, 2019

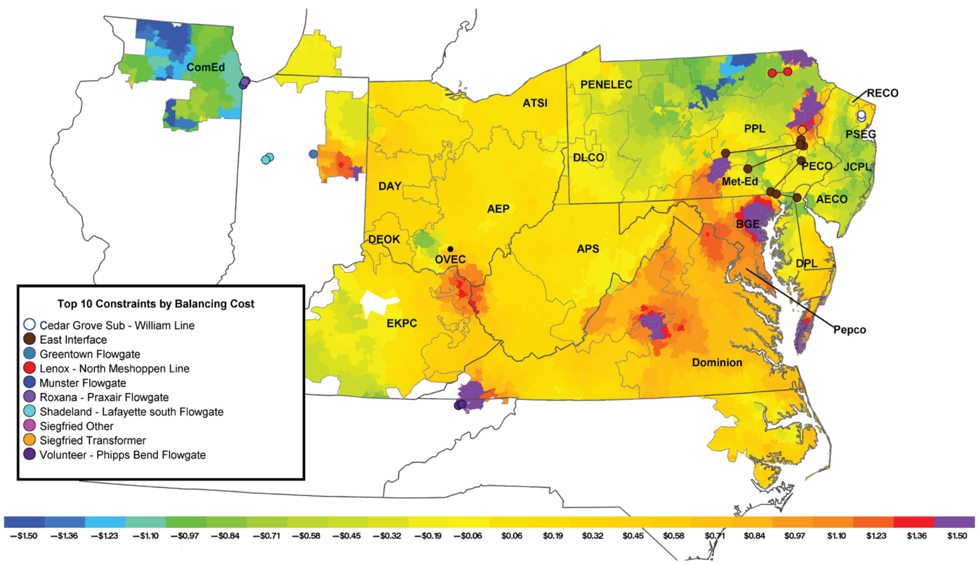
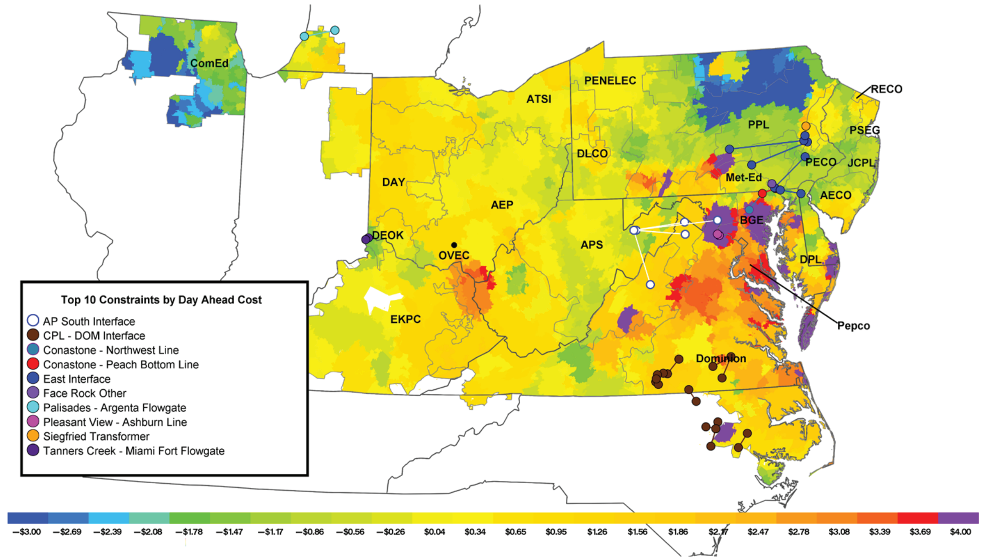


Figure 11-5 Location of the top 10 constraints by PJM day-ahead congestion costs: January through June, 2019



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.

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.

In the first six months of 2019, the average hourly cleared UTC MW decreased in January and February, compared to January and February, 2018. Day-ahead congestion event hours decreased by 36.5 percent from 81,854 congestion event hours in the first six months of 2018 to 51,990 congestion event hours in the first six months of 2019 (Table 11-22). The majority (94.2 percent) of decrease in day-ahead congestion event hours in the first six 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 June 30, 2019.

Figure 11-6 Daily congestion event hours: January 2014 through June 2019

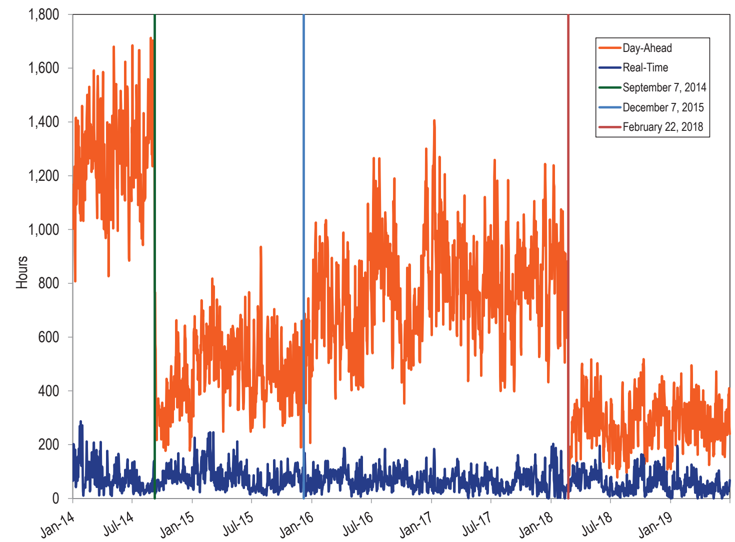
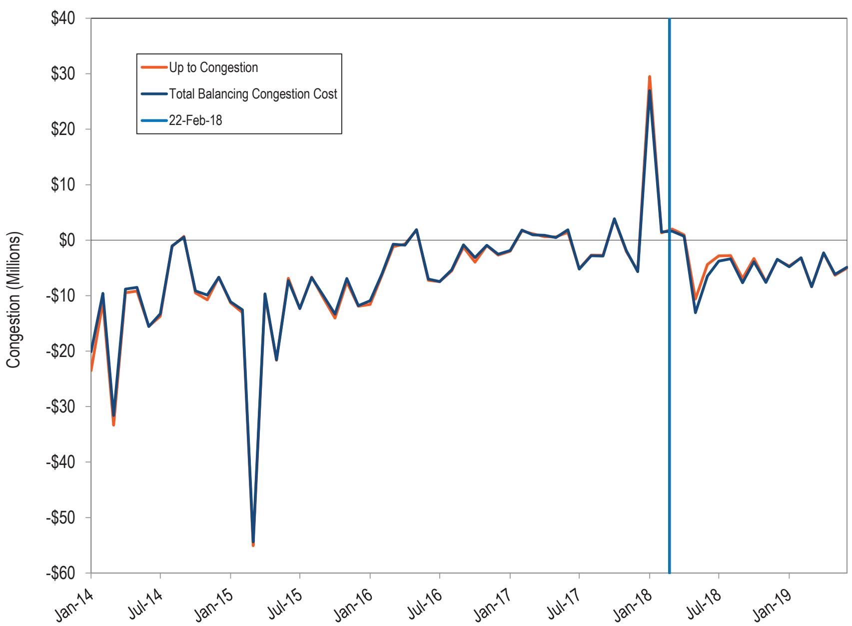


Figure 11-7 shows the change in up to congestion balancing explicit congestion costs from January 1, 2014, through December 31, 2018. Within this period, Figure 11-7 shows the highest monthly payment ($55.1 million) in balancing congestion credits to up to congestion transactions occurred in March 2015 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 June 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. Negative balancing congestion reduces total congestion collected from the day-ahead position, as the net difference between load charges and generation credits is reduced relative to the day-ahead results.

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 D. 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 load loss payments minus generation loss credits, plus explicit loss costs, incurred in both the Day-Ahead Energy Market and the balancing energy market.

Total marginal loss costs can be more accurately thought of as net marginal loss costs. Total marginal loss costs equal net implicit marginal loss costs plus net explicit marginal loss costs plus net inadvertent loss charges. Net implicit marginal loss costs equal load loss payments minus generation loss credits. Net explicit marginal loss costs are the net marginal loss costs associated with point to point energy transactions. Net inadvertent loss charges are the losses associated with the hourly difference between the net actual energy flow and the net scheduled energy flow into or out of the PJM control area.[26] 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.[27] Each of these categories of marginal loss costs is comprised of day-ahead and balancing marginal loss costs.

Marginal loss costs can be both positive and negative and consequently load payments and generation credits can also be both positive and negative. Total loss costs, when positive, measure the total loss payment by a PJM member and when negative, measure the total loss credit paid to a PJM member. Load loss payments, when positive, measure the total loss payment by a PJM member and when negative, measure the total loss credit paid to a PJM member. Generation loss credits, when negative, measure the total loss payment by a PJM member and when positive, measure the total loss credit paid to a PJM member.

The loss component of LMP is calculated with respect to the system marginal price (SMP). An increase in generation at a bus that results in an increase in losses will cause the marginal loss component of that bus to be negative. If the increase in generation at the bus results in a decrease of system losses, then the marginal loss component is positive.

26 PJM Operating Agreement Schedule 1 §3.7.
27 *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.[28]

- **Day-Ahead Load Loss Payments.** Day-ahead load loss payments are calculated for all cleared demand, decrement bids and day-ahead energy market sale transactions. Day-ahead, load loss payments are calculated using MW and the load bus MLMP, the decrement bid MLMP or the MLMP at the source of the sale transaction.
- **Day-Ahead Generation Loss Credits.** Day-ahead generation loss credits are calculated for all cleared generation and increment offers and day-ahead energy market purchase transactions. Day-ahead, generation loss credits are calculated using MW and the generator bus MLMP, the increment offer MLMP or the MLMP at the sink of the purchase transaction.
- **Balancing Load Loss Payments.** Balancing load loss payments are calculated for all deviations between a PJM member's real-time load and energy sale transactions and their day-ahead cleared demand, decrement bids and energy sale transactions. Balancing, load loss payments are calculated using MW deviations and the real-time MLMP for each bus where a deviation exists.
- **Balancing Generation Loss Credits.** Balancing generation loss credits are calculated for all deviations between a PJM member's real-time generation and energy purchase transactions and the day-ahead cleared generation, increment offers and energy purchase transactions. Balancing, generation loss credits are calculated using MW deviations and the real-time MLMP for each bus where a deviation exists.
- **Explicit Loss Costs.** Explicit loss costs are the net loss costs associated with point to point energy transactions, including UTCs. These costs equal the product of the transacted MW and MLMP differences between sources (origins) and sinks (destinations) in the Day-Ahead Energy Market. Balancing energy market explicit loss costs equal the product of the differences between the real-time and day-ahead transacted MW and the differences between the real-time MLMP at the transactions' sources and sinks.
- **Inadvertent Loss Charges.** Inadvertent loss charges are the net loss charges resulting from the differences between the net actual energy flow and the net scheduled energy flow into or out of the PJM control area each hour. This inadvertent interchange of energy may be positive or negative, where positive interchange typically results in a charge while negative interchange typically results in a credit. Inadvertent loss charges are common costs, not directly attributable to specific participants, that are distributed on a load ratio basis.[29]

28 See PJM. "Manual 28: Operating Agreement Accounting," Rev. 81 (Oct. 25. 2018).
29 PJM. Operating Agreement Schedule 1 §3.7.

Total Marginal Loss Cost

The total marginal loss cost in PJM for the first six months of 2019 was $323.1 million, which was comprised of load loss payments of -$22.9 million, generation loss credits of -$352.6 million, explicit loss costs of -$6.6 million and inadvertent loss charges of $0.0 million (Table 11-32).

Monthly marginal loss costs in the first six months of 2019 ranged from $38.8 million in April to $86.5 million in January. Total marginal loss surplus decreased in the first six months of 2019 by $71.4 million or 40.7 percent from $175.6 million in the first six months of 2018 to $104.2 million in the first six months of 2019.

Table 11-31 shows the total marginal loss component costs and the total PJM billing for January through June, 2008 through 2019.

Table 11-31 Total PJM loss component costs (Dollars (Millions)): January through June, 2008 through 2019[30]

(Jan - Jun)	Loss Costs	Percent Change	Total PJM Billing	Percent of PJM Billing
2008	$1,271	NA	$16,549	7.7%
2009	$705	(44.6%)	$13,457	5.2%
2010	$751	6.5%	$16,314	4.6%
2011	$701	(6.6%)	$18,685	3.8%
2012	$445	(36.6%)	$13,991	3.2%
2013	$494	11.2%	$15,571	3.2%
2014	$1,006	103.5%	$31,060	3.2%
2015	$608	(39.5%)	$23,390	2.6%
2016	$306	(49.7%)	$18,290	1.7%
2017	$321	4.8%	$18,960	1.7%
2018	$521	62.6%	$25,780	2.0%
2019	$323	(38.0%)	$20,070	1.6%

Table 11-32 shows PJM total marginal loss costs by accounting category for January through June, 2008 through 2019. Table 11-33 shows PJM total marginal loss costs by accounting category by market for January through June, 2008 through 2019.

Table 11-32 Total PJM marginal loss costs by accounting category (Dollars (Millions)): January through June, 2008 through 2019

	Marginal Loss Costs (Millions)				
(Jan - Jun)	Load Payments	Generation Credits	Explicit Costs	Inadvertent Charges	Total
2008	($130.8)	($1,349.6)	$52.4	$0.0	$1,271.2
2009	($42.2)	($726.4)	$20.7	$0.0	$704.8
2010	($15.7)	($750.5)	$16.2	($0.0)	$750.9
2011	($70.6)	($755.3)	$16.8	$0.0	$701.5
2012	($17.9)	($473.4)	($10.6)	$0.0	$444.9
2013	$8.6	($512.4)	($26.6)	($0.0)	$494.5
2014	($35.7)	($1,083.3)	($41.4)	$0.0	$1,006.2
2015	($15.4)	($635.5)	($11.9)	$0.0	$608.3
2016	($19.5)	($338.7)	($13.4)	$0.0	$305.8
2017	($24.9)	($363.5)	($17.9)	$0.0	$320.6
2018	($31.9)	($559.3)	($6.0)	$0.0	$521.4
2019	($22.9)	($352.6)	($6.6)	$0.0	$323.1

30 The loss costs include net inadvertent charges.

Table 11-33 Total PJM marginal loss costs by accounting category by market (Dollars (Millions)): January through June, 2008 through 2019

	Marginal Loss Costs (Millions)									
	Day-Ahead				Balancing					
(Jan - Jun)	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
2008	($64.9)	($1,299.8)	$64.3	$1,299.2	($65.9)	($49.8)	($11.9)	($28.0)	$0.0	$1,271.2
2009	($43.8)	($723.3)	$44.6	$724.1	$1.5	($3.1)	($23.9)	($19.3)	$0.0	$704.8
2010	($27.2)	($751.6)	$33.5	$757.9	$11.4	$1.2	($17.3)	($7.0)	($0.0)	$750.9
2011	($90.4)	($774.1)	$44.3	$728.1	$19.8	$18.8	($27.5)	($26.6)	$0.0	$701.5
2012	($30.4)	($481.4)	$15.5	$466.5	$12.5	$8.0	($26.1)	($21.6)	$0.0	$444.9
2013	($7.2)	($528.2)	$25.0	$546.0	$15.9	$15.8	($51.6)	($51.6)	($0.0)	$494.5
2014	($75.4)	($1,118.8)	$51.6	$1,095.0	$39.7	$35.6	($93.0)	($88.8)	$0.0	$1,006.2
2015	($33.2)	($643.0)	$15.6	$625.4	$17.8	$7.4	($27.5)	($17.1)	$0.0	$608.3
2016	($23.3)	($339.8)	$18.9	$335.4	$3.9	$1.1	($32.4)	($29.5)	$0.0	$305.8
2017	($29.6)	($364.1)	$30.2	$364.7	$4.6	$0.6	($48.1)	($44.0)	$0.0	$320.6
2018	($35.3)	($553.0)	$16.7	$534.4	$3.4	($6.3)	($22.7)	($12.9)	$0.0	$521.4
2019	($23.0)	($350.2)	$22.6	$349.7	$0.1	($2.4)	($29.2)	($26.6)	$0.0	$323.1

Table 11-34 and Table 11-35 show the total loss costs for each transaction type in the first six months of 2019 and 2018. In the first six months of 2019, generation paid loss costs of $339.6 million, 105.1 percent of total loss costs. In the first six months of 2018, generation paid loss costs of $522.6 million, 100.2 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 six months of 2019, DECs were paid $2.2 million in loss credits in the day-ahead market, paid $2.8 million in loss costs in the balancing energy market and paid $0.6 million in total loss payments. In the first six months of 2019, INCs paid $5.4 million in loss costs in the day-ahead market, were paid $6.2 million in loss credits in the balancing energy market and were paid $0.9 million in total loss credits. In the first six months of 2019, up to congestion paid $22.7 million in loss costs in the day-ahead market, were paid $29.3 million in loss credits in the balancing energy market and received $6.6 million in total loss credits.

Table 11-34 Total PJM loss costs by transaction type by market (Dollars (Millions)): January through June, 2019

	Marginal Loss Costs (Millions)									
	Day-Ahead				Balancing					
Transaction Type	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
DEC	($2.2)	$0.0	$0.0	($2.2)	$2.8	$0.0	$0.0	$2.8	$0.0	$0.6
Demand	($2.8)	$0.0	$0.0	($2.8)	$2.6	$0.0	$0.0	$2.6	$0.0	($0.2)
Demand Response	($0.0)	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Explicit Congestion and Loss Only	$0.0	$0.0	($0.3)	($0.3)	$0.0	$0.0	($0.0)	($0.0)	$0.0	($0.3)
Export	($9.4)	$0.0	$0.0	($9.3)	($4.8)	$0.0	$0.4	($4.5)	$0.0	($13.8)
Generation	$0.0	($335.2)	$0.0	$335.2	$0.0	($4.4)	$0.0	$4.4	$0.0	$339.6
Import	$0.0	($1.1)	$0.0	$1.1	$0.0	($3.7)	($0.1)	$3.6	$0.0	$4.8
INC	$0.0	($5.4)	$0.0	$5.4	$0.0	$6.2	$0.0	($6.2)	$0.0	($0.9)
Internal Bilateral	($8.6)	($8.5)	$0.1	$0.0	($0.5)	($0.5)	$0.0	($0.0)	$0.0	$0.0
Up to Congestion	$0.0	$0.0	$22.7	$22.7	$0.0	$0.0	($29.3)	($29.3)	$0.0	($6.6)
Wheel In	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.1)	($0.1)	$0.0	($0.1)
Total	($23.0)	($350.2)	$22.6	$349.7	$0.1	($2.4)	($29.2)	($26.6)	$0.0	$323.1

Table 11-35 Total PJM loss costs by transaction type by market (Dollars (Millions)): January through June, 2018

	Marginal Loss Costs (Millions)									
	Day-Ahead				Balancing					
Transaction Type	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
DEC	($0.9)	$0.0	$0.0	($0.9)	$0.9	$0.0	$0.0	$0.9	$0.0	($0.0)
Demand	($3.8)	$0.0	$0.0	($3.8)	$7.0	$0.0	$0.0	$7.0	$0.0	$3.2
Demand Response	($0.0)	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Explicit Congestion Only	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.0
Explicit Congestion and Loss Only	$0.0	$0.0	($0.1)	($0.1)	$0.0	$0.0	($0.0)	($0.0)	$0.0	($0.2)
Export	($12.7)	$0.0	($0.0)	($12.7)	($5.0)	$0.0	$0.2	($4.9)	$0.0	($17.6)
Generation	$0.0	($525.9)	$0.0	$525.9	$0.0	$3.4	$0.0	($3.4)	$0.0	$522.6
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	($2.2)	$0.0	$2.2	$0.0	($18.2)	($0.4)	$17.8	$0.0	$20.0
INC	$0.0	($7.2)	$0.0	$7.2	$0.0	$8.0	$0.0	($8.0)	$0.0	($0.7)
Internal Bilateral	($8.8)	($8.6)	$0.3	$0.0	$0.5	$0.5	$0.0	($0.0)	$0.0	($0.0)
Up to Congestion	$0.0	$0.0	$17.1	$17.1	$0.0	$0.0	($22.3)	($22.3)	$0.0	($5.2)
Wheel In	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.1)	($0.1)	$0.0	($0.1)
Total	($26.3)	($543.9)	$16.7	$534.4	$3.4	($6.3)	($22.7)	($12.9)	$0.0	$521.4

Monthly Marginal Loss Costs

Table 11-36 shows a monthly summary of marginal loss costs by market type for January 2018 through June 2019.

Table 11-36 Monthly marginal loss costs by market (Millions): January 2018 through June 2019

	Marginal Loss Costs (Millions)							
	2018				2019			
	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand 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	$67.2	$0.0	$0.0	$67.2	$68.5	($7.0)	$0.0	$61.6
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				
Aug	$87.7	($4.6)	$0.0	$83.1				
Sep	$73.2	($2.9)	$0.0	$70.2				
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	$997.2	($37.1)	$0.0	$960.1	$349.7	($26.6)	$0.0	$323.1

Figure 11-8 shows PJM monthly marginal loss costs for January 2008 through June 2019.

Figure 11-8 PJM monthly marginal loss costs (Dollars (Millions)): January 2008 through June 2019

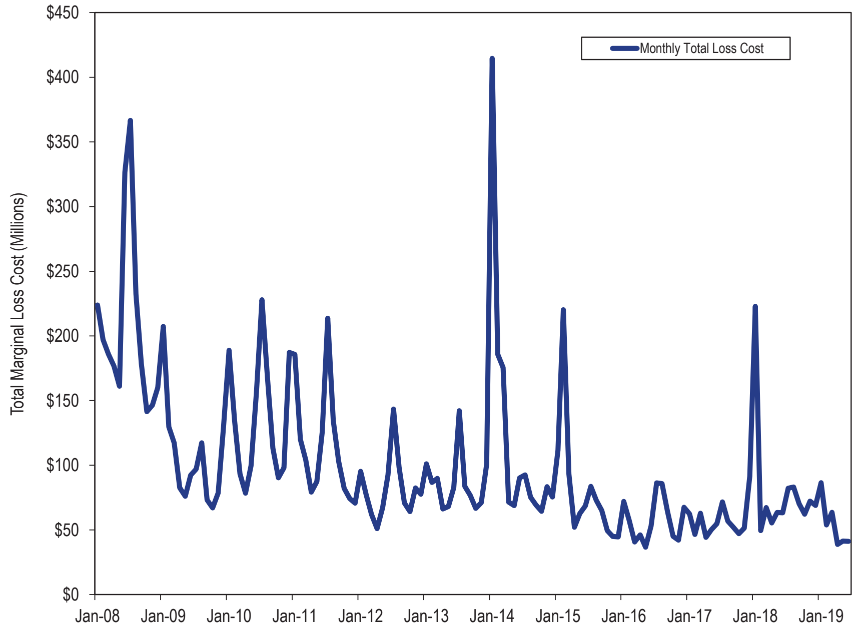


Table 11-37 shows the monthly total loss costs for each virtual transaction type in the first six months of 2019 and year of 2018.

Table 11-37 Monthly PJM loss costs by virtual transaction type and by market (Dollars (Millions)): January 2018 through June 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	($0.1)	$0.2	$0.0	$1.3	($1.4)	($0.1)	$5.9	($6.8)	($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)
	Total	($2.2)	$2.8	$0.6	$5.4	($6.2)	($0.9)	$22.7	($29.3)	($6.6)	($6.9)

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 costs (load energy payments minus generation energy credits) plus net inadvertent energy charges. Total marginal loss costs are equal to the net implicit marginal loss costs (generation loss credits less load loss payments) plus net explicit loss costs plus net inadvertent loss charges.

Ignoring interchange, total generation MWh must be greater than total load MWh in any hour in order to provide for losses. Since the hourly integrated energy component of LMP is the same for every bus within every hour, the net energy bill is negative (ignoring net interchange), with more generation credits than load payments in every hour. Total energy costs plus total marginal loss costs plus net residual market adjustments equal marginal loss credits which are distributed to the PJM market participants according to the ratio of their real-time load plus their real-time exports to total PJM real-time load plus real-time exports as marginal loss credits. The net residual market adjustment is calculated as known day-ahead error value minus day-ahead loss MW congestion value and minus balancing loss MW congestion value.

Table 11-38 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 June, 2008 through 2019. The total marginal loss surplus decreased $71.4 million in the first six months of 2019 from the first six months of 2018.

Table 11-38 Marginal loss surplus (Dollars (Millions)): January through June, 2008 through 2019[31]

Marginal Loss Surplus (Millions)						
			Net Residual Market Adjustment			
(Jan - Jun)	Total Energy Charges	Total Marginal Loss Charges	Known Day-Ahead Error	Day-Ahead Loss MW Congestion	Balancing Loss MW Congestion	Total
2008	($610.2)	$1,271.2	$0.0	$0.0	$0.0	$661.0
2009	($343.6)	$704.8	$0.0	($1.2)	($0.0)	$362.5
2010	($372.8)	$750.9	$0.0	$0.6	($0.0)	$377.5
2011	($393.9)	$701.5	($0.0)	($0.9)	$0.0	$308.4
2012	($262.0)	$444.9	$0.1	$0.8	$0.0	$182.1
2013	($332.6)	$494.5	$0.0	$3.9	$0.1	$157.9
2014	($677.2)	$1,006.2	($0.3)	$3.7	($0.1)	$325.1
2015	($397.6)	$608.3	$0.0	$1.3	($0.1)	$209.5
2016	($204.2)	$305.8	$0.0	$0.3	($0.1)	$101.4
2017	($222.2)	$320.6	($0.0)	$1.3	($0.0)	$97.2
2018	($345.2)	$521.4	($0.0)	$0.7	($0.0)	$175.6
2019	($218.9)	$323.1	$0.0	$0.0	$0.0	$104.2

Energy Costs

Energy Accounting

The energy component of LMP is the system reference bus LMP, also called the system marginal price (SMP). The energy cost is based on the day-ahead and real-time energy components of LMP. Total energy costs, analogous to total congestion costs or total loss costs, are equal to the load energy payments minus generation energy credits, 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.

31 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.

Total Energy Costs

The total energy cost for the first six months of 2019 was -$218.9 million, which was comprised of load energy payments of $15,347.6 million, generation energy credits of $15,567.8 million, explicit energy costs of $0.0 million and inadvertent energy charges of $1.3 million. The monthly energy costs for the first six 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 June, 2008 through 2019. The total energy component costs are net energy costs.

Table 11-39 Total PJM energy component costs (Dollars (Millions)): January through June, 2008 through 2019[32]

(Jan - Jun)	Energy Costs	Percent Change	Total PJM Billing	Percent of PJM Billing
2008	($610)	NA	$16,549	(3.7%)
2009	($344)	(43.7%)	$13,457	(2.6%)
2010	($373)	8.5%	$16,314	(2.3%)
2011	($394)	5.7%	$18,685	(2.1%)
2012	($262)	(33.5%)	$13,991	(1.9%)
2013	($333)	26.9%	$15,571	(2.1%)
2014	($677)	103.6%	$31,060	(2.2%)
2015	($398)	(41.3%)	$23,390	(1.7%)
2016	($204)	(48.6%)	$18,290	(1.1%)
2017	($222)	8.8%	$18,960	(1.2%)
2018	($345)	55.3%	$25,780	(1.3%)
2019	($219)	(36.6%)	$20,070	(1.1%)

Energy costs for January through June, 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.

32 The energy costs include net inadvertent charges.

Table 11-40 Total PJM energy costs by accounting category (Dollars (Millions)): January through June, 2008 through 2019

	Energy Costs (Millions)				
(Jan - Jun)	Load Payments	Generation Credits	Explicit Costs	Inadvertent Charges	Total
2008	$61,281.2	$61,891.4	$0.0	$0.0	($610.2)
2009	$22,815.7	$23,162.1	$0.0	$2.9	($343.6)
2010	$25,040.9	$25,406.7	$0.0	($7.1)	($372.8)
2011	$23,524.8	$23,932.1	$0.0	$13.3	($393.9)
2012	$16,823.4	$17,092.7	$0.0	$7.2	($262.0)
2013	$20,488.2	$20,819.3	$0.0	($1.5)	($332.6)
2014	$39,885.0	$40,556.7	$0.0	($5.4)	($677.2)
2015	$24,267.0	$24,667.1	$0.0	$2.5	($397.6)
2016	$14,857.8	$15,062.3	$0.0	$0.4	($204.2)
2017	$16,768.7	$16,991.8	$0.0	$0.9	($222.2)
2018	$23,079.7	$23,429.7	$0.0	$4.9	($345.2)
2019	$15,347.6	$15,567.8	$0.0	$1.3	($218.9)

Table 11-41 Total PJM energy costs by market category (Dollars (Millions)): January through June, 2008 through 2019

	Energy Costs (Millions)									
	Day-Ahead				Balancing					
(Jan - Jun)	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
2008	$42,539.7	$43,214.3	$0.0	($674.6)	$18,741.5	$18,677.1	$0.0	$64.5	$0.0	($610.2)
2009	$22,893.0	$23,278.1	$0.0	($385.1)	($77.3)	($116.0)	$0.0	$38.7	$2.9	($343.6)
2010	$25,072.6	$25,450.1	$0.0	($377.5)	($31.6)	($43.4)	$0.0	$11.8	($7.1)	($372.8)
2011	$23,685.6	$24,076.3	$0.0	($390.6)	($160.8)	($144.1)	$0.0	($16.7)	$13.3	($393.9)
2012	$16,907.0	$17,148.9	$0.0	($241.9)	($83.6)	($56.2)	$0.0	($27.4)	$7.2	($262.0)
2013	$20,543.4	$20,895.6	$0.0	($352.2)	($55.1)	($76.3)	$0.0	$21.2	($1.5)	($332.6)
2014	$39,831.7	$40,780.0	$0.0	($948.3)	$53.3	($223.3)	$0.0	$276.6	($5.4)	($677.2)
2015	$24,389.1	$24,858.0	$0.0	($468.9)	($122.1)	($190.9)	$0.0	$68.8	$2.5	($397.6)
2016	$14,970.7	$15,252.9	$0.0	($282.3)	($112.9)	($190.6)	$0.0	$77.7	$0.4	($204.2)
2017	$16,974.1	$17,296.6	$0.0	($322.5)	($205.3)	($304.8)	$0.0	$99.4	$0.9	($222.2)
2018	$23,126.4	$23,506.8	$0.0	($380.4)	($46.7)	($77.1)	$0.0	$30.3	$4.9	($345.2)
2019	$15,552.6	$15,820.6	$0.0	($268.0)	($205.0)	($252.7)	$0.0	$47.7	$1.3	($218.9)

Table 11-42 and Table 11-43 show the total energy costs for each transaction type in the first six months of 2019 and 2018. In the first six months of 2019, generation was paid $11,097.2 million and demand paid $10,476.8 million in net energy payment. In the first six months of 2018, generation was paid $16,315.6 million and demand paid $15,914.4 million in net energy payment.

Table 11-42 Total PJM energy costs by transaction type by market (Dollars (Millions)): January through June, 2019

	Energy Costs (Millions)								
	Day-Ahead				Balancing				
Transaction Type	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total
DEC	$462.9	$0.0	$0.0	$462.9	($455.9)	$0.0	$0.0	($455.9)	$7.0
Demand	$10,468.1	$0.0	$0.0	$10,468.1	$8.7	$0.0	$0.0	$8.7	$10,476.8
Demand Response	($0.4)	$0.0	$0.0	($0.4)	$0.4	$0.0	$0.0	$0.4	($0.0)
Export	$339.7	$0.0	$0.0	$339.7	$217.8	$0.0	$0.0	$217.8	$557.5
Generation	$0.0	$11,138.7	$0.0	($11,138.7)	$0.0	($41.5)	$0.0	$41.5	($11,097.2)
Import	$0.0	$46.6	$0.0	($46.6)	$0.0	$110.2	$0.0	($110.2)	($156.8)
INC	$0.0	$353.0	$0.0	($353.0)	$0.0	($345.4)	$0.0	$345.4	($7.6)
Internal Bilateral	$4,282.2	$4,282.2	$0.0	($0.0)	$11.3	$11.3	$0.0	($0.0)	($0.0)
Wheel In	$0.0	$0.0	$0.0	$0.0	$0.0	$12.7	$0.0	($12.7)	($12.7)
Wheel Out	$0.0	$0.0	$0.0	$0.0	$12.7	$0.0	$0.0	$12.7	$12.7
Total	$15,552.6	$15,820.6	$0.0	($268.0)	($205.0)	($252.7)	$0.0	$47.7	($220.3)

Table 11-43 Total PJM energy costs by transaction type by market (Dollars (Millions)): January through June, 2018

	Energy Costs (Millions)								
	Day-Ahead				Balancing				
Transaction Type	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total
DEC	$515.3	$0.0	$0.0	$515.3	($532.4)	$0.0	$0.0	($532.4)	($17.0)
Demand	$15,627.6	$0.0	$0.0	$15,627.6	$286.8	$0.0	$0.0	$286.8	$15,914.4
Demand Response	($0.7)	$0.0	$0.0	($0.7)	$0.7	$0.0	$0.0	$0.7	$0.0
Export	$398.3	$0.0	$0.0	$398.3	$184.6	$0.0	$0.0	$184.6	$583.0
Generation	$0.0	$16,382.6	$0.0	($16,382.6)	$0.0	($67.0)	$0.0	$67.0	($16,315.6)
Import	$0.0	$85.4	$0.0	($85.4)	$0.0	$432.9	$0.0	($432.9)	($518.3)
INC	$0.0	$453.0	$0.0	($453.0)	$0.0	($456.5)	$0.0	$456.5	$3.5
Internal Bilateral	$6,585.8	$6,585.8	$0.0	($0.0)	$9.6	$9.6	$0.0	$0.0	($0.0)
Wheel In	$0.0	$0.0	$0.0	$0.0	$0.0	$4.0	$0.0	($4.0)	($4.0)
Wheel Out	$0.0	$0.0	$0.0	$0.0	$4.0	$0.0	$0.0	$4.0	$4.0
Total	$23,126.4	$23,506.8	$0.0	($380.4)	($46.7)	($77.0)	$0.0	$30.3	($350.0)

Monthly Energy Costs

Table 11-44 shows a monthly summary of energy costs by market type for January 2018 through June 2019. Marginal total energy costs in the first six months of 2019 increased from the first six months of 2018. Monthly total energy costs in the first six 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 June 2019

	Energy Costs (Millions)							
	2018				2019			
	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand 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)				
Aug	($60.7)	$5.7	$0.3	($54.6)				
Sep	($50.8)	$5.3	($0.0)	($45.4)				
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)	($268.0)	$47.7	$1.3	($218.9)

Figure 11-9 shows PJM monthly energy costs for January 2008 through June 2019.

Figure 11-9 PJM monthly energy costs (Millions): January 2008 through June 2019

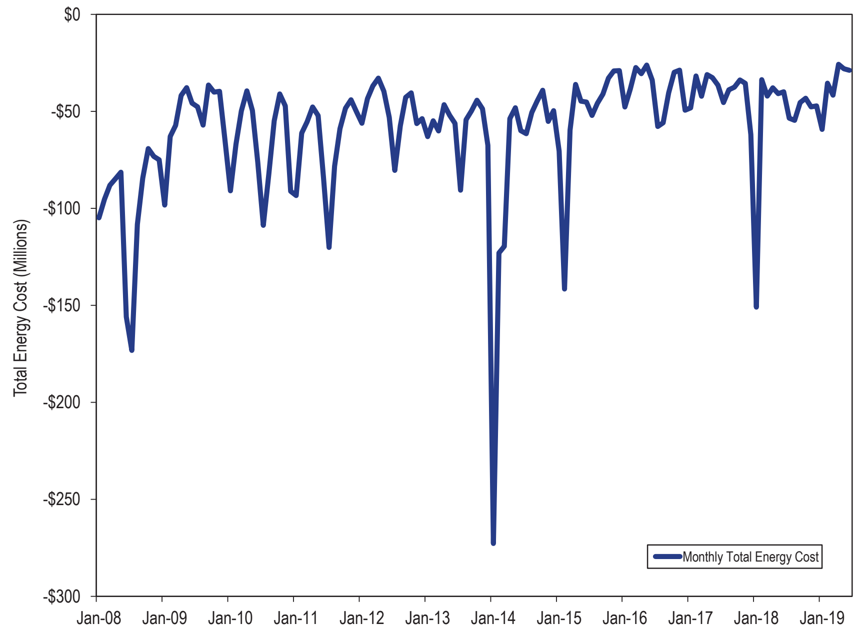


Table 11-45 shows the monthly total energy costs for each virtual transaction type in the first six months of 2019 and year of 2018. In the first six months of 2019, DECs paid $462.9 million in energy costs in the day-ahead market, were paid $455.9 million in energy credits in the balancing energy market and paid $7.0 million in total energy costs. In the first six months of 2019, INCs were paid $353.0 million in energy credits in the day-ahead market, paid $345.4 million in energy costs in the balancing market and were paid $7.6 million in total energy credits. In the first six months of 2018, DECs paid $515.3 million in energy costs in the day-ahead market, were paid $532.4 million in energy credits in the balancing energy market and were paid $17.0 million in total energy credits. In the first six months of 2018, INCs were paid $453.0 million in energy credits in the day-ahead market, paid $456.5 million in energy cost in the balancing energy market and paid $3.5 million in total energy costs.

Table 11-45 Monthly PJM energy costs by virtual transaction type and by market (Dollars (Millions)): January 2018 through June 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	$65.6	($67.2)	($1.6)	($66.0)	$66.5	$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	$1,010.9	($1,019.5)	($8.6)	($860.1)	$853.0	($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)
	Total	$462.9	($455.9)	$7.0	($353.0)	$345.4	($7.6)	($0.6)

Generation and Transmission Planning[1]

Overview

Generation Interconnection Planning

Existing Generation Mix

- As of June 30, 2019, PJM had a total installed capacity of 198,599.2 MW, of which 55,952.4 MW (28.2 percent) are coal fired steam units, 47,591.6 MW (24.0 percent) are combined cycle units and 34,257.6 MW (17.2 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 198,599.2 MW of PJM total installed capacity, 31,643.0 MW (15.9 percent) are in the AEP Zone, of which 14,727.8 MW (46.5 percent) are coal fired steam units, 6,990.0 MW (22.1 percent) are combined cycle units and 2,071.0 MW (6.5 percent) are nuclear units.
- Pennsylvania has the most total installed capacity of any PJM state. Of the 198,599.2 MW of installed capacity, 46,077.5 MW (23.2 percent) are in Pennsylvania, of which 9,415.7 MW (20.4 percent) are coal fired steam units, 15,021.5 MW (32.6 percent) are combined cycle units and 9,648.8 MW (20.9 percent) are nuclear units.
- Of the 198,599.2 MW of installed capacity, 74,483.0 MW (37.5 percent) are from units older than 40 years, of which 39,667.2 MW (53.3 percent) are coal fired steam units, 532 MW (0.7 percent) are combined cycle units and 16,044.9 MW (21.5 percent) are nuclear units.

Generation Retirements[2]

- There are 46,448.9 MW of generation that have been, or are planned to be, retired between 2011 and 2022, of which 32,486.2 MW (69.9 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 six months of 2019, 3,225.8 MW of generation retired. The largest generators that retired in the first six 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 3,225.8 MW of generation that retired, 1,660.0 MW (51.5 percent) were located in the ATSI Zone.
- As of June 30 2019, there are 11,852.0 MW of generation that have requested retirement after June 30, 2019, of which 5,131.0 MW (43.3 percent) are located in the ATSI Zone. Of the ATSI generation requesting retirement, 2,960.0 MW (57.7 percent) are coal fired steam units and 2,134.0 MW (41.6 percent) are nuclear 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 six months of 2019, the AE2 queue window closed, and the AF1 queue window opened. Combined, these queue windows added 32,555.1 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 June 30, 2019, there were 125,757.4 total MW in generation queues, in the status of active, under construction or suspended, an increase of 10,803.7 MW (9.4 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 June 30, 2019, there were 45,732.1 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).[4] As of June 30, 2019, there were only 133.0 MW of coal fired steam capacity active, suspended or under construction in PJM queues.

1 Totals presented in this section include corrections to historical data and may not match totals presented in previous reports.
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>.
4 The unit type RICE refers to Reciprocating Internal Combustion Engines.

- As of June 30, 2019, 4,500 projects, representing 560,874.6 MW, have entered the queue process since its inception in 1998. Of those, 854 projects, representing 66,918.4 MW, went into service. Of the projects that entered the queue process, 2,530 projects, representing 368,198.8 MW (65.6 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 June 30, 2019, 125,757.4 MW of capacity were in generation request queues in the status of active, under construction or suspended. Of the total 125,757.4 MW in the queue, 56,685.8 MW (45.1 percent) have reached at least the system impact study (SIS) milestone and 69,071.6 MW (54.9 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), 33,654.7 MW of new generation in the queue are expected to go into service.

Regional Transmission Expansion Plan (RTEP)

Backbone Facilities

- There are currently six backbone projects under development, the Surry-Skiffes Creek 500kV Line, the Loudoun-Brambleton 500kV Line, the conversion of the Marion-Bayonne and Bayway-Linden lines from 138 kV to 345 kV, the conversion of the Robinson Park-Sorenson lines to double circuit 345kV and the Meadow Lake-Reynolds 345kV Line rebuild.[5]

Market Efficiency Process

- PJM's first market efficiency analysis was performed in 2013, prior to Order 1000. This analysis evaluated the reasons for congestion on 25 flowgates.[6] The proposal window was open from August 12, 2013, through September 26, 2013. PJM received 38 proposals from six entities. One project was approved by the PJM Board.
- Through June 30, 2019, PJM has completed two market efficiency cycles under Order No. 1000. In the first cycle, PJM received 93 proposals for 57 identified sources of congestion. In the second cycle, PJM received 96 proposals for four identified sources of congestion. The proposal window for 2018/2019 opened on November 1, 2018, and closed on February 28, 2019. PJM received 22 proposals for one identified source of congestion.
- 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, using PJM's flawed approach.
- 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.

PJM MISO Interregional Targeted Market Efficiency Process (TMEP)

- The first Targeted Market Efficiency Process (TMEP) analysis occurred in 2017 and included the investigation of congestion on 50 market to market flowgates. The study resulted in the evaluation of 13 potential upgrades, resulting in the recommendation of five TMEP projects. The five projects address $59.0 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.[7]

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

6 Historical congestion drivers are identified using the historical congestion tables presented in the *2018 State of the Market Report for PJM*, Section 11: Congestion and Marginal Losses, historical analysis of real-time constraints, the NERC Book of Flowgates and PROMOD simulations.

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

- The 2018 TMEP analysis included the investigation of congestion on 61 market to market flowgates. The study resulted in the evaluation of 19 potential upgrades, resulting in the recommendation of 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.[8]

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.”[9] Supplemental projects are exempt from the competitive planning process.
- The average number of supplemental projects in each expected in service year increased by 615.0 percent, from 20 for years 1998 through 2007 (pre Order No. 890) to 143 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. End of life transmission projects fall under the Transmission Owner Form 715 Planning Criteria, and are currently exempt from the competitive planning process.[10] End of life transmission projects are already included in the supplemental projects totals or, if included in the transmission owners’ reliability plan, will be included in the baseline project list as a reliability criteria project.
- 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.[11] On February 12, 2019, the PJM Board of Managers authorized an additional $272.0 million in transmission upgrades and additions. As of June 30, 2019, the PJM Board has approved $38.5 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 cost effective 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 binding cost containment proposals versus proposals without cost containment provisions.

8 See PJM. “MISO PJM IPSAC,” (January 18, 2019) <https://www.pjm.com/-/media/committees-groups/stakeholder-meetings/ipsac/20190118/20190118-ipsac-presentation.ashx>.

9 See PJM. "Transmission Construction Status," (Accessed on June 30, 2019) <http://www.pjm.com/planning/rtep-upgrades-status/construct-status.aspx>.

10 See PJM. Operating Agreement Schedule 6 § 1.5.8(o).

11 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 into an LDA and can be offered into capacity auctions as capacity.
- QTU projects are submitted and tracked through the PJM queue.[12] A total of 51 QTU projects have entered the queue since 2007. Of the 51 submitted QTU projects, 38 projects (74.5 percent) have been withdrawn, six (11.8 percent) are in service and seven (13.7 percent) are currently in active development.

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.[13]
- There were 22,091 transmission outage requests submitted in the 2018/2019 planning period. Of the requested outages, 77.0 percent of the requested outages were planned for less than or equal to five days and 7.7 percent of requested outages were planned for greater than 30 days. Of the requested outages, 47.3 percent were late according to the rules in PJM's Manual 3.

Recommendations

The MMU recommends improvements to the planning process:

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.[14] (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

12 See PJM. Planning. "New Services Queue," at <https://www.pjm.com/planning/services-requests/interconnection-queues.aspx>.
13 See PJM. "PJM Manual 03: Transmission Operations," Rev. 55 (May 31, 2019).
14 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>.

transmission also owns generation. (Priority: Low. First reported 2013. Status: Not adopted.)

Market Efficiency Process

- The MMU recommends that 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. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that 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.[15] (Priority: Medium. First reported 2015. Status: Not adopted.)

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

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 direct competition between transmission and generation to meet loads in the affected area. In addition, despite FERC Order No. 1000, there is not yet a transparent, robust and clearly defined mechanism to permit competition to build transmission projects, to ensure that competitors provide a total project cost cap, or to obtain least cost financing through the capital markets.

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

Managing the generation queues is a highly complex process. The PJM queue evaluation process has been substantially improved in recent years and it is more efficient and effective as a result. The PJM queue evaluation process should continue to be improved to help ensure that barriers to competition for new generation investments are not created. Issues that need to be addressed include the ownership rights to CIRs, whether transmission owners should perform interconnection studies, and improvements in queue management to ensure that projects are removed from the queue if they are not viable, as well as a process to allow commercially viable projects to advance in the queue ahead of projects which have failed to make progress.

The PJM rules for competitive transmission development through the RTEP should build upon FERC Order No. 1000 to create real competition between incumbent transmission providers and 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.

The inclusion of market efficiency transmission projects in the transmission planning process, in addition to reliability projects, effectively results in direct competition between generation and transmission to address congestion issues in the wholesale power market, including congestion in the energy and capacity markets but with a bias towards the transmission option. The role of the market efficiency process and its impact on competition should be more thoroughly evaluated. But PJM fails to explicitly address this fact in the design of the market efficiency process. While the market efficiency process and metrics require modification, for example to ensure that all congestion is measured, the role of the market efficiency process and its impact on competition should also be more thoroughly evaluated. Building transmission under cost of service regulation already provides a significant competitive advantage to transmission over generation which is built entirely based on market prices and for which investors take the risks. The risks of cost increases for transmission projects should also be incorporated in the cost benefit analysis.

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.

The current rules governing the benefit/cost analysis evaluate competing projects with different in service dates on an asymmetric basis. Under the current rules, projects are evaluated on a present value, benefit/cost basis over a 15 year service horizon, starting with the in service date of the project. A better approach would be to establish a common end date for all evaluated competing projects so that the minimum included years for any evaluated project is 15 years. This means that if there were an RTEP year zero project and a RTEP year +2 project competing, the benefit/cost ratio analysis would include the benefits and costs for both projects for every year from RTEP year zero to RTEP+16. Under this approach all projects would be evaluated over an identical term rather than an artificially truncated term and all projects would be evaluated on a present value basis at year zero.[16]

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.

16 See "Comments of the Independent Market Monitor for PJM," (January 11, 2019) <http://www.monitoringanalytics.com/Filings/2019/IMM_Comments_Docket_No_ER19-80_20190111.pdf>.

Generation Interconnection Planning

Existing Generation Mix

Table 12-1 shows the existing PJM capacity by control zone and unit type.[17] As of June 30, 2019, PJM had an installed capacity of 198,599.2 MW, of which 55,952.4 MW (28.2 percent) are coal fired steam units, 47,591.6 MW (24.0 percent) are combined cycle units and 34,257.6 MW (17.2 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 198,599.2 MW of PJM total installed capacity, 31,643.0 MW (15.9 percent) are in the AEP Zone, of which 14,727.8 MW (46.5 percent) are coal fired steam units, 6,990.0 MW (22.1 percent) are combined cycle units and 2,071.0 MW (6.5 percent) are nuclear units.

Table 12-1 Existing PJM capacity: June 30, 2019 (By zone and unit type (MW))[18]

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	0.0	26.0	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	0.0	21.0	0.0	66.0	486.9	2,071.0	0.0	0.0	20.4	14.7	14,727.8	738.0	0.0	50.0	2,790.0	31,643.0
APS	80.4	2,179.0	1,223.3	0.0	2.0	0.0	0.0	129.2	0.0	0.0	29.6	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	0.0	659.4	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	0.0	248.8	0.0	0.0	0.4	1,716.0	0.0	0.0	7.2	1.1	1,713.0	240.5	397.0	57.0	0.0	4,881.1
ComEd	148.5	2,621.1	6,969.3	0.0	226.2	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	0.0	56.0	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	0.0	15.0	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	0.0	266.4	0.0	3,003.0	586.3	3,581.3	0.0	39.0	112.8	722.1	4,122.1	35.0	1,586.0	368.4	208.0	27,565.3
DPL	0.0	1,742.5	978.2	0.0	478.2	30.0	0.0	0.0	0.0	0.0	88.0	14.1	225.4	410.0	882.0	153.0	0.0	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	0.0	232.0	0.4	400.0	0.0	0.0	0.0	0.0	16.1	287.4	0.0	0.0	0.0	10.0	0.0	3,919.6
Met-Ed	0.0	2,101.0	2.0	0.0	398.5	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	50.8	0.0	834.0	0.0	1,070.0	572.0	4,546.8	0.0	2.0	0.9	3.0	3.3	762.0	0.0	163.0	0.0	12,096.8
PENELEC	28.4	850.0	350.5	0.0	57.0	0.0	513.0	77.8	0.0	0.0	128.2	17.8	0.0	6,141.5	610.0	0.0	42.0	1,028.8	9,845.0
Pepco	0.0	1,729.5	764.2	0.0	308.0	0.0	0.0	0.0	0.0	0.0	0.0	11.1	0.0	2,433.0	1,164.1	0.0	52.0	0.0	6,461.9
PPL	20.0	5,558.5	252.0	0.0	150.1	0.0	0.0	706.6	2,520.0	0.0	17.0	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	205.6	0.0	3.0	0.0	179.1	0.0	9,355.8
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	47,591.6	25,235.0	0.0	3,978.6	32.0	5,052.0	3,040.6	34,257.6	0.0	360.3	396.0	1,598.9	55,952.4	8,581.6	2,136.0	1,010.5	9,027.2	198,599.2

17 The unit type RICE refers to Reciprocating Internal Combustion Engines.
18 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 198,599.2 MW of installed capacity, 46,077.5 MW (23.2 percent) are in Pennsylvania, of which 9,415.7 MW (20.4 percent) are coal fired steam units, 15,021.5 MW (32.6 percent) are combined cycle units and 9,648.8 MW (20.9 percent) are nuclear units.

Table 12-2 Existing PJM capacity: June 30, 2019 (By state and unit type (MW))

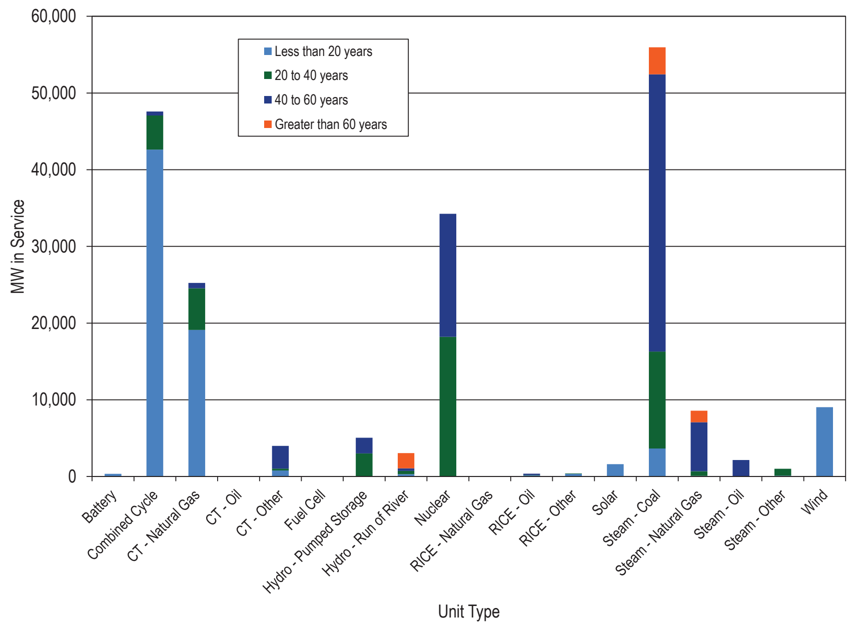
State	Battery	Combined Cycle	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Total
DC	0.0	19.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	19.5
DE	0.0	742.5	325.5	0.0	116.3	30.0	0.0	0.0	0.0	0.0	0.0	8.1	0.0	410.0	882.0	0.0	0.0	0.0	2,514.4
IL	148.5	2,621.1	6,969.3	0.0	226.2	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	0.0	572.7	0.0	0.0	0.4	1,716.0	0.0	76.0	24.3	251.6	4,386.0	1,404.6	550.0	109.0	295.0	14,032.6
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	432.7	115.5	0.0	0.0	0.0	208.0	1,254.2
NJ	45.7	7,714.7	2,115.0	0.0	258.0	2.0	400.0	5.0	3,493.0	0.0	4.0	41.7	552.4	458.9	3.0	0.0	189.1	7.5	15,289.9
OH	24.0	6,627.7	4,201.2	0.0	731.6	0.0	0.0	200.0	2,134.0	0.0	52.5	55.4	1.1	12,423.8	372.0	0.0	0.0	766.8	27,590.1
PA	49.9	15,021.5	1,542.7	0.0	1,454.6	0.0	1,583.0	1,445.7	9,648.8	0.0	176.8	95.1	18.0	9,415.7	3,821.0	0.0	294.0	1,510.7	46,077.5
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	0.0	603.4	0.0	3,069.0	460.1	3,581.3	0.0	33.0	118.8	319.4	3,001.6	495.0	1,586.0	368.4	0.0	26,742.9
WV	60.9	0.0	1,073.9	0.0	11.0	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	47,591.6	25,235.0	0.0	3,978.6	32.0	5,052.0	3,040.6	34,257.6	0.0	360.3	396.0	1,598.9	55,952.4	8,581.6	2,136.0	1,010.5	9,027.2	198,599.2

Table 12-3 and Figure 12-1 show the age of existing PJM generators, by unit type, as of June 30, 2019. Of the 198,599.2 MW of installed capacity, 74,483.0 MW (37.5 percent) are from units older than 40 years, of which 39,667.2 MW (53.3 percent) are coal fired steam units, 532 MW (0.7 percent) are combined cycle units and 16,044.9 MW (21.5 percent) are nuclear units.

Table 12-3 PJM capacity (MW) by unit type and age (years): June 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	42,616.1	19,109.7	0.0	784.6	32.0	0.0	297.2	0.0	0.0	149.8	341.6	1,598.9	3,655.0	82.0	0.0	97.4	9,027.2	78,140.4
20 to 40	0.0	4,443.5	5,423.1	0.0	231.6	0.0	3,003.0	427.2	18,212.7	0.0	37.0	54.4	0.0	12,630.2	600.0	0.0	913.1	0.0	45,975.8
40 to 60	0.0	532.0	702.2	0.0	2,962.4	0.0	2,049.0	340.0	16,044.9	0.0	173.5	0.0	0.0	36,156.4	6,391.1	2,136.0	0.0	0.0	67,487.5
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	3,510.8	1,508.5	0.0	0.0	0.0	6,995.5
Total	349.0	47,591.6	25,235.0	0.0	3,978.6	32.0	5,052.0	3,040.6	34,257.6	0.0	360.3	396.0	1,598.9	55,952.4	8,581.6	2,136.0	1,010.5	9,027.2	198,599.2

Figure 12-1 PJM capacity (MW) by age (years): June 30, 2019



Generation Retirements[19]

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.[20] 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.[21]

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.[22] 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.[23] 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.[24]

19 See PJM. Planning. "Generator Deactivations," at <http://www.pjm.com/planning/services-requests/gen-deactivations.aspx>.
20 See OATT Section V and Attachment M–Appendix § IV.
21 See PJM. "*Explaining Power Plant Retirements in PJM*," at <http://learn.pjm.com/three-priorities/planning-for-the-future/explaining-power-plant-retirements.aspx>.
22 See OATT § 230.3.3.
23 See *PJM Interconnection, L.L.C.*, Docket No. ER12-1177 (Feb. 29, 2012).
24 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>.

Generation Retirements 2011 through 2022

Table 12-4 shows that there are 46,448.9 MW of generation that have been, or are planned to be, retired between 2011 and 2022, of which 32,486.2 MW (69.9 percent) are coal fired steam units, as of June 30, 2019. 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	31.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3,027.0	97.0	10.0	10.0	0.0	3,225.8
Planned Retirements (July 2019 and later)	0.0	0.0	528.5	0.0	56.4	0.0	0.0	0.0	4,716.0	0.0	13.0	8.0	0.0	5,582.1	102.0	786.0	60.0	0.0	11,852.0
Total	41.0	425.0	2,284.3	0.0	1,846.5	0.0	0.5	0.0	5,330.5	0.0	57.1	41.9	0.0	32,486.2	2,065.5	1,658.0	202.0	10.4	46,448.9

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 46,448.9 MW of units that has been, or are planned to be, retired between 2011 and 2022, 32,486.2 MW (69.9 percent) are coal fired steam units. These coal fired steam units have an average age of 52.6 years and an average size of 195.7 MW. Over half of the retiring coal fired steam units, 59.9 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	0.9%
Combustion Turbine	114	36.2	41.4	4,130.8	8.9%
Natural Gas	59	38.7	41.4	2,284.3	4.9%
Oil	0	0.0	0.0	0.0	0.0%
Other	55	33.6	41.4	1,846.5	4.0%
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	6	888.4	41.6	5,330.5	11.5%
RICE	23	4.4	29.3	99.0	0.2%
Natural Gas	0	0.0	0.0	0.0	0.0%
Oil	11	5.2	46.1	57.1	0.1%
Other	12	3.5	12.4	41.9	0.1%
Solar	0	0.0	0.0	0.0	0.0%
Steam	197	153.9	46.1	36,411.7	78.4%
Coal	166	195.7	52.6	32,486.2	69.9%
Natural Gas	18	114.8	60.8	2,065.5	4.4%
Oil	6	276.3	45.7	1,658.0	3.6%
Other	7	28.9	25.1	202.0	0.4%
Wind	1	10.4	15.6	10.4	0.0%
Total	346	134.2	46.5	46,448.9	100.0%

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	3.8	0.0	635.0	171.0	0.0	0.0	0.0	1,262.9
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	2,134.0	0.0	32.3	0.9	0.0	14,669.4	0.0	0.0	0.0	0.0	17,162.6
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	4,801.3	283.0	176.0	109.0	10.4	8,098.4
VA	0.0	267.0	0.0	0.0	79.3	0.0	0.0	0.0	0.0	0.0	2.9	2.0	0.0	2,739.0	543.0	786.0	83.0	0.0	4,502.2
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	2,284.3	0.0	1,846.5	0.0	0.5	0.0	5,330.5	0.0	57.1	41.9	0.0	32,486.2	2,065.5	1,658.0	202.0	10.4	46,448.9

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

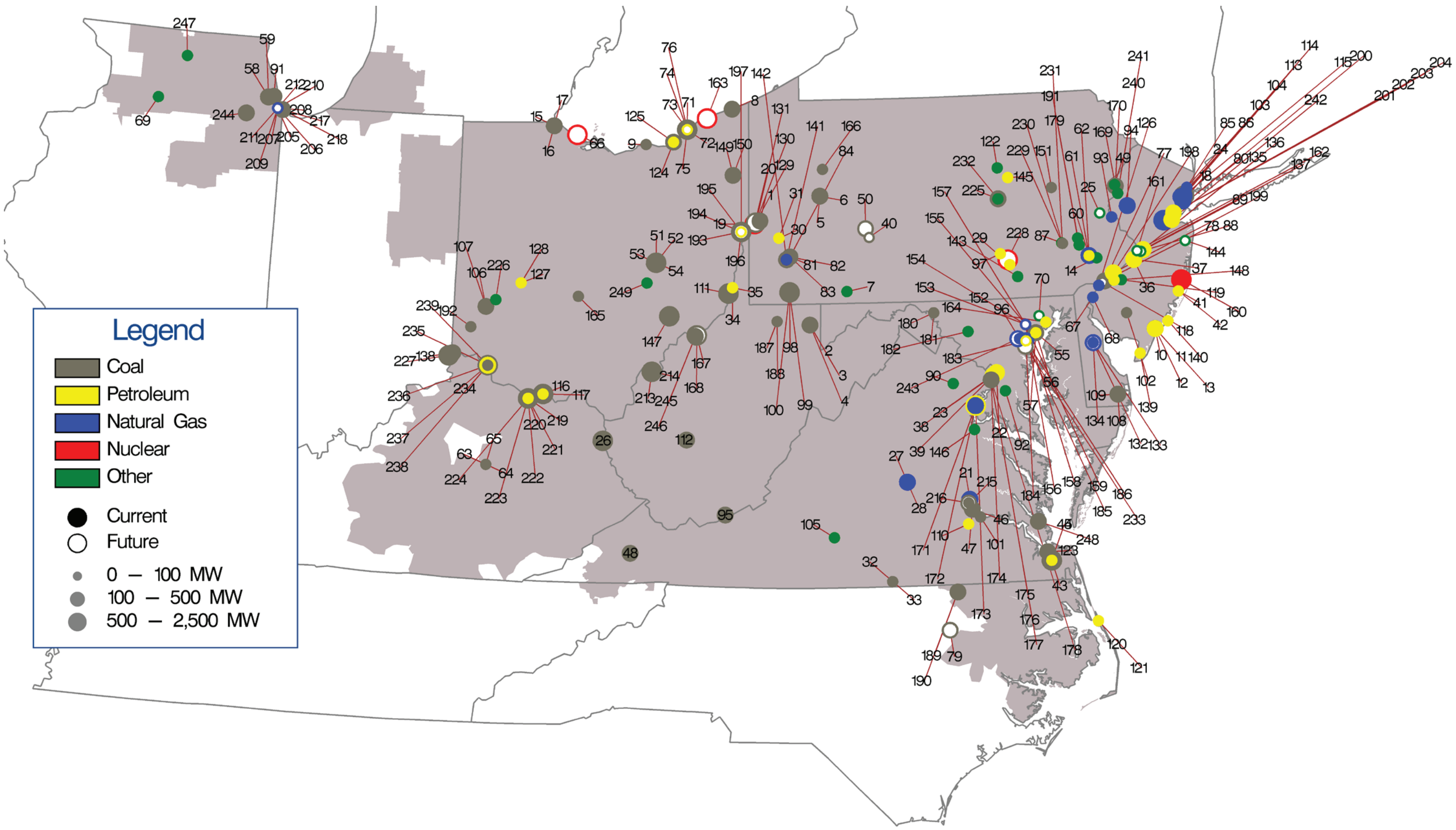


Table 12-7 Unit identification for map of PJM unit retirements: 2011 through 2022

ID	Unit	ID	Unit	ID	Unit	ID	Unit	ID	Unit
1	AES Beaver Valley	51	Conesville 3	101	Hopewell James River Cogeneration	151	Northeastern Power NEPCO	201	Sewaren 2
2	Albright 1	52	Conesville 4	102	Howard Down 10	152	Notch Cliff GT1	202	Sewaren 3
3	Albright 2	53	Conesville 5	103	Hudson 1	153	Notch Cliff GT2	203	Sewaren 4
4	Albright 3	54	Conesville 6	104	Hudson 2	154	Notch Cliff GT3	204	Sewaren 6
5	Armstrong 1	55	Crane 1	105	Hurt NUG	155	Notch Cliff GT4	205	Southeast Chicago CT11
6	Armstrong 2	56	Crane 2	106	Hutchings 1-3, 5-6	156	Notch Cliff GT5	206	Southeast Chicago CT12
7	Arnold (Green Mtn. Wind Farm	57	Crane GT1	107	Hutchings 4	157	Notch Cliff GT6	207	Southeast Chicago CT5
8	Ashtabula 5	58	Crawford 7	108	Indian River 1	158	Notch Cliff GT7	208	Southeast Chicago CT6
9	Avon Lake 7	59	Crawford 8	109	Indian River 3	159	Notch Cliff GT8	209	Southeast Chicago CT7
10	BL England 1	60	Cromby 1	110	Ingenco Petersburg	160	Oyster Creek	210	Southeast Chicago CT8
11	BL England 2	61	Cromby 2	111	Kammer 1-3	161	Pennsbury Generator Landfill 1	211	Southeast Chicago GT10
12	BL England 3	62	Cromby D	112	Kanawha River 1-2	162	Pennsbury Generator Landfill 2	212	Southeast Chicago GT9
13	BL England Diesel Units 1-4	63	Dale 1-2	113	Kearny 10	163	Perry U1 Nuclear Generating Unit	213	Sporn 1-4
14	Barbados AES Battery	64	Dale 3	114	Kearny 11	164	Perryman 2	214	Sporn 5
15	Bay Shore 2	65	Dale 4	115	Kearny 9	165	Picway 5	215	Spruance NUG1 (Rich 1-2)
16	Bay Shore 3	66	Davis Besse U1 Nuclear Generating Unit	116	Killen 2	166	Piney Creek NUG	216	Spruance NUG2 (Rich 3-4)
17	Bay Shore 4	67	Deepwater 1	117	Killen CT	167	Pleasants Power Station U1	217	State Line 3
18	Bayonne Cogen Plant (CC)	68	Deepwater 6	118	Kimberly Clark Generator	168	Pleasants Power Station U2	218	State Line 4
19	Beaver Valley U1 Nuclear Generating Unit	69	Dixon Lee Landfill Generator	119	Kinsley Landfill	169	Portland 1	219	Stuart 1
20	Beaver Valley U2 Nuclear Generating Unit	70	Eastern Landfill Gas Generator	120	Kitty Hawk GT 1	170	Portland 2	220	Stuart 2
21	Bellemeade	71	Eastlake 1	121	Kitty Hawk GT 2	171	Possum Point 3	221	Stuart 3
22	Benning 15	72	Eastlake 2	122	Koppers Co. IPP	172	Possum Point 4	222	Stuart 4
23	Benning 16	73	Eastlake 3	123	Lake Kingman	173	Possum Point 5	223	Stuart Diesels 1-4
24	Bergen 3	74	Eastlake 4	124	Lake Shore 18	174	Potomac River 1	224	Stuart Diesels 1-4
25	Bethlehem Renewable Energy Generator (Landfill)	75	Eastlake 5	125	Lake Shore EMD	175	Potomac River 2	225	Sunbury 1-4
26	Big Sandy 2	76	Eastlake 6	126	MH50 Markus Hook Co-gen	176	Potomac River 3	226	Tait Battery
27	Bremo 3	77	Eddystone 1	127	Mad River CTs A	177	Potomac River 4	227	Tanners Creek 1-4
28	Bremo 4	78	Eddystone 2	128	Mad River CTs B	178	Potomac River 5	228	Three Mile Island Unit 1
29	Brunner Island Diesels	79	Edgecomb NUG (Rocky 1-2)	129	Mansfield 1	179	Pottstown LF (Moser)	229	Titus 1
30	Brunot Island 1B	80	Edison 1-3	130	Mansfield 2	180	R Paul Smith 3	230	Titus 2
31	Brunot Island 1C	81	Elrama 1	131	Mansfield 3	181	R Paul Smith 4	231	Titus 3
32	Buggs Island 1 (Mecklenberg)	82	Elrama 2	132	McKee 1	182	Reichs Ford Road Landfill Generator	232	Viking Energy NUG
33	Buggs Island 2 (Mecklenberg)	83	Elrama 3	133	McKee 2	183	Riverside 4	233	Wagner 2
34	Burger 3	84	Elrama 4	134	McKee 3	184	Riverside 6	234	Walter C Beckjord 1
35	Burger EMD	85	Essex 10-11	135	Mercer 1	185	Riverside 7	235	Walter C Beckjord 2
36	Burlington 8,11	86	Essex 12	136	Mercer 2	186	Riverside 8	236	Walter C Beckjord 3
37	Burlington 9	87	Evergreen Power United Corstack	137	Mercer 3	187	Riversville 5	237	Walter C Beckjord 4
38	Buzzard Point East Banks 1,2,4-8	88	Fairless Hills Landfill A	138	Miami Fort 6	188	Riversville 6	238	Walter C Beckjord 5-6
39	Buzzard Point West Banks 1-9	89	Fairless Hills Landfill B	139	Middle 1-3	189	Roanoke Valley 1	239	Walter C Beckjord GT 1-4
40	Cambria CoGen	90	Fauquier County Landfill	140	Missouri Ave B,C,D	190	Roanoke Valley 2	240	Warren County Landfill
41	Cedar 1	91	Fisk Street 19	141	Mitchell 2	191	Rolling Hills Landfill Generator	241	Warren County NUG
42	Cedar 2	92	GUDE Landfill	142	Mitchell 3	192	SMART Paper	242	Werner 1-4
43	Chesapeake 1-4	93	Gilbert 1-4	143	Modern Power Landfill NUG	193	Sammis 1-4	243	Westport 5
44	Chesapeake 7-10	94	Glen Gardner 1-8	144	Monmouth NUG landfill	194	Sammis 5	244	Will County 3
45	Chesapeake 7-10	95	Glen Lyn 5-6	145	Montour ATG	195	Sammis 6	245	Willow Island 1
46	Chesterfield 3	96	Gould Street Generation Station	146	Morris Landfill Generator	196	Sammis 7	246	Willow Island 2
47	Chesterfield 4	97	Harrisburg 4 CT	147	Muskingum River 1-5	197	Sammis Diesel	247	Winnebago Landfill
48	Clinch River 3	98	Hatfield's Ferry 1	148	National Park 1	198	Schuylkill 1	248	Yorktown 1-2
49	Columbia Dam Hydro	99	Hatfield's Ferry 2	149	Niles 1	199	Schuylkill Diesel	249	Zanesville Landfill
50	Colver Power Project	100	Hatfield's Ferry 3	150	Niles 2	200	Sewaren 1		

Current Year Generation Retirements

Table 12-8 shows that in the first six months of 2019, 3,225.8 MW of generation retired. The largest generators that retired in the first six 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 3,225.8 MW of generation that retired, 1,660.0 MW (51.5 percent) were located in the ATSI Zone.

Table 12-8 Unit deactivations: January through June, 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
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
Total		3,225.8				

Planned Generation Retirements

Table 12-9 shows that, as of June 30, 2019, there are 11,852.0 MW of generation that have requested retirement after June 30, 2019, of which 5,131.0 MW (43.3 percent) are located in the ATSI Zone, 2,960.0 MW (57.7 percent) are coal fired steam units and 2,134.0 MW (41.6 percent) are nuclear units.

Table 12-9 Planned retirement of PJM units: June 30, 2019

Company	Unit Name	ICAP (MW)	Unit Type	Zone Name	Projected Deactivation Date
Exelon Corporation	Bethlehem Renewable Energy Generator (Landfill)	5.0	RICE-Other	PPL	31-Aug-19
Exelon Corporation	Eastern Landfill Gas Generator	3.0	RICE-Other	BGE	31-Aug-19
Northern Star Generation Services, Llc	Cambria CoGen	88.0	Steam-Coal	PENELEC	17-Sep-19
Kimberly-Clark Corporation	Kimberly Clark Generator	3.3	Steam-Coal	PECO	24-Sep-19
Exelon Corporation	Three Mile Island Unit 1 Nuclear Generating Station	805.0	Nuclear	Met-Ed	30-Sep-19
Exelon Corporation	Riverside 8	20.0	CT-Other	BGE	01-Dec-19
Ares Management LP	Spruance NUG1 (aka Spruance 1 Rich 1-2)	115.5	Steam-Coal	Dominion	12-Jan-20
FirstEnergy Corp.	Davis Besse U1 Nuclear Generating Unit	894.0	Nuclear	ATSI	31-May-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
Ares Management LP	Edgecomb NUG (aka Edgecomb Rocky 1-2)	115.5	Steam-Coal	Dominion	31-Oct-20
NextEra Energy, Inc.	Monmouth NUG landfill	6.4	CT-Other	JCPL	31-Dec-20
FirstEnergy Corp.	Beaver Valley U1 Nuclear Generating Unit	892.0	Nuclear	DLCO	31-May-21
FirstEnergy Corp.	Perry U1 Nuclear Generating Unit	1,240.0	Nuclear	ATSI	31-May-21
Dominion Resources, Inc.	Possum Point 5	786.0	Steam-Oil	Dominion	31-May-21
Exelon Corporation	Southeast Chicago CT11	37.0	CT-Natural Gas	ComEd	31-May-21
Exelon Corporation	Southeast Chicago CT12	37.0	CT-Natural Gas	ComEd	31-May-21
Exelon Corporation	Southeast Chicago CT5	37.0	CT-Natural Gas	ComEd	31-May-21
Exelon Corporation	Southeast Chicago CT6	37.0	CT-Natural Gas	ComEd	31-May-21
Exelon Corporation	Southeast Chicago CT7	37.0	CT-Natural Gas	ComEd	31-May-21
Exelon Corporation	Southeast Chicago CT8	37.0	CT-Natural Gas	ComEd	31-May-21
Exelon Corporation	Southeast Chicago GT10	37.0	CT-Natural Gas	ComEd	31-May-21
Exelon Corporation	Southeast Chicago GT9	37.0	CT-Natural Gas	ComEd	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
FirstEnergy Corp.	Sammis 5	290.0	Steam-Coal	ATSI	01-Jun-22
FirstEnergy Corp.	Sammis 6	600.0	Steam-Coal	ATSI	01-Jun-22
FirstEnergy Corp.	Sammis 7	600.0	Steam-Coal	ATSI	01-Jun-22
Total		11,852.0			

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.[25] 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 AE2began on October 1, 2018 and closed on March 31, 2019. Queue AF1 began on April 1, 2019 and will close 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.[26] 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.[27]

The PJM queue evaluation process has been substantially improved in recent years and it is more efficient and effective as a result.[28] 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. Until there has been additional time and queue processing to validate the effectiveness of these changes, 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.

25 See OATT Parts IV & VI.
26 See PJM. "PJM Manual 14C: Generation and Transmission Interconnection Process," Rev. 13 (August 23, 2018).
27 PJM does not track the duration of suspensions or PJM termination of projects.
28 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 June 30, 2019, 125,757.4 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.[29]

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 six months of 2019, the AE2 queue window closed, and the AF1 queue window opened. Combined, these queue windows added 32,555.1 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 June 30, 2019, there were 125,757.4 total MW in generation queues, in the status of active, under construction or suspended, an increase of 10,803.7 MW (9.4 percent). Table 12-11 shows MW in queues by expected completion year and MW changes in the queue between December 31, 2018, and June 30, 2019, for ongoing projects, i.e. projects with the status active, under construction or suspended.[30]

Table 12-11 Queue comparison by expected completion year (MW): December 31, 2018 and June 30, 2019[31]

			Year Change	
Year	As of 12/31/2018	As of 06/30/2019	MW	Percent
2008	12.0	12.0	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	417.2	201.4	(215.8)	(51.7%)
2016	1,818.6	657.4	(1,161.2)	(63.9%)
2017	3,063.8	1,986.2	(1,077.6)	(35.2%)
2018	10,189.3	4,468.7	(5,720.5)	(56.1%)
2019	16,270.4	15,964.7	(305.7)	(1.9%)
2020	22,508.9	24,030.5	1,521.6	6.8%
2021	5,846.0	33,978.6	28,132.6	481.2%
2022	2,460.9	27,756.1	25,295.2	1027.9%
2023	0.0	7,995.1	7,995.1	0.0%
2024	0.0	4,283.8	4,283.8	0.0%
2025	0.0	2,286.9	2,286.9	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	62,794.1	125,757.4	62,963.3	100.3%

29 See "*New Generation in the PJM Capacity Market: MW and Funding Sources for Delivery Years 2007/2008 through 2018/2019*," <http://www.monitoringanalytics.com/reports/Reports/2016/New_Generation_in_the_PJM_Capacity_Market_20160504.pdf>.

30 Expected completion dates are entered when the project enters the queue. Actual completion dates are generally different than expected completion dates.

31 Wind and solar capacity in Table 12-11 through Table 12-15 have not been adjusted to reflect derating.

Table 12-12 shows the project status changes in more detail and how scheduled queue capacity has changed between December 31, 2018, and June 30, 2019. For example, 86,919.1 MW entered the queue in the first six months of 2019. Of those 86,919.1 MW, 23,922.1 MW have been withdrawn. Of the total 71,173.0 MW marked as active on December 31, 2018, 18,562.6 MW were withdrawn, 3,322.2 MW were suspended, 3,353.3 MW started construction, and 1,126.0 MW went into service by June 30, 2019. Analysis of projects that were suspended on December 31, 2018 show that 3,711.0 MW came out of suspension and are now active as of June 30, 2019.

Table 12-12 Change in project status (MW): December 31, 2018 to June 30, 2019

		Status at 6/30/2019				
Status at 12/31/2018	Total at 12/31/2018	Active	In Service	Under Construction	Suspended	Withdrawn
(Entered during 2019)	0.0	62,950.1	33.8	13.2	0.0	23,922.1
Active	71,173.0	44,808.9	1,126.0	3,353.3	3,322.2	18,562.6
In Service	51,674.6	0.0	51,672.7	0.0	0.0	1.9
Under Construction	18,904.2	791.3	13,945.9	3,259.1	544.0	363.9
Suspended	9,356.1	3,711.0	140.0	0.0	3,004.4	2,500.7
Withdrawn	322,847.7	0.0	0.0	0.0	0.0	322,847.7
Total	473,955.5	112,261.2	66,918.4	6,625.6	6,870.6	368,198.8

On June 30, 2019, 125,757.4 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 112,261.2 MW in the status of Active on June 30, 2019, 31,451.1 MW (28.0 percent) were combined cycle projects. Of the 6,625.6 MW in the status of under construction, 3,564.5 MW (53.8 percent) were combined cycle projects.

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 June 30, 2019, there were 45,732.1 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 June 30, 2019, there were only 133.0 MW of coal fired steam capacity active, suspended or under construction in PJM queues.

There are 5,582.1 MW of coal fired steam capacity and 638.5 MW of natural gas capacity slated for deactivation between July 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 June 30, 2019, there are 125,757.4 MW of capacity in queues that are not yet in service or withdrawn, of which 5.5 percent are suspended, 5.3 percent are under construction and 89.3 percent have not begun construction.

Table 12-13 Current project status (MW) by unit type: June 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	2,426.2	31,451.1	5,267.4	14.0	0.0	0.0	1,000.0	114.0	123.5	91.9	0.0	0.8	47,091.6	85.0	94.0	0.0	40.0	24,461.8	112,261.2
Suspended	52.3	4,769.1	200.0	0.0	0.0	0.0	0.0	0.0	0.0	39.8	0.0	0.0	487.4	0.0	0.0	0.0	16.0	1,306.0	6,870.6
Under Construction	4.6	3,564.5	253.0	0.0	0.0	0.0	0.0	22.7	44.0	1.3	4.0	0.0	664.9	48.0	0.0	0.0	62.5	1,956.1	6,625.6
Total	2,483.0	39,784.7	5,720.4	14.0	0.0	0.0	1,000.0	136.7	167.5	133.0	4.0	0.8	48,243.9	133.0	94.0	0.0	118.5	27,723.9	125,757.4

Table 12-14 Capacity in PJM queues (MW): June 30, 2019[32]

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	600.0	1,986.4	0.0	440.0	19,668.9	22,695.3
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	206.9	12.0	0.0	7,937.8	8,156.7
U2 Expired 31-Jul-08	400.0	267.5	260.0	300.0	15,952.2	17,179.7
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	345.9	300.0	0.0	5,139.5	5,798.9
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	490.3	57.7	100.0	8,574.1	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	585.0	5,578.4	9,895.2
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	378.3	1,434.4	4.5	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	11.6	2,861.4	200.0	33.0	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	4,943.2	1,020.8	190.8	756.0	9,155.5	16,066.3
AB1 Expired 31-Oct-15	8,977.5	1,056.5	78.4	91.2	10,249.0	20,452.6
AB2 Expired 31-Mar-16	6,467.3	207.5	198.9	1,269.6	7,074.1	15,217.4
AC1 Expired 30-Sep-16	10,327.3	234.7	198.0	1,258.7	8,056.9	20,075.6
AC2 Expired 30-Apr-17	4,878.4	94.0	0.6	53.9	7,574.8	12,601.6
AD1 Expired 30-Sep-17	8,682.5	26.7	113.0	35.0	2,450.9	11,308.1
AD2 Expired 31-Mar-18	9,641.3	33.8	13.2	0.0	10,726.4	20,414.7
AE1 Expired 30-Sep-18	21,389.0	0.0	0.0	0.0	11,810.9	33,199.8
AE2 Through 31-Mar-19	31,339.3	0.0	0.0	0.0	2,916.2	34,255.5
AF1 Through 30-Sep-19	1,215.7	0.0	0.0	0.0	20.0	1,235.7
Total	112,261.2	66,918.4	6,625.6	6,870.6	368,198.8	560,874.6

32 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 June 30, 2019, 125,757.4 MW of capacity were in generation request queues for construction through 2029.[33] Table 12-15 also shows the planned retirements for each zone.

33 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 27,723.9 MW of wind resources and 48,243.9 MW of solar resources, using the average derate factors, the 125,757.4 MW currently under construction, suspended or active in the queue would be reduced to 76,810.8 MW.

Table 12-15 Queue totals for projects (active, suspended and under construction) by LDA, control zone and unit type (MW): June 30, 2019[34]

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	100.0	1,068.6	230.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	611.5	0.0	0.0	0.0	0.0	2,803.6	4,813.7	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	1,729.2	0.0	0.0	0.0	0.0	727.1	2,938.3	102.0
	JCPL	241.8	600.0	200.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	250.5	0.0	0.0	0.0	0.0	4,559.2	5,851.5	6.4
	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	18.0	0.0	0.0	0.0	0.0	0.0	247.0	69.3
	PSEG	2.0	1,792.5	675.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	87.7	0.0	0.0	0.0	0.0	0.0	2,557.2	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	60.0	0.0	0.0	0.0	0.0	0.0	60.0	0.0
	EMAAC Total	374.8	4,014.1	1,134.0	0.0	0.0	0.0	0.0	0.0	94.0	0.0	4.0	0.0	2,756.8	0.0	0.0	0.0	0.0	8,089.9	16,467.7	177.7
SWMAAC	BGE	0.1	0.0	153.6	14.0	0.0	0.0	0.0	0.0	45.5	1.3	0.0	0.0	4.0	0.0	0.0	0.0	0.0	0.0	218.5	390.5
	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	190.9	0.0	0.0	0.0	0.0	0.0	1,368.5	0.0
	SWMAAC Total	0.1	1,177.6	153.6	14.0	0.0	0.0	0.0	0.0	45.5	1.3	0.0	0.0	194.9	0.0	0.0	0.0	0.0	0.0	1,587.0	390.5
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	876.1	0.0	0.0	0.0	0.0	0.0	990.0	805.0
	PENELEC	160.0	1,368.0	481.0	0.0	0.0	0.0	0.0	0.0	0.0	79.8	0.0	0.0	1,467.5	0.0	0.0	0.0	0.0	290.3	3,846.6	198.0
	PPL	234.0	1,327.8	0.0	0.0	0.0	0.0	1,000.0	0.0	0.0	0.0	0.0	0.0	736.2	0.0	0.0	0.0	16.0	563.1	3,877.1	5.0
	WMAAC Total	394.0	2,809.7	481.0	0.0	0.0	0.0	1,000.0	0.0	0.0	79.8	0.0	0.0	3,079.8	0.0	0.0	0.0	16.0	853.4	8,713.7	1,008.0
Non-MAAC	AEP	736.6	8,016.0	1,097.0	0.0	0.0	0.0	0.0	99.0	28.0	12.0	0.0	0.8	12,139.3	101.0	30.0	0.0	40.0	6,187.3	28,487.0	776.8
	APS	94.0	8,629.7	116.0	0.0	0.0	0.0	0.0	15.0	0.0	39.9	0.0	0.0	2,013.4	0.0	0.0	0.0	0.0	1,073.4	11,981.4	1,278.0
	ATSI	20.3	5,805.0	70.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,783.8	0.0	0.0	0.0	0.0	816.1	8,495.1	5,131.0
	ComEd	290.9	5,342.6	1,238.0	0.0	0.0	0.0	0.0	22.7	0.0	0.0	0.0	0.0	4,367.5	0.0	64.0	0.0	0.0	7,514.7	18,840.3	296.0
	DAY	19.9	1,150.0	127.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,257.7	12.0	0.0	0.0	0.0	100.0	3,667.1	0.0
	DEOK	19.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	530.0	20.0	0.0	0.0	0.0	0.0	569.8	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	532.6	2,840.0	1,098.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	17,268.4	0.0	0.0	0.0	62.5	3,089.2	24,891.0	1,017.0
	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	1,781.0	0.0	0.0	0.0	0.0	0.0	1,781.0	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	1,714.1	31,783.3	3,951.8	0.0	0.0	0.0	0.0	136.7	28.0	51.9	0.0	0.8	42,212.4	133.0	94.0	0.0	102.5	18,780.6	98,989.1	10,275.8
	Total	2,483.0	39,784.7	5,720.4	14.0	0.0	0.0	1,000.0	136.7	167.5	133.0	4.0	0.8	48,243.9	133.0	94.0	0.0	118.5	27,723.9	125,757.4	11,852.0

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.[35] 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.

Table 12-16 shows the milestone status when projects were withdrawn, for all withdrawn projects. Of the 2,530 projects withdrawn, 1,257 (49.7 percent) were withdrawn before the system impact study was completed. Once a Construction Service Agreement (CSA) is executed, the financial obligation for any necessary

34 This data includes only projects with a status of active, under construction, or suspended.
35 See PJM. "PJM Manual 14B: PJM Region Transmission Planning Process," Rev. 44 (Feb. 21, 2019).

transmission upgrades cannot be retracted. Of the 2,530 projects withdrawn, 486 (19.2 percent) were withdrawn after the completion of a Construction Service Agreement.

Table 12-16 Last milestone at time of withdrawal: January 1997 through June 2019

Milestone Completed	Projects Withdrawn	Percent	Average Days	Maximum Days
Never Started	449	17.7%	92	875
Feasibility Study	808	31.9%	277	1,633
System Impact Study	504	19.9%	752	3,248
Facilities Study	283	11.2%	1,080	3,810
Construction Service Agreement (CSA) or beyond	486	19.2%	1,304	4,249
Total	2,530	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 1,017 days, or 2.8 years, between entering a queue and going into service. For withdrawn projects, there is an average time of 617 days, or 1.7 years, between entering a queue and withdrawing.

Table 12-17 Project queue times by status (days): June 30, 2019[36]

Status	Average (Days)	Standard Deviation	Minimum	Maximum
Active	501	609	0	4,211
In-Service	1,017	728	0	4,024
Suspended	1,500	905	366	4,177
Under Construction	1,820	1,073	486	4,933
Withdrawn	617	689	0	4,249

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 1,116 projects in the queue as of June 30, 2019, 281 (25.2 percent) had a completed feasibility study and 280 (25.1 percent) had a completed construction service agreement.

36 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 Project queue times by milestone (days): June 30, 2019

Milestone Reached	Number of Projects	Percent of Total Projects	Average Days	Maximum Days
Under Review	351	31.5%	132	473
Feasibility Study	281	25.2%	482	1,160
System Impact Study	176	15.8%	905	1,704
Facilities Study	28	2.5%	1,603	3,927
Construction Service Agreement (CSA) or beyond	280	25.1%	1,542	5,389
Total	1,116	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, 16.9 percent of the queued MW have gone into service. The completion rate for wind projects increases to 31.8 percent when wind projects complete the facility study agreement, and further increases to 50.1 percent when wind projects complete the construction service agreement. Of all wind projects to enter the queue, only 7.9 percent of the queued MW have 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 June 2019

Unit Type	Completion Rate (SIS)	Completion Rate (FSA)	Completion Rate (CSA)	Completion Rate (ALL)
Battery	27.3%	44.8%	56.1%	5.4%
CC	33.4%	53.1%	87.1%	13.0%
CT - Natural Gas	77.1%	83.5%	87.5%	47.7%
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	41.0%	57.1%	62.5%	20.9%
Nuclear	34.8%	41.7%	51.1%	28.6%
RICE - Natural Gas	34.5%	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%	28.5%	36.1%	1.9%
Steam - Coal	13.3%	24.9%	37.0%	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	16.9%	31.8%	50.1%	7.9%

On June 30, 2019, 125,757.4 MW of capacity were in generation request queues in the status of active, under construction or suspended. Of the total 125,757.4MW in the queue, 56,685.8 MW (45.1 percent) have reached at least the SIS milestone and 69,071.6 MW (54.9 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), 33,654.7 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 1,848 projects entered from January 2015 through June 2019, 1,540 projects, 83.3 percent, were renewable. Of the 345 projects entered in the first six months of 2019, 333 projects, 96.5 percent, were renewable.

Table 12-20 Number of projects entered in the queue: June 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	333	12	345
Total	70	2,954	1,476	4,500

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 63.3 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: June 30, 2019

Fuel Group	Number of Projects	Percent of Projects	MW	Percent MW
Nuclear	9	0.8%	167.5	0.1%
Renewable	945	84.7%	79,587.5	63.3%
Traditional	162	14.5%	46,002.4	36.6%
Total	1,116	100.0%	125,757.4	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 June 30, 2019. As of June 30, 2019, 4,500 projects, representing 560,874.6 MW, have entered the queue process since its inception. Of those, 854 projects, representing 66,918.4 MW, went into service. Of the projects that entered the queue process, 2,530 projects, representing 368,198.8 MW (65.6 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 3,671 projects have been classified as new generation and 829 projects have been classified as upgrades. Wind, solar and natural gas projects have accounted for 3,602 projects, or 80.0 percent, of all 4,500 generation queue projects.

Table 12-22 Status of all generation queue projects: January 1997 through June 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	11	2	9	0	55	136	8	5	0	3	80	476
	Upgrade	5	88	90	15	5	0	3	17	41	8	1	15	17	52	7	0	7	7	378
Under Construction	New Generation	21	3	1	0	0	0	0	2	0	1	0	0	17	0	0	0	0	11	56
	Upgrade	0	9	2	0	0	0	0	0	1	0	1	0	3	2	0	0	1	2	21
Suspended	New Generation	5	5	0	0	0	0	0	0	0	2	0	0	26	0	0	0	1	9	48
	Upgrade	2	5	1	0	0	0	0	0	0	0	0	0	1	0	0	0	0	1	10
Withdrawn	New Generation	110	412	21	9	81	26	2	39	9	22	12	16	1,033	55	1	0	34	421	2,303
	Upgrade	17	83	10	13	13	2	0	4	9	0	2	3	28	14	0	0	2	27	227
Active	New Generation	47	34	14	1	0	0	2	1	1	5	0	0	600	0	0	0	0	83	788
	Upgrade	23	36	28	0	0	0	0	3	7	1	0	1	72	4	3	0	1	14	193
Total Projects	New Generation	204	514	84	20	106	29	4	53	12	39	12	71	1,812	63	6	0	38	604	3,671
	Upgrade	47	221	131	28	18	2	3	24	58	9	4	19	121	72	10	0	11	51	829

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, 70.8 percent of all hydro run of river projects classified as upgrades are currently in service in PJM, 16.7 percent of hydro run of river upgrades were withdrawn and 12.5 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 June 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	10.3%	11.7%	57.1%	50.0%	23.6%	10.3%	0.0%	20.8%	16.7%	23.1%	0.0%	77.5%	7.5%	12.7%	83.3%	0.0%	7.9%	13.2%	13.0%
	Upgrade	10.6%	39.8%	68.7%	53.6%	27.8%	0.0%	100.0%	70.8%	70.7%	88.9%	25.0%	78.9%	14.0%	72.2%	70.0%	0.0%	63.6%	13.7%	45.6%
Under Construction	New Generation	10.3%	0.6%	1.2%	0.0%	0.0%	0.0%	0.0%	3.8%	0.0%	2.6%	0.0%	0.0%	0.9%	0.0%	0.0%	0.0%	0.0%	1.8%	1.5%
	Upgrade	0.0%	4.1%	1.5%	0.0%	0.0%	0.0%	0.0%	0.0%	1.7%	0.0%	25.0%	0.0%	2.5%	2.8%	0.0%	0.0%	9.1%	3.9%	2.5%
Suspended	New Generation	2.5%	1.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	5.1%	0.0%	0.0%	1.4%	0.0%	0.0%	0.0%	2.6%	1.5%	1.3%
	Upgrade	4.3%	2.3%	0.8%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.8%	0.0%	0.0%	0.0%	0.0%	2.0%	1.2%
Withdrawn	New Generation	53.9%	80.2%	25.0%	45.0%	76.4%	89.7%	50.0%	73.6%	75.0%	56.4%	100.0%	22.5%	57.0%	87.3%	16.7%	0.0%	89.5%	69.7%	62.7%
	Upgrade	36.2%	37.6%	7.6%	46.4%	72.2%	100.0%	0.0%	16.7%	15.5%	0.0%	50.0%	15.8%	23.1%	19.4%	0.0%	0.0%	18.2%	52.9%	27.4%
Active	New Generation	23.0%	6.6%	16.7%	5.0%	0.0%	0.0%	50.0%	1.9%	8.3%	12.8%	0.0%	0.0%	33.1%	0.0%	0.0%	0.0%	0.0%	13.7%	21.5%
	Upgrade	48.9%	16.3%	21.4%	0.0%	0.0%	0.0%	0.0%	12.5%	12.1%	11.1%	0.0%	5.3%	59.5%	5.6%	30.0%	0.0%	9.1%	27.5%	23.3%

Table 12-24 shows the nameplate generating capacity of projects in the PJM generation queue by technology type and project classification. For example, the 421 new generation wind projects that have been withdrawn from the queue as of June 30, 2019, (as shown in Table 12-22) constitute 71,835.0 MW of nameplate capacity. The 495 new generation and upgrade combined cycle projects that have been withdrawn in the same time period constitute 208,895.3 MW of nameplate capacity.

Table 12-24 Status of all generation capacity (MW) in the PJM generation queue: January 1997 through June 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	471.5	1,639.0	138.1	0.0	440.1	1,471.0	1,343.0	723.0	0.0	60.0	7,952.7	53,564.1
	Upgrade	46.4	6,031.4	2,323.5	127.8	12.3	0.0	390.0	379.1	2,282.8	15.7	23.3	49.9	17.4	897.5	131.5	0.0	605.3	20.5	13,354.4
Under Construction	New Generation	4.6	3,202.0	205.0	0.0	0.0	0.0	0.0	22.7	0.0	1.3	0.0	0.0	501.0	0.0	0.0	0.0	0.0	1,768.6	5,705.2
	Upgrade	0.0	362.5	48.0	0.0	0.0	0.0	0.0	0.0	44.0	0.0	4.0	0.0	163.9	48.0	0.0	0.0	62.5	187.5	920.4
Suspended	New Generation	29.3	4,119.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	39.8	0.0	0.0	467.4	0.0	0.0	0.0	16.0	1,289.7	5,961.2
	Upgrade	23.0	650.1	200.0	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	909.4
Withdrawn	New Generation	1,734.2	198,666.1	2,113.3	1,721.0	1,244.2	5.5	500.0	1,986.9	8,161.0	368.1	63.9	88.6	29,335.9	33,511.6	27.0	0.0	1,035.8	71,835.0	352,398.0
	Upgrade	406.3	10,229.3	495.5	589.0	72.5	0.9	0.0	57.1	916.0	0.0	13.0	10.0	835.1	865.0	0.0	0.0	37.1	1,274.0	15,800.8
Active	New Generation	1,792.3	26,592.3	4,003.9	14.0	0.0	0.0	1,000.0	15.0	28.0	90.3	0.0	0.0	44,653.4	0.0	0.0	0.0	0.0	23,714.0	101,903.2
	Upgrade	633.9	4,858.8	1,263.5	0.0	0.0	0.0	0.0	99.0	95.5	1.6	0.0	0.8	2,438.2	85.0	94.0	0.0	40.0	747.8	10,358.1
Total Projects	New Generation	3,777.2	264,257.9	12,922.7	2,411.5	1,395.6	7.4	1,500.0	2,496.1	9,828.0	637.6	63.9	528.7	76,428.6	34,854.6	750.0	0.0	1,111.8	106,560.0	519,531.6
	Upgrade	1,109.6	22,132.1	4,330.5	716.8	84.8	0.9	390.0	535.2	3,338.3	17.3	40.3	60.7	3,474.6	1,895.5	225.5	0.0	744.9	2,246.1	41,343.0

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, 67.4 percent of wind project MW classified as new generation have been withdrawn from the queue between January 1, 1997, and June 30, 2019.

Table 12-25 Status of all generation queue projects as percent of total MW in project classification: January 1997 through June 2019

Project Status	Percent of Total Projects by Classification																			
	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	5.7%	12.0%	51.1%	28.1%	10.8%	26.2%	0.0%	18.9%	16.7%	21.7%	0.0%	83.2%	1.9%	3.9%	96.4%	0.0%	5.4%	7.5%	10.3%
	Upgrade	4.2%	27.3%	53.7%	17.8%	14.5%	0.0%	100.0%	70.8%	68.4%	90.8%	57.8%	82.2%	0.5%	47.3%	58.3%	0.0%	81.3%	0.9%	32.3%
Under Construction	New Generation	0.1%	1.2%	1.6%	0.0%	0.0%	0.0%	0.0%	0.9%	0.0%	0.2%	0.0%	0.0%	0.7%	0.0%	0.0%	0.0%	0.0%	1.7%	1.1%
	Upgrade	0.0%	1.6%	1.1%	0.0%	0.0%	0.0%	0.0%	0.0%	1.3%	0.0%	9.9%	0.0%	4.7%	2.5%	0.0%	0.0%	8.4%	8.3%	2.2%
Suspended	New Generation	0.8%	1.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	6.2%	0.0%	0.0%	0.6%	0.0%	0.0%	0.0%	1.4%	1.2%	1.1%
	Upgrade	2.1%	2.9%	4.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.6%	0.0%	0.0%	0.0%	0.0%	0.7%	2.2%
Withdrawn	New Generation	45.9%	75.2%	16.4%	71.4%	89.2%	73.8%	33.3%	79.6%	83.0%	57.7%	100.0%	16.8%	38.4%	96.1%	3.6%	0.0%	93.2%	67.4%	67.8%
	Upgrade	36.6%	46.2%	11.4%	82.2%	85.5%	100.0%	0.0%	10.7%	27.4%	0.0%	32.3%	16.5%	24.0%	45.6%	0.0%	0.0%	5.0%	56.7%	38.2%
Active	New Generation	47.4%	10.1%	31.0%	0.6%	0.0%	0.0%	66.7%	0.6%	0.3%	14.2%	0.0%	0.0%	58.4%	0.0%	0.0%	0.0%	0.0%	22.3%	19.6%
	Upgrade	57.1%	22.0%	29.2%	0.0%	0.0%	0.0%	0.0%	18.5%	2.9%	9.2%	0.0%	1.3%	70.2%	4.5%	41.7%	0.0%	5.4%	33.3%	25.1%

Table 12-26 shows the project MW that entered the PJM generation queue by unit type and year of entry. Since 2016, 92.8 percent of all new projects entering the generation queue have been either combined cycle (24.6 percent), wind (22.0 percent) or solar projects (46.3 percent).

Table 12-26 Queue project MW by unit type and queue entry year: January 1997 through June 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	255.4	368.0	0.0	0.0	56.5	3.3	9,078.0	190.0	0.0	50.5	18,525.6	43,794.4
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	11,199.7	41,907.3
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	9,940.4	24,045.7
2011	24.1	20,354.5	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	28,889.3
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	18,804.5	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	35,832.2
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	1,402.4	9,787.4	2,647.4	14.0	0.0	0.0	1,000.0	0.0	28.1	0.0	0.0	0.8	24,650.3	29.0	0.0	0.0	40.0	17,929.3	57,528.7
2019	1,943.4	2,284.0	134.5	0.0	0.0	0.0	500.0	99.0	0.0	0.0	0.0	0.0	18,134.8	0.0	0.0	0.0	0.0	5,663.4	28,759.1
Total	4,886.8	286,390.0	17,253.2	3,128.3	1,480.3	8.3	1,890.0	3,031.3	13,166.3	654.9	104.2	589.4	79,903.2	36,750.1	975.5	0.0	1,856.7	108,806.1	560,874.6

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 June 30, 2019, by zone. Of the 92 combined cycle projects classified either as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, 45 projects (48.9 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 June 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	8	7	3	0	4	0	0	0	14	5	0	6	2	0	10	3	2	7	14	0	88
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	1	1	0	0	0	0	0	0	1	0	0	1	0	0	0	0	1	0	0	0	5
	Upgrade	0	0	0	0	0	0	0	0	0	0	1	0	2	0	0	0	0	2	0	0	0	5
Withdrawn	New Generation	21	18	40	12	8	13	0	1	2	17	17	3	25	25	0	43	39	33	40	53	2	412
	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	8	9	3	0	5	1	0	0	1	0	0	0	0	0	0	2	0	1	2	0	34
	Upgrade	2	6	8	1	0	5	0	0	0	3	0	0	1	2	0	1	2	0	4	1	0	36
Total Projects	New Generation	24	31	52	19	10	19	1	3	2	26	19	3	33	29	0	48	43	38	51	61	2	514
	Upgrade	11	23	20	9	0	12	0	1	0	27	10	0	14	11	0	16	11	9	17	30	0	221

Table 12-28 shows the status of all combined cycle projects by MW that entered PJM generation queues from January 1, 1997 through June 30, 2019, by zone. Of the 39,784.7 MW of combined cycle projects classified either as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, 21,988.3 MW (55.3 percent) are located within AEP, ComEd and APS.

Table 12-28 Status of all combined cycle queue projects by zone (MW): January 1997 through June 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	585.0	1,140.0	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	4,119.0
	Upgrade	0.0	0.0	0.0	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	650.1
Withdrawn	New Generation	7,515.4	11,249.5	16,982.1	7,471.0	3,122.1	7,579.3	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	15,931.0	20,414.2	17,270.7	23,171.7	6.9	198,666.1
	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	6,589.0	6,606.0	3,065.0	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	183.0	0.0	1,030.0	1,741.4	0.0	26,592.3
	Upgrade	41.6	742.0	883.7	550.0	0.0	1,741.7	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	4,858.8
Total Projects	New Generation	9,192.4	21,455.5	26,183.1	14,287.0	3,262.1	11,780.2	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	27,361.6	6.9	264,257.9
	Upgrade	386.0	1,783.0	2,252.7	980.0	0.0	3,750.3	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	22,132.1

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 June 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, 25 projects (54.3 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 June 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	6	1	0	9	6	0	0	24	7	0	0	1	0	2	2	3	4	14	0	90
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	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	1
Withdrawn	New Generation	1	4	0	0	0	1	0	0	0	2	0	1	0	0	0	1	5	0	1	5	0	21
	Upgrade	2	1	0	1	0	1	0	0	0	3	0	0	0	1	0	0	1	0	0	0	0	10
Active	New Generation	1	2	0	0	2	2	1	0	0	3	0	0	0	0	0	1	1	0	0	1	0	14
	Upgrade	0	2	5	1	0	13	1	0	0	3	1	0	0	0	0	1	1	0	0	0	0	28
Total Projects	New Generation	7	6	6	0	5	3	1	0	1	7	7	1	3	1	0	4	10	2	5	15	0	84
	Upgrade	6	10	11	3	0	24	7	0	0	30	8	0	2	2	0	3	4	3	4	14	0	131

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 June 30, 2019, by zone. Of the 5,720.4 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, 2,451.0 MW (42.8 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 June 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	0.0	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	200.0
Withdrawn	New Generation	7.5	460.0	0.0	0.0	0.0	10.0	0.0	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	2,113.3
	Upgrade	165.5	6.0	0.0	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	495.5
Active	New Generation	230.0	1,059.0	0.0	0.0	153.6	230.0	104.0	0.0	0.0	1,060.3	0.0	0.0	0.0	0.0	0.0	29.0	463.0	0.0	0.0	675.0	0.0	4,003.9
	Upgrade	0.0	38.0	116.0	70.0	0.0	960.0	23.5	0.0	0.0	38.0	0.0	0.0	0.0	0.0	0.0	0.0	18.0	0.0	0.0	0.0	0.0	1,263.5
Total Projects	New Generation	598.2	1,519.0	1,176.0	0.0	176.6	240.0	104.0	0.0	205.0	2,150.8	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	12,922.7
	Upgrade	209.2	234.0	303.7	135.0	0.0	1,272.0	83.5	0.0	0.0	982.7	86.0	0.0	200.0	34.1	0.0	13.0	278.0	32.0	252.3	215.0	0.0	4,330.5

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 June 30, 2019, by zone. Of the 87 wind projects to achieve in service status, 51 projects (58.6 percent) are located within AEP, ComEd and APS. Of the 120 wind projects currently active, suspended or under construction in the PJM generation queue, 81 projects (67.5 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 June 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	1	0	0	0	0	0	0	22	0	8	0	0	80
	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	2	0	0	0	0	0	0	1	0	0	0	0	11
	Upgrade	0	0	1	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2
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	42	8	0	103	14	0	0	21	10	1	1	0	0	0	63	0	43	1	0	421
	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	6	25	6	3	0	22	1	0	0	4	4	0	6	0	0	0	0	0	6	0	0	83
	Upgrade	0	1	3	0	0	7	0	0	0	0	1	0	0	0	0	0	2	0	0	0	0	14
Total Projects	New Generation	23	142	67	11	0	149	15	0	0	29	14	1	7	0	0	0	87	0	58	1	0	604
	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 June 30, 2019, by zone. Of the 7,973.2 MW of wind generation capacity to achieve the in service status, 6,641.2 MW (83.3 percent) of nameplate capacity is located within AEP, ComEd and APS. Of the 27,723.9 MW of wind generation capacity currently active, suspended or under construction in the PJM generation queue, 14,775.3 MW of generation capacity (53.3 percent) is located within AEP, ComEd and APS.

Table 12-32 Status of all wind generation queue projects by zone (MW): January 1997 through June 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	102.5	0.0	0.0	0.0	0.0	0.0	0.0	995.0	0.0	226.5	0.0	0.0	7,952.7
	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	312.0	0.0	0.0	0.0	0.0	0.0	0.0	70.0	0.0	0.0	0.0	0.0	1,768.6
	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	0.0	0.0	0.0	0.0	0.0	187.5
Suspended	New Generation	0.0	722.0	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	1,289.7
	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	3,244.1	1,295.6	0.0	23,869.2	2,028.0	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	3,242.1	20.0	0.0	71,835.0
	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	2,803.6	5,145.3	429.0	816.1	0.0	5,975.5	100.0	0.0	0.0	2,700.6	719.8	0.0	4,559.2	0.0	0.0	0.0	0.0	0.0	465.1	0.0	0.0	23,714.0
	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	120.3	0.0	0.0	0.0	0.0	747.8
Total Projects	New Generation	6,457.5	28,909.2	5,280.8	2,111.7	0.0	33,649.1	2,128.0	0.0	0.0	8,180.1	3,536.6	150.3	5,663.2	0.0	0.0	0.0	6,442.0	0.0	4,031.7	20.0	0.0	106,560.0
	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 June 30, 2019, by zone. Of the 153 solar projects to achieve in service status, 9 projects (5.9 percent) are located within AEP, ComEd and APS. Of the 719 solar projects currently active, suspended or under construction in the PJM generation queue, 210 projects (29.2 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 June 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	21	11	0	42	0	0	1	0	0	2	41	0	136
	Upgrade	0	0	0	0	0	0	0	0	0	2	8	0	7	0	0	0	0	0	0	0	0	17
Under Construction	New Generation	0	0	1	0	0	0	0	0	0	5	1	0	3	0	0	0	0	1	0	6	0	17
	Upgrade	0	0	0	0	0	0	0	0	0	2	1	0	0	0	0	0	0	0	0	0	0	3
Suspended	New Generation	0	5	13	0	0	0	1	0	0	1	0	0	3	2	0	0	0	0	0	1	0	26
	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	168	90	65	11	12	31	14	12	0	163	120	4	180	14	1	6	16	14	29	83	0	1,033
	Upgrade	2	2	1	0	0	2	0	0	0	11	1	0	8	0	0	0	0	0	0	1	0	28
Active	New Generation	24	102	42	19	1	33	19	5	4	188	41	17	16	16	0	1	22	16	19	14	1	600
	Upgrade	1	9	1	1	0	4	2	3	1	32	4	2	2	1	0	0	0	1	5	2	1	72
Total Projects	New Generation	199	201	125	30	14	65	35	17	4	378	173	21	244	32	1	8	38	31	50	145	1	1,812
	Upgrade	3	11	2	1	0	6	2	3	1	47	14	2	17	2	0	0	0	1	5	3	1	121

Table 12-34 shows the status of all solar projects by MW that entered PJM generation queues from January 1, 1997 through June 30, 2019, by zone. Of the 1,488.4 MW of solar generation capacity to achieve in service status, 76.7 MW (5.2 percent) of nameplate capacity is located within AEP, ComEd and APS. Of the 48,243.9 MW of solar generation capacity currently active, suspended or under construction in the PJM generation queue, 18,520.3 MW of generation capacity (38.4 percent) is located within AEP, ComEd and APS.

Table 12-34 Status of all solar generation queue projects by zone (MW): January 1997 through June 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	675.9	130.4	0.0	295.3	0.0	0.0	3.3	0.0	0.0	15.0	213.5	0.0	1,471.0
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.1	0.0	0.0	14.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	17.4
Under Construction	New Generation	0.0	0.0	10.0	0.0	0.0	0.0	0.0	0.0	0.0	383.3	20.0	0.0	51.9	0.0	0.0	0.0	0.0	2.5	0.0	33.3	0.0	501.0
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	13.9	150.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	163.9
Suspended	New Generation	0.0	60.0	244.4	0.0	0.0	0.0	20.0	0.0	0.0	91.0	0.0	0.0	8.0	38.0	0.0	0.0	0.0	0.0	0.0	6.0	0.0	467.4
	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	1,738.2	7,056.7	1,793.7	429.3	53.3	1,916.8	523.9	279.4	0.0	10,220.9	1,581.2	309.9	1,424.7	502.0	78.0	51.4	273.7	180.6	403.7	518.3	0.0	29,335.9
	Upgrade	10.0	106.0	0.0	0.0	0.0	20.0	0.0	0.0	0.0	674.0	0.0	0.0	23.8	0.0	0.0	0.0	0.0	0.0	0.0	1.3	0.0	835.1
Active	New Generation	611.5	11,627.3	1,684.0	1,763.8	4.0	3,987.5	2,197.7	445.0	63.0	15,718.4	1,484.2	1,661.0	183.0	798.1	0.0	18.0	1,467.5	179.3	676.2	44.0	40.0	44,653.4
	Upgrade	0.0	452.0	75.0	20.0	0.0	380.0	40.0	85.0	8.3	1,061.8	75.0	120.0	7.6	20.0	0.0	0.0	0.0	9.1	60.0	4.4	20.0	2,438.2
Total Projects	New Generation	2,407.0	18,758.8	3,785.2	2,193.1	58.4	5,913.3	2,744.1	724.4	63.0	27,089.5	3,215.8	1,970.9	1,962.9	1,338.1	78.0	72.7	1,741.2	362.4	1,094.9	815.2	40.0	76,428.6
	Upgrade	10.0	558.0	75.0	20.0	0.0	400.0	40.0	85.0	8.3	1,752.8	225.0	120.0	45.7	40.0	0.0	0.0	0.0	9.1	60.0	5.7	20.0	3,474.6

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."[37] 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 June 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 560,874.6 MW that have entered the queue during the time period of January 1, 1997, through June 30, 2019, 62,562.2 MW (11.2 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 36,456.6 MW that entered the queue during the time period of January 1, 1997, through June 30, 2019, 14,287.9 MW (39.2 percent) have been submitted by PSEG or one of their affiliated companies.

37 See OATT § 1 (Transmission Owner).

Table 12-35 Relationship between project developer and transmission owner for all interconnection queue projects MW by unit type: June 30, 2019

				MW by Unit Type																		
Parent Company	Transmission Owner	Related to Developer	Number of Projects	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	680.0	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	5,094.7
		Unrelated	537	1,279.6	22,558.5	1,753.0	7.5	127.3	0.0	0.0	547.4	0.0	12.0	0.0	75.4	19,174.1	10,368.0	0.0	0.0	492.0	29,279.2	85,673.9
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	60	39.9	1,150.0	149.5	0.0	1.9	0.0	0.0	0.0	0.0	0.0	0.0	10.0	2,762.6	0.0	0.0	0.0	0.0	2,128.0	6,241.9
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	102	0.0	12,364.0	907.7	100.0	0.0	0.0	340.0	0.0	1,944.0	0.0	0.0	60.0	1,316.2	301.0	0.0	0.0	4.0	146.0	17,482.9
		Unrelated	534	625.6	9,044.5	2,225.8	0.5	227.3	0.0	0.0	35.0	0.0	0.0	10.0	119.4	27,526.1	20.0	0.0	0.0	316.3	8,148.1	48,298.7
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	29	68.2	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	1,775.5
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	27	20.3	170.0	73.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,090.9	0.0	0.0	0.0	0.0	150.3	2,504.5
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	309	141.0	8,848.4	807.4	380.0	20.7	2.8	0.0	0.0	0.0	2.0	5.0	10.3	2,408.7	15.0	5.5	0.0	10.0	6,462.5	19,119.3
	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	58	40.6	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	6,717.9
	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	365	647.5	15,530.5	1,512.0	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	34,888.0	61,221.8
	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	293	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	3,433.4	653.0	15.0	0.0	65.0	3,543.9	15,429.0
	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	80	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	72.7	0.0	0.0	0.0	0.0	0.0	21,067.7
	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	371.5	0.0	0.0	0.0	0.0	0.0	25,468.9
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	383	280.9	26,982.8	1,479.7	0.0	84.4	0.0	0.0	623.3	0.0	140.0	53.8	25.4	3,860.2	4,092.0	0.0	0.0	184.4	5,421.5	43,228.3
	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	90	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	2,213.1	0.0	16.5	0.0	0.0	2,111.7	18,379.7
	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	376	509.8	15,751.4	722.1	0.0	4.8	0.6	0.0	1.6	0.0	0.6	0.0	12.8	1,996.6	0.0	0.0	0.0	30.0	5,663.2	24,693.5
	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	108	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	1,378.1	0.0	0.0	0.0	84.0	0.0	20,361.3
	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	264	257.4	18,747.9	1,424.7	0.0	214.4	0.0	16.0	46.3	0.0	341.8	8.0	14.8	1,741.2	561.0	590.0	0.0	525.0	6,806.2	31,294.4
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	256	544.0	23,299.5	423.1	8.0	234.5	0.0	1,500.0	142.6	388.0	19.9	2.4	44.7	1,135.1	6,896.6	0.0	0.0	31.0	4,037.7	38,707.1
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	213	14.5	18,640.4	1,137.9	608.0	62.5	4.9	0.0	1,000.0	0.0	10.6	0.0	13.7	636.2	0.0	20.0	0.0	0.0	20.0	22,168.7
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	393	119.8	40,973.9	3,134.8	189.5	0.0	0.0	374.0	394.0	5,886.3	0.0	0.0	68.5	1,747.9	9,288.5	235.0	0.0	4.0	146.0	62,562.2
		Unrelated	4107	4,767.0	245,416.1	14,118.4	2,938.8	1,480.3	8.3	1,516.0	2,637.3	7,280.0	654.9	104.2	520.9	78,155.3	27,461.6	740.5	0.0	1,852.7	108,660.1	498,312.4

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 June 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 June 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: June 30, 2019

			MW by Project Status					
Parent Company	Transmission Owner	Related to Developer	Active	In Service	Under Construction	Suspended	Withdrawn	Total
AEP	AEP	Related	100.0	580.0	0.0	0.0	0.0	680.0
		Unrelated	7,231.0	2,682.0	100.0	585.0	11,960.5	22,558.5
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	5,342.6	1,233.6	0.0	0.0	8,954.3	15,530.5
	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	7,489.7	1,720.0	0.0	1,140.0	16,633.1	26,982.8
	ATSI	Related	0.0	0.0	0.0	0.0	1,678.0	1,678.0
		Unrelated	3,615.0	1,905.0	2,190.0	0.0	5,879.0	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	268.0	942.3	1,100.0	0.0	16,437.6	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	1,741.4	806.4	0.0	0.0	16,092.6	18,640.4
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	241.1	9,156.0	0.0	0.0	31,576.8	40,973.9
		Unrelated	31,210.0	28,553.9	3,564.5	4,769.1	177,318.5	245,416.1

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 June 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 June 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: June 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	1,097.0	190.0	0.0	0.0	466.0	1,753.0
AES	DAY	Related	0.0	38.0	0.0	0.0	0.0	38.0
		Unrelated	127.5	22.0	0.0	0.0	0.0	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	64.7	786.0	0.0	0.0	57.0	907.7
		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	1,190.0	257.0	48.0	0.0	17.0	1,512.0
	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	116.0	1,363.7	0.0	0.0	0.0	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	481.0	381.9	0.0	0.0	561.8	1,424.7
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	64.7	2,107.0	0.0	0.0	963.1	3,134.8
		Unrelated	5,202.7	6,817.0	253.0	200.0	1,645.7	14,118.4

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 June 30, 2019, by transmission owner and project status. Of the 9,929.3 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 8,294.1 MW that entered the queue during the time period of January 1, 1997, through June 30, 2019, 146.0 MW (1.8 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: June 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	722.0	20,353.2	29,279.2
AES	DAY	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	100.0	0.0	0.0	0.0	2,028.0	2,128.0
DLCO	DLCO	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0
Dominion	Dominion	Related	0.0	0.0	12.0	0.0	134.0	146.0
		Unrelated	2,700.6	102.5	300.0	76.6	4,968.4	8,148.1
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	2,803.6	7.5	0.0	0.0	3,651.4	6,462.5
	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	6,401.2	2,898.5	1,113.5	0.0	24,474.8	34,888.0
	DPL	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	727.1	0.0	0.0	0.0	2,816.8	3,543.9
	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	453.4	1,004.0	310.6	309.4	3,344.1	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	4,559.2	0.0	0.0	0.0	1,104.0	5,663.2
	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	120.3	995.5	70.0	100.0	5,520.3	6,806.2
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	465.1	226.5	0.0	98.0	3,248.1	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	0.0	0.0	12.0	0.0	134.0	146.0
		Unrelated	24,461.8	7,973.2	1,944.1	1,306.0	72,975.0	108,660.1

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 June 30, 2019, by transmission owner and project status. Of the 2,153.3 solar project MW that have achieved in service or under construction status during this time period, 815.8 MW (37.9 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 June 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: June 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	12,011.3	0.0	0.0	50.0	7,112.7	19,174.1
AES	DAY	Related	0.0	0.0	0.0	0.0	21.5	21.5
		Unrelated	2,237.7	2.5	0.0	20.0	502.4	2,762.6
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	437.9	349.2	297.2	0.0	231.9	1,316.2
		Unrelated	16,342.3	329.8	100.0	91.0	10,663.0	27,526.1
Duke	DEOK	Related	0.0	0.0	0.0	0.0	6.4	6.4
		Unrelated	530.0	0.0	0.0	0.0	273.0	803.0
EKPC	EKPC	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	1,781.0	0.0	0.0	0.0	309.9	2,090.9
Exelon	AECO	Related	0.0	0.0	0.0	0.0	8.3	8.3
		Unrelated	611.5	57.3	0.0	0.0	1,739.9	2,408.7
	BGE	Related	0.0	0.0	0.0	0.0	20.0	20.0
		Unrelated	4.0	1.1	0.0	0.0	33.3	38.4
	ComEd	Related	0.0	9.0	0.0	0.0	0.0	9.0
		Unrelated	4,367.5	0.0	0.0	0.0	1,936.8	6,304.3
	DPL	Related	0.0	7.4	0.0	0.0	0.0	7.4
		Unrelated	1,559.2	123.0	170.0	0.0	1,581.2	3,433.4
	PECO	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	18.0	3.3	0.0	0.0	51.4	72.7
	Pepco	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	188.4	0.0	2.5	0.0	180.6	371.5
FirstEnergy	APS	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	1,759.0	53.0	10.0	244.4	1,793.7	3,860.2
	ATSI	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	1,783.8	0.0	0.0	0.0	429.3	2,213.1
	JCPL	Related	0.0	0.0	0.0	0.0	12.0	12.0
		Unrelated	190.6	309.6	51.9	8.0	1,436.5	1,996.6
	Met-Ed	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	818.1	0.0	0.0	58.0	502.0	1,378.1
	PENELEC	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	1,467.5	0.0	0.0	0.0	273.7	1,741.2
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	716.4	15.0	0.0	0.0	403.7	1,135.1
PSEG	PSEG	Related	5.5	121.1	17.2	0.0	40.9	184.7
		Unrelated	42.9	92.4	16.1	6.0	478.7	636.2
Con Ed	RECO	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	60.0	0.0	0.0	0.0	0.0	60.0
Total		Related	531.2	501.4	314.4	10.0	391.0	1,747.9
		Unrelated	46,560.4	987.0	350.5	477.4	29,780.0	78,155.3

Regional Transmission Expansion Plan (RTEP)[38]

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.

Backbone Facilities

PJM baseline transmission projects are implemented to resolve reliability criteria violations. PJM backbone transmission projects are a subset of significant baseline projects, which are intended to resolve multiple reliability criteria violations and congestion issues and which may have substantial impacts on energy and capacity markets. There are currently six backbone projects under development, the Surry-Skiffes Creek 500kV Line, the Loudoun-Brambleton 500kV Line, the conversion of the Marion-Bayonne and Bayway-Linden lines from 138 kV to 345 kV, the conversion of the Robinson Park-Sorenson lines to double circuit 345kV and the Meadow Lake-Reynolds 345kV Line rebuild.[39]

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.[40] 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.[41]

PJM's first market efficiency analysis was performed in 2013, prior to Order 1000. That analysis evaluated the historical sources of congestion on 25

38 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. 44 (Feb. 21, 2019).

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

40 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>.

41 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>.

flowgates.[42] The proposal window was open from August 12, 2013, through September 26, 2013. PJM received 38 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. That analysis evaluated the historical sources of congestion on 77 flowgates, 57 of which could be addressed by market efficiency projects. The proposal window was open from October 30, 2014, through February 27, 2015. PJM received 119 proposals, 93 of which addressed the market efficiency issues, with the remaining submissions addressing reliability issues identified by PJM. A total of 14 projects were approved by the PJM Board for this window, 13 of which were market efficiency projects and one of which was for reliability.

The second market efficiency cycle was performed during the 2016/2017 RTEP long term window. That analysis evaluated the historical sources of congestion on a total of four flowgates, all four of which could be addressed by market efficiency projects. The proposal window was open from November 1, 2016, through February 28, 2017. PJM received 96 proposals, all 96 of which addressed market efficiency issues. A total of four projects were approved by the PJM Board for this window, all four of which were market efficiency projects.

The third market efficiency cycle is currently being prepared for the 2018/2019 RTEP long term window. The proposal window was open between November 1, 2018 and February 28, 2019. PJM received 22 proposals for one identified source of congestion.

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.[43] [44] [45] [46] 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. PJM also concluded that there would be significant reliability violations with the project removed from the model.[47]

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. Benefits are 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. 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,

42 Historical congestion drivers are identified using the historical congestion tables presented in the *2018 State of the Market Report for PJM*, Volume 2, Section 11: Congestion and Marginal Losses, historical analysis of real-time constraints, the NERC Book of Flowgates and PROMOD simulations.

43 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>.

44 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>.

45 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>.

46 See Letter from Paula M. Carmody, People 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>.

47 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>.

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. Energy production costs are the sum of generation payments in the energy market simulation in each modeled year. The change in the energy production costs in each modeled year is calculated on a system wide basis using the modeled changes in LMPs, changes in load energy payments are calculated on a zonal basis and are netted against corresponding changes in the estimated value of any Auction Revenue Rights (ARR) that sink in that zone. 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, historic 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 cost with and without the project plus 50 percent of the change in zonal load capacity payments with and without the project, including only those zones where the project reduced the load capacity payments. For subregional projects, the reliability pricing model benefits for each modeled year is equal to the change in zonal load capacity payments with and without the project, including only those zones where the project reduced the load 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 congestion costs that an RTEP project may create in some zones when calculating the energy 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. 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 definition of benefits should also be reevaluated.

PJM MISO Interregional Targeted Market Efficiency Process (TMEP)

PJM and MISO developed a process to facilitate the construction of interregional projects in response to the Commissions concerns about interregional coordination along the PJM-MISO seam, called the Targeted Market Efficiency Process (TMEP).[48]

The allocation of costs to each RTO for TMEPs will be in proportion to the benefits received.[49]

48 See *PJM Interconnection, L.L.C*, Docket No. ER17-718-000 (December 30, 2016).
49 See *PJM Interconnection, L.L.C*, Docket No. ER17-729-000 (December 30, 2016).

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.[50 51]

The first TMEP analysis occurred in 2017 and included the investigation of congestion on 50 market to market flowgates. The study resulted in the evaluation of 13 potential upgrades, resulting in the recommendation of five TMEP projects. The five projects address $59.0 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.[52]

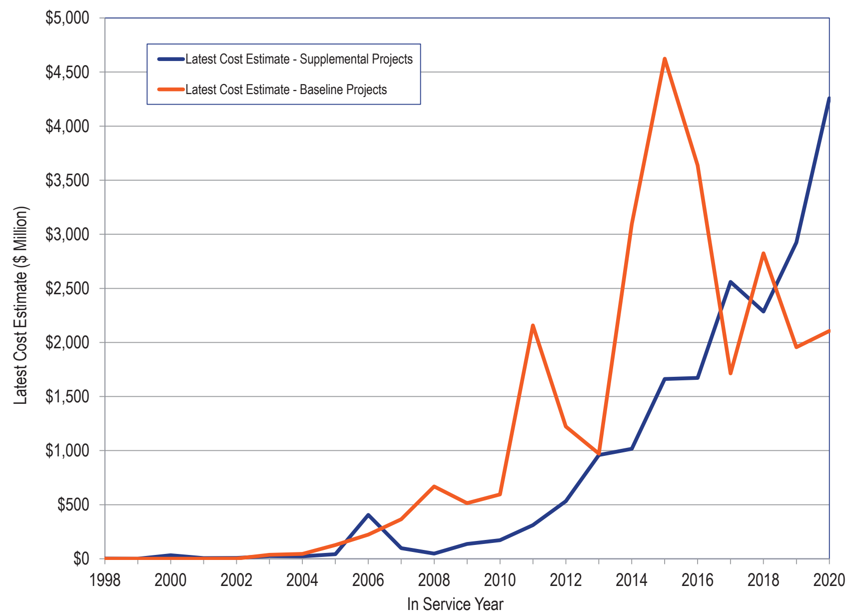
The 2018 TMEP analysis included the investigation of congestion on 61 market to market flowgates. The study resulted in the evaluation of 19 potential upgrades, resulting in the recommendation of two TMEP projects. The two projects address $25.0 million in historical congestion, with a TMEP benefit of $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.[53]

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."[54] 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 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



50 See *PJM Interconnection, L.L.C*, Docket No. ER17-718-000, ER17-721-000 and ER17-729-000 (Not Consolidated) (November 2, 2017).
51 161 FERC ¶ 61,005.
52 See PJM. "*MISO PJM IPSAC*," (January 12, 2018) <http://www.pjm.com/-/media/committees-groups/stakeholder-meetings/ipsac/20180112/20180112-ipsac-presentation.ashx>.
53 See PJM. "*MISO PJM IPSAC*," (January 18, 2019) <https://www.pjm.com/-/media/committees-groups/stakeholder-meetings/ipsac/20190118/20190118-ipsac-presentation.ashx>.
54 See PJM. Planning. "Transmission Construction Status," (Accessed on June 30, 2019) <http://www.pjm.com/planning/rtep-upgrades-status/construct-status.aspx>.

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 615.0 percent, from 20 for years 1998 through 2007 (pre Order 890) to 143 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	130	4	13	1	20	0	15	4	25	6	2	0	0	0	2	0	1	19	28	0	280
2019	4	202	2	34	6	14	2	22	2	17	7	4	0	16	0	1	31	1	15	19	0	399
2020	9	114	0	18	2	6	0	5	1	7	5	4	0	7	0	0	34	0	30	28	0	270
2021	3	67	0	12	0	1	2	0	1	9	3	4	1	2	0	0	4	0	24	27	1	161
2022	4	6	0	1	2	0	3	2	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	1	3	0	0	1	0	14	7	0	46
2024	1	0	1	0	7	0	0	0	0	0	2	0	1	0	0	0	0	0	12	0	0	24
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	199	12	79	58	189	151	27	16	36	0	22	85	13	245	292	1	2,519

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 1,745.0 percent, from $64.5 million for years 1998 through 2007 (pre Order 890) to $1,190.1 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	$142.05	$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	$2,559.97
2018	$66.55	$707.72	$14.80	$64.52	$4.08	$80.94	$0.00	$75.29	$4.98	$169.64	$68.94	$1.72	$0.00	$0.00	$0.00	$47.60	$0.00	$156.00	$186.64	$635.70	$0.00	$2,285.12
2019	$48.50	$1,361.96	$4.73	$231.47	$71.01	$93.19	$7.81	$127.73	$5.30	$46.08	$40.40	$16.69	$0.00	$12.80	$0.00	$2.00	$99.20	$70.00	$257.30	$428.34	$0.00	$2,924.51
2020	$91.82	$1,053.02	$0.00	$157.80	$62.50	$110.10	$0.00	$45.30	$18.10	$29.68	$36.02	$22.55	$0.00	$46.60	$0.00	$0.00	$180.30	$0.00	$456.17	$1,947.53	$0.00	$4,257.49
2021	$24.26	$1,010.03	$0.00	$299.70	$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	$988.77	$17.00	$2,877.63
2022	$81.90	$50.20	$0.00	$27.90	$263.00	$0.00	$10.25	$21.42	$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	$2,362.17
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	$8.50	$16.30	$0.00	$0.00	$200.00	$0.00	$179.60	$177.00	$0.00	$886.59
2024	$11.40	$0.00	$3.60	$0.00	$223.00	$0.00	$0.00	$0.00	$0.00	$0.00	$29.72	$0.00	$22.00	$0.00	$0.00	$0.00	$0.00	$0.00	$254.33	$0.00	$0.00	$544.05
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	$6,162.92	$142.69	$1,220.77	$763.54	$1,336.64	$64.91	$402.42	$443.08	$1,009.59	$491.16	$66.57	$66.25	$141.55	$0.00	$411.90	$508.63	$817.70	$3,128.69	$8,733.22	$17.00	$26,560.06

The role of supplemental projects in the market efficiency process needs to be modified. It is not clear how a supplemental project can be a market efficiency project that has been identified as a PJM issue based on a cost/benefit analysis and why such a project should not be subject to competition. 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.[55] End of life transmission projects fall under the Transmission Owner Form 715 Planning Criteria, and are currently exempt from the competitive planning process.[56] End of life transmission projects are already included in the supplemental projects totals or, if included in the transmission owners' reliability plan, will be included in the baseline project list as a reliability criteria project.

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."[57] 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."[58] The Commission did not address end of life projects that are not incidental. The MMU recommends, to increase the role of competition, that the exemption of supplemental and end of life projects from the Order No. 1000 competitive process be terminated.

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 considered to be infeasible. As a result, the local Transmission Owner is the Designated Entity.[59]
- **Below 200kV:** Due to the lower voltage level of the identified violation(s), the driver(s) for this project are currently excluded from the competitive proposal window process. As a result, the local Transmission Owner is the Designated Entity.[60]
- **FERC 715 (Transmission Owner (TO) Criteria):** Due to the violation need of this project resulting solely from FERC 715 TO Reliability Criteria, the driver(s) for this project are currently excluded from the competitive proposal window process. As a result, the local Transmission Owner is the Designated Entity.[61]
- **Substation Equipment:** Due to identification of the limiting element(s) as substation equipment, the driver(s) for this project are currently excluded from the competitive proposal window process. As a result, the local Transmission Owner is the Designated Entity.[62]

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

55 The useful life of a transmission investment typically exceeds its depreciable life.
56 See PJM Operating Agreement Schedule 6 § 1.5.8(o).
57 164 FERC ¶ 61,160 at P 31 (Aug. 31, 2018) (Docket Nos. ER18-370 and ED18-12).
58 164 FERC ¶ 61,160 at P 33 (Aug. 31, 2018) (Docket Nos. ER18-370 and ED18-12).
59 See PJM Operating Agreement Schedule 6 § 1.5.8(m).
60 See PJM Operating Agreement Schedule 6 § 1.5.8(n).
61 See PJM Operating Agreement Schedule 6 § 1.5.8(o).
62 See PJM Operating Agreement Schedule 6 § 1.5.8(p).

does not appear to be any market reason to exclude transmission projects from competition.

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. The proposed comparative framework, along with the advice and recommendation of the MMU, will be presented to the PJM Planning Committee for review and comment prior to an MRC vote. The comparative framework will be presented at the December 2019 meeting of the MRC.

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.[63]

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.

On February 12, 2019, the PJM Board of Managers authorized an additional $272.0 million in transmission upgrades and additions. As of June 30, 2019, the PJM Board has approved $38.5 billion in system enhancements since 1999.

63 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: "a proposed enhancement or addition to the transmission system that: (a) will increase the Capacity Emergency Transfer Limit into an LDA by a megawatt quantity certified by the Office of the Interconnection; (b) the Office of the Interconnection has determined will be in service on or before the commencement of the first Delivery Year for which such upgrade is the subject of a Sell Offer in the Base Residual Auction; (c) is the subject of a Facilities Study Agreement executed before the conduct of the Base Residual Auction for such Delivery Year and (d) a New Service Customer is obligated to fund through a rate or charge specific to such facility or upgrade."[64] 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 June 30, 2019, no QTUs have cleared a BRA.

QTU projects are submitted and tracked through the PJM queue.[65] A total of 51 QTU projects have entered the queue since 2007. Of the 51 submitted QTU projects, 38 projects (74.5 percent) have been withdrawn, six (11.8 percent) are in service and seven (13.7 percent) are currently in active development.

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."[66] FERC convened

64 See OATT § 1 (Qualifying Transmission Upgrade).
65 See PJM. Planning. "New Services Queue," at <https://www.pjm.com/planning/services-requests/interconnection-queues.aspx>.
66 153 FERC ¶ 61,245 at P 35 (Nov. 24, 2015) (Docket Nos. ER15-2562 and ER15-2563.).

a technical conference on January 12, 2016, to address the complaints in multiple proceedings and to address these two core issues.[67]

The issues identified in the complaints and at the technical conference include: whether the solutions based allocation method is appropriate for upgrades not related to transmission overload issues; whether the solutions based allocation method correctly identifies all the beneficiaries of the upgrades; whether it is reasonable to allocate a level of costs to a merchant transmission project that could force bankruptcy; and whether the significant shifts in allocation that result from use of the 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.

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.[68] 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.[69] The specific timeline is shown in Table 12-43.[70]

67 See Docket Nos. EL15-18-000 (ConEd), EL15-67-000 (Linden), and EL15-95-000 (Artificial Island).
68 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).
69 See PJM. "Manual 3: Transmission Operations," Rev. 55 (May 31, 2019).
70 See PJM. "Manual 3: Transmission Operations," Rev. 55 (May 31, 2019).

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 2017/2018 planning period and the 2018/2019 planning period, regardless of when they were initially submitted.[71] The outage data for the day-ahead market are for outages scheduled to occur from January 2015 through June 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.[72] Table 12-42 shows that 77.0 percent of requested outages were planned for less than or equal to five days and 7.7 percent of requested outages were planned for greater than 30 days in the 2018/2019 planning period. Table 12-42 also shows that 76.1 percent of the requested outages were planned for less than or equal to five days and 7.7 percent of requested outages were planned for greater than 30 days in the 2017/2018 planning period.

Table 12-42 Transmission facility outage request summary by planned duration: 2017/2018 and 2018/2019

	2017/2018		2018/2019	
Planned Duration (Days)	Outage Requests	Percent of Total	Outage Requests	Percent of Total
<=5	16,159	76.1%	17,003	77.0%
>5 & <=30	3,460	16.3%	3,376	15.3%
>30	1,626	7.7%	1,712	7.7%
Total	21,245	100.0%	22,091	100.0%

71 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.
72 *Id.* at 70.

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.[73]

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.[74]

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

Table 12-44 shows a summary of requests by received status. In the 2018/2019 planning period, 47.3 percent of outage requests received were late. In the 2017/2018 planning period, 49.5 percent of outage requests received were late.

Table 12-44 Transmission facility outage request summary by received status: 2017/2018 and 2018/2019

	2017/2018				2018/2019			
Planned Duration (Days)	On Time	Late	Total	Percent Late	On Time	Late	Total	Percent Late
<=5	8,418	7,741	16,159	47.9%	9,306	7,697	17,003	45.3%
>5 & <=30	1,713	1,747	3,460	50.5%	1,633	1,743	3,376	51.6%
>30	607	1,019	1,626	62.7%	700	1,012	1,712	59.1%
Total	10,738	10,507	21,245	49.5%	11,639	10,452	22,091	47.3%

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.[75]

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.[76] Table 12-45 is a summary of outage requests by emergency status. Of all outage requests scheduled to occur in the 2018/2019 planning period, 12.5 percent were for emergency outages. Of all outage requests scheduled to occur in the 2017/2018 planning period, 12.3 percent were for emergency outages.

Table 12-45 Transmission facility outage request summary by emergency: 2017/2018 and 2018/2019

	2017/2018				2018/2019			
Planned Duration (Days)	Emergency	Non Emergency	Total	Percent Emergency	Emergency	Non Emergency	Total	Percent Emergency
<=5	2,005	14,154	16,159	12.4%	2,024	14,979	17,003	11.9%
>5 & <=30	370	3,090	3,460	10.7%	469	2,907	3,376	13.9%
>30	231	1,395	1,626	14.2%	262	1,450	1,712	15.3%
Total	2,606	18,639	21,245	12.3%	2,755	19,336	22,091	12.5%

73 See PJM. "Manual 3: Transmission Operations," Rev. 55 (May 31, 2019).
74 See "*Report of PJM Interconnection, L.L.C. on Transmission Oversight Procedures*," Docket No. EL01-122-000 (November 2, 2001).

75 See PJM. "Manual 3: Transmission Operations," Rev. 55 (May 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).
76 PJM. "Manual 3: Transmission Operations," Rev. 55 (May 31, 2019).

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."[77]

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 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). Of all outage requests submitted to occur in the 2017/2018 planning period, 7.5 percent were expected to cause congestion. Of all the outage requests that were expected to cause congestion, 3.6 percent (58 out of 1,602) were denied by PJM in the 2017/2018 planning period and 19.6 percent (314 out of 1,602) were cancelled (Table 12-48).

Table 12-46 Transmission facility outage request summary by congestion: 2017/2018 and 2018/2019

	2017/2018				2018/2019			
Planned Duration (Days)	Congestion Expected	No Congestion Expected	Total	Percent Congestion Expected	Congestion Expected	No Congestion Expected	Total	Percent Congestion Expected
<=5	1,094	15,065	16,159	6.8%	1,138	15,865	17,003	6.7%
>5 & <=30	357	3,103	3,460	10.3%	270	3,106	3,376	8.0%
>30	151	1,475	1,626	9.3%	158	1,554	1,712	9.2%
Total	1,602	19,643	21,245	7.5%	1,566	20,525	22,091	7.1%

Table 12-47 shows the outage requests summary by received status, congestion status and emergency status. In the 2018/2019 planning period, 34.9 percent of requests were submitted late and were nonemergency while 1.1 percent of requests (250 out of 22,091) were late, nonemergency, and expected to cause congestion. In the 2017/2018 planning period, 37.3 percent of request were submitted late and were nonemergency while 1.4 percent of requests (297 out of 21,245) were late, nonemergency, and expected to cause congestion.

Table 12-47 Transmission facility outage request summary by received status, emergency and congestion: 2017/2018 and 2018/2019

		2017/2018				2018/2019			
Received Status		Congestion Expected	No Congestion Expected	Total	Percent of Total	Congestion Expected	No Congestion Expected	Total	Percent of Total
Late	Emergency	85	2,500	2,585	12.2%	72	2,662	2,734	12.4%
	Non Emergency	297	7,625	7,922	37.3%	250	7,468	7,718	34.9%
On Time	Emergency	3	18	21	0.1%	3	18	21	0.1%
	Non Emergency	1,217	9,500	10,717	50.4%	1,241	10,377	11,618	52.6%
Total		1,602	19,643	21,245	100.0%	1,566	20,525	22,091	100.0%

77 PJM added this definition to Manual 38 in February 2017. PJM. "Manual 38: Operations Planning," Rev. 12 (Feb. 1, 2019).

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.[78] 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, 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. Of all the outage requests that were expected to cause congestion, 3.6 percent (58 out of 1,602) were denied by PJM in the 2017/2018 planning period, 70.8 percent were complete and 19.6 percent (314 out of 1,602) were cancelled.

Table 12-48 Transmission facility outage requests that might cause congestion status summary: 2017/2018 and 2018/2019

		2017/2018						2018/2019					
Received Status		Cancelled	Complete	In Process	Denied	Congestion Expected	Percent Complete	Cancelled	Complete	In Process	Denied	Congestion Expected	Percent Complete
Late	Emergency	11	74	0	0	85	87.1%	7	64	0	0	72	88.9%
	Non Emergency	47	220	9	18	297	74.1%	47	170	11	20	250	68.0%
On Time	Emergency	2	1	0	0	3	33.3%	0	3	0	0	3	100.0%
	Non Emergency	254	840	76	40	1,217	69.0%	289	826	73	46	1,241	66.6%
Total		314	1,135	85	58	1,602	70.8%	343	1,063	84	66	1,566	67.9%

There are clear rules defined for assigning On Time or Late status for submitted outage requests in both the PJM Tariff and PJM Manuals.[79] 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 2017/2018 planning period, 297 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 2017/2018 planning period and the 2018/2019 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 2018/2019 planning period, 32.0 percent of transmission outage requests were approved by PJM and then rescheduled by the TOs, and 12.1 percent of the transmission outages were approved by PJM and subsequently cancelled by the TOs. In the 2017/2018 planning period, 32.9 percent of transmission outage requests were approved by PJM and then rescheduled by the TO, and 12.6 percent of the transmission outages were approved by PJM and subsequently cancelled by the TO.

78 See PJM Markets & Operations, PJM Tools "Outage Information," <http://www.pjm.com/markets-and-operations/etools/oasis/system-information/outage-info.aspx> (2019).
79 PJM Operating Agreement Schedule 1 § 1.9.2.

Table 12-49 Rescheduled and cancelled transmission outage request summary: 2017/2018 and 2018/2019

	2017/2018					2018/2019				
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	16,159	3,657	22.6%	2,385	14.8%	17,003	3,955	23.3%	2,407	14.2%
>5 & <=30	3,460	2,182	63.1%	236	6.8%	3,376	2,033	60.2%	210	6.2%
>30	1,626	1,158	71.2%	66	4.1%	1,712	1,079	63.0%	54	3.2%
Total	21,245	6,997	32.9%	2,687	12.6%	22,091	7,067	32.0%	2,671	12.1%

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.[80] 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.[81] 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 13,100 transmission equipment planned outages in the 2018/2019 planning period, of which 1,720 were longer than 30 days, and of which 246 or 1.9 percent were scheduled longer than 30 days when the duration of all the outage requests are combined for the same equipment.

80 PJM. "Manual 3: Transmission Operations," Rev. 55 (May 31, 2019).
81 *Id.*

Table 12-50 Transmission outage summary: 2017/2018 and 2018/2019

		2017/2018		2018/2019	
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	1,418	11.2%	1,474	11.3%
	Yes	242	1.9%	246	1.9%
<= 30		11,016	86.9%	11,380	86.9%
Total		12,676	100.0%	13,100	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 2018/2019 planning period, within effective duration greater than a month and shorter than two months, there were 26 outages with a combined duration longer than 30 days.

Table 12-51 Equipment outages: 2017/2018 and 2018/2019

	2017/2018		2018/2019	
Effective Duration of Outage	Count of Equipment with Planned Outages	Percent of Total	Count of Equipment with Planned Outages	Percent of Total
<=31	6	2.5%	3	1.2%
>31 & <=62	25	10.3%	26	10.6%
>62 & <=93	18	7.4%	22	8.9%
>93	193	79.8%	195	79.3%
Total	242	100.0%	246	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.[82]

In the 2018/2019 planning period, 239 outage requests were included in the annual FTR market outage list and 21,852 outage requests were not included.[83] In the 2017/2018 planning period, 225 outage requests were included in the annual FTR market outage list and 21,020 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 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 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. It also shows that 4.0 percent of the outage requests modeled in the Annual FTR Market for the 2017/2018 planning period had a planned duration of less than two weeks and that 16.9 percent of the outage requests (38 out of 225) modeled in the Annual FTR Market for the planning period were submitted late according to outage submission rules.

82 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).

83 PJM's treatment of transmission outages in the FTR models is discussed in: *See* the *2019 State of the Market Report for PJM: Volume 2*, Section 13: FTRs and ARRs: Supply and Demand.

Table 12-52 Annual FTR market modeled transmission facility outage requests by received status: 2017/2018 and 2018/2019

	2017/2018				2018/2019			
Planned Duration	On Time	Late	Total	Percent of Total	On Time	Late	Total	Percent of Total
<2 weeks	6	3	9	4.0%	19	3	22	9.2%
>=2 weeks & <2 months	65	12	77	34.2%	65	9	74	31.0%
>=2 months	116	23	139	61.8%	115	28	143	59.8%
Total	187	38	225	100.0%	199	40	239	100.0%

Table 12-53 shows the annual FTR market modeled outage requests summary by emergency status and received status. One of the annual FTR market modeled outages expected to occur in the 2018/2019 planning period was an emergency outage. None of the modeled outages expected to occur in the 2017/2018 planning period were emergency outages.

Table 12-53 Annual FTR market modeled transmission facility outage requests by emergency and received status: 2017/2018 and 2018/2019

		2017/2018				2018/2019			
Received Status	Planned Duration	Emergency	Non Emergency	Total	Percent Non Emergency	Emergency	Non Emergency	Total	Percent Non Emergency
On Time	<2 weeks	0	6	6	100.0%	0	19	19	100.0%
	>=2 weeks & <2 months	0	65	65	100.0%	0	65	65	100.0%
	>=2 months	0	116	116	100.0%	0	115	115	100.0%
	Total	0	187	187	100.0%	0	199	199	100.0%
Late	<2 weeks	0	3	3	100.0%	0	3	3	100.0%
	>=2 weeks & <2 months	0	12	12	100.0%	0	9	9	100.0%
	>=2 months	0	23	23	100.0%	1	27	28	96.4%
	Total	0	38	38	100.0%	1	39	40	97.5%

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. 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. Of all the annual FTR market modeled outages expected to occur in the 2017/2018 planning period and submitted late, 10.5 percent (4 out of 38) were expected to cause congestion.

Table 12-54 Annual FTR market modeled transmission facility outage requests by congestion and received status: 2017/2018 and 2018/2019

		2017/2018				2018/2019			
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	3	3	6	50.0%	10	9	19	52.6%
	>=2 weeks & <2 months	18	47	65	27.7%	17	48	65	26.2%
	>=2 months	37	79	116	31.9%	29	86	115	25.2%
	Total	58	129	187	31.0%	56	143	199	28.1%
Late	<2 weeks	0	3	3	0.0%	0	3	3	0.0%
	>=2 weeks & <2 months	1	11	12	8.3%	0	9	9	0.0%
	>=2 months	3	20	23	13.0%	0	28	28	0.0%
	Total	4	34	38	10.5%	0	40	40	0.0%

Table 12-55 shows that 25.7 percent of outage requests modeled in the annual FTR market for the 2018/2019 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 32.5 percent for the 2017/2018 planning period. Table 12-55 also shows that 23.1 percent of outages requests modeled in the Annual FTR Market for the 2018/2019 planning period and with a duration of two months or longer were cancelled, compared to 12.9 percent for the 2017/2018 planning period.

Table 12-55 Annual FTR market modeled transmission facility outage requests by processed status: 2017/2018 and 2018/2019

		2017/2018		2018/2019	
Planned Duration	Processed Status	Outage Requests	Percent	Outage Requests	Percent
<2 weeks	In Progress	0	0.0%	2	9.1%
	Denied	0	0.0%	0	0.0%
	Approved	0	0.0%	1	4.5%
	Cancelled	3	33.3%	4	18.2%
	Active	0	0.0%	0	0.0%
	Completed	6	66.7%	15	68.2%
	Total	9	100.0%	22	100.0%
>=2 weeks & <2 months	In Progress	7	9.1%	7	9.5%
	Denied	1	1.3%	0	0.0%
	Approved	0	0.0%	0	0.0%
	Cancelled	25	32.5%	19	25.7%
	Active	0	0.0%	0	0.0%
	Completed	44	57.1%	48	64.9%
	Total	77	100.0%	74	100.0%
>=2 months	In Progress	26	18.7%	20	14.0%
	Denied	0	0.0%	1	0.7%
	Approved	2	1.4%	1	0.7%
	Cancelled	18	12.9%	33	23.1%
	Active	2	1.4%	11	7.7%
	Completed	91	65.5%	77	53.8%
	Total	139	100.0%	143	100.0%

More outage requests were not modeled in the Annual FTR Market than were modeled in the Annual FTR Market. In the 2018/2019 planning period, 239 outage requests were modeled and 21,852 outage requests were not modeled in the Annual FTR Market. In the 2017/2018 planning period, 225 outage requests were modeled and 21,020 outage requests were not modeled in the Annual FTR Market.

Table 12-56 shows that 13.5 percent of outage requests not modeled in the Annual FTR Auction with duration longer than or equal to two months, labelled On Time according to the rules, were submitted after the Annual FTR Auction bidding opening date for the 2018/2019 planning period compared to 21.4 percent in the 2017/2018 planning period.

Table 12-56 Transmission facility outage requests not modeled in Annual FTR Auction: 2017/2018 and 2018/2019

	2017/2018						2018/2019					
	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	1,350	8,020	85.6%	216	8,546	97.5%	1,717	8,457	83.1%	204	8,571	97.7%
>=2 weeks & <2 months	582	412	41.4%	122	1,020	89.3%	647	367	36.2%	156	914	85.4%
>=2 months	147	40	21.4%	195	370	65.5%	218	34	13.5%	200	367	64.7%
Total	2,079	8,472	80.3%	533	9,936	94.9%	2,582	8,858	77.4%	560	9,852	94.6%

Table 12-57 shows that 69.2 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. It also shows that 85.9 percent of late outage requests which were not modeled in the Annual FTR Auction with duration longer than or equal to two months and submitted after the Annual FTR Auction bidding opening date were approved and completed in the 2017/2018 planning period.

Table 12-57 Late transmission facility outage requests not modeled in Annual FTR Auction and submitted after annual bidding opening date: 2017/2018 and 2018/2019

	2017/2018			2018/2019		
Planned Duration	Completed Outages	Total	Percent Complete	Completed Outages	Total	Percent Complete
<2 weeks	7,111	8,546	83.2%	7,087	8,571	82.7%
>=2 weeks & <2 months	897	1,020	87.9%	790	914	86.4%
>=2 months	318	370	85.9%	254	367	69.2%
Total	8,326	9,936	83.8%	8,131	9,852	82.5%

Although the definition of late outages was developed in order to prevent outages for the planning period being submitted after the opening of bidding in the Annual FTR Auction, the rules have not functioned effectively because the rule has no direct connection to the date on which bidding opens for the Annual FTR Auction. By requiring all long-duration transmission outages to be submitted before February 1, PJM outage submission rules only prevent long-duration transmission outages from being submitted late. The rule does not address the situation in which long-duration transmission outages are submitted on time, but are rescheduled so that they are late. There is no rule to address the situation in which short-duration outages (duration <= 5 days) are submitted on time, but are changed to long-duration transmission outages after the outages are approved and active. The Annual FTR Auction model may consider transmission outages planned for longer than two weeks but less than two months. Those outages not only include long duration outages but also include outages shorter than 30 days. In those cases, PJM outage submission rules failed to prevent long duration transmission outages from being submitted late. The MMU recommends that PJM modify the rules to eliminate the approval of outage requests submitted or rescheduled after the opening of bidding in the Annual FTR Auction.

Monthly FTR Market

When determining transmission outages to be modeled in the 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.[84] 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, 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. On average, 33.3 percent of the outage requests modeled in the Monthly Balance of Planning Period FTR Auction were submitted late according to outage submission rules in the 2017/2018 planning period.

Table 12-58 Monthly Balance of Planning Period FTR Auction modeled transmission facility outage requests by received status: 2017/2018 and 2018/2019

	2017/2018				2018/2019			
Month	On Time	Late	Total	Percent Late	On Time	Late	Total	Percent Late
Jun	134	116	250	46.4%	208	106	314	33.8%
Jul	83	72	155	46.5%	136	71	207	34.3%
Aug	100	73	173	42.2%	137	78	215	36.3%
Sep	394	125	519	24.1%	465	136	601	22.6%
Oct	598	162	760	21.3%	536	191	727	26.3%
Nov	453	177	630	28.1%	391	129	520	24.8%
Dec	330	142	472	30.1%	363	129	492	26.2%
Jan	194	78	272	28.7%	199	90	289	31.1%
Feb	214	125	339	36.9%	213	109	322	33.9%
Mar	391	168	559	30.1%	389	146	535	27.3%
Apr	444	204	648	31.5%	427	159	586	27.1%
May	396	203	599	33.9%	362	181	543	33.3%
Average	311	137	448	33.3%	319	127	446	29.8%

Table 12-59 shows that on average, 19.6 percent of outage requests modeled in the Monthly Balance of Planning Period FTR Auction were cancelled in the 2018/2019 planning period. On average, 19.0 percent of outage requests modeled in the Monthly Balance of Planning Period FTR Auction were cancelled in the 2017/2018 planning period.

84 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: 2017/2018 and 2018/2019

Planning Year	Month	In Process	Denied	Approved	Cancelled	Revised	Active	Complete	Total	Percent Cancelled
2017/2018	Jun	19	5	5	52	0	64	105	250	20.8%
	Jul	11	2	8	25	0	54	55	155	16.1%
	Aug	10	0	1	27	0	64	71	173	15.6%
	Sep	67	8	13	100	3	161	167	519	19.3%
	Oct	77	2	27	142	0	201	311	760	18.7%
	Nov	39	5	10	121	2	177	276	630	19.2%
	Dec	42	4	9	97	0	74	246	472	20.6%
	Jan	29	6	9	59	0	80	89	272	21.7%
	Feb	33	1	3	63	1	108	130	339	18.6%
	Mar	66	5	15	114	3	171	185	559	20.4%
	Apr	55	1	20	115	0	202	255	648	17.7%
	May	20	11	16	108	0	145	299	599	18.0%
	Avg	39	4	11	85	1	125	182	448	19.0%
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	19.6%

Table 12-60 shows that on average, 10.6 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 2018/2019 planning period, compared to 10.6 percent in the 2017/2018 planning period. On average, 68.7 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 2018/2019 planning period, compared to 70.3 percent in the 2017/2018 planning period.

Table 12-60 Transmission facility outage requests that are not modeled in Monthly Balance of Planning Period FTR Auction: 2017/2018 and 2018/2019

	2017/2018						2018/2019					
	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	642	96	13.0%	310	847	73.2%	757	120	13.7%	389	830	68.1%
Jul	294	48	14.0%	245	608	71.3%	393	64	14.0%	271	643	70.4%
Aug	341	28	7.6%	211	651	75.5%	483	68	12.3%	259	715	73.4%
Sep	859	84	8.9%	256	599	70.1%	819	145	15.0%	283	712	71.6%
Oct	986	89	8.3%	346	867	71.5%	1,232	116	8.6%	329	945	74.2%
Nov	815	83	9.2%	364	792	68.5%	869	77	8.1%	406	860	67.9%
Dec	610	68	10.0%	324	693	68.1%	663	44	6.2%	321	672	67.7%
Jan	565	74	11.6%	286	746	72.3%	554	75	11.9%	369	726	66.3%
Feb	591	51	7.9%	340	700	67.3%	642	100	13.5%	330	738	69.1%
Mar	1,068	219	17.0%	340	802	70.2%	1,092	112	9.3%	380	772	67.0%
Apr	1,203	119	9.0%	446	852	65.6%	1,405	96	6.4%	440	747	62.9%
May	1,203	149	11.0%	463	1,084	70.1%	1,263	111	8.1%	448	850	65.5%
Avg	765	92	10.6%	328	770	70.3%	848	94	10.6%	352	768	68.7%

Table 12-61 shows that on average, 68.6 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 2018/2019 planning period, compared to 68.3 percent in the 2017/2018 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: 2017/2018 and 2018/2019

	2017/2018			2018/2019		
	Completed Outages	Total	Percent Complete	Completed Outages	Total	Percent Complete
Jun	622	847	73.4%	633	830	76.3%
Jul	410	608	67.4%	449	643	69.8%
Aug	473	651	72.7%	506	715	70.8%
Sep	406	599	67.8%	480	712	67.4%
Oct	595	867	68.6%	614	945	65.0%
Nov	490	792	61.9%	570	860	66.3%
Dec	508	693	73.3%	468	672	69.6%
Jan	493	746	66.1%	471	726	64.9%
Feb	457	700	65.3%	470	738	63.7%
Mar	569	802	70.9%	568	772	73.6%
Apr	560	852	65.7%	504	747	67.5%
May	731	1,084	67.4%	586	850	68.9%
Avg	526	770	68.3%	527	768	68.6%

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. [85]

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.

85 PJM. "Manual 3: Transmission Operations," Rev. 55 (May 31, 2019).

Figure 12-4 Illustration of day-ahead market analysis: May 5, 2018

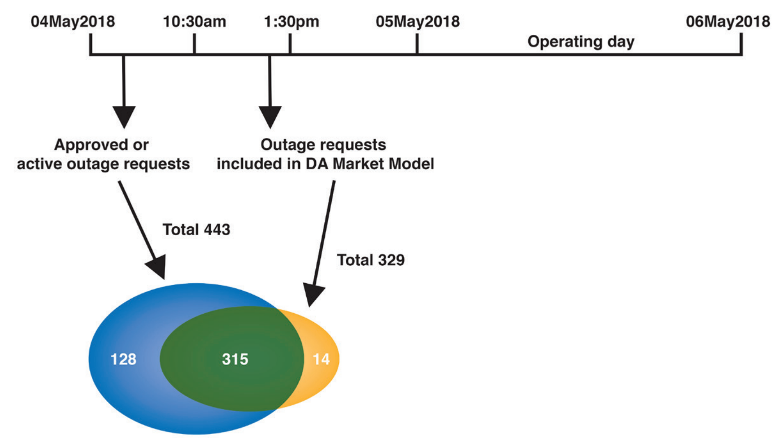


Figure 12-5 compares the weekly average number of active or approved outages available to market participants prior to the close of the day-ahead market with the outages included as inputs to the day-ahead market by PJM.

Figure 12-6 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 12-5 Approved or active outage requests: January 2015 through June 2019

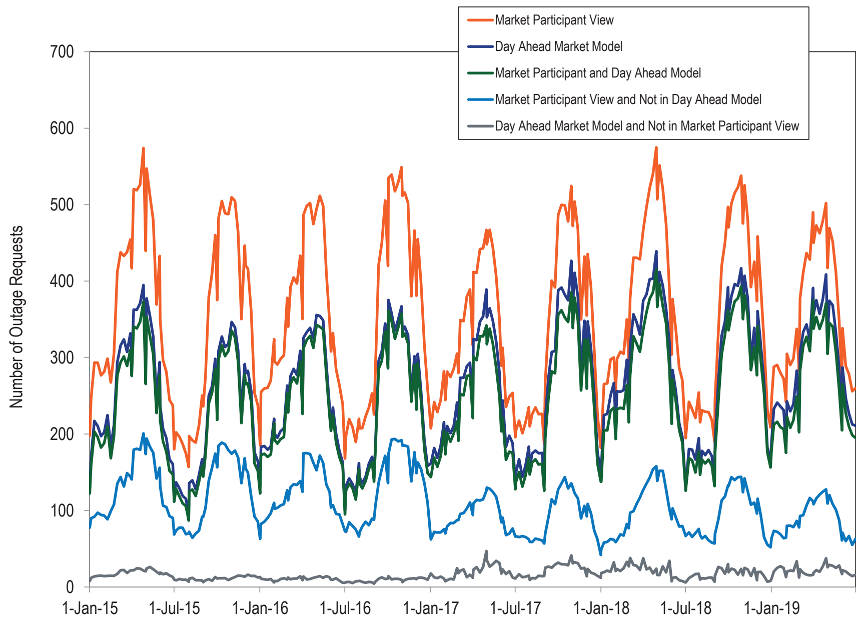


Figure 12-6 Day-ahead market model outages: January 2015 through June 2019

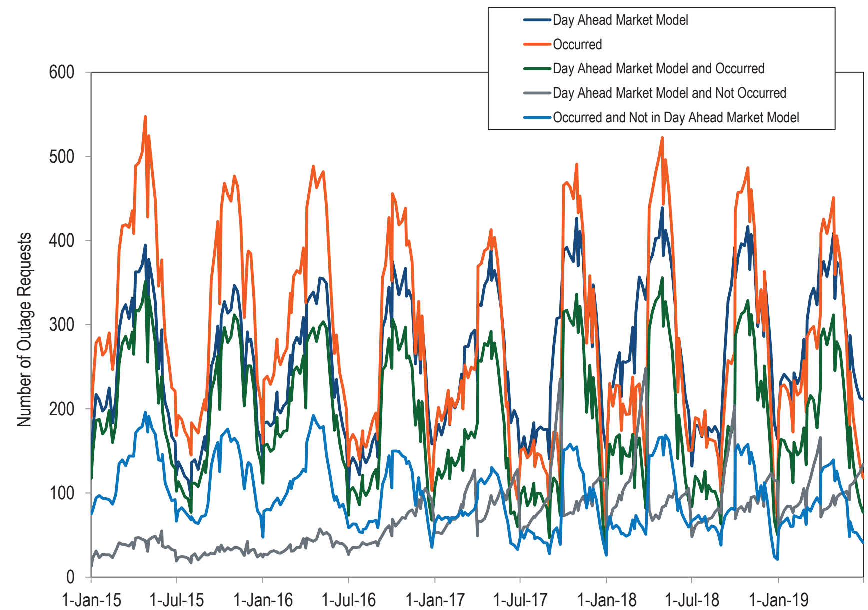


Figure 12-7 compares the weekly average number of active or approved outages available to market participants prior to the close of the day-ahead market with the outages that actually occurred during the operating day.

Figure 12-7 Approved or active outage requests: January 2015 through June 2019

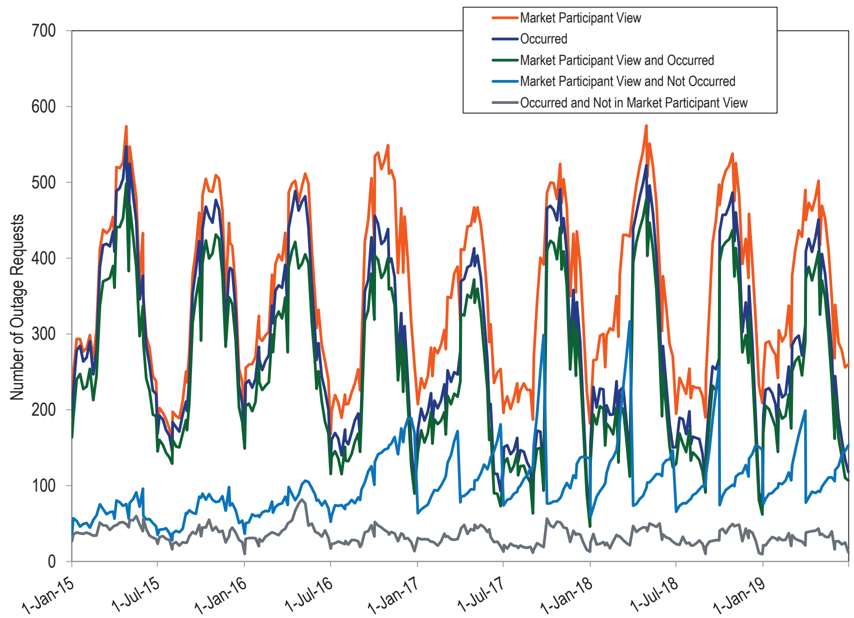


Figure 12-5, Figure 12-6, and Figure 12-7 show that on a weekly average basis, the active or approved outages available to day-ahead market participants, the outages included as inputs in the day-ahead market model and the outages that actually occurred in real time are not consistent. The active or 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 2018/2019 planning period, 92.1 percent of congestion was offset.

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 Market Monitor 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 June* 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 June 30, 2019. A caveat that applies to the 2018/2019 planning period is that the results may change depending on the final FERC actions in the GreenHat Energy, LLC matter.[6]

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).

6 See 166 FERC ¶ 61,072, *reh'g pending*; see also 163 FERC ¶ 61,157 (establishing settlement judge proceedings).

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.

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 2018/2019 planning period, PJM allocated a total of 27,335.6 MW of residual ARRs, down from 39,597.4 MW in the 2017/2018 planning period, with a total target allocation of $11.8 million for the 2018/2019 planning period, down from $17.5 million for the 2017/2018 planning period.
- **ARR Reassignment for Retail Load Switching.** There were 35,571 MW of ARRs associated with $423,100 of revenue that were reassigned in the 2018/2019 planning period. There were 44,823 MW of ARRs associated with $339,500 of revenue that were reassigned for the 2017/2018 planning period.

Market Performance

- **Revenue Adequacy.** For the 2018/2019 planning period, the ARR target allocations, which are based on the nodal price differences from the Annual FTR Auction, were $726.8 million, while PJM collected $907.6 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 2017/2018 planning period, the ARR target allocations were $573.8 million while PJM collected $601.2 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, ARRs, self scheduled FTRs and surplus congestion revenue offset 92.1 percent of total congestion costs. 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 2019/2022 Long Term FTR Auction, total participant FTR sell offers were 318,022 MW. In the 2019/2020 Annual FTR Auction, total participant FTR sell offers were 375,582 MW. In the Monthly Balance of Planning Period FTR Auctions for the 2018/2019 planning period, total participant FTR sell offers were 8,483,263 MW, up from 4,401,873 MW for the same period during the 2017/2018 planning period.
- **Demand.** In the 2019/2022 Long Term FTR auction, total FTR buy bids were 1,949,546 MW, down 5.0 percent from 2,052,820 MW the previous long term auction. There were 2,816,861 MW of buy and self scheduled bids in the 2019/2020 Annual FTR Auction, down 3.1 percent from 2,907,583 MW the previous planning period. The total FTR buy bids from the Monthly Balance of Planning Period FTR Auctions for the 2018/2019 planning period increased 3.6 percent from 19,138,752 MW for the same time period of the prior planning period, to 19,827,194 MW.
- **Patterns of Ownership.** For the 2019/2022 Long Term FTR Auction, financial entities purchased 68.1 percent of prevailing flow FTRs and 70.4 percent of counter flow FTRs. For the 2019/2020 Annual FTR Auction, financial participants purchased 64.8 percent of all prevailing flow FTRs and 79.5 percent of all counter flow FTRs. For the Monthly Balance of Planning Period Auctions, financial entities purchased 72.3 percent of prevailing flow and 81.5 percent of counter flow FTRs for January through June of 2019. Financial entities owned 71.2 percent of all prevailing and counter flow FTRs, including 63.9 percent of all prevailing flow FTRs and 81.7 percent of all counter flow FTRs during the period from January through June 2019.

Market Behavior

- **FTR Forfeitures.** For the period January 19, 2017, through June 30, 2019, total FTR forfeitures were $14.5 million.
- **Credit.** There were no collateral defaults in the first six 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 $39.1 million in the first six months of 2019, for a total of $116.1 million in defaults for the company, including the auction liquidation costs.

Market Performance

- **Volume.** The 2019/2022 Long Term FTR Auction cleared 408,237 MW (20.9 percent) of FTR buy bids, up 18.2 percent from 345,506 MW (16.8 percent) in the 2018/2021 Long Term FTR Auction. The Long Term FTR Auction also cleared 35,412 MW (11.1 percent) of FTR sell offers, compared to 42,555 (17.8 percent), a 16.9 percent decrease.

- In the Annual FTR Auction for the 2019/2020 planning period 641,023 MW (22.8 percent) of buy and self schedule bids cleared, up 4.2 percent from 615,254 MW (21.2 percent) for the previous planning period. In the 2018/2019 planning period Monthly Balance of Planning Period FTR Auctions cleared 3,157,852 MW (15.9 percent) of FTR buy bids and 1,703,548 MW (20.1 percent) of FTR sell offers.
- **Price.** The weighted average buy bid FTR price in the 2019/2020 Long Term FTR Auction was $0.10 per MW, up from $0.03 per MW for the 2018/2021 planning period. The weighted average buy bid FTR price in the Annual FTR Auction for the 2019/2020 planning period was $0.66 per MW, up from $0.59 per MW in the 2018/2019 planning period. The weighted average buy bid cleared FTR price in the Monthly Balance of Planning Period FTR Auctions for the 2018/2019 planning period was $0.20, up from $0.13 per MW for the same period in the 2017/2018 planning period.
- **Revenue.** The 2019/2022 Long Term FTR Auction generated $161.7 million of net revenue for all FTRs, up from $29.6 million for the 2018/2021 Long Term FTR Auction. The 2018/2019 Annual FTR Auction generated $822.6 million in net revenue, up from $542.2 million for the 2017/2018 Annual FTR Auction. The Monthly Balance of Planning Period FTR Auctions generated $59.7 million in net revenue for all FTRs of the 2018/2019 planning period, up from $40.3 million for the same time period in the 2017/2018 planning period.
- **Revenue Adequacy.** FTRs were paid at 100 percent of the target allocation level for the 2018/2019 planning period. 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 2018/2019 planning period, physical entities made -$52.3 million in profits on FTRs purchased directly (not self scheduled), while receiving $129.9 million in returned congestion from self scheduled FTRs, and financial entities made $116.5 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.)
- 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 should 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

7 See "PJM Manual 6: Financial Transmission Rights," Rev. 22 (June 27, 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, 100.0, 50.0 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 planning years. With surplus through May 2019 distributed, total ARR and self scheduled FTR revenue offset 92.1 percent of total congestion costs for the 2018/2019 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.

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).

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 2017/2018 planning period would have been $1,315.1 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 2017/2018 planning period, ARRs and FTRs would have offset 74.3 percent of total congestion rather than 50.0 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.

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

10 163 FERC ¶61,165 (2018).

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.

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 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,

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.

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.

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.[13] 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.

12 See "PJM Incremental Auction Revenue Rights Model Development and Analysis," P(June 12, 2017) <https://www.pjm.com/~/media/markets-ops/ftr/pjm-iarr-model-development-and-analysis.ashx>.

13 "PJM Manual 6: Financial Transmission Rights," Rev. 22 (June 27, 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>.

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.[14] 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.[15]

Each March, PJM allocates annual ARRs to eligible customers in a three stage process:

- Stage 1A. In the first stage of the allocation, network transmission service customers can obtain ARRs, up to their share of Zonal Base Load, which is the lowest daily peak load in the prior twelve month period increased by load growth projections. The amount of Stage 1A ARRs a participant can request is based on generation to load paths that reflect generation resources that had historically served load, or their qualified replacements if the resource has retired, in the historical reference year for the zone. The historical reference year is the year prior to the creation of PJM markets, which is 1999 for the original zones, or the year in which a zone joined PJM. Firm, point to point transmission service customers can obtain Stage 1A ARRs, up to 50 percent of the MW of firm, point to point transmission service provided between the receipt and delivery points for the historical reference year. Stage 1A ARRs cannot be prorated. If Stage 1A ARRs are found to be infeasible, transmission system upgrades must be undertaken to maintain feasibility.[16]
- 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.[17] 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.[18]

14 See *2006 State of the Market Report for PJM* (March 8, 2007) for the rules of the annual ARR allocation process for the 2006 to 2007 and prior planning periods.
15 OATT Attachment K 7.1.1.(b).

16 See "PJM Manual 6: Financial Transmission Rights," Rev. 22 (June 27, 2019).
17 *Id.* at 21.
18 *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>.

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.[19] 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[20]

$$MW = Constraint\ Capability\ x\ \left(\frac{Individual\ Requested\ MW}{Total\ Requested\ MW}\right) x \left(\frac{1}{MW\ impact\ on\ line}\right)$$

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.[21] PJM replaced retired units with operating generators, termed qualified replacement resources (QRRs).[22]

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

Volume

Table 13-3 shows the MW of ARR allocations for each round of the 2018/2019 and 2019/2020 planning periods.

Table 13-3 Annual ARR Allocation volume: 2018/2019 and 2019/2020

Planning Period	Stage	Round	Requested Count	Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
2018/2019	1A	0	30,813	77,407	76,250	98.5%	1,157	1.5%
	1B	1	17,496	37,203	20,054	53.9%	17,149	46.1%
	2	2	6,553	20,327	1,892	9.3%	18,435	90.7%
		3	5,039	19,420	3,314	17.1%	16,106	82.9%
		4	5,405	19,731	3,716	18.8%	16,015	81.2%
		Total	16,997	59,478	8,922	15.0%	50,556	85.0%
	Total		65,306	174,088	105,226	60.4%	68,862	39.6%
2019/2020	1A	0	30,204	72,130	72,130	100.0%	0	0.0%
	1B	1	15,261	34,567	23,620	68.3%	10,947	31.7%
	2	2	7,238	21,418	1,745	8.1%	19,673	91.9%
		3	4,557	20,863	3,432	16.5%	17,431	83.5%
		4	3,593	20,776	3,992	19.2%	16,784	80.8%
		Total	15,388	63,057	9,169	14.5%	53,888	85.5%
	Total		60,853	169,754	104,919	61.8%	64,835	38.2%

19 "PJM Manual 6: Financial Transmission Rights," Rev. 22 (June 27, 2019).
20 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>.
21 156 FERC ¶ 61,180 (2016).
22 See FERC Docket No. EL16-6-003.

Stage 1A Infeasibility

Stage 1A ARRs are allocated for a 10 year period, with the ability for a participant to opt out of any planning period. PJM conducts a simultaneous feasibility analysis to determine the transmission upgrades required to ensure that the long term ARRs can remain feasible. The rules provide that if a simultaneous feasibility test violation occurs in any year, PJM will identify or accelerate any transmission upgrades to resolve the violation and these upgrades will be recommended for inclusion in the PJM RTEP process.[23] But such transmission upgrades must pass PJM's RTEP process.

PJM's transmission planning process (RTEP) does not identify a need for new transmission associated with Stage 1A overallocations because there is, in fact, no need for new transmission associated with Stage 1A ARRs. The Stage 1A overallocation issue is a fiction based on the use of outdated and irrelevant generation to load paths to assign Stage 1A rights that have nothing to do with actual power flows. This continues to be true even with the replacement of retired generating units.

For the 2018/2019 planning period, Stage 1A of the Annual ARR Allocation was infeasible, resulting in an over allocation of ARRs on the affected facilities. As a result, modeled system capability, in excess of actual system capability, was provided to the Stage 1A ARRs and added to the FTR auction. According to Section 7.4.2 (i) of the OATT, the capability limits of the binding constraints rendering these ARRs infeasible must be increased in the model and these increased limits must be used in subsequent ARR and FTR allocations and auctions for the entire planning period, except in the case of extraordinary circumstances.

Table 13-4 shows the MW quantity and count of overloaded facilities and the reasons for the modeled overload. In order to eliminate the infeasibilities for the requested Stage 1A ARR allocations, PJM was required to raise the modeled capacity limits on 72 facility/contingency pairs, 24 of which were internal to PJM and the rest were in MISO, a total of 5,858 MW.[24]

23 See "PJM Manual 6: Financial Transmission Rights," Rev. 22 (June27, 2019) at 22.
24 PJM. "*PJM 2018/2019 Stage 1A Over allocation notice*,"<http://www.pjm.com/-/media/markets-ops/ftr/annual-arr-allocation/2018-2019/2018-2019-stage-1a-over-allocation-notice.ashx?la=en> (June 13, 2018).

Table 13-4 Stage 1A overloaded facility reasons and MW

Reason	Type	MW	Count
Network Load	M2M Flowgate	1,137	21
Network Load	Pseudo Tie Flowgate	98	3
Transmission Outage	Internal PJM	3,600	38
Transmission Outage	M2M Flowgate	983	9
Transmission Outage	Pseudo Tie Flowgate	40	1

Figure 13-1 shows the predicted and estimated impact of Stage 1A infeasibilities on funding for the 2012/2013 through 2017/2018 planning periods, as well as the predicted impact on funding for the 2019/2020 planning period. The predicted funding is based on the infeasible ARR MW and the nodal price of the source and sink in the Annual FTR Auction. The estimated funding is calculated assuming every infeasible ARR MW is self scheduled, and uses the hourly congestion LMP values of the applicable day-ahead hours. In the 2016/2017 planning period, Stage 1A ARR infeasibilities accounted for $293.5 million in estimated over allocation. Predicted funding impacts are lower in the 2017/2018, 2018/2019 and 2019/2020 planning periods from the previous two planning periods, likely as a result of PJM relaxing model constraints. PJM's newly implemented Qualified Replacement Resource rules may slightly reduce revenue inadequacy from Stage 1A ARRs, but do not eliminate the actual issues with historical Stage 1A resources.

Figure 13-1 Stage 1A Infeasibility funding impact

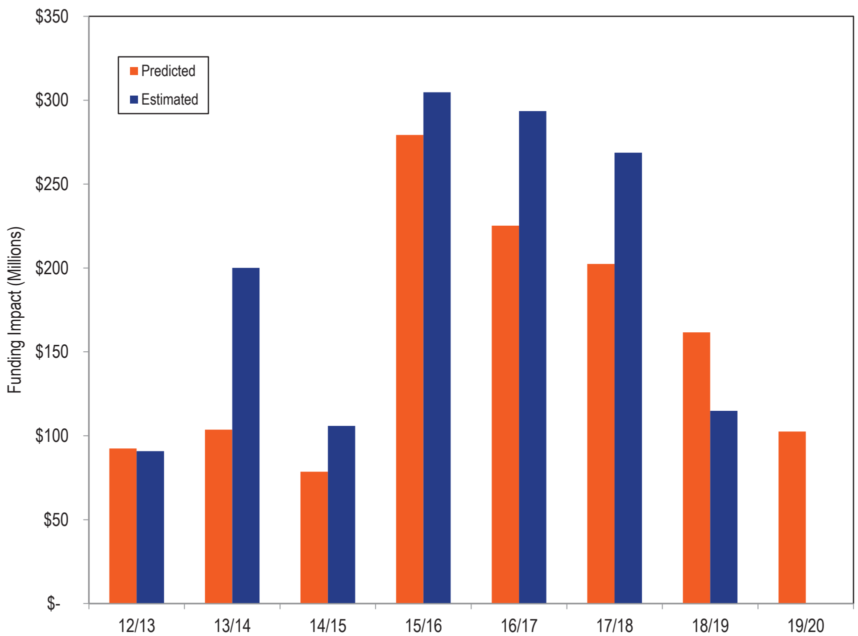


Table 13-5 shows the MW of retired generation sources for Stage 1A ARRs, the QRR MW assigned by PJM for all resources and the replacement MW that were considered rate-based. PJM created the synthetic zone Midatlantic for the QRR assignment although it is not clear why.

Table 13-5 Qualified Replacement Resource results: 2019/2020

Zone	Historical Retired	Replacement (All)	Replacement (Rate-based)
AEP/DAY	8,826.3	6,702.4	1,838.3
ATSI	4,027.3	2,463.4	50.4
ComEd	5,646.8	4,440.5	4.5
DEOK	2,318.0	1,729.2	57.6
Dominion	3,071.1	2,679.4	2,628.4
DLCO	834.0	211.7	0.0
EKPC	198.1	229.3	0.0
Midatlantic	16,813.8	14,044.3	375.9
Total	41,735.4	32,500.2	4,955.1

Revenue

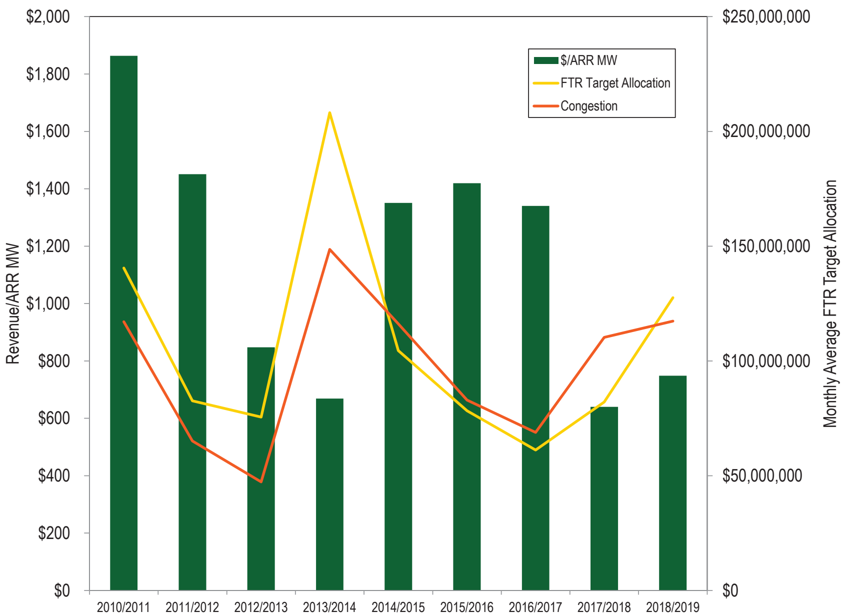
ARRs are allocated to qualifying customers rather than sold, so ARR revenue (target allocation) is different from the revenue that results from the FTR auctions which generally exceeds the sum of the ARR target allocations.

Figure 13-2 shows the revenue per ARR MW held for each month of the 2010/2011 planning period through the 2018/2019 planning period. The revenue per ARR MW held do not include target allocation related payouts for self scheduled FTRs, but do include Residual ARRs starting in August 2012.

FTR prices increased in the 2014/2015 Annual FTR Auction in part as a result of reduced supply caused by PJM's assumption of more outages in the model used to allocate Stage 1B and Stage 2 ARRs. The increased FTR prices resulted in an increase in revenue per ARR MW, but fewer ARR MW. For the 2014/2015 planning period, the total dollars per MW of ARR allocation was $11,279, while the previous planning period resulted in revenue per MW of $6,692, a 68.5 percent increase in revenue per allocated ARR MW. Some of the ARR MW lost from proration were provided in the Residual ARR process, but the residual allocations are not comparable to the ARRs awarded in the annual process because residual ARR allocations change each month and cannot be self scheduled as FTRs. For the 2015/2016 and 2016/2017 planning periods, the revenue per MW of ARR allocation was $10,641.54 and $10,411. During these planning periods PJM chose more restrictive modeling criteria, which did not release the full capacity of the FTR model to account for revenue inadequacies. Beginning in the 2017/2018 planning period, when balancing congestion was removed from FTR funding, PJM reinstated less restrictive modeling criteria, and the revenue per MW of ARR decreased. For the 2017/2018 and 2018/2019 planning periods the revenue per MW of ARR was $5,168 and $6,841.

The revenue per MW value of ARRs for the 2018/2019 planning period increased 32.4 percent from the previous planning period. Figure 13-2 shows that the total congestion and FTR target allocations increased from last planning period, primarily from a very high congestion in January 2018, but that ARR value was significantly lower. Load is now paying balancing congestion costs, not accounted for in this figure, reducing revenue received by ARR holders while not receiving the asserted benefit of higher ARR value that proponents of balancing congestion reallocation had asserted would be forthcoming.

Figure 13-2 Revenue per ARR MW paid to ARR holders compared to congestion and FTR target allocations: 2010/2011 through 2018/2019



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.

There were 44,823 MW of ARRs associated with $339,500 of revenue that were reassigned in the 2017/2018 planning period. There were 35,571 MW of ARRs associated with $423,100 of revenue that were reassigned for the 2018/2019 planning period.

Table 13-6 summarizes ARR MW and associated revenue reassigned for network load in each control zone where changes occurred between June 2017 and May 2019.

25 See "PJM Manual 6: Financial Transmission Rights," Rev. 22 (June 27, 2019).

Table 13-6 ARRs and ARR revenue automatically reassigned for network load changes by control zone: June 2017 through May 2019

	ARRs Reassigned (MW-day)		ARR Revenue Reassigned [Dollars (Thousands) per MW-day]	
Control Zone	2017/2018 (12 months)	2018/2019 (12 months)	2017/2018 (12 months)	2018/2019 (12 months)
AECO	438	392	$3.2	$2.1
AEP	2,271	2,730	$13.0	$35.0
APS	1,660	945	$19.7	$17.6
ATSI	6,235	4,923	$20.6	$49.9
BGE	2,688	1,732	$57.7	$46.1
ComEd	4,519	3,261	$77.0	$43.9
DAY	1,565	718	$2.8	$3.7
DEOK	4,318	2,442	$23.4	$60.3
DLCO	5,995	4,576	$18.5	$44.6
DPL	1,865	1,932	$36.5	$43.3
Dominion	13	70	$0.1	$0.6
EKPC	0	0	$0.0	$0.0
JCPL	1,146	1,172	$2.4	$1.6
Met-Ed	678	604	$5.6	$4.7
PECO	3,226	2,997	$11.1	$20.9
PENELEC	696	716	$7.3	$8.4
PPL	3,447	3,643	$3.2	$8.0
PSEG	1,495	1,195	$18.6	$14.2
Pepco	2,423	1,477	$18.9	$18.1
RECO	147	46	$0.0	$0.0
Total	44,823	35,571	$339.5	$423.1

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 13-7 shows the Residual ARRs (cleared volume) allocated to participants, along with the target allocations (bid and requested) from the effective month. In the 2018/2019 planning period, PJM allocated a total of 27,335.6 MW of Residual ARRs with a target allocation of $11.8 million. In the same time period for the 2017/2018 planning period, PJM allocated a total of 39,597.4 MW of residual ARRs with a target allocation of $17.5 million. In the 2017/2018 planning period 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.

Table 13-7 Residual ARR allocation volume and target allocation: 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
Total	25,403.8	13,506.1	53.2%	$6,935,210

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

26 See FERC Letter Order, Docket No. ER17-1057 (April 5, 2017).

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 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

27 *See* "PJM Manual 6: Financial Transmission Rights," Rev. 22 (June 27, 2019).

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.

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 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.

29 116 FERC ¶ 61,077 (2006).

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).

- 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 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.

Secondary Bilateral Market

Market participants can buy and sell existing FTRs through the PJM administered, bilateral market, or market participants can trade FTRs among themselves without PJM involvement. Bilateral transactions that are not done through PJM can involve parties that are not PJM members. PJM has no knowledge of bilateral transactions that are done outside of PJM's bilateral market system.

For bilateral trades done through PJM, the FTR transmission path must remain the same, FTR obligations must remain obligations, and FTR options must remain options. However, an individual FTR may be split up into multiple, smaller FTRs, down to increments of 0.1 MW. FTRs can also be given 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,

31 See "PJM Manual 6: Financial Transmission Rights," Rev. 22 (June 27, 2019).

32 "PJM Manual 6: Financial Transmission Rights," Rev. 22 (June 27, 2019).

33 "PJM Manual 6: Financial Transmission Rights," Rev. 22 (June 27, 2019).

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 13-8 shows the 2019/2022 long term FTR auction market cleared FTRs by trade type, organization type and FTR direction. The results show that financial entities purchased 68.1 percent of prevailing flow buy bid FTRs and 70.4 percent of counter flow buy bid FTRs with the result that financial entities purchased 69.1 percent of all long term FTR auction cleared buy bids. Physical entities purchased 30.9 percent of all cleared long term FTRs in the 2019/2022 Long Term FTR Auction, up 5.0 percentage points from the previous Long Term FTR Auction.

Table 13-8 Long term FTR auction patterns of ownership by FTR direction: 2019/2022

		FTR Direction		
Trade Type	Organization Type	Prevailing Flow	Counter Flow	All
Buy Bids	Physical	31.9%	29.6%	30.9%
	Financial	68.1%	70.4%	69.1%
	Total	100.0%	100.0%	100.0%
Sell Offers	Physical	20.7%	23.5%	21.7%
	Financial	79.3%	76.5%	78.3%
	Total	100.0%	100.0%	100.0%

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 13-9 shows the HHI for the periods in the 2017/2020 through 2019/2022 Long Term FTR Auctions. The YRALL auction is Highly Concentrated. The individual annual auctions are Unconcentrated with the exception of years two and three of the 17/20 Auction.

Table 13-9 Long term HHIs by auction

Auction	YR1	YR2	YR3	YRALL
17/20 Long Term Auction	462	1696	1252	8533
18/21 Long Term Auction	586	850	577	8654
19/22 Long Term Auction	344	521	666	9954

Table 13-10 shows the annual FTR auction cleared FTRs for the 2019/2020 planning period by trade type, organization type and FTR direction. In the Annual FTR Auction for the 2019/2020 planning period, financial entities purchased 64.8 percent of prevailing flow FTRs, down 2.1 percentage points, and 79.5 percent of counter flow FTRs, down 4.7 percentage points, with the results that financial entities purchased 69.8 percent, down 3.0 percentage points, of all annual FTR auction cleared buy bids for the 2019/2020 planning period.

Table 13-10 Annual FTR Auction patterns of ownership by FTR direction: 2019/2020

			FTR Direction		
Trade Type	Organization Type	Self-Scheduled FTRs	Prevailing Flow	Counter Flow	All
Buy Bids	Physical	Yes	6.8%	0.3%	4.5%
		No	28.4%	20.3%	25.7%
		Total	35.2%	20.5%	30.2%
	Financial	No	64.8%	79.5%	69.8%
	Total		100.0%	100.0%	100.0%
Sell Offers	Physical		18.0%	20.0%	18.8%
	Financial		82.0%	80.0%	81.2%
	Total		100.0%	100.0%	100.0%

Table 13-11 shows the HHI values for cleared buy and self scheduled bids for the 2016/2017 through 2018/2019 Annual FTR Auctions. Obligation buy bids are consistently Unconcentrated, while Option buy bids are Unconcentrated to Moderately Concentrated. Cleared self scheduled bids are always Highly Concentrated.

Table 13-11 Annual auction HHIs by auction

Auction	Offset Type	Trade Type	HHI
19/20 Annual Auction	Obligation	Buy	251
	Obligation	SelfScheduled	2661
	Option	Buy	978
18/19 Annual Auction	Obligation	Buy	357
	Obligation	SelfScheduled	2620
	Option	Buy	1213
17/18 Annual Auction	Obligation	Buy	303
	Obligation	SelfScheduled	2794
	Option	Buy	2099

Table 13-12 presents the monthly balance of planning period FTR auction cleared FTRs for 2019 by trade type, organization type and FTR direction. Financial entities purchased 72.3 percent of prevailing flow FTRs, down 0.4 percentage points, and 81.5 percent of counter flow FTRs, down 0.7 percentage points, for the year, with the result that financial entities purchased 76.4 percent, down 0.6 percentage points, of all prevailing and counter flow FTR buy bids in the monthly balance of planning period FTR auction cleared FTRs for 2019.

Table 13-12 Monthly Balance of Planning Period FTR Auction patterns of ownership by FTR direction: 2019

		FTR Direction		
Trade Type	Organization Type	Prevailing Flow	Counter Flow	All
Buy Bids	Physical	27.7%	18.5%	23.6%
	Financial	72.3%	81.5%	76.4%
	Total	100.0%	100.0%	100.0%
Sell Offers	Physical	14.9%	14.3%	14.7%
	Financial	85.1%	85.7%	85.3%
	Total	100.0%	100.0%	100.0%

Table 13-13 shows the HHI values for cleared MW for the 2018/2019 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.

Table 13-13 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-18	Obligation	353	432	487	587	659	773
	Option	3796	5981	7006	4854	4761	6586
Jul-18	Obligation	329	434	1283	827	559	681
	Option	2270	5044	2751	3666	3918	6260
Aug-18	Obligation	254	534	527	509	430	522
	Option	2437	3135	4673	5486	4729	5578
Sep-18	Obligation	330	481	534		610	772
	Option	1412	4864	3118		1622	4876
Oct-18	Obligation	378	457	834		478	678
	Option	1192	1938	3884		1892	4399
Nov-18	Obligation	329	591	641		523	580
	Option	1337	1715	2610		1650	2312
Dec-18	Obligation	327	456	546			685
	Option	1255	1944	1662			2038
Jan-19	Obligation	320	382	879			629
	Option	1515	2709	4218			1485
Feb-19	Obligation	263	372	566			735
	Option	1248	2064	3847			2534
Mar-19	Obligation	287	387	396			
	Option	1163	2853	2805			
Apr-19	Obligation	255	423				
	Option	1012	3136				
May-19	Obligation	314					
	Option	1226					

Table 13-14 shows the average daily net position ownership for all FTRs for 2019, by FTR direction.

Table 13-14 Daily FTR net position ownership by FTR direction: 2019

	FTR Direction		
Organization Type	Prevailing Flow	Counter Flow	All
Physical	36.1%	18.3%	28.8%
Financial	63.9%	81.7%	71.2%
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 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.

Long Term FTR Auction

In the 2019/2022 Long Term FTR Auction, 179,727 MW (36.7 percent of bid volume; 44.0 percent of total FTR volume) of counter flow FTR buy bids cleared, an increase from 164,911 MW and 47.7 percent of total FTR volume. In the same auction, prevailing flow FTR buy bids cleared 228,510 MW (15.6 percent of bid volume; 60.0 percent of total FTR volume) an increase from 180,596 MW and 52.3 percent of total FTR volume. In the 2019/2022 Long Term FTR Auction, there were 12,790 MW (7.4 percent) of counter flow sell offers and 22,622 MW (15.6 percent) of prevailing flow sell offers cleared.

Table 13-15 Long Term FTR Auction market volume: 2019/2022

Trade Type	FTR Direction	Period Type	Bid and Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
Buy bids	Counter Flow	Year 1	77,290	222,831	80,816	36.3%	142,015	63.7%
		Year 2	56,949	151,934	53,512	35.2%	98,423	64.8%
		Year 3	45,133	111,957	43,417	38.8%	68,540	61.2%
		Year All	428	2,681	1,983	74.0%	698	26.0%
		Total	179,800	489,404	179,727	36.7%	309,677	63.3%
	Prevailing Flow	Year 1	195,478	664,524	105,442	15.9%	559,081	84.1%
		Year 2	134,844	431,316	69,639	16.1%	361,677	83.9%
		Year 3	103,713	350,104	53,232	15.2%	296,872	84.8%
		Year All	2,325	14,199	197	1.4%	14,001	98.6%
		Total	436,360	1,460,142	228,510	15.6%	1,231,632	84.4%
	Total		616,160	1,949,546	408,237	20.9%	1,541,309	79.1%
Sell offers	Counter Flow	Year 1	46,482	110,181	8,634	7.8%	101,547	92.2%
		Year 2	17,352	47,115	3,800	8.1%	43,315	91.9%
		Year 3	6,538	15,802	355	2.2%	15,447	97.8%
		Year All	NA	NA	NA	NA	NA	NA
		Total	70,372	173,098	12,790	7.4%	160,308	92.6%
	Prevailing Flow	Year 1	33,785	78,017	14,373	18.4%	63,644	81.6%
		Year 2	17,460	44,902	6,529	14.5%	38,373	85.5%
		Year 3	9,488	22,005	1,720	7.8%	20,285	92.2%
		Year All	NA	NA	NA	NA	NA	NA
		Total	60,733	144,924	22,622	15.6%	122,301	84.4%
	Total		131,105	318,022	35,412	11.1%	282,610	88.9%

35 See "PJM Manual 6: Financial Transmission Rights," Rev. 21 (Dec. 6, 2018).
36 See id.

Figure 13-3 shows the percent of FTR MW cleared, and bid and cleared volume, by direction, for each round of the Long Term FTR Auction from the 2015/2018 through the 2019/2022 auctions.

Figure 13-3 Long Term FTR Auction bid and cleared volume by round and direction

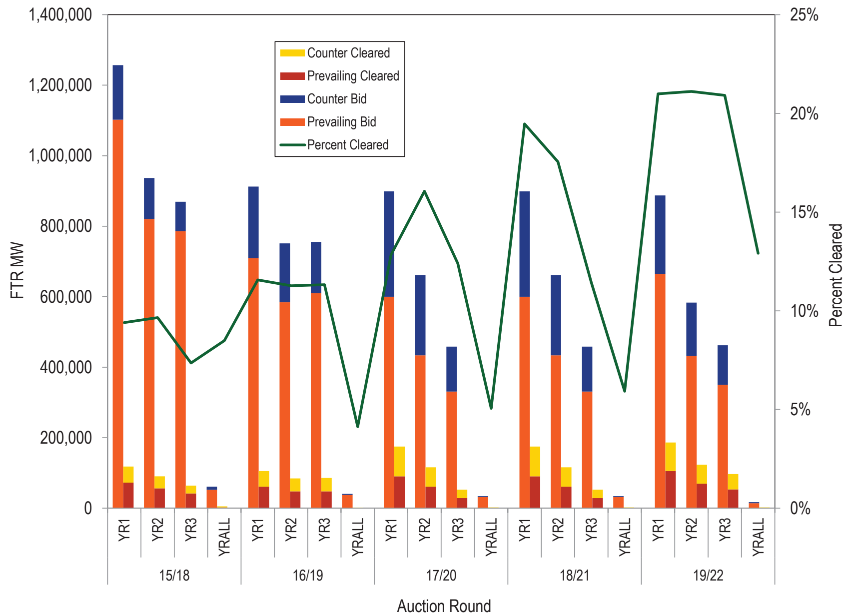


Table 13-16 compares cleared FTR obligations (not options) acquired in the Long Term FTR Auctions to the total cleared FTR obligations from the Annual FTR Auction, for FTRs in the 2014/2015 through 2019/2020 planning periods. A three year FTR is distributed to each individual planning period during its three year effective period. Long term FTRs that are effective in a single planning period were an average of 41.5 percent of total FTR volume in the 2014/2015 through 2019/2020 planning periods.

Table 13-16 Long Term and Annual Auction total cleared FTR MW

	Long Term FTR Product (Including YRALL)			Obligation Volume (MW)		
Effective Planning Period	YR3	YR2	YR1	Total Long Term	Annual (including self scheduled)	Long Term Percent of Total Cleared
2014/2015	81,666	86,754	131,911	300,330	356,522	45.7%
2015/2016	89,419	99,329	123,400	312,148	355,682	46.7%
2016/2017	97,837	95,637	107,182	300,656	397,258	43.1%
2017/2018	69,161	86,323	108,126	263,609	493,683	34.8%
2018/2019	87,232	109,827	176,998	374,057	549,669	40.5%
2019/2020	80,947	118,112	188,438	387,496	576,937	40.2%

Annual FTR Auction

Table 13-17 shows the annual FTR auction market volume for the 2019/2020 planning period. Total FTR buy bids were 2,787,716 MW, down 3.2 percent from 2,880,105 MW for the previous planning period. For the 2019/2020 planning period 611,878 MW (32.8 percent) of buy bids cleared, up 12.4 percentage points from 587,755 MW for the previous planning period. There were 375,583 MW of sell offers with 62,103 MW (16.5 percent) clearing for the 2019/2020 planning period. The total volume of cleared buy and self scheduled bids was 641,023 MW, up 4.2 percent from 615,254 MW in the previous Annual FTR Auction.

Table 13-17 Annual FTR Auction market volume: 2019/2020

Trade Type	Type	FTR Direction	Bid and Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
Buy bids	Obligations	Counter Flow	222,525	665,370	218,484	32.8%	446,886	67.2%
		Prevailing Flow	488,843	1,650,028	329,308	20.0%	1,320,720	80.0%
		Total	711,368	2,315,397	547,792	23.7%	1,767,606	76.3%
	Options	Counter Flow	41	1,335	52	3.9%	1,283	96.1%
		Prevailing Flow	38,110	470,983	64,034	13.6%	406,949	86.4%
		Total	38,151	472,318	64,086	13.6%	408,232	86.4%
	Total	Counter Flow	222,566	666,705	218,536	32.8%	448,169	67.2%
		Prevailing Flow	526,953	2,121,011	393,342	18.5%	1,727,669	81.5%
		Total	749,519	2,787,716	611,878	21.9%	2,175,838	78.1%
Self-scheduled bids	Obligations	Counter Flow	196	592	592	100.0%	0	0.0%
		Prevailing Flow	3,624	28,554	28,554	100.0%	0	0.0%
		Total	3,820	29,146	29,146	100.0%	0	0.0%
Buy and self-scheduled bids	Obligations	Counter Flow	222,721	665,962	219,076	32.9%	446,886	67.1%
		Prevailing Flow	492,467	1,678,581	357,861	21.3%	1,320,720	78.7%
		Total	715,188	2,344,543	576,937	24.6%	1,767,606	75.4%
	Options	Counter Flow	41	1,335	52	3.9%	1,283	96.1%
		Prevailing Flow	38,110	470,983	64,034	13.6%	406,949	86.4%
		Total	38,151	472,318	64,086	13.6%	408,232	86.4%
	Total	Counter Flow	222,762	667,297	219,128	32.8%	448,169	67.2%
		Prevailing Flow	530,577	2,149,564	421,895	19.6%	1,727,669	80.4%
		Total	753,339	2,816,861	641,023	22.8%	2,175,838	77.2%
Sell offers	Obligations	Counter Flow	62,099	148,782	23,340	15.7%	125,443	84.3%
		Prevailing Flow	91,175	208,379	37,751	18.1%	170,627	81.9%
		Total	153,274	357,161	61,091	17.1%	296,070	82.9%
	Options	Counter Flow	0	0	0	NA	0	NA
		Prevailing Flow	1,238	18,422	1,012	5.5%	17,410	94.5%
		Total	1,238	18,422	1,012	5.5%	17,410	94.5%
	Total	Counter Flow	62,099	148,782	23,340	15.7%	125,443	84.3%
		Prevailing Flow	92,413	226,801	38,763	17.1%	188,037	82.9%
		Total	154,512	375,583	62,103	16.5%	313,480	83.5%

Figure 13-4 shows the percent of FTR MW cleared and bid and cleared volume, by direction, for each round of the Annual FTR Auction from the 2015/2016 planning period through the 2019/2020 planning period.

Figure 13-4 Annual FTR Auction bid and cleared volume by round and direction

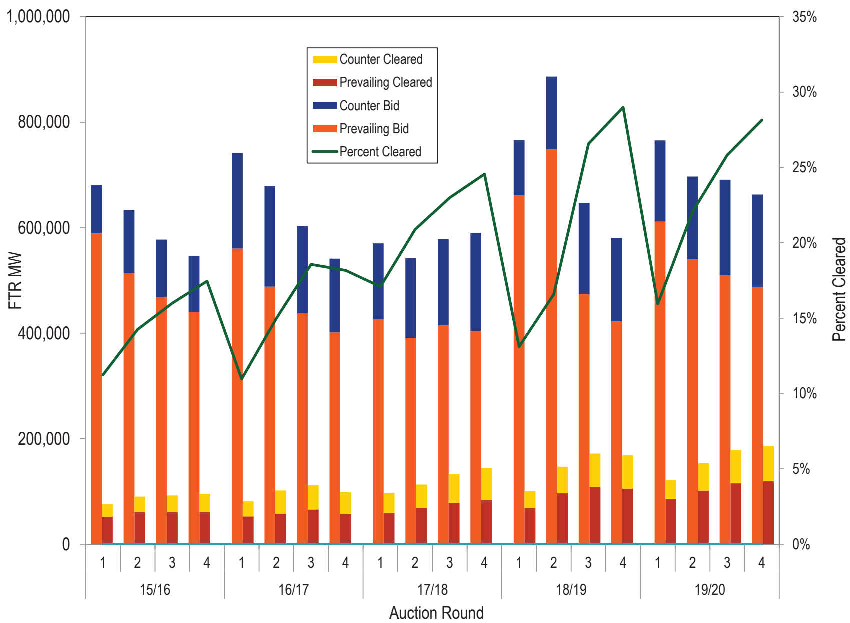


Figure 13-5 shows the proportion of ARRs self scheduled as FTRs for the last eleven planning periods. The maximum possible level of self scheduled FTRs is equal to total ARRs. Eligible participants self scheduled 29,146 MW (27.6 percent) of ARRs as FTRs for the 2019/2020 planning period, up from 27,479 MW (25.9 percent) in the previous planning period.

Figure 13-5 Comparison of self scheduled FTRs: 2009/2010 through 2019/2020

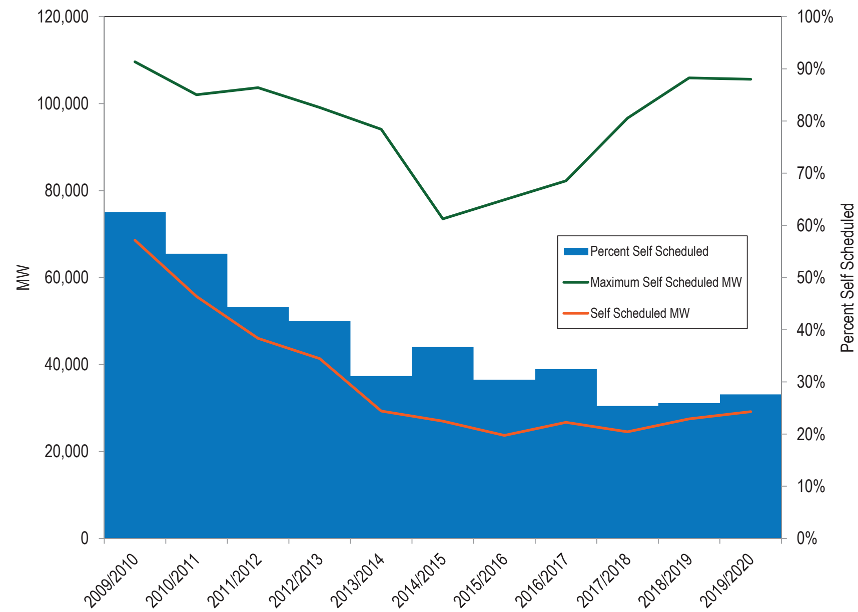


Table 13-18 shows the relationship between source and sink node type market share in the cleared buy and self scheduled bids for all FTRs in the 2019/2020 Annual FTR Auction.

Generator to generator FTRs comprise 49.2 percent of all cleared FTR buy and self scheduled bids, up 0.9 percentage points from the previous planning period. It is not clear why generator to generator FTRs make up such a disproportionate share of total FTRs. Congestion results from load paying more for generation than generators receive. By definition, congestion is between generator sources and load sinks. Generator to generator paths do not represent the delivery of generation to load. FTRs between generators simply create a speculative opportunity because they can be a low cost or zero cost FTR in the current design with a significant payoff if there is a price difference between the two nodes.

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.

Table 13-18 Annual auction FTR node type matrix: 2019/2020

	Sink Type							
Source Type	Aggregate	EHV Aggregate	Generator	Hub	Interface	Load	Residual Metered Aggregate	Zone
Aggregate	1.6%	0.0%	5.8%	0.2%	0.1%	0.3%	0.2%	0.3%
EHV Aggregate	0.0%	0.0%	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%
Generator	10.9%	0.1%	49.2%	3.9%	0.8%	3.6%	4.7%	7.1%
Hub	0.2%	0.0%	0.5%	0.6%	0.1%	0.0%	0.2%	2.2%
Interface	0.1%	0.0%	0.4%	0.0%	0.1%	0.0%	0.1%	0.1%
Load	0.6%	0.0%	2.3%	0.0%	0.0%	0.3%	0.0%	0.1%
Residual Metered Aggregate	0.0%	0.0%	0.3%	0.0%	0.0%	0.0%	0.0%	0.1%
Zone	0.3%	0.0%	0.6%	0.4%	0.1%	0.0%	0.5%	0.8%

Table 13-19 shows the node type cleared market shares for option bids in the 2019/2020 Annual FTR Auction.

Table 13-19 Annual auction FTR node type matrix: 2019/2020 Options

	Sink Type					
Source Type	Aggregate	Generator	Hub	Interface	Load	Zone
Aggregate	6.0%	2.0%	0.4%	0.1%	0.0%	0.7%
Generator	42.1%	2.0%	5.2%	2.9%	0.0%	26.7%
Hub	0.1%	1.4%	0.2%	0.0%	0.1%	1.1%
Interface	0.1%	1.1%	0.0%	0.0%	0.0%	0.0%
Load	2.6%	0.0%	0.1%	0.0%	0.0%	0.9%
Residual Metered Aggregate	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%
Zone	0.9%	1.7%	0.5%	0.1%	0.2%	0.5%

Monthly Balance of Planning Period Auctions

Table 13-20 provides the monthly balance of planning period FTR auction market volume for the entire 2017/2018 and 2018/2019 planning periods. There were 19,827,194 MW of FTR obligation buy bids and 8,483,263 MW of FTR obligation sell offers for all bidding periods in the 2018/2019 planning period. The monthly balance of planning period FTR auction cleared 2,966,810 (18.9 percent) of FTR obligation buy bids and 1,237,274 MW (18.3 percent) of FTR obligation sell offers.

There were 4,168,186 MW of FTR option buy bids and 1,708,827 MW of FTR option sell offers for all bidding periods in the Monthly Balance of Planning Period FTR Auctions for the 2018/2019 planning period. The monthly auctions cleared 191,043 MW (4.6 percent) of FTR option buy bids, and 466,274 MW (27.3 percent) of FTR option sell offers.

Table 13-20 Monthly Balance of Planning Period FTR Auction market volume: 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%
2017/2018*	Obligations	Buy bids	3,595,933	15,443,102	2,548,608	16.5%	12,894,494	83.5%
		Sell offers	2,057,542	3,898,145	1,001,900	25.7%	2,896,245	74.3%
	Options	Buy bids	37,328	3,695,650	59,513	1.6%	3,636,138	98.4%
		Sell offers	67,177	503,728	147,361	29.3%	356,366	70.7%
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%

* Shows 12 months for 2017/2018 ** Shows 12 months for 2018/2019

Table 13-21 presents the buy bid, bid and cleared volume of the Monthly Balance of Planning Period FTR Auction, and the effective periods for the volume. The average monthly cleared volume for 2019 was 256,233 MW. The average monthly cleared volume for 2018 was 226,127.6 MW.

Table 13-21 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				0	1,293,106
	Cleared	154,347	61,658	45,242				0	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

Secondary Bilateral Market

Table 13-22 provides the secondary bilateral FTR market volume for the entire 2017/2018 and 2018/2019 planning periods.

Table 13-22 Secondary bilateral FTR market volume: 2017/2018 and 2018/2019[37]

Planning Period	Type	Class Type	Volume (MW)
2017/2018	Obligation	24-Hour	167.4
		On Peak	8,630.0
		Off Peak	6,755.4
		Total	15,552.8
	Option	24-Hour	5.8
		On Peak	0.0
		Off Peak	0.0
		Total	5.8
2018/2019	Obligation	24-Hour	2,782.1
		On Peak	21,423.5
		Off Peak	21,636.9
		Total	45,842.5
	Option	24-Hour	0.0
		On Peak	0.0
		Off Peak	40.0
		Total	40.0

Figure 13-6 shows the FTR bid, cleared and net bid volume from June 2003 through June 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.

Figure 13-6 Long Term, Annual and Monthly FTR Auction bid and cleared volume: June 2003 through June 2019

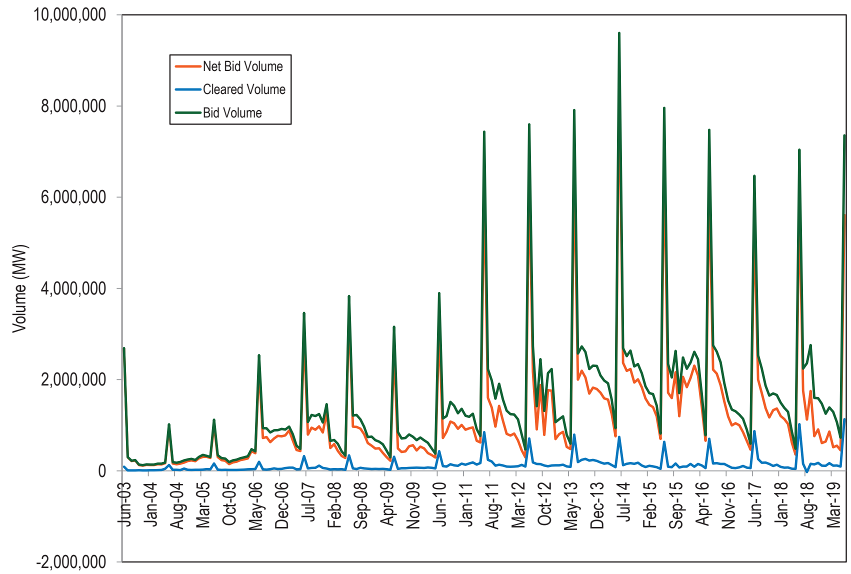
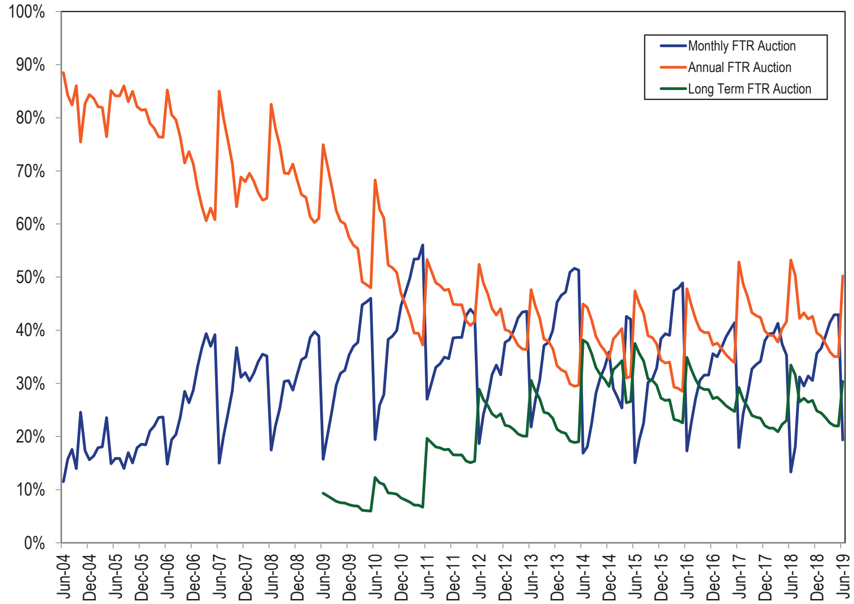


Figure 13-7 shows cleared auction volumes by auction type as a percent of the total FTR cleared volume by calendar months for June 2004 through June 2019, by type of auction. FTR volumes are included in the calendar month they are effective, with long term and annual FTR auction volume spread equally 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.

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 13-7 Cleared auction volume (MW) as a percent of total FTR cleared volume by calendar month: June 2004 through June 2019



Price

Table 13-23 shows the cleared, weighted-average prices by trade type, FTR direction, period type and class type for the 2019/2022 Long Term FTR Auction. Only FTR obligation products (no options) are available in the Long Term FTR Auctions. In this auction, weighted average buy bid counter flow and prevailing flow FTR prices were -\$0.36 and \$0.46, compared to -\$0.41 and \$0.44 from the 2018/2021 Long Term FTR Auction. Weighted average sell bid counter flow and prevailing flow FTR prices were -\$0.31 and \$0.43, compared to -\$0.32 for counter flow FTRs and \$0.35 for prevailing flow FTRs.

Table 13-23 Long Term FTR Auction weighted-average cleared prices (Dollars per MW): 2019/2022

			Class Type			
Trade Type	FTR Direction	Period Type	24-Hour	On Peak	Off Peak	All
Buy bids	Counter Flow	Year 1	(\$1.22)	(\$0.27)	(\$0.46)	(\$0.41)
		Year 2	(\$0.91)	(\$0.25)	(\$0.43)	(\$0.36)
		Year 3	(\$0.75)	(\$0.24)	(\$0.41)	(\$0.34)
		Year All	NA	(\$0.03)	(\$0.05)	(\$0.04)
		Total	(\$1.03)	(\$0.25)	(\$0.43)	(\$0.36)
	Prevailing Flow	Year 1	\$0.99	\$0.29	\$0.52	\$0.47
		Year 2	\$0.96	\$0.27	\$0.48	\$0.44
		Year 3	\$1.00	\$0.28	\$0.51	\$0.46
		Year All	NA	\$0.01	\$0.04	\$0.03
		Total	\$0.99	\$0.28	\$0.51	\$0.46
	Total		\$0.50	\$0.04	\$0.09	\$0.10
Sell offers	Counter Flow	Year 1	(\$0.37)	(\$0.20)	(\$0.45)	(\$0.30)
		Year 2	NA	(\$0.18)	(\$0.42)	(\$0.27)
		Year 3	NA	(\$0.41)	(\$1.24)	(\$0.76)
		Year All	NA	NA	NA	NA
		Total	(\$0.37)	(\$0.20)	(\$0.46)	(\$0.31)
	Prevailing Flow	Year 1	\$0.82	\$0.33	\$0.56	\$0.46
		Year 2	\$0.00	\$0.24	\$0.44	\$0.34
		Year 3	NA	\$0.37	\$0.72	\$0.57
		Year All	NA	NA	NA	NA
		Total	\$0.82	\$0.30	\$0.54	\$0.43
	Total		\$0.70	\$0.09	\$0.23	\$0.16

Table 13-24 shows the weighted-average cleared buy bid prices by trade type, FTR product, FTR direction and class type for the Annual FTR Auction for the 2019/2020 planning period. The weighted-average cleared buy bid price in the 2019/2020 Annual FTR Auction was $0.28 per MW, equal to $0.28 per MW in the 2018/2019 planning period.

Table 13-24 Annual FTR Auction weighted-average cleared prices (Dollars per MW): 2019/2020

			Class Type			
Trade Type	Type	FTR Direction	24-Hour	On Peak	Off Peak	All
Buy bids	Obligations	Counter Flow	($0.59)	($0.42)	($0.24)	($0.34)
		Prevailing Flow	$1.20	$0.72	$0.37	$0.60
		Total	$0.64	$0.27	$0.12	$0.23
	Options	Counter Flow	$0.00	$0.00	$0.00	$0.00
		Prevailing Flow	$0.05	$0.38	$0.20	$0.27
		Total	$0.05	$0.38	$0.20	$0.27
Self-scheduled bids	Obligations	Counter Flow	($0.19)	NA	NA	($0.19)
		Prevailing Flow	$0.91	NA	NA	$0.91
		Total	$0.89	NA	NA	$0.89
Buy and self-scheduled bids	Obligations	Counter Flow	($0.56)	($0.42)	($0.24)	($0.34)
		Prevailing Flow	$1.01	$0.72	$0.37	$0.65
		Total	$0.78	$0.27	$0.12	$0.29
	Options	Counter Flow	$0.00	$0.00	$0.00	$0.00
		Prevailing Flow	$0.05	$0.38	$0.20	$0.27
		Total	$0.05	$0.38	$0.20	$0.27
Sell offers	Obligations	Counter Flow	($0.70)	($0.57)	($0.30)	($0.42)
		Prevailing Flow	$0.59	$0.58	$0.27	$0.43
		Total	$0.32	$0.17	$0.05	$0.11
	Options	Counter Flow	NA	NA	NA	NA
		Prevailing Flow	$0.00	$0.31	$0.08	$0.16
		Total	$0.00	$0.31	$0.08	$0.16

Table 13-25 shows the cleared buy bid volume, cleared buy bid revenue and cleared revenue/cleared MW for the six latest planning periods. In the 2014/2015 planning period the $/MW increased significantly from the 2013/2014 planning period due to PJM's decisions to limit capacity through conservative modeling. In the 2017/2018 Annual FTR Auction, the $/MW decreased to lower than 2013/2014 levels, due in part to the partial relaxation of PJM's conservative modeling practices due to the reassignment of balancing congestion and M2M payments to load and exports. This reduction continued into the 2018/2019 planning period. The reassignment of balancing congestion and M2M payments to load did not increase the per MW value of ARRs.

Table 13-25 Cleared volume, revenue and $/MW: 2012/2013 through 2019/2020 Annual FTR Auction

	Cleared Buy Bid Volume	Percent Cleared	Buy Bid Revenue (millions)	Buy Bid Revenue ($/MW)
2012/2013	371,295	14.5%	$627.3	$1,689
2013/2014	420,489	12.8%	$567.6	$1,350
2014/2015	365,843	11.2%	$789.7	$2,159
2015/2016	378,328	15.4%	$948.6	$2,507
2016/2017	420,198	16.2%	$918.0	$2,185
2017/2018	513,263	22.3%	$555.2	$1,082
2018/2019	587,775	20.4%	$833.4	$1,418
2019/2020	611,878	21.9%	$876.4	$1,432

Table 13-26 shows the weighted average cleared buy bid price in the Monthly Balance of Planning Period FTR Auctions by bidding period for January through June 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 June 2019 was $0.17 per MW, down from $0.21 per MW in the same time last year, a 19.0 percent decrease in FTR prices. The cleared weighted-average price for the current planning period was $0.20, up 53.8 percent from $0.13 for the previous planning period.

Table 13-26 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

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 13-29). 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 13-27 lists FTR profits by organization type and FTR direction for the 2018/2019 planning period. Some participants classified as physical, such as a company that holds one generator, are not eligible for ARRs but do have a physical presence on the PJM system 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. In the 2018/2019 planning period, companies made profits of $194.0 million. ARR holders who self scheduled FTRs received $129.9 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 13-27 FTR profits and revenues by organization type and FTR direction: 2018/2019

	FTR Direction				
Organization Type	Prevailing Flow Profit	Self Scheduled Prevailing Flow Revenue Returned	Counter Flow Profit	Self Scheduled Counter Flow Revenue Returned	All
Financial	($134,048,844)	$0	$250,544,104	$0	$116,495,260
Physical	($149,886,373)	$127,257,187	$97,557,416	$2,625,897	$77,554,127
Total	($283,935,218)	$127,257,187	$348,101,520	$2,625,897	$194,049,386

Table 13-28 lists the monthly FTR profits for the 2017/2018 and the 2018/2019 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 13-28 Monthly FTR profits by organization type: 2017/2018 and 2018/2019

	Organization Type		
Month	Physical	Financial	Total
Jun-17	$764,708	$14,019,198	$14,783,906
Jul-17	($2,987,829)	$7,306,611	$4,318,783
Aug-17	($3,234,012)	$2,414,244	($819,767)
Sep-17	$2,168,231	$22,644,485	$24,812,716
Oct-17	$777,230	$14,400,509	$15,177,739
Nov-17	$2,350,616	$3,244,972	$5,595,588
Dec-17	$820,082	$23,681,735	$24,501,817
Jan-18	$32,871,784	$103,179,520	$136,051,304
Feb-18	$317,895	($2,047,899)	($1,730,004)
Mar-18	$8,526,358	$13,327,501	$21,853,859
Apr-18	$574,714	$7,467,985	$8,042,698
May-18	$10,386,785	$36,679,052	$47,065,837
Summary for Planning Period 2017/2018			
Total	$53,336,562	$246,317,915	$299,654,477
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

Table 13-29 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 will impact total profitability. The surplus or uplift is distributed prorata based on positive target allocations until the 2018/2019 planning period. Beginning with the 2018/2019 planning period annual surplus congestion revenue was distributed to ARR holders. 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.

Table 13-29 FTR profits by organization type: 2012/2013 through 2018/2019

		2012/2013	2013/2014	2014/2015	2015/2016	2016/2017	2017/2018	2018/2019
Financial	Profit	$63,457,511	$557,583,317	$236,692,290	$41,264,165	($13,519,824)	$246,317,915	$116,495,260
	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
Physical	Profit	($65,702,875)	$401,144,350	$160,694,399	$22,585,629	($112,955,478)	$88,426,464	($52,328,957)
	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)
Total		($166,028,386)	$596,960,039	$456,282,380	$80,820,304	($94,973,195)	$549,669,736	$64,166,303

Revenue

Long Term FTR Auction Revenue

Table 13-30 shows the long term FTR auction revenue data by trade type, FTR direction, period type and class type. The 2019/2022 Long Term FTR Auction netted $161.7 million in revenue, $132.1 million more than the previous Long Term FTR Auction. Buyers paid $186.9 million and sellers received $25.2 million, up $134.7 million and $2.6 million over the previous Long Term FTR Auction.

Table 13-30 Long Term FTR Auction Revenue: 2019/2022

			Class Type			
Trade Type	FTR Direction	Period Type	24-Hour	On Peak	Off Peak	All
Buy bids	Counter Flow	Year 1	($24,371,535)	($73,884,329)	($49,931,125)	($148,186,990)
		Year 2	($9,426,319)	($46,879,640)	($29,745,022)	($86,050,981)
		Year 3	($6,221,645)	($36,046,808)	($23,352,067)	($65,620,520)
		Year All	$0	($530,720)	($542,459)	($1,073,179)
		Total	($40,019,499)	($157,341,498)	($103,570,673)	($300,931,670)
	Prevailing Flow	Year 1	$56,342,786	$110,041,760	$65,535,011	$231,919,557
		Year 2	$35,772,980	$67,840,105	$39,064,743	$142,677,828
		Year 3	$27,836,762	$54,322,644	$30,971,170	$113,130,576
		Year All	$0	$67,125	$8,271	$75,396
		Total	$119,952,527	$232,271,635	$135,579,195	$487,803,357
	Total		$79,933,028	$74,930,136	$32,008,523	$186,871,687
Sell offers	Counter Flow	Year 1	($32,570)	($6,863,849)	($4,683,412)	($11,579,831)
		Year 2	$0	($2,736,399)	($1,873,414)	($4,609,814)
		Year 3	0	($829,854)	($365,625)	($1,195,479)
		Year All	NA	NA	NA	NA
		Total	($32,570)	($10,430,102)	($6,922,451)	($17,385,123)
	Prevailing Flow	Year 1	$647,479	$18,398,499	$9,654,110	$28,700,088
		Year 2	$0	$6,208,776	$3,401,660	$9,610,437
		Year 3	0	$3,064,644	$1,183,365	$4,248,009
		Year All	NA	NA	NA	NA
		Total	$647,479	$27,671,919	$14,239,135	$42,558,533
	Total		$614,909	$17,241,817	$7,316,683	$25,173,410
Total			$79,318,119	$57,688,319	$24,691,839	$161,698,277

Annual FTR Auction Revenue

Table 13-31 shows the Annual FTR Auction revenue by trade type, type, FTR direction and class type. The Annual FTR Auction for the 2019/2020 planning period generated $844.6 million, up 2.7 percent from $822.6 million in the 2018/2019 planning period, and up 55.8 percent from $542.2 million in the 2017/2018 planning period. Counter flow FTR holders received $293.3 million, up 6.7 percent from the previous planning period and prevailing flow FTR holders paid $1,137.8 million, up 3.7 percent from the previous planning period.

Table 13-31 Annual FTR auction revenue: 2019/2020

			Class Type			
Trade Type	Type	FTR Direction	24-Hour	On Peak	Off Peak	All
Buy bids	Obligations	Counter Flow	($33,941,839)	($188,817,805)	($112,719,091)	($335,478,736)
		Prevailing Flow	$151,953,708	$497,205,253	$257,220,412	$906,379,374
		Total	$118,011,869	$308,387,448	$144,501,321	$570,900,638
	Options	Counter Flow	$0	$0	$0	$0
		Prevailing Flow	$1,114,280	$49,556,288	$27,428,870	$78,099,438
		Total	$1,114,280	$49,556,288	$27,428,870	$78,099,438
	Total	Counter Flow	($33,941,839)	($188,817,805)	($112,719,091)	($335,478,736)
		Prevailing Flow	$153,067,988	$546,761,542	$284,649,282	$984,478,812
		Total	$119,126,149	$357,943,737	$171,930,191	$649,000,076
Self-scheduled bids	Obligations	Counter Flow	($989,199)	NA	NA	($989,199)
		Prevailing Flow	$228,400,870	NA	NA	$228,400,870
		Total	$227,411,671	NA	NA	$227,411,671
Buy and self-scheduled bids	Obligations	Counter Flow	($34,931,038)	($188,817,805)	($112,719,091)	($336,467,935)
		Prevailing Flow	$380,354,578	$497,205,253	$257,220,412	$1,134,780,244
		Total	$345,423,540	$308,387,448	$144,501,321	$798,312,309
	Options	Counter Flow	$0	$0	$0	$0
		Prevailing Flow	$1,114,280	$49,556,288	$27,428,870	$78,099,438
		Total	$1,114,280	$49,556,288	$27,428,870	$78,099,438
	Total	Counter Flow	($34,931,038)	($188,817,805)	($112,719,091)	($336,467,935)
		Prevailing Flow	$381,468,859	$546,761,542	$284,649,282	$1,212,879,682
		Total	$346,537,820	$357,943,737	$171,930,191	$876,411,748
Sell offers	Obligations	Counter Flow	($2,126,088)	($24,747,002)	($16,333,984)	($43,207,074)
		Prevailing Flow	$6,900,493	$44,650,824	$22,795,861	$74,347,179
		Total	$4,774,405	$19,903,822	$6,461,877	$31,140,105
	Options	Counter Flow	$0	$0	$0	$0
		Prevailing Flow	$0	$452,889	$255,162	$708,051
		Total	$0	$452,889	$255,162	$708,051
	Total	Counter Flow	($2,126,088)	($24,747,002)	($16,333,984)	($43,207,074)
		Prevailing Flow	$6,900,493	$45,103,714	$23,051,023	$75,055,230
		Total	$4,774,405	$20,356,711	$6,717,039	$31,848,155
Total			$341,763,415	$337,587,025	$165,213,152	$844,563,592

The total net of all buy and sell offers in the Annual FTR Auction, not including self scheduled FTRs, was $393.5 million for the 2017/2018 planning period and $624.8 million for the 2018/2019 planning period, a 58.8 percent increase in revenue. The total buy bids were 488,734.1 MW for the 2017/2018 planning period and 587,775.4 MW for the 2018/2019 planning period. The revenue of FTRs per cleared MW increased from $805.14 for the 2017/2018 planning period to $1,062.99 for the 2018/2019 planning period, a 32.0 percent increase. The per MW revenue of FTRs in the 2016/2017 planning period was $1,564.83.

FTRs sold in Long Term FTR Auctions are sold at a substantial discount to the same FTR sold in Annual FTR Auctions. Table 13-32 shows the increase in total auction revenue that would have resulted for the 2014/2015 through 2018/2019 planning periods if long term FTRs were sold at annual auction clearing prices. This difference provides a good estimate of the value of the transmission capability made available in the Long Term FTR Auction that is not made available to ARR holders. This capability should be made available to ARR holders in the Annual FTR Auction where it is the most valuable.

Table 13-32 Estimated additional Long Term FTR Auction revenue at Annual FTR Auction prices

	Long Term FTR Product				
Planning Period	YR3	YR2	YR1	YRALL	Total Difference
2014/2015	$59,598,642	$30,284,173	$52,030,909	$926,989	$142,840,713
2015/2016	$67,896,588	$40,975,278	$9,936,078	$303,082	$119,111,026
2016/2017	$42,378,048	$3,854,373	$11,055,824	$1,079,901	$58,368,147
2017/2018	$6,134,076	($1,841,715)	$12,396,817	$227,524	$16,916,702
2018/2019	$7,872,604	$2,926,457	$13,480,353	($111,226)	$24,168,189
2019/2020	$9,711,188	$4,098,887	$103,227,004	$805,425	$117,842,504
Total	$183,879,959	$76,198,567	$98,899,981	$2,426,270	$361,404,776

Monthly Balance of Planning Period FTR Auction Revenue

Table 13-33 shows monthly balance of planning period FTR auction revenue by trade type, type and class type for January through May 2019. The Monthly Balance of Planning Period FTR Auctions for the 2018/2019 planning period netted $59.7 million in revenue, the difference between buyers paying $324.9 million and sellers receiving $265.2 million. For the entire 2017/2018 planning period, the Monthly Balance of Planning Period FTR Auctions netted $40.3 million in revenue with buyers paying $182.0 million and sellers receiving $141.7 million.

Table 13-33 Monthly Balance of Planning Period FTR Auction revenue: 2019

Monthly			Class Type			
Auction	Type	Trade 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
2017/2018*	Obligations	Buy bids	$48,624,806	$80,725,915	$45,185,177	$174,535,897
		Sell offers	$3,856,422	$66,996,797	$39,571,417	$110,424,636
	Options	Buy bids	$888,416	$4,051,136	$2,566,754	$7,506,306
		Sell offers	$106,899	$19,516,633	$11,671,850	$31,295,383
	Net Total		$45,549,900	($1,736,379)	($3,491,336)	$40,322,185
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

* Shows Twelve Months

FTR Target Allocations

FTR target allocations were examined separately by source and sink contribution. Hourly FTR target allocations were divided into those that were benefits and liabilities and summed by sink and by source. Figure 13-8 shows the 10 largest positive and negative FTR target allocations, summed by sink, for the 2018/2019 planning period. The top 10 sinks that produced financial benefit accounted for 28.3 percent of total positive target allocations with the Western Hub accounting for 7.7 percent of all positive target allocations. The top 10 sinks that created liability accounted for 13.7 percent of total negative target allocations with PSEG Zone accounting for 1.9 percent of all negative target allocations.

Figure 13-8 Ten largest positive and negative FTR target allocations summed by sink: 2018/2019

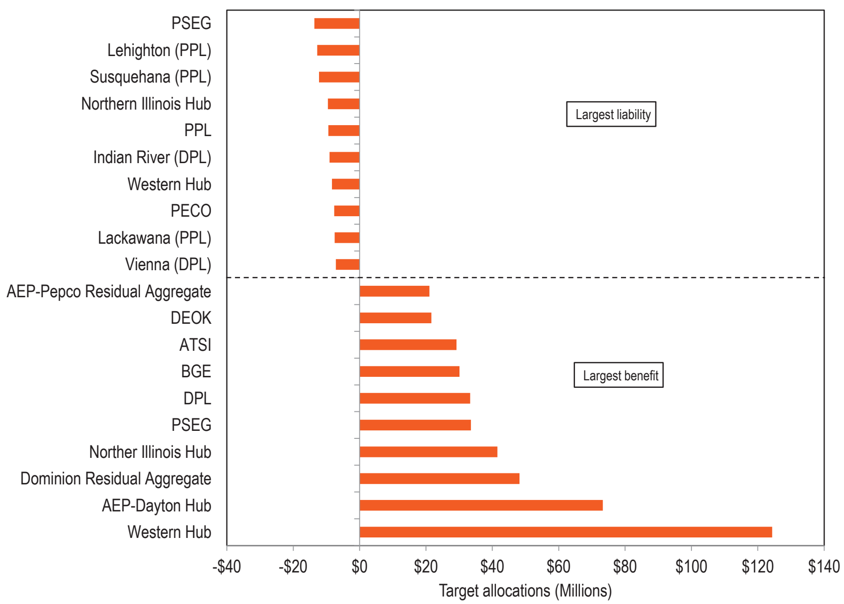
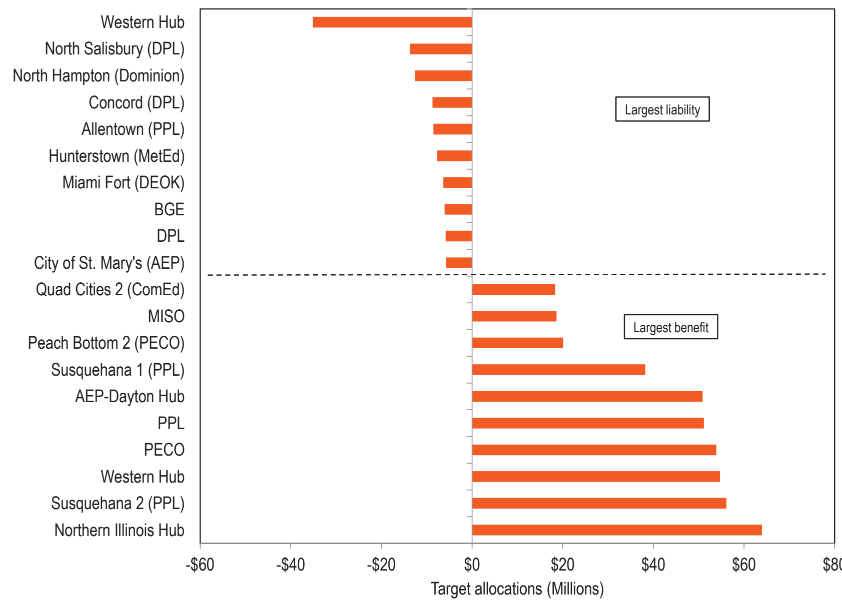


Figure 13-9 shows the 10 largest positive and negative FTR target allocations, summed by source, for the 2018/2019 planning period. The top 10 sources with a positive target allocation accounted for 26.4 percent of total positive target allocations with the Northern Illinois Hub accounting for 4.0 percent of total positive target allocations. The top 10 sources with a negative target allocation accounted for 15.6 percent of all negative target allocations, with the Western Hub accounting for 5.0 percent.

Figure 13-9 Ten largest positive and negative FTR target allocations summed by source: 2018/2019



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.

FTR revenues are primarily comprised of hourly congestion revenue, from the day-ahead market, but also include negative FTR target allocations.[38] Total day-ahead congestion revenues in excess of FTR payments are carried

38 When hourly congestion revenues are negative, it is defined as a net negative congestion hour.

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.

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, will be 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

39 163 FERC ¶61,165 (2018).

rights to ARR holders, it does not fully recognize that ARR holders own the rights to all congestion revenues.

Figure 13-10 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 13-10 this would mean that the full bars would be assigned to ARR holders in every month.

Figure 13-10 Monthly surplus ARR revenue to ARR and FTR holders: 2017/2018 through 2018/2019

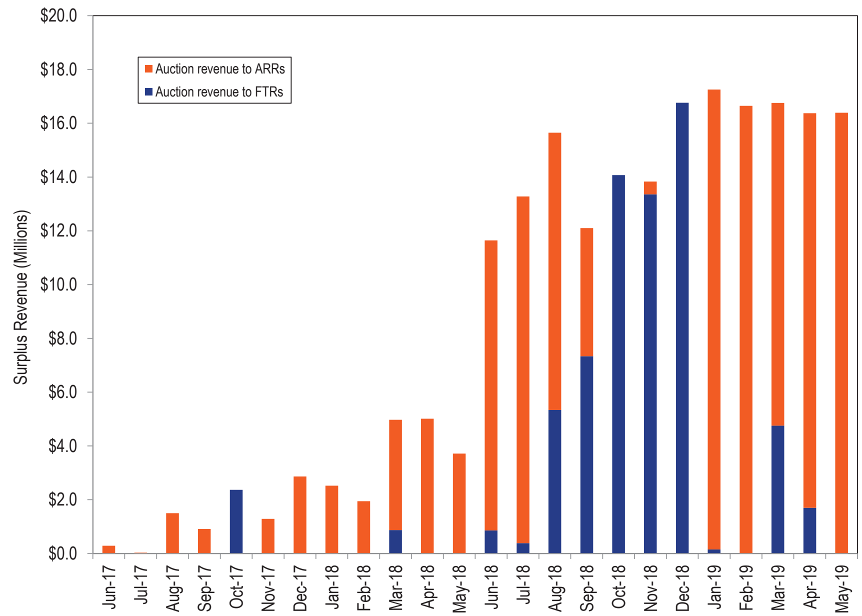


Figure 13-11 shows the monthly auction revenue collected each month from FTR auctions above ARR target allocations from the 2011/2012 through 2018/2019 planning periods.

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 is 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. The subsequent assignment of any part of that auction revenue back to the buyers is providing an unsupported rebate.

40 *See* "PJM Manual 6: Financial Transmission Rights," Rev. 22 (June 27, 2019).

Auction revenue collected should be distributed directly and completely to ARR holders. The MMU recommends that all FTR auction revenue be distributed to ARR holders.

Figure 13-11 Monthly surplus ARR revenue: 2011/2012 through 2018/2019

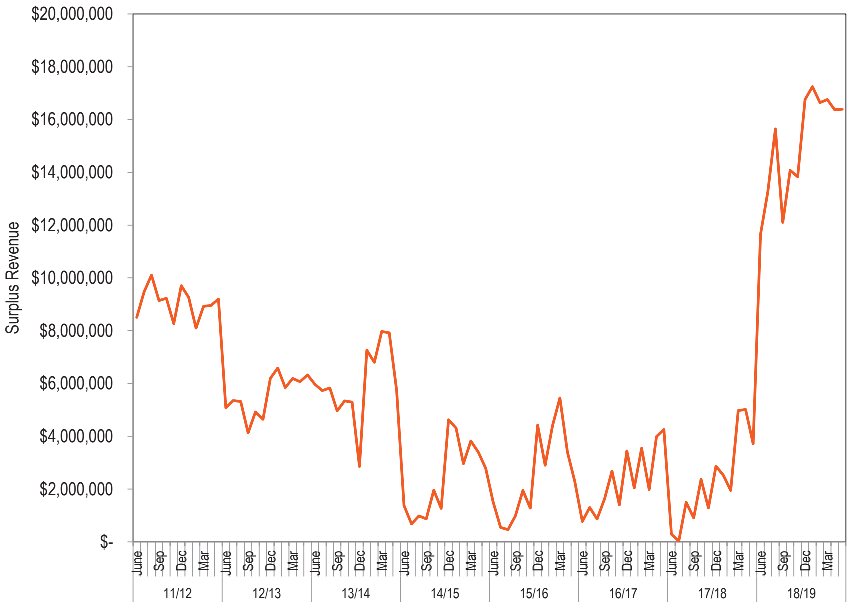


Table 13-34 shows the auction revenue over ARR target allocations, by planning period, for planning periods 2010/2011 through 2018/2019.

Table 13-34 Additional Auction Revenue: 2010/2011 through 2018/2019

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
Total	$571,671,756

*Start of counter flow "buy back"

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 13-35 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 13-35 presents the PJM FTR revenue detail for the 2017/2018 planning period the 2018/2019 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. For the 2017/2018 planning period there was $0.5 million and $0.7 million in negative day-ahead congestion in October and November 2017 for a total of $1.2 million in negative day-ahead congestion charged to FTR holders.

Table 13-35 Total annual PJM ARR and FTR revenue detail (Dollars (Millions)): 2017/2018 and 2018/2019

Accounting Element	2017/2018	2018/2019
ARR information		
ARR target allocations	$573.8	$726.8
ARR credits	$573.8	$726.8
FTR auction revenue	$601.2	$907.6
Annual FTR Auction net revenue	$542.2	$822.6
Long Term FTR Auction net revenue	$18.6	$25.2
Monthly Balance of Planning Period FTR Auction net revenue	$40.3	$59.7
Surplus auction revenue		
ARR excess	$27.4	$180.8
ARR payout ratio	100%	100%
FTR targets		
Positive target allocations	$1,396.2	$1,137.6
Negative target allocations	($411.2)	($234.2)
FTR target allocations	$985.0	$903.3
Adjustments:		
Adjustments to FTR target allocations	($6.2)	($2.1)
Total FTR targets	$978.8	$901.2
FTR payout ratio	100%	100%
FTR revenues		
ARR excess	$27.4	$180.8
Congestion		
Net Negative Congestion (enter as negative)	($1.2)	$0.0
Hourly congestion revenue	$1,323.3	$832.7
Midwest ISO M2M (credit to PJM minus credit to Midwest ISO)	($6.3)	$0.0
Adjustments:		
Excess revenues carried forward into future months	$15.7	$6.5
Excess revenues distributed back to previous months	$0.0	$0.0
Other adjustments to FTR revenues	$0.0	$0.0
Total FTR revenues		
Excess revenues distributed to other months	$15.7	$6.5
Net Negative Congestion charged to DA Operating Reserves	$0.0	$0.0
Total FTR congestion credits	$1,365.0	$1,020.0
Total congestion credits on bill (includes CEPSW and end-of-year distribution)	$1,365.0	$914.3
Remaining deficiency	($370.5)	($112.3)

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 13-36 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 13-36 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 2017 had revenue shortfalls totaling $15.6 million, but was fully funded using excess revenue from previous months.

Table 13-36 Monthly FTR accounting summary (Dollars (Millions)): 2017/2018 and 2018/2019

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-17	$64.8	$60.1	100.0%	$64.8	100.0%	($4.7)
Jul-17	$51.8	$45.4	100.0%	$51.8	100.0%	($6.3)
Aug-17	$35.7	$31.0	100.0%	$35.7	100.0%	($4.7)
Sep-17	$100.5	$93.0	100.0%	$100.5	100.0%	($7.5)
Oct-17	$53.2	$68.8	77.2%	$68.8	100.0%	$15.7
Nov-17	$61.2	$51.0	100.0%	$61.2	100.0%	($10.1)
Dec-17	$142.7	$81.4	100.0%	$142.7	100.0%	($61.3)
Jan-18	$520.2	$268.1	100.0%	$520.2	100.0%	($252.1)
Feb-18	$45.8	$36.1	100.0%	$45.8	100.0%	($9.6)
Mar-18	$85.2	$81.1	100.0%	$85.2	100.0%	($4.1)
Apr-18	$62.4	$55.6	100.0%	$62.4	100.0%	($6.9)
May-18	$125.9	$108.8	100.0%	$125.9	100.0%	($17.1)
Summary for Planning Period 2017/2018						
Total	$1,349.3	$980.5		$1,365.0		($368.8)
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)

Figure 13-12 shows the original PJM reported FTR payout ratio by month, excluding excess revenue distribution, for January 2004 through May 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 13-12 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 13-12 FTR payout ratio by month, excluding and including excess revenue distribution: January 2004 through May 2019

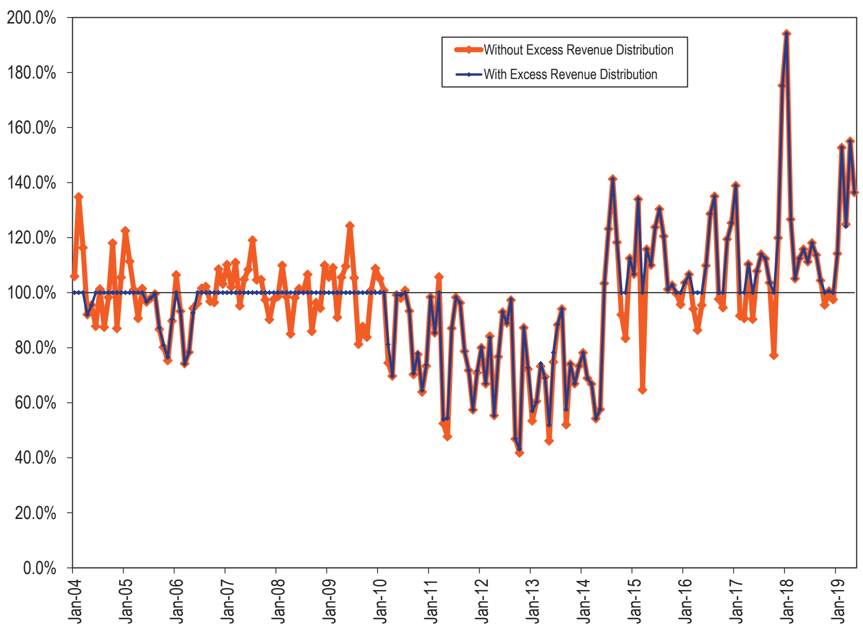


Table 13-37 shows the FTR payout ratio by planning period from the 2003/2004 planning period forward. Planning period 2013/2014 includes the additional revenue from unallocated congestion charges from Balancing Operating Reserves. For the 2014/2015, 2015/2016 and 2016/2017 planning periods, there was 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 13-37 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%

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.

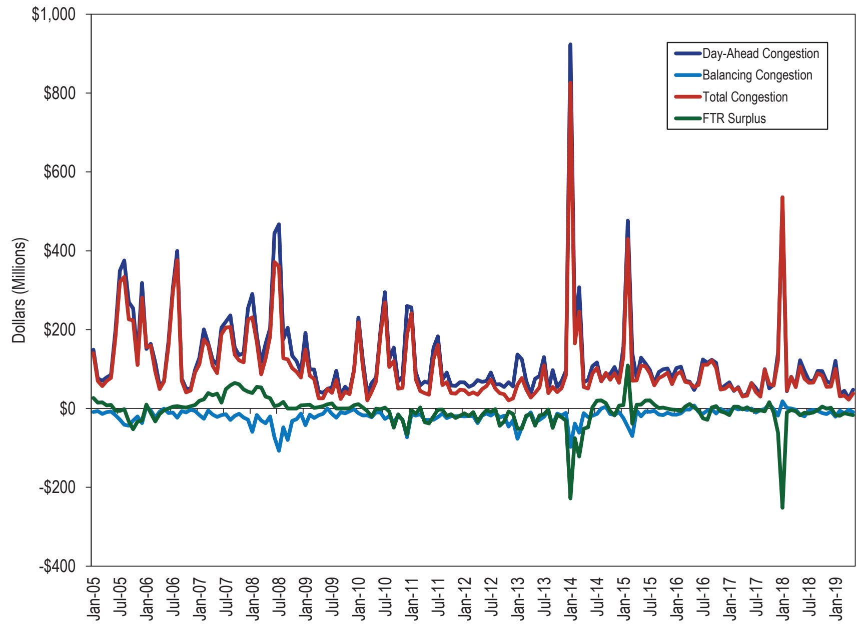
Revenue Adequacy Issues and Solutions

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 13-13 shows the FTR surplus, collected day-ahead, balancing and total congestion payments from January 2005 through May 2019. May 2016 had positive total balancing congestion of $7.5 million. March 2015 had balancing congestion of -$70.0 million.

Figure 13-13 FTR surplus and the collected day-ahead, balancing and total congestion: January 2005 through May 2019



41 *2018 State of the Market Report for PJM*, Vol. 2, Section 13: FTRs and ARRs.

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 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.

42 See 156 FERC ¶ 61,180 (2016), *reh'g denied*, 156 FERC ¶ 61,093 (2017).

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.")

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]

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 13-39 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 outlined in red 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 100 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

44 163 FERC ¶61,165 (2018).

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. The actual underpayment to load in the 2017/2018 planning period was $306.1 million with a $370.7 million overpayment to FTR holders. For the 2018/2019 planning period the underpayment to load in the same period would have been $85.9 million.

Allocating surplus congestion revenue to load rather than FTRs in the 2018/2019 planning period would change the total congestion offset for load to 92.1 percent from 78.1 percent under the rules that allocated balancing congestion to load, or 99.4 percent under the old rules which include balancing in total congestion but assigned all surplus to FTR holders.

Table 13-38 ARR and FTR total congestion offset (in millions) for ARR holders: 2011/2012 through 2018/2019

	Revenue				Pre 2017/2018 (Without Balancing)		2017/2018 (With Balancing)		Post 2017/2018 (With Surplus)	
Planning Period	ARR Credits	FTR Credits	Total Congestion	Excess 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	100.0%	$598.6	79.8%	$563.0	79.8%
2012/2013	$349.5	$181.9	$524.8	($292.3)	$531.4	100.0%	$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	100.0%	$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%
Total	$3,913.6	$2,109.2	$8,107.3	($425.4)	$6,039.5	74.5%	$4,734.4	58.4%	$5,180.5	63.9%

Table 13-39 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 13-39 shows the congestion offsets paid to load: the allocation of ARR revenue; self scheduled FTR revenue; and the allocation of end of planning year surplus. Table 13-39 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 13-39 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 13-39 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 13-39 Zonal ARR and FTR total congestion offset (in millions) for ARR holders: 2018/2019 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	$4.9	$0.0	($1.9)	$0.8	$3.8	$11.9	($1.5)	($0.4)	$10.0	37.8%
AEP	$56.8	$38.9	($23.7)	$21.8	$93.8	$129.6	($18.9)	($5.1)	$105.7	88.7%
APS	$40.8	$10.4	($9.2)	$8.9	$50.9	$53.7	($6.9)	($2.0)	$44.8	113.6%
ATSI	$43.3	$0.3	($12.4)	$6.7	$37.9	$64.8	($9.7)	($2.6)	$52.5	72.3%
BGE	$67.2	$1.5	($5.8)	$10.7	$73.6	$26.1	($4.8)	($1.2)	$20.0	367.3%
ComEd	$91.7	$10.2	($17.8)	$17.3	$101.3	$113.0	($12.7)	($3.8)	$96.5	105.0%
DAY	$7.2	$0.5	($3.2)	$1.1	$5.5	$16.1	($2.6)	($0.7)	$12.8	42.8%
DEOK	$41.5	$9.1	($5.0)	$7.7	$53.4	$28.9	($4.1)	($1.1)	$23.7	225.5%
DLCO	$9.1	$0.0	($2.5)	$1.4	$8.0	$10.2	($1.9)	($0.5)	$7.7	104.2%
Dominion	$7.1	$44.3	($18.7)	$9.4	$42.3	$84.4	($14.2)	($4.0)	$66.2	63.9%
DPL	$39.3	$8.2	($3.4)	$7.0	$51.0	$63.0	($3.3)	($0.7)	$59.0	86.5%
EKPC	$0.0	$0.0	($2.4)	$0.0	($2.3)	$11.8	($1.7)	($0.5)	$9.5	(24.1%)
EXT	$3.4	$0.0	$0.0	$0.5	$3.9	$0.7	($4.8)	$0.0	($4.1)	(95.8%)
JCPL	$2.5	$0.0	($4.2)	$0.4	($1.3)	$24.6	($3.3)	($0.9)	$20.4	(6.2%)
Met-Ed	$7.9	$0.4	($2.9)	$1.3	$6.6	$17.9	($2.6)	($0.6)	$14.6	45.2%
PECO	$21.2	$0.2	($7.5)	$3.3	$17.2	$37.3	($5.7)	($1.6)	$30.0	57.3%
Penelec	$10.9	$4.0	($3.2)	$2.0	$13.7	$21.7	($3.4)	($0.7)	$17.6	77.7%
Pepco	$28.9	$2.0	($5.5)	$5.0	$30.3	$23.6	($4.2)	($1.2)	$18.2	166.3%
PPL	$4.4	$0.0	($7.6)	$0.7	($2.4)	$44.2	($5.9)	($1.6)	$36.7	(6.7%)
PSEG	$40.9	$0.0	($8.1)	$6.3	$39.2	$47.3	($7.0)	($1.7)	$38.6	101.5%
RECO	$0.1	$0.0	($0.3)	$0.0	($0.2)	$2.0	($0.9)	($0.1)	$1.1	(19.0%)
Total	$529.0	$130.1	($145.2)	$112.3	$626.2	$832.7	($120.0)	($31.1)	$681.6	91.9%

The total congestion offset paid to loads was 91.9 percent of congestion costs.[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 13-39 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 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 $$39.1 million in the first six months of 2019 for a total of $116.1 million in defaults to date, which will continue to accrue through May 2021, including the auction liquidation costs.

Modified Credit Requirements

PJM modified its credit requirements based on the GreenHat Energy default.

On December 11, 2017, PJM filed, and FERC accepted, a modification to the credit rules for Long Term FTR Auctions.[47] Credit requirements are based on a calculation of the expected FTR values relative to the price of FTRs. Under the prior rules, PJM calculated the expected FTR value based on a three year weighted average of nodal prices. The method was based solely on historical data, and did not account for transmission upgrades that could affect congestion and therefore FTR values. Under the new rules, PJM calculates the FTR credit requirement using the higher of: the expected FTR value based on a three year weighted average of the previous three year's nodal prices; and the expected FTR value based on a planning model simulation of expected

46 The 91.9 offset result is not identical to the 92.1 included in this section as a result of rounding and the use of congestion data at a different temporal granularity.

47 See Docket No. ER18-425.

congestion over the next year incorporating transmission upgrades (the adjusted historical value).

The new approach to calculating the expected value of FTRs is only used for one year, including the YR1 long term FTR. PJM's modeling change does not address the same sources of credit risk for YR2 and YR3 of LTFTRs. PJM continues to use the old method of calculating expected FTR values for YR2 and Y3 of LTFTRs.

On July 27, 2018, PJM filed, and FERC accepted, a modification to the credit rules for the FTR Market that adds a volumetric credit requirement of $0.10 per MWh on participants' FTR portfolios.[48]

On January 31, 2019, PJM filed a modification to the credit rules that would allow PJM to update the credit requirements for already acquired FTRs.[49] PJM terms this proposal mark to auction. Under the current rules PJM cannot issue a collateral call within an FTR's effective period. Under the proposed mark to auction rules PJM could calculate the credit requirement based on the most recent auction price and make any required collateral calls.

PJM's proposed credit policy incorporates all of these changes. The final credit requirement is the higher of the historical weighted value, the adjusted historical weighted value, the volumetric requirement or the mark to auction requirement. If, during the planning period, the mark to auction requirement is higher than the current credit requirement, the mark to auction credit requirement is adopted.

GreenHat Energy, LLC Default

On June 21, 2018, GreenHat Energy, LLC was declared in payment default for non-payment of a $1.2 million weekly invoice on June 5, 2018. GreenHat had been declared in default twice earlier in June 2018 for two collateral calls totaling $2.8 million.[50]

GreenHat held a large FTR position which, according to the tariff provisions effective in June 2018, must be liquidated in the FTR auctions closest to the effective dates of the positions held.[51] The net gain or loss on these liquidated positions is added to the payment default amount that will then be allocated to PJM members according to OA sections 15.1.2A(1) and 15.2.2.

GreenHat's FTR initial portfolio was primarily long term FTRs, many of which were counterflow, although GreenHat subsequently purchased annual FTRs to offset their credit requirements. Liquidation of the counterflow positions through an auction would require payment to the acquiring party an amount equal to the expected value of the counterflow FTR position, plus a risk premium plus a profit. Given the size of GreenHat's portfolio, liquidation was expected to have a significant effect on FTR market prices in any months where liquidation occurred and result in significant payments by PJM members.

On July 26, 2018, PJM filed a request with FERC for a waiver of the tariff provision requiring immediate liquidation of a defaulted FTR position.[52]

Between the default date and the filing of the waiver, one monthly FTR auction occurred for August 2018. In this auction, PJM was required, by existing tariff provisions, to liquidate GreenHat's prompt month FTR positions. The result of this liquidation of prompt month August FTRs was $24.1 million in costs charged to the default allocation assessment.

Consistent with the waiver request, in September 2018, Members elected to settle GreenHat's FTR portfolio at the time the FTRs are due, rather than liquidate them, so default allocation assessment charges would continue to accrue on GreenHat's defaulted FTR portfolio through May 2021.

On August 23, 2019 PJM filed, and FERC accepted, effective August 24, 2018, a tariff revision that replaces the rule requiring immediate liquidation.[53] Under the new rule FTRs within a defaulted participant's portfolio will settle, as do all FTRs, at the hourly day-ahead value. Any positive or negative target allocations will then be credited or charged to the default allocation assessment. The

48 164 FERC ¶ 61,215 (2018).
49 *See* "PJM Interconnection, LLC Revisions to PJM Tariff to Incorporate FTR Mark-to-Auction Provisions," Docket No. ER19-945 (January 31, 2019).
50 Daugherty, Suzanne, email sent to the MC, MRC, CS, and MSS email distribution list, "Notification of GreenHat Energy, LLC Payment Default," (June 22, 2018).
51 "PJM Manual 6: Financial Transmission Rights," Rev. 22 (June 27, 2019).
52 See 166 FERC ¶ 61,072, *reh'g pending*.
53 See Letter Order, FERC Docket No. ER18-2289-000 (October 19, 2018).

default allocation assessment is charged to all PJM participants in proportion to their gross bill as the assessment is calculated monthly for the duration of the defaulted positions. The final amount of payments is not known until the end of the term of all the defaulted FTRs.

On January 30, 2019, FERC denied PJM's request for a waiver regarding the liquidation of FTRs in the July 2018 Balance of Planning Period FTR Auction and the preceding month's non-liquidation of FTRs. In the waiver denial, FERC ordered PJM to take "steps that are necessary to comply with the effective Tariff language when the July 2018 auction was conducted and by unwinding settlements made for the September, October, November, December and January positions that should have been liquidated."[54] PJM has estimated that market participants could be required to pay $250 to $300 million to resolve GreenHat's defaulted FTRs.[55]

On February 21, 2019 PJM filed a motion to stay FERC's waiver denial, and on February 26, 2019 PJM filed a request for rehearing or clarification on the waiver denial.[56] [57] On March 26, 2019 FERC granted PJM's request for rehearing.[58] On June 5, 2019, FERC issued an order established a paper hearing and settlement judge procedures regarding the GreenHat liquidation waiver request. FERC recognized "...there are multiple complexities associated with implementing the Waiver Order Directive that should be addressed in a paper hearing..."[59] Before the paper hearing begins, FERC established a settlement procedure to "...encourage the parties to make every effort to settle their disputes before the paper hearing commences."[60]

As an alternative to the PJM proposal, the MMU recommended the cancellation of defaulted FTRs, which would have a fixed impact within the FTR market alone, and would not have extended the potential impacts past the current planning period.

54 *See* 166 FERC ¶ 61,072 P35, *reh'g pending.*
55 *See* Presentation. "Update on FERC Order Denying PJM's Request for Waiver re: Liquidating FTR Positions of Defaulted Member," MRC. February 21, 2019.
56 *See* "Motion of PJM Interconnection, LLC for Stay," Docket No. 18-2068 (February 21, 2019).
57 *See* "Request of PJM Interconnection LLC for Rehearing or, in the Alternative, Motion for Clarification of Commission Order," Docket No. 18-2069 (February 26, 2019).
58 *See* "Order Granting Rehearings for Further Consideration," Docket No. ER18-2016-001 (March 26, 2019).
59 *See* "Order Establishing Paper Hearing and Settlement Judge Procedures," Docket No. ER18-2068 (June 5, 2019), P27.
60 *See* "Order Establishing Paper Hearing and Settlement Judge Procedures," Docket No. ER18-2068 (June 5, 2019), P28.

GreenHat Energy Default Lessons Learned

On August 14, 2018, PJM hosted an FTR risk management workshop whose participants included experts in energy market and risk management in addition to PJM and the MMU.[61] The objective of this workshop was to examine the credit policies of the FTR market and develop suggestions for enhancements in light of the GreenHat default.

The recommendations of members of the group directly related to credit issues included: increased participation requirements; PJM discretion to make collateral calls; position limits; creation of a liquidity margin in credit requirements; limitations on credit netting for prevailing flow and counter flow positions; volatility adder to credit requirements; transfer risk management to an external authority.

The recommendations of members of the group related to relevant market design issues included: eliminate long term FTRs; revise the eligible FTR bidding points; remove at risk generators from the FTR model; and hold more frequent FTR auctions.

Bilateral Indemnification Provisions

The purchaser of an FTR in an auction may sell the FTR to a third party buyer in a bilateral transaction. PJM's credit rules included a bilateral indemnification provision that requires the seller of the FTR to pay any charges if the buyer defaults. PJM interprets the indemnification provision to make the seller solely responsible for only the charges on the FTR without receiving any of the associated credits. For example, even if the portfolio of FTRs held by the buyer is net positive, the seller must still pay all charges associated with those FTRs.[62]

By failing to net the indemnification obligation within the full portfolio of FTRs sold in a bilateral transaction, PJM's current interpretation of the rule goes beyond having the seller indemnify PJM against losses associated with a bilateral trade with the defaulting buyer. PJM's interpretation of the

61 *See* "PJM Financial Transmission Right (FTR) Risk Management Workshop," Credit Subcommittee, September 17, 2018.
62 For a more complete discussion, see: "Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM," Docket No. ER19-24 (November 27, 2018).

indemnification rule requires that the seller pay any charges associated with the bilateral FTRs, regardless of the net value of the portfolio of bilateral FTRs. Even if the value of the portfolio of bilateral FTRs is net positive, the seller still pays any charges associated with any individual FTRs in that portfolio. This means that PJM is requiring the seller to indemnify PJM against charges over and above those incurred by the relevant bilaterally traded FTRs.

Under this interpretation, bilateral sellers are held to stricter credit rules than other holders of FTRs because they must guarantee more than the net amount of FTR credits for that portfolio. The requirements and obligations associated with selling an FTR should be the same regardless of how the FTR was sold.

PJM must approve every bilateral transaction. There is no reason a bilateral sale should be held to different standards than a sale within an FTR auction. If the implemented credit rules are sufficient there is no need for an indemnification provision. If the credit rules are not sufficient to protect participants from bilateral transfer risk, then bilateral transactions should be eliminated.

The indemnification rule should be modified so that the indemnifying seller was responsible for the net charges associated with the FTRs it sold to a buyer and this would still eliminate socialized default charges associated with the bilateral arrangement between the seller and the buyer. PJM's proposal to allow the indemnifying seller a onetime option to assume ownership of the negative bilateral FTRs could be modified to allow the seller to acquire all the FTRs the seller sold to the defaulting buyer. With this modification, no snap shot determination of the relative value of the FTRs is needed. In terms of socialized costs to the membership, this change in the rules and proposal would eliminate the inconsistency in the indemnification by bilateral and auction transactions.

Report of the Independent Consultants on the GreenHat Default

As a result of the GreenHat Energy default, the Board commissioned an independent group of experts to examine the default event and provide suggestions for future improvements.[63] The independent consultants examined PJM's FTR credit rules and the events that led to the GreenHat default and developed a list of causes of the GreenHat default event and solutions to help prevent such an event in the future.

The report stated four main causes of the default event:[64]

1. PJM did not have staff with the necessary training and credentials to successfully manage the financial risks posed by the numerous participants in its FTR markets. For a number of years prior to GreenHat, PJM's FTR market participants self-regulated their conduct, and the market ran smoothly. GreenHat, however, provided a set of conditions for which the framework that PJM developed over time to manage risk was inadequate.
2. PJM made a decision not to terminate GreenHat's trading rights when PJM initially understood the potential for a default. Instead PJM chose to manage the situation, which PJM believed could not get worse. As is discussed in detail in this report, PJM did not effectively manage the situation, which grew materially worse.
3. PJM personnel were naive about GreenHat's assurances of creditworthiness and a future revenue stream pledged to PJM. What is more, they did not appreciate GreenHat's determined ability to increase its position, and incur additional risk, thus expanding its losses well beyond anything PJM imagined could happen. PJM mistakenly believed it would contain and control GreenHat's behavior and risk, which in the end it did not. If PJM were better prepared to monitor market participant behavior, and better measure risk, we believe it could have and would have responded more effectively to GreenHat's empty assurances.

63 PJM. "*Report of the Independent Consultants on the GreenHat Default*," March 18, 2019 <https://www.pjm.com/-/media/library/reports-notices/special-reports/2019/report-of-the-independent-consultants-on-the-greenhat-default.ashx?la=en>.
64 PJM. "*Report of the Independent Consultants on the GreenHat Default*," P7. March 18, 2019 <https://www.pjm.com/-/media/library/reports-notices/special-reports/2019/report-of-the-independent-consultants-on-the-greenhat-default.ashx?la=en>.

4. PJM was late to recognize GreenHat as a problem. Had PJM declared a default upon first recognizing the GreenHat problem, the amount of the loss would have been substantial but far less than what PJM must deal with today. In any case, we find that even if PJM had made such a default declaration, our recommendations would stand as set forth in this document.

Based on these findings, the independent committee made seven recommendations including: incorporating credit/collateral best practices; clarify PJM's role as risk manager in its financial markets; build customer awareness of PJM's role in FTR market; improve analysis of participant risks; establish a Chief Risk Officer reporting to a new committee of the PJM Board of Managers; increase the frequency of Long Term Auctions; and make critical organizational changes to address financial risk management.[65]

PJM has created a stakeholder process at the MRC level to discuss improvements that address the recommendations.[66]

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 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.[67]

65 PJM. "*Report of the Independent Consultants on the GreenHat Default*," P33. March 18, 2019 <https://www.pjm.com/-/media/library/reports-notices/special-reports/2019/report-of-the-independent-consultants-on-the-greenhat-default.ashx?la=en>.
66 *See* "Financial Risk Mitigation Senior Task Force Charter," MRC. April 25, 2019.
67 *See* "Minor modification to Tariff Language for FTR Forfeiture Rule," Docket No. ER19-2240 (June 24, 2019).

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.[68] 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

68 *See* 158 FERC ¶ 61,038.

is the hourly profit of the FTR and an FTR cannot forfeit more than once per hour.

Figure 13-14 shows the monthly FTR forfeitures under the newly established FTR forfeiture rule from January 19, 2017, through June 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. For the period of January 19, 2017, through June 30, 2019, total FTR forfeitures were $14.5 million.

Figure 13-14 Monthly FTR forfeitures for physical and financial participants