Introduction

2019 Q3 in Review

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

One of the benefits of competitive power markets is that changes in input prices and changes in the balance of supply and demand are reflected immediately in energy prices. PJM real-time energy market prices decreased significantly in the first nine months of 2019 compared to the first nine months of 2018. The load-weighted average real-time LMP was 30.0 percent lower in the first nine months of 2019 than in the first nine months of 2018, $27.60 per MWh versus $39.43 per MWh. Of the $11.83 per MWh decrease, 34.2 percent was a result of lower fuel costs. Other contributors to the decrease were the dispatch of lower cost units, decreased load and lower markups.

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

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

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

Net revenues for nuclear power plants increased significantly in 2018 but decreased from that level in the first nine months of 2019. There are currently two nuclear power plants in PJM that are not economic at expected levels of energy and capacity market clearing prices. The decisions on how to proceed belong to the owners of those plants. The fact that some plants are uneconomic does not call into question the fundamentals of PJM markets. Many generating plants have retired in PJM since the introduction of markets and many generating plants have been built since the introduction of markets.

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

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

PJM Market Summary Statistics

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

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

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

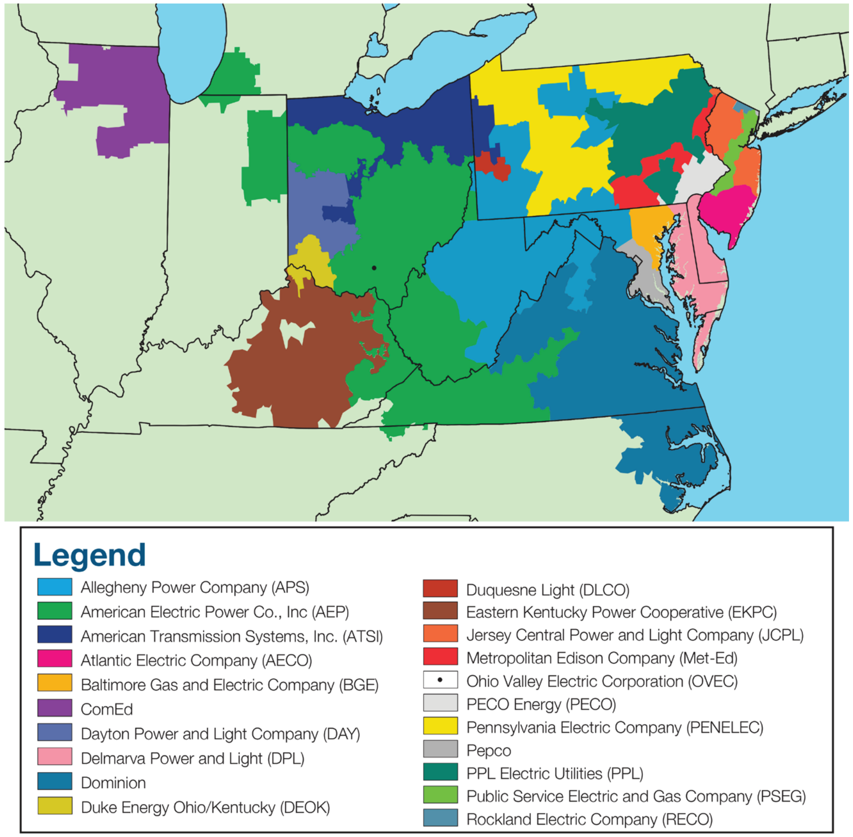
PJM Market Background

The PJM Interconnection, L.L.C. (PJM) operates a centrally dispatched, competitive wholesale electric power market that, as of September 30, 2019, had installed generating capacity of 186,503 megawatts (MW) and 1,044 members including market buyers, sellers and traders of electricity in a region including more than 65 million people in all or parts of 13 states (Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia) and the District of Columbia (Figure 1-1).[3] [4] [5]

As part of the market operator function, PJM coordinates and directs the operation of the transmission grid and plans transmission expansion improvements to maintain grid reliability in this region.

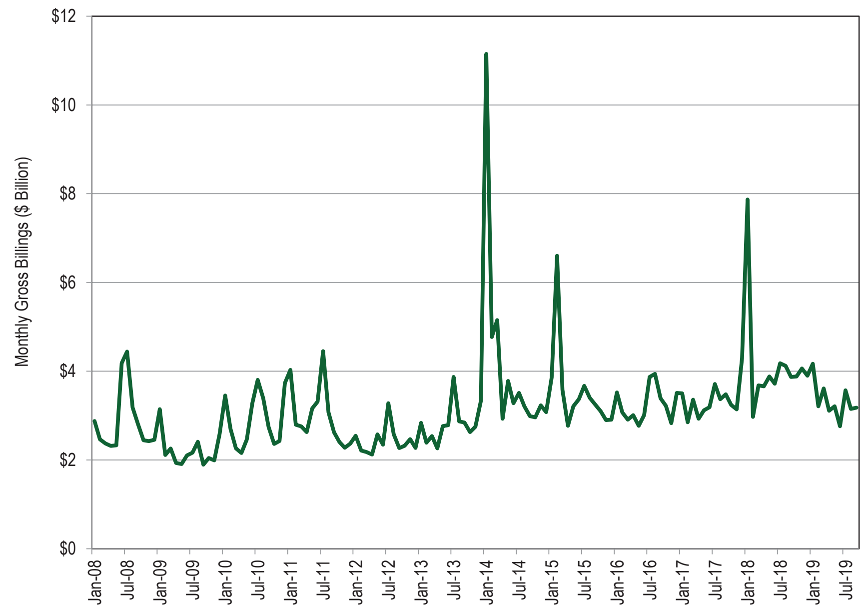
2 The load reported in this table is the accounting load plus net withdrawals at generator buses. The average hourly accounting load is reported in Section 3, "Energy Market."
3 See PJM. "Member List," which can be accessed at: <http://pjm.com/about-pjm/member-services/member-list.aspx>.
4 See PJM. "Who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

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



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

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



PJM operates the Day-Ahead Energy Market, the Real-Time Energy Market, the Reliability Pricing Model (RPM) Capacity Market, the Regulation Market, the Synchronized Reserve Market, the Day-Ahead Scheduling Reserve (DASR) Market and the Financial Transmission Rights (FTRs) Markets.

PJM introduced energy pricing with cost-based offers and market-clearing nodal prices on April 1, 1998, and market-clearing nodal prices with market-based offers on April 1, 1999. PJM introduced the Daily Capacity Market on January 1, 1999, and the Monthly and Multimonthly Capacity Markets for the

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

January through May 1999 period. PJM implemented FTRs on May 1, 1999. PJM implemented the Day-Ahead Energy Market and the Regulation Market on June 1, 2000. PJM modified the Regulation Market design and added a market in Synchronized Reserve on December 1, 2002. PJM introduced an Auction Revenue Rights (ARR) allocation process and an associated Annual FTR Auction effective June 1, 2003. PJM introduced the RPM Capacity Market effective June 1, 2007. PJM implemented the DASR Market on June 1, 2008. PJM introduced the Capacity Performance capacity market design effective on August 10, 2015, with the Base Residual Auction for 2018/2019.[7] [8]

Conclusions

This report assesses the competitiveness of the markets managed by PJM in the first nine months of 2019, including market structure, participant behavior and market performance. This report was prepared by and represents the analysis of the Independent Market Monitor for PJM, also referred to as the Market Monitoring Unit or MMU.

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

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

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

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

Market performance refers to the outcomes of the market. Market performance results from the behavior of market participants within a market structure, mediated by market design.

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

Energy Market Conclusion

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

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

8 Analysis of 2019 market results requires comparison to prior years. During calendar years 2004 and 2005, PJM conducted the phased integration of five control zones: ComEd, American Electric Power (AEP), The Dayton Power & Light Company (DAY), Duquesne Light Company (DLCO) and Dominion. In June 2011, PJM integrated the American Transmission Systems, Inc. (ATSI) Control Zone. In January 2012, PJM integrated the Duke Energy Ohio/Kentucky (DEOK) Control Zone. In June 2013, PJM integrated the Eastern Kentucky Power Cooperative (EKPC). In December 2018, PJM integrated the Ohio Valley Electric Corporation (OVEC.) By convention, control zones bear the name of a large utility service provider working within their boundaries. The nomenclature applies to the geographic area, not to any single company. For additional information on the integrations, their timing and their impact on the footprint of the PJM service territory prior to 2019, see *2018 State of the Market Report for PJM*, Volume 2, Appendix A: "PJM Geography."

Table 1-2 The Energy Market results were competitive

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

- The aggregate market structure was evaluated as partially competitive because the aggregate market power test based on pivotal suppliers indicates that the aggregate day-ahead market structure was not competitive on every day. The hourly HHI (Herfindahl-Hirschman Index) results indicate that the PJM energy market in the first nine months of 2019 was unconcentrated by FERC HHI standards in 98.2 percent of market hours and moderately concentrated in 1.8 percent of market hours. Average HHI was 773 with a minimum of 572 and a maximum of 1098 in the first nine months of 2019. The PJM energy market intermediate and peaking segments of supply were highly concentrated. The fact that the average HHI is in the unconcentrated range and the maximum hourly HHI is in the moderately concentrated range does not mean that the aggregate market was competitive in all hours. As demonstrated for the day-ahead market, it is possible to have pivotal suppliers in the aggregate market even when the HHI level is not in the highly concentrated range. It is possible to have an exercise of market power even when the HHI level is not in the highly concentrated range. The number of pivotal suppliers in the energy market is a more precise measure of structural market power than the HHI. The HHI is not a definitive measure of structural market power.
- The local market structure was evaluated as not competitive due to the highly concentrated ownership of supply in local markets created by transmission constraints and local reliability issues. The results of the three pivotal supplier (TPS) test, used to test local market structure, indicate the existence of market power in local markets created by transmission constraints. The local market performance is competitive as a result of the application of the TPS test. While transmission constraints create the potential for the exercise of local market power, PJM's application of the three pivotal supplier test identified local market power and resulted in offer capping to force competitive offers, correcting for structural issues created by local transmission constraints. There are, however, identified issues with the definition of cost-based offers and the application of market power mitigation to resources whose owners fail the TPS test that need to be addressed because unit owners can exercise market power even when they fail the TPS test.
- Participant behavior was evaluated as competitive because the analysis of markup shows that marginal units generally make offers at, or close to, their marginal costs in both Day-Ahead and Real-Time Energy Markets, although the behavior of some participants both routinely and during periods of high demand represents economic withholding and the markups of those participants affected LMP.
- Market performance was evaluated as competitive because market results in the energy market reflect the outcome of a competitive market, as PJM prices are set, on average, by marginal units operating at, or close to, their marginal costs in both Day-Ahead and Real-Time Energy Markets, although high markups for some marginal units did affect prices.
- Market design was evaluated as effective because the analysis shows that the PJM energy market resulted in competitive market outcomes. In general, PJM's energy market design provides incentives for competitive behavior and results in competitive outcomes. In local markets, where market power is an issue, the market design identifies market power and causes the market to provide competitive market outcomes in most cases although issues with the implementation of market power mitigation and development of cost-based offers remain. The role of UTCs in the Day-Ahead Energy Market continues to cause concerns. Market design implementation issues, including inaccuracies in modeling of the transmission system and of generator capabilities as well as inefficiencies in real-time dispatch and price formation, undermine market efficiency in the energy market.
- PJM markets are designed to promote competitive outcomes derived from the interaction of supply and demand in each of the PJM markets.

Market design itself is the primary means of achieving and promoting competitive outcomes in PJM markets. One of the MMU's primary goals is to identify actual or potential market design flaws.[9] The approach to market power mitigation in PJM has focused on market designs that promote competition (a structural basis for competitive outcomes) and on limiting market power mitigation to instances where the market structure is not competitive and thus where market design alone cannot mitigate market power. In the PJM energy market, this occurs primarily in the case of local market power. When a transmission constraint creates the potential for local market power, PJM applies a structural test to determine if the local market is competitive, applies a behavioral test to determine if generator offers exceed competitive levels and applies a market performance test to determine if such generator offers would affect the market price.[10] There are, however, identified issues with the application of market power mitigation to resources whose owners fail the TPS test that can result in the exercise of local market power even when market power mitigation rules are applied. These issues need to be addressed. There are issues related to the definition of gas costs includable in energy offers that need to be addressed. There are issues related to the level of maintenance expense includable in energy offers that need to be addressed. There are currently no market power mitigation rules in place that limit the ability to exercise market power when aggregate market conditions are tight and there are pivotal suppliers in the aggregate market. Aggregate market power needs to be addressed. Now that generators are allowed to modify offers hourly, market design must reflect appropriate incentives for competitive behavior, the application of local market power mitigation needs to be fixed, the definition of a competitive offer needs to be fixed, and aggregate market power mitigation rules need to be developed. The importance of these issues is amplified by the new rules permitting cost-based offers in excess of $1,000 per MWh.

9 OATT Attachment M (PJM Market Monitoring Plan).
10 The market performance test means that offer capping is not applied if the offer does not exceed the competitive level and therefore market power would not affect market performance.

Capacity Market Conclusion

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

Table 1-3 The Capacity Market results were not competitive

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

- The aggregate market structure was evaluated as not competitive. For almost all auctions held from 2007 to the present, the PJM region failed the three pivotal supplier test (TPS), which is conducted at the time of the auction.[12] Structural market power is endemic to the capacity market.
- The local market structure was evaluated as not competitive. For almost every auction held, all LDAs have failed the TPS test, which is conducted at the time of the auction.[13]
- Participant behavior was evaluated as not competitive in the 2021/2022 RPM Base Residual Auction. Market power mitigation measures were applied when the capacity market seller failed the market power test for the auction, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, would increase the market clearing price. But the net CONE times B offer cap under the capacity performance design, in the absence of performance assessment hours, exceeds the competitive level and should be reevaluated for each BRA. In the 2021/2022 RPM Base Residual Auction, some participants' offers were above the competitive level. The MMU recognizes that these market

11 The values stated in this report for the RTO and LDAs refer to the aggregate level including all nested LDAs unless otherwise specified. For example, RTO values include the entire PJM market and all LDAs. Rest of RTO values are RTO values net of nested LDA values.
12 In the 2008/2009 RPM Third Incremental Auction, 18 participants in the RTO market passed the TPS test. In the 2018/2019 RPM Second Incremental Auction, 35 participants in the RTO market passed the test.
13 In the 2012/2013 RPM Base Residual Auction, six participants included in the incremental supply of EMAAC passed the TPS test. In the 2014/2015 RPM Base Residual Auction, seven participants in the incremental supply in MAAC passed the TPS test. In the 2021/2022 RPM First Incremental Auction, two participants in the incremental supply in EMAAC passed the TPS test.

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

- Market performance was evaluated as not competitive based on the 2021/2022 RPM Base Residual Auction. Although structural market power exists in the Capacity Market, a competitive outcome can result from the application of market power mitigation rules. The outcome of the 2021/2022 RPM Base Residual Auction was not competitive as a result of participant behavior which was not competitive, specifically offers which exceeded the competitive level.
- Market design was evaluated as mixed because while there are many positive features of the Reliability Pricing Model (RPM) design and the capacity performance modifications to RPM, there are several features of the RPM design which still threaten competitive outcomes. These include the definition of DR which permits inferior products to substitute for capacity, the replacement capacity issue, the definition of unit offer parameters, the inclusion of imports which are not substitutes for internal capacity resources, and the definition of the default offer cap.

Tier 2 Synchronized Reserve Market Conclusion

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

Table 1-4 The tier 2 synchronized reserve market results were competitive

Market Element	Evaluation	Market Design
Market Structure: Regional Markets	Not Competitive	
Participant Behavior	Competitive	
Market Performance	**Competitive**	**Mixed**

- The tier 2 synchronized reserve market structure was evaluated as not competitive because of high levels of supplier concentration.
- Participant behavior was evaluated as competitive because the market rules require competitive, cost-based offers.
- Market performance was evaluated as competitive because the interaction of participant behavior with the market design results in competitive prices.
- Market design was evaluated as mixed. Market power mitigation rules result in competitive outcomes despite high levels of supplier concentration. However, tier 1 reserves are inappropriately compensated when the nonsynchronized reserve market clears with a nonzero price.

Day-Ahead Scheduling Reserve Market Conclusion

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

Table 1-5 The day-ahead scheduling reserve market results were competitive

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

- The DASR market would have failed a three pivotal supplier test in less than one percent of cleared hours in the first nine months of 2019. The day-ahead scheduling reserve market structure remains evaluated as not competitive based on persistent structural issues.
- Participant behavior was evaluated as mixed because while most offers were equal to marginal costs, a significant proportion of offers reflected economic withholding.
- Market performance was evaluated as competitive because there were adequate offers in every hour to satisfy the requirement and the clearing prices reflected those offers, although there is concern about offers above the competitive level affecting prices. Offers above $0.00 were part of the

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

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

Regulation Market Conclusion

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

Table 1-6 The regulation market results were competitive

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

- The regulation market structure was evaluated as not competitive because the PJM Regulation Market failed the three pivotal supplier (TPS) test in 93.3 percent of the hours in the first nine months of 2019.
- Participant behavior in the PJM Regulation Market was evaluated as competitive for the first nine months of 2019 because market power mitigation requires competitive offers when the three pivotal supplier test is failed and there was no evidence of generation owners engaging in noncompetitive behavior.
- Market performance was evaluated as competitive, despite significant issues with the market design.
- Market design was evaluated as flawed. The market design has failed to correctly incorporate a consistent implementation of the marginal benefit factor in optimization, pricing and settlement. The market results continue to include the incorrect definition of opportunity cost. The result is significantly flawed market signals to existing and prospective suppliers of regulation.

FTR Auction Market Conclusion

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

Table 1-7 The FTR auction markets results were competitive

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

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

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

Role of MMU

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

Reporting

The MMU performs its reporting function primarily by issuing and filing annual and quarterly state of the market reports; regular reports on market issues; such as RPM auction reports; reports responding to requests from regulators and other authorities; and ad hoc reports on specific topics. The state of the market reports provide a comprehensive analysis of market structure, participant conduct and market performance for the PJM markets. State of the market reports and other reports are intended to inform PJM, the PJM Board, FERC, other regulators, other authorities, market participants, stakeholders and the general public about how well PJM markets achieve the competitive outcomes necessary to realize the goals of regulation through competition, and how the markets can be improved.

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

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

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

Monitoring

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

The MMU monitors market behavior for violations of FERC Market Rules and PJM Market Rules, including the actual or potential exercise of market power.[19] The MMU will investigate and refer "Market Violations," which refer to any of "a tariff violation, violation of a Commission-approved order, rule or regulation, market manipulation, or inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies..."[20] [21] [22] The MMU also monitors PJM for compliance with the rules, in addition to market participants.[23]

An important component of the monitoring function is the review of inputs to mitigation. The actual or potential exercise of market power is addressed in part through *ex ante* mitigation rules incorporated in PJM's market clearing software for the energy market, the capacity market and the regulation market. If a market participant fails the TPS test in any of these markets its offer is set

16 OATT Attachment M § IV.

17 OATT Attachment M § IV.K.3.

18 OATT Attachment M § IV.H.

19 OATT § I.1 ("FERC Market Rules" mean the market behavior rules and the prohibition against electric energy market manipulation codified by the Commission in its Rules and Regulations at 18 CFR §§ 1c.2 and 35.37, respectively; the Commission-approved PJM Market Rules and any related proscriptions or any successor rules that the Commission from time to time may issue, approve or otherwise establish... "PJM Market Rules" mean the rules, standards, procedures, and practices of the PJM Markets set forth in the PJM Tariff, the PJM Operating Agreement, the PJM Reliability Assurance Agreement, the PJM Consolidated Transmission Owners Agreement, the PJM Manuals, the PJM Regional Practices Document, the PJM-Midwest Independent Transmission System Operator Joint Operating Agreement or any other document setting forth market rules.")

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

21 OATT § I.1.

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

23 OATT Attachment M § IV.C.

to the lower of its price-based or cost-based offer. This prevents the exercise of market power and ensures competitive pricing, provided that the cost-based offer accurately reflects short run marginal cost.

If the cost-based offer does not accurately reflect short run marginal cost, the market power mitigation process does not ensure competitive pricing in PJM markets. The MMU evaluates the fuel cost policy for every unit as well as the other inputs to cost-based offers. PJM Manual 15 does not clearly or accurately describe the short run marginal cost of generation. Manual 15 should be replaced with a straightforward description of the components of cost offers based on short run marginal costs and the correct calculation of cost offers. The MMU evaluates every offer in each capacity market (RPM) auction using data submitted to the MMU through web-based data input systems developed by the MMU.[24]

The MMU also reviews operational parameter limits included with unit offers, evaluates compliance with the requirement to offer into the energy and capacity markets, evaluates the economic basis for unit retirement requests and evaluates and compares offers in the Day-Ahead and Real-Time Energy Markets.[25] [26] [27] [28]

The MMU reviews offers and inputs in order to evaluate whether those offers raise market power concerns. Market participants, not the MMU, determine and take responsibility for offers that they submit and the market conduct that those offers represent. If the MMU has a concern about an offer, the MMU may raise that concern with FERC or other regulatory authorities. FERC and other regulators have enforcement and regulatory authority that they may exercise with respect to offers submitted by market participants. PJM also reviews offers, but it does so in order to determine whether offers comply with the PJM tariff and manuals. PJM, in its role as the market operator, may reject an offer that fails to comply with the market rules. The respective reviews performed by the MMU and PJM are separate and non-sequential.

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

The PJM Markets monitored by the MMU include market related procurement processes conducted by PJM, such as for Black Start resources included in the PJM system restoration plan.[29] [30]

The MMU also monitors transmission planning, interconnections and rules for vertical market power issues, and with the introduction of competitive transmission development policy in Order No. 1000, horizontal market power issues.[31]

Market Design

In order to perform its role in PJM market design, the MMU evaluates existing and proposed PJM Market Rules and the design of the PJM Markets.[32] The MMU initiates and proposes changes to the design of such markets or the PJM Market Rules in stakeholder or regulatory proceedings.[33] In support of this function, the MMU engages in discussions with stakeholders, State Commissions, PJM Management, and the PJM Board; participates in PJM stakeholder meetings or working groups regarding market design matters; publishes proposals, reports or studies on such market design issues; and makes filings with the Commission on market design issues.[34] The MMU also recommends changes to the PJM Market Rules to the staff of the Commission's Office of Energy Market Regulation, State Commissions, and the PJM Board.[35] The MMU may provide in its annual, quarterly and other reports "recommendations regarding any matter within its purview."[36]

New Recommendations

Consistent with its core function to "[e]valuate existing and proposed market rules, tariff provisions and market design elements and recommend proposed rule and tariff changes,"[37] the MMU recommends specific enhancements to existing market rules and implementation of new rules that are required for

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

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

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

New Recommendations from Section 3, Energy Market

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

New Recommendation from Section 10, Ancillary Services

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

New Recommendation from Section 11, Congestion and Marginal Losses

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

New Recommendation from Section 12, Generation and Transmission Planning

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

Total Price of Wholesale Power

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

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

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

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

adjustments to eliminate certain transmission owners' network charges and monthly bilateral corrections.

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

Components of Total Price

- The Energy component is the real-time load weighted average PJM locational marginal price (LMP).
- The Capacity component is the average price per MWh of Reliability Pricing Model (RPM) payments.
- The Transmission Service Charges component is the average price per MWh of network integration charges, and firm and nonfirm point to point transmission service.[40]
- The Energy Uplift (Operating Reserves) component is the average price per MWh of day-ahead and balancing operating reserves and synchronous condensing charges.[41]
- The Reactive component is the average cost per MWh of reactive supply and voltage control from generation and other sources.[42]
- The Regulation component is the average cost per MWh of regulation procured through the PJM Regulation Market.[43]
- The PJM Administrative Fees component is the average cost per MWh of PJM's monthly expenses for a number of administrative services, including Advanced Control Center (AC^2) and OATT Schedule 9 funding of FERC, OPSI, CAPS and the MMU.
- The Transmission Enhancement Cost Recovery component is the average cost per MWh of PJM billed (and not otherwise collected through utility rates) costs for transmission upgrades and projects, including annual recovery for the TrAIL and PATH projects.[44]
- The Capacity (FRR) component is the average cost per MWh under the Fixed Resource Requirement (FRR) Alternative for an eligible LSE to satisfy its Unforced Capacity obligation.[45]
- The Emergency Load Response component is the average cost per MWh of the PJM Emergency Load Response Program.[46]
- The Day-Ahead Scheduling Reserve component is the average cost per MWh of Day-Ahead scheduling reserves procured through the Day-Ahead Scheduling Reserve Market.[47]
- The Transmission Owner (Schedule 1A) component is the average cost per MWh of transmission owner scheduling, system control and dispatch services charged to transmission customers.[48]
- The Synchronized Reserve component is the average cost per MWh of synchronized reserve procured through the Synchronized Reserve Market.[49]
- The Black Start component is the average cost per MWh of black start service.[50]
- The RTO Startup and Expansion component is the average cost per MWh of charges to recover AEP, ComEd and DAY's integration expenses.[51]
- The NERC/RFC component is the average cost per MWh of NERC and RFC charges, plus any reconciliation charges.[52]
- The Economic Load Response component is the average cost per MWh of day-ahead and real-time economic load response program charges to LSEs.[53]
- The Transmission Facility Charges component is the average cost per MWh of Ramapo Phase Angle Regulators charges allocated to PJM Mid-Atlantic transmission owners.[54]

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

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

Table 1-8 shows that Energy, Capacity and Transmission Charges are the three largest components of the total price per MWh of wholesale power, comprising 97.3 percent of the total price per MWh in the first nine months of 2019.

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

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

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

Table 1-9 shows the inflation adjusted average price, by component, for January through September, 2018 and 2019. To obtain the inflation adjusted average prices, the individual components' prices are deflated using the US Consumer Price Index for all items, Urban Consumers (with a base period of January 1998).[59]

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

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

59 US Consumer Price Index for all items, Urban Consumers (base period: January 1998), published by Bureau of Labor Statistics. <http://download.bls.gov/pub/time.series/cu/cu.data.1.AllItems> (October 10, 2019)
60 Note: The totals in this table include after the fact billing adjustments and may not match totals presented in past reports.

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

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

Category	1999 $/MWh	2000 $/MWh	2001 $/MWh	2002 $/MWh	2003 $ /MWh	2004 $/MWh	2005 $ /MWh	2006 $/MWh	2007 $/MWh	2008 $/MWh	2009 $/MWh	2010 $/MWh	2011 $/MWh	2012 $/MWh	2013 $/MWh	2014 $/MWh	2015 $/MWh	2016 $/MWh	2017 $/MWh	2018 $/MWh
Load Weighted Energy	$34.07	$30.72	$36.65	$31.60	$41.23	$44.34	$63.46	$53.35	$61.66	$71.13	$39.05	$48.35	$45.94	$35.23	$38.66	$53.14	$36.16	$29.23	$30.99	$38.24
Capacity	$0.14	$0.25	$0.27	$0.12	$0.08	$0.09	$0.04	$0.11	$3.58	$7.84	$10.79	$12.17	$10.37	$6.66	$7.29	$9.25	$11.25	$10.96	$11.27	$13.02
Capacity	$0.14	$0.25	$0.27	$0.12	$0.08	$0.09	$0.03	$0.03	$3.53	$7.80	$10.78	$12.15	$9.71	$6.05	$7.13	$9.01	$11.12	$10.96	$11.23	$12.97
Capacity (FRR)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.53	$0.52	$0.11	$0.20	$0.13	$0.00	$0.00	$0.00
Capacity (RMR)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.02	$0.08	$0.05	$0.04	$0.01	$0.02	$0.13	$0.08	$0.06	$0.04	($0.00)	($0.00)	$0.04	$0.05
Transmission	$3.49	$4.13	$3.56	$3.46	$3.64	$3.43	$3.30	$3.34	$3.55	$3.83	$4.22	$4.33	$4.86	$5.32	$5.65	$6.46	$7.69	$8.42	$9.54	$9.47
Transmission Service Charges	$3.41	$4.03	$3.48	$3.39	$3.57	$3.28	$2.71	$3.18	$3.45	$3.68	$4.03	$4.04	$4.49	$4.90	$5.21	$5.96	$7.09	$7.81	$8.83	$8.81
Transmission Enhancement Cost Recovery	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.01	$0.06	$0.11	$0.20	$0.27	$0.34	$0.36	$0.41	$0.51	$0.52	$0.64	$0.57
Transmission Owner (Schedule 1A)	$0.07	$0.09	$0.08	$0.07	$0.07	$0.10	$0.09	$0.09	$0.09	$0.09	$0.09	$0.09	$0.09	$0.08	$0.08	$0.09	$0.09	$0.09	$0.10	$0.09
Transmission Seams Elimination Cost Assignment (SECA)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.05	$0.50	$0.07	$0.00	$0.00	$0.00	$0.00	($0.00)	$0.00	$0.00	$0.00	$0.00	$0.00	($0.03)	$0.00
Transmission Facility Charges	$0.01	$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Ancillary	$0.41	$0.68	$0.75	$0.63	$0.91	$0.91	$1.19	$0.92	$1.00	$1.15	$0.78	$0.90	$0.90	$0.84	$1.24	$0.99	$0.91	$0.71	$0.77	$0.82
Reactive	$0.26	$0.29	$0.22	$0.20	$0.24	$0.26	$0.26	$0.29	$0.29	$0.34	$0.36	$0.45	$0.41	$0.46	$0.76	$0.40	$0.37	$0.38	$0.43	$0.42
Regulation	$0.15	$0.39	$0.53	$0.42	$0.50	$0.51	$0.80	$0.53	$0.63	$0.70	$0.34	$0.36	$0.32	$0.26	$0.25	$0.33	$0.23	$0.11	$0.14	$0.18
Black Start	$0.00	$0.00	$0.00	$0.00	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.04	$0.14	$0.08	$0.08	$0.09	$0.09	$0.08
Synchronized Reserves	$0.00	$0.00	$0.00	$0.01	$0.15	$0.13	$0.11	$0.08	$0.06	$0.08	$0.05	$0.07	$0.09	$0.04	$0.04	$0.12	$0.11	$0.05	$0.06	$0.06
Non-Synchronized Reserves	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.02	$0.02	$0.01	$0.01	$0.02
Day Ahead Scheduling Reserve (DASR)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.01	$0.00	$0.01	$0.05	$0.05	$0.06	$0.05	$0.10	$0.07	$0.05	$0.05
Administration	$0.23	$0.26	$0.73	$0.86	$1.05	$1.00	$0.73	$0.75	$0.75	$0.41	$0.34	$0.39	$0.40	$0.46	$0.45	$0.46	$0.47	$0.46	$0.52	$0.50
PJM Administrative Fees	$0.23	$0.26	$0.71	$0.86	$1.05	$0.93	$0.72	$0.74	$0.72	$0.39	$0.31	$0.36	$0.37	$0.43	$0.42	$0.43	$0.43	$0.43	$0.48	$0.47
NERC/RFC	$0.00	($0.00)	$0.01	$0.01	$0.01	$0.01	$0.01	($0.00)	$0.01	$0.01	$0.02	$0.02	$0.02	$0.02	$0.02	$0.03	$0.03	$0.03	$0.03	$0.03
RTO Startup and Expansion	$0.00	$0.00	$0.00	$0.00	$0.00	$0.06	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.00	$0.00	$0.00
Energy Uplift (Operating Reserves)	$0.52	$0.93	$1.27	$0.72	$0.89	$0.95	$1.07	$0.47	$0.65	$0.64	$0.48	$0.80	$0.78	$0.74	$0.55	$1.11	$0.38	$0.17	$0.14	$0.23
Demand Response	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.03	$0.06	$0.05	$0.01	$0.03	$0.03	$0.03	$0.08	$0.08	$0.02	$0.01	$0.01	$0.01
Load Response	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.03	$0.06	$0.05	$0.01	$0.01	$0.01	$0.02	$0.01	$0.03	$0.02	$0.01	$0.01	$0.01
Emergency Load Response	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.02	$0.02	$0.01	$0.06	$0.06	$0.00	$0.00	$0.00	$0.00
Emergency Energy	$0.07	$0.02	$0.00	$0.00	$0.02	$0.00	$0.02	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.01	$0.00	$0.00	$0.00	$0.00
Total Price ($/MWh)	$38.92	$36.98	$43.22	$37.39	$47.83	$50.71	$69.81	$58.97	$71.25	$85.05	$55.66	$66.97	$63.28	$49.28	$53.93	$71.49	$56.87	$49.97	$53.24	$62.29
Total Load (GWh)	259,623	264,510	265,398	312,899	327,533	438,874	684,592	696,165	715,524	698,459	666,069	697,391	723,101	764,300	773,790	780,505	776,093	778,269	758,775	791,094
Total Billing ($ Billions)	$10.10	$9.78	$11.47	$11.70	$15.67	$22.26	$47.79	$41.05	$50.98	$59.40	$37.08	$46.70	$45.76	$37.67	$41.73	$55.80	$44.14	$38.89	$40.39	$49.28

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

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

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

Category	1999 $/MWh	2000 $/MWh	2001 $/MWh	2002 $/MWh	2003 $/MWh	2004 $/MWh	2005 $/MWh	2006 $/MWh	2007 $/MWh	2008 $/MWh	2009 $/MWh	2010 $/MWh	2011 $/MWh	2012 $/MWh	2013 $/MWh	2014 $/MWh	2015 $/MWh	2016 $/MWh	2017 $/MWh	2018 $/MWh
Load Weighted Energy	$33.04	$28.80	$33.45	$28.35	$36.24	$37.91	$52.37	$42.73	$48.06	$53.27	$29.46	$35.83	$33.01	$24.80	$26.82	$36.37	$24.69	$19.68	$20.43	$24.65
Capacity	$0.13	$0.23	$0.24	$0.11	$0.07	$0.08	$0.03	$0.08	$2.77	$5.88	$8.12	$9.02	$7.46	$4.69	$5.06	$6.31	$7.66	$7.38	$7.43	$8.37
Capacity	$0.13	$0.23	$0.24	$0.11	$0.07	$0.08	$0.02	$0.02	$2.73	$5.85	$8.11	$9.00	$6.99	$4.26	$4.94	$6.15	$7.58	$7.38	$7.40	$8.34
Capacity (FRR)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.38	$0.37	$0.07	$0.14	$0.09	$0.00	$0.00	$0.00
Capacity (RMR)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.01	$0.06	$0.04	$0.03	$0.01	$0.01	$0.09	$0.06	$0.04	$0.03	($0.00)	($0.00)	$0.02	$0.03
Transmission	$3.38	$3.88	$3.25	$3.10	$3.20	$2.93	$2.73	$2.68	$2.76	$2.87	$3.18	$3.21	$3.49	$3.74	$3.92	$4.41	$5.24	$5.67	$6.29	$6.10
Transmission Service Charges	$3.31	$3.79	$3.17	$3.04	$3.13	$2.80	$2.24	$2.55	$2.69	$2.76	$3.04	$2.99	$3.23	$3.45	$3.61	$4.07	$4.84	$5.26	$5.82	$5.67
Transmission Enhancement Cost Recovery	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.04	$0.08	$0.15	$0.20	$0.24	$0.25	$0.28	$0.34	$0.35	$0.42	$0.37
Transmission Owner (Schedule 1A)	$0.07	$0.08	$0.07	$0.06	$0.06	$0.08	$0.07	$0.07	$0.07	$0.07	$0.06	$0.07	$0.06	$0.06	$0.06	$0.06	$0.06	$0.06	$0.06	$0.06
Transmission Seams Elimination Cost Assignment (SECA)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.04	$0.41	$0.06	$0.00	$0.00	$0.00	$0.00	($0.00)	$0.00	$0.00	$0.00	$0.00	$0.00	($0.02)	$0.00
Transmission Facility Charges	$0.01	$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Ancillary	$0.40	$0.64	$0.68	$0.56	$0.80	$0.77	$0.98	$0.74	$0.78	$0.86	$0.59	$0.66	$0.64	$0.59	$0.86	$0.67	$0.62	$0.48	$0.51	$0.53
Reactive	$0.25	$0.27	$0.20	$0.18	$0.21	$0.22	$0.21	$0.23	$0.23	$0.25	$0.27	$0.33	$0.29	$0.32	$0.53	$0.27	$0.25	$0.26	$0.28	$0.27
Regulation	$0.15	$0.37	$0.48	$0.38	$0.44	$0.43	$0.66	$0.42	$0.49	$0.52	$0.26	$0.27	$0.23	$0.18	$0.17	$0.22	$0.16	$0.07	$0.09	$0.12
Black Start	$0.00	$0.00	$0.00	$0.00	$0.01	$0.01	$0.02	$0.02	$0.02	$0.02	$0.02	$0.01	$0.01	$0.03	$0.10	$0.05	$0.05	$0.06	$0.06	$0.05
Synchronized Reserves	$0.00	$0.00	$0.00	$0.01	$0.13	$0.11	$0.09	$0.07	$0.05	$0.06	$0.04	$0.05	$0.07	$0.03	$0.03	$0.08	$0.08	$0.04	$0.04	$0.04
Non-Synchronized Reserves	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.01	$0.01	$0.01	$0.01	$0.01
Day Ahead Scheduling Reserve (DASR)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.01	$0.00	$0.01	$0.04	$0.03	$0.04	$0.03	$0.07	$0.05	$0.03	$0.03
Administration	$0.22	$0.24	$0.66	$0.77	$0.93	$0.85	$0.61	$0.60	$0.58	$0.31	$0.25	$0.29	$0.29	$0.33	$0.31	$0.32	$0.32	$0.31	$0.34	$0.32
PJM Administrative Fees	$0.22	$0.25	$0.65	$0.77	$0.92	$0.79	$0.60	$0.59	$0.56	$0.29	$0.23	$0.27	$0.26	$0.30	$0.29	$0.29	$0.29	$0.29	$0.32	$0.30
NERC/RFC	$0.00	($0.00)	$0.01	$0.01	$0.01	$0.01	$0.00	($0.00)	$0.01	$0.01	$0.01	$0.02	$0.01	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02
RTO Startup and Expansion	$0.00	$0.00	$0.00	$0.00	$0.00	$0.05	$0.00	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.00	$0.00	$0.00	$0.00
Energy Uplift (Operating Reserves)	$0.50	$0.87	$1.15	$0.65	$0.78	$0.81	$0.88	$0.38	$0.51	$0.48	$0.36	$0.59	$0.56	$0.52	$0.38	$0.77	$0.26	$0.12	$0.09	$0.15
Demand Response	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.02	$0.05	$0.03	$0.00	$0.02	$0.02	$0.02	$0.05	$0.05	$0.01	$0.01	$0.00	$0.00
Load Response	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.02	$0.05	$0.03	$0.00	$0.01	$0.01	$0.01	$0.01	$0.02	$0.01	$0.01	$0.00	$0.00
Emergency Load Response	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.01	$0.01	$0.01	$0.04	$0.04	$0.00	$0.00	$0.00	$0.00
Emergency Energy	$0.07	$0.02	$0.00	$0.00	$0.02	$0.00	$0.02	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total Price ($/MWh)	$37.75	$34.68	$39.44	$33.54	$42.04	$43.36	$57.63	$47.23	$55.51	$63.71	$41.97	$49.63	$45.48	$34.69	$37.41	$48.90	$38.81	$33.64	$35.09	$40.12
Total Load (GWh)	259,623	264,510	265,398	312,899	327,533	438,874	684,592	696,165	715,524	698,459	666,069	697,391	723,101	764,300	773,790	780,505	776,093	778,269	758,775	791,094
Total Billing ($ Billions)	$9.80	$9.17	$10.47	$10.50	$13.77	$19.03	$39.45	$32.88	$39.72	$44.50	$27.95	$34.61	$32.88	$26.52	$28.95	$38.17	$30.12	$26.18	$26.63	$31.74

62 US Consumer Price Index for all items, Urban Consumers (base period: January 1998), published by Bureau of Labor Statistics. <http://download.bls.gov/pub/time.series/cu/cu.data.1.AllItems> (October 10, 2019)

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

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

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

Category	Percent of Total Charges 1999	Percent of Total Charges 2000	Percent of Total Charges 2001	Percent of Total Charges 2002	Percent of Total Charges 2003	Percent of Total Charges 2004	Percent of Total Charges 2005	Percent of Total Charges 2006	Percent of Total Charges 2007	Percent of Total Charges 2008	Percent of Total Charges 2009	Percent of Total Charges 2010	Percent of Total Charges 2011	Percent of Total Charges 2012	Percent of Total Charges 2013	Percent of Total Charges 2014	Percent of Total Charges 2015	Percent of Total Charges 2016	Percent of Total Charges 2017	Percent of Total Charges 2018
Load Weighted Energy	87.5%	83.1%	84.8%	84.5%	86.2%	87.4%	90.9%	90.5%	86.5%	83.6%	70.1%	72.2%	72.6%	71.5%	71.7%	74.3%	63.6%	58.5%	58.2%	61.4%
Capacity	0.4%	0.7%	0.6%	0.3%	0.2%	0.2%	0.1%	0.2%	5.0%	9.2%	19.4%	18.2%	16.4%	13.5%	13.5%	12.9%	19.8%	21.9%	21.2%	20.9%
Capacity	0.4%	0.7%	0.6%	0.3%	0.2%	0.2%	0.0%	0.0%	4.9%	9.2%	19.4%	18.1%	15.4%	12.3%	13.2%	12.6%	19.6%	21.9%	21.1%	20.8%
Capacity (FRR)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Capacity (RMR)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.0%	0.0%	0.0%	0.2%	0.2%	0.1%	0.1%	-0.0%	-0.0%	0.1%	0.1%
Transmission	9.0%	11.2%	8.2%	9.3%	7.6%	6.8%	4.7%	5.7%	5.0%	4.5%	7.6%	6.5%	7.7%	10.8%	10.5%	9.0%	13.5%	16.9%	17.9%	15.2%
Transmission Service Charges	8.8%	10.9%	8.0%	9.1%	7.5%	6.5%	3.9%	5.4%	4.8%	4.3%	7.2%	6.0%	7.1%	9.9%	9.7%	8.3%	12.5%	15.6%	16.6%	14.1%
Transmission Enhancement Cost Recovery	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.2%	0.3%	0.4%	0.7%	0.7%	0.6%	0.9%	1.0%	1.2%	0.9%
Transmission Owner (Schedule 1A)	0.2%	0.2%	0.2%	0.2%	0.1%	0.2%	0.1%	0.1%	0.1%	0.1%	0.2%	0.1%	0.1%	0.2%	0.2%	0.1%	0.2%	0.2%	0.2%	0.2%
Transmission Seams Elimination Cost Assignment (SECA)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	-0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	-0.0%	0.0%
Transmission Facility Charges	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Ancillary	1.1%	1.8%	1.7%	1.7%	1.9%	1.8%	1.7%	1.6%	1.4%	1.4%	1.4%	1.3%	1.4%	1.7%	2.3%	1.4%	1.6%	1.4%	1.4%	1.3%
Reactive	0.7%	0.8%	0.5%	0.5%	0.5%	0.5%	0.4%	0.5%	0.4%	0.4%	0.7%	0.7%	0.6%	0.9%	1.4%	0.6%	0.7%	0.8%	0.8%	0.7%
Regulation	0.4%	1.1%	1.2%	1.1%	1.1%	1.0%	1.1%	0.9%	0.9%	0.8%	0.6%	0.5%	0.5%	0.5%	0.5%	0.5%	0.4%	0.2%	0.3%	0.3%
Black Start	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.3%	0.1%	0.1%	0.2%	0.2%	0.1%
Synchronized Reserves	0.0%	0.0%	0.0%	0.0%	0.3%	0.3%	0.2%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.2%	0.2%	0.1%	0.1%	0.1%
Non-Synchronized Reserves	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Day Ahead Scheduling Reserve (DASR)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.1%	0.1%	0.2%	0.1%	0.1%	0.1%
Administration	0.6%	0.7%	1.7%	2.3%	2.2%	2.0%	1.1%	1.3%	1.0%	0.5%	0.6%	0.6%	0.6%	0.9%	0.8%	0.6%	0.8%	0.9%	1.0%	0.8%
PJM Administrative Fees	0.6%	0.7%	1.7%	2.3%	2.2%	1.8%	1.0%	1.3%	1.0%	0.5%	0.6%	0.5%	0.6%	0.9%	0.8%	0.6%	0.8%	0.9%	0.9%	0.8%
NERC/RFC	0.0%	-0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	-0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.1%	0.1%
RTO Startup and Expansion	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Energy Uplift (Operating Reserves)	1.3%	2.5%	2.9%	1.9%	1.9%	1.9%	1.5%	0.8%	0.9%	0.8%	0.9%	1.2%	1.2%	1.5%	1.0%	1.6%	0.7%	0.3%	0.3%	0.4%
Demand Response	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.0%	0.0%	0.0%	0.1%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%
Load Response	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Emergency Load Response	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%
Emergency Energy	0.2%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Total Price	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

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

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

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

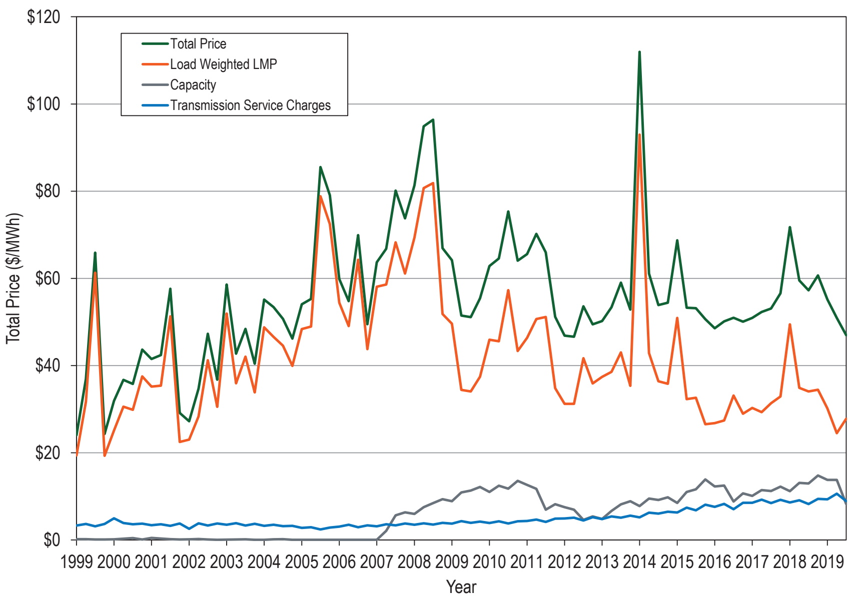
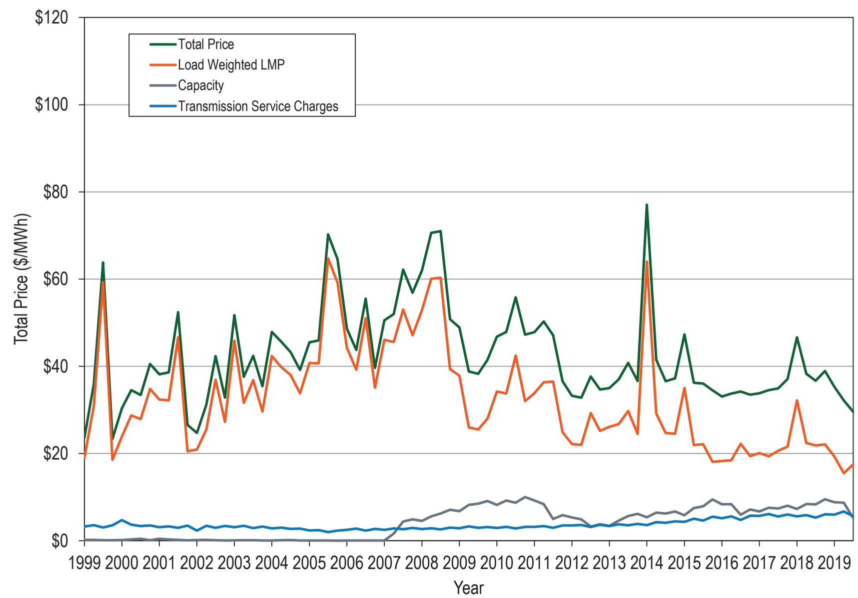


Figure 1-4 shows the inflation adjusted contributions of load-weighted energy, capacity and transmission service charges to the total price of wholesale power for each quarter since 1999.[66]

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



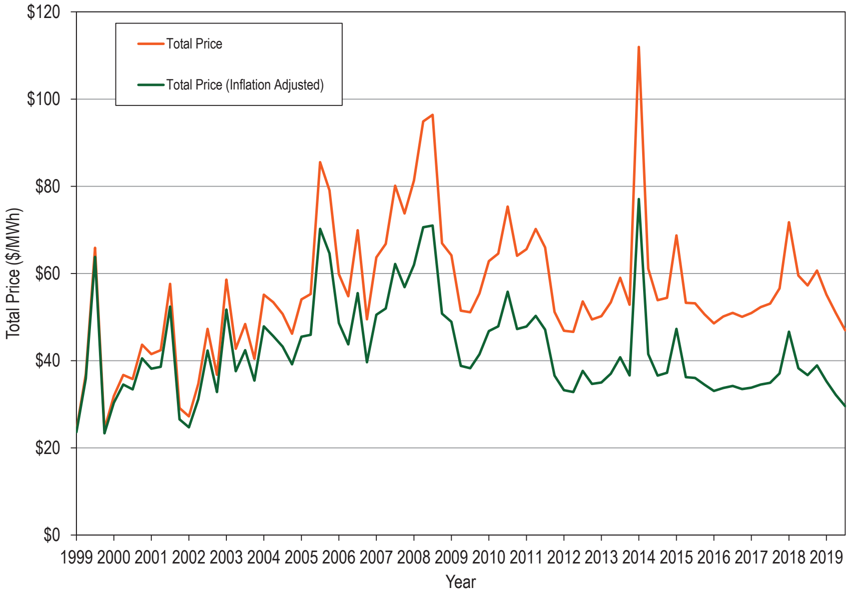
65 Note: The totals presented in this figure include after the fact billing adjustments and may not match totals presented in past reports.

66 US Consumer Price Index for all items, Urban Consumers (base period: January 1998), published by Bureau of Labor Statistics. <http://download.bls.gov/pub/time.series/cu/cu.data.1.AllItems> (October 10, 2019)

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

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

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



68 US Consumer Price Index for all items, Urban Consumers (base period: January 1998), published by Bureau of Labor Statistics. <http://download.bls.gov/pub/time.series/cu/cu.data.1.AllItems> (October 10, 2019)
69 Note: The totals presented in this figure include after the fact billing adjustments and may not match totals presented in past reports.
70 US Consumer Price Index for all items, Urban Consumers (base period: January 1998), published by Bureau of Labor Statistics. <http://download.bls.gov/pub/time.series/cu/cu.data.1.AllItems> (October 10, 2019)

Section Overviews

Overview: Section 3, Energy Market

Supply and Demand

Market Structure

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

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

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

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

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

Market Behavior

- **Generator Offers.** Generator offers are categorized as dispatchable and self scheduled. Units which are available for economic dispatch are dispatchable. Units which are self scheduled to generate fixed output are categorized as self scheduled. Units which are self scheduled at their economic minimum and are available for economic dispatch up to their economic maximum are categorized as self scheduled and dispatchable. Of all generator offers by MW in the first nine months of 2019, 26.3 percent were offered as available for economic dispatch, 30.4 percent were offered at their economic minimum, 4.2 percent were offered as emergency dispatch, 14.9 percent were offered as self scheduled, and 24.2 percent were offered as self scheduled and dispatchable.

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

Market Performance

- **Generation Fuel Mix.** In the first nine months of 2019, coal units provided 24.5 percent, nuclear units 33.2 percent and natural gas units 36.0 percent of total generation. Compared to the first nine months of 2018, generation from coal units decreased 16.4 percent, generation from natural gas units increased 17.2 percent and generation from nuclear units decreased 1.9 percent.

- **Fuel Diversity.** In the first nine months of 2019, the fuel diversity of energy generation, measured by the fuel diversity index for energy (FDI_e), decreased 0.9 percent over the FDI_e for the first nine months of 2018.

- **Marginal Resources.** In the PJM Real-Time Energy Market, in the first nine months of 2019, coal units were 27.2 percent and natural gas units were 69.7 percent of marginal resources. In the first nine months of 2018, coal units were 29.7 percent and natural gas units were 62.1 percent of marginal resources.

  In the PJM Day-Ahead Energy Market, in the first nine months of 2019, up to congestion transactions were 57.7 percent, INCs were 12.9 percent, DECs were 18.4 percent, and generation resources were 10.9 percent of marginal resources. In the first nine months of 2018, up to congestion transactions were 63.9 percent, INCs were 9.2 percent, DECs were 16.1 percent, and generation resources were 10.7 percent of marginal resources.

- **Prices.** PJM LMPs are a direct measure of market performance. Price level is a good, general indicator of market performance, although the number of factors influencing the overall level of prices means it must be analyzed carefully. Among other things, overall average prices reflect changes in supply and demand, generation fuel mix, the cost of fuel, emissions related expenses, markup and local price differences caused by congestion. PJM also may administratively set prices with the creation of closed loop interfaces related to demand side resources or reactive power, the application of transmission penalty factors, or the application of price setting logic.

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

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

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

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

- **Price Convergence.** Hourly and daily price differences between the Day-Ahead and Real-Time Energy Markets fluctuate continuously and substantially from positive to negative. The difference between the average day-ahead and real-time prices was $0.48 per MWh in the first nine months of 2018 and -$0.11 per MWh in the first nine months of 2019. The difference between average day-ahead and real-time prices, by itself, is not a measure of the competitiveness or effectiveness of the Day-Ahead Energy Market.

Scarcity

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

Competitive Assessment

Market Structure

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

Market Behavior

- **Offer Capping for Local Market Power.** PJM offer caps units when the local market structure is noncompetitive. Offer capping is an effective means of addressing local market power when the rules are designed and implemented properly. Offer capping levels have historically been low in PJM. In the Day-Ahead Energy Market, for units committed to provide energy for local constraint relief, offer-capped unit hours increased from 0.1 percent in the first nine months of 2018 to 1.1 percent in the first nine months of 2019. In the Real-Time Energy Market, for units committed to provide energy for local constraint relief, offer-capped unit hours increased from 1.0 percent in the first nine months of 2018 to 1.6 percent in the first nine months of 2019. While overall offer capping levels have been low, there are a significant number of units with persistent structural local market power that would have a significant impact on prices in the absence of local market power mitigation.

  In the first nine months of 2019, 11 control zones experienced congestion resulting from one or more constraints binding for 75 or more hours. The analysis of the application of the TPS test to local markets demonstrates that it is working to identify pivotal owners when the market structure is noncompetitive and to ensure that owners are not subject to offer capping when the market structure is competitive. There are, however, identified issues with the application of market power mitigation to resources whose owners fail the TPS test that can result in the exercise of local market power. These issues need to be addressed.
- **Offer Capping for Reliability.** PJM also offer caps units that are committed for reliability reasons, including for reactive support. In the Day-Ahead

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

- **Markup Index.** The markup index is a summary measure of participant offer behavior for individual marginal units. In the first nine months of 2019, in the PJM Real-Time Energy Market, 97.6 percent of marginal units had offer prices less than $50 per MWh. The average dollar markup of units with offer prices less than $25 was positive ($0.18 per MWh) when using unadjusted cost-based offers. The average dollar markup of units with offer prices between $25 and $50 was positive ($1.77 per MWh) when using unadjusted cost-based offers. Negative markup means the unit is offering to run at a price less than its cost-based offer, demonstrating a revealed short run marginal cost that is less than the allowable cost-based offer under the PJM market rules. Some marginal units did have substantial markups. Using the unadjusted cost-based offers, the highest markup for any marginal unit in the first nine months of 2019 was more than $400 per MWh while the highest markup in the first nine months of 2018 was more than $500 per MWh. During the period of cold weather and high demand in January 2018, several units in the PJM market were offered with high markups.

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

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

  The markup behavior shown in the markup frequency distributions also shows that a substantial number of units were offered with high markups, consistent with the exercise of market power. Markup for gas fired units decreased in the first nine months of 2019.

- **Frequently Mitigated Units (FMU) and Associated Units (AU).** A new FMU rule became effective November 1, 2014, limiting the availability of FMU adders to units with net revenues less than unit going forward costs. The number of units that were eligible for an FMU or AU adder declined from an average of 70 units during the first 11 months of 2014, to zero units eligible for an FMU or AU adder for the period between December 2014 and August 2019. One unit qualified for an FMU adder for the month of September 2019.

Market Performance

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

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

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

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

Section 3 Recommendations

Market Power

- The MMU recommends that the market rules explicitly require that offers in the energy market be competitive, where competitive is defined to be the short run marginal cost of the units. The short run marginal cost should reflect opportunity cost when and where appropriate. The MMU recommends that the level of incremental costs includable in cost-based offers not exceed the short run marginal cost of the unit. (Priority: Medium. First reported 2009. Status: Not adopted.)
- The MMU recommends that PJM require that all fuel cost policies be algorithmic, verifiable, and systematic, and accurately reflect short run marginal costs. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that the tariff be changed to allow units to have Fuel Cost Policies that do not include fuel procurement practices, including fuel contracts. Fuel procurement practices, including fuel contracts, may be used as the basis for Fuel Cost Policies but should not be required. (Priority: Low. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM change the Fuel Cost Policy requirement to apply only to units that will be offered with non-zero cost-based offers. The PJM market rules should require that the cost-based offers of units without an approved Fuel Cost Policy be set to zero. (Priority: Low. First reported 2018. Status: Not adopted.)
- The MMU recommends that Manual 15 (Cost Development Guidelines) be replaced with a straightforward description of the components of cost-based offers based on short run marginal costs and the correct calculation of cost-based offers. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends removal of all use of FERC System of Accounts in the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends the removal of all use of cyclic starting and peaking factors from the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends the removal of all labor costs from the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends changing the definition of the start heat input for combined cycles to include only the amount of fuel used from firing each combustion turbine in the combined cycle to the breaker close of each combustion turbine. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends the removal of nuclear fuel and nonfuel operations and maintenance costs that are not short run marginal costs from the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends revising the pumped hydro fuel cost calculation to include day-ahead and real-time power purchases. (Priority: Low. First reported 2016. Status: Not adopted.)
- The MMU recommends revisions to the calculation of energy market opportunity costs to incorporate all time based offer parameters and all limitations that impact the opportunity cost of generating unit output. (Priority: Medium. First reported 2016. Status: Adopted, 2018.)

- The MMU recommends removing the catastrophic designation for force majeure fuel supply limitations in Schedule 2. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that the rules governing the application of the TPS test be clarified and documented. The TPS test application in the Day-Ahead Energy Market is not documented. (Priority: High. First reported 2015. Status: Partially adopted.)
- The MMU recommends that PJM require every market participant to make available at least one cost schedule based on the same hourly fuel type(s) and parameters at least as flexible as their offered price schedule. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends, in order to ensure effective market power mitigation when the TPS test is failed, that markup be constant across the full MWh range of price and cost-based offers. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that in order to ensure effective market power mitigation when the TPS test is failed, the operating parameters in the cost-based offer and the price-based parameter limited schedule (PLS) offer be at least as flexible as the operating parameters in the available price-based non-PLS offer, and that the price-MW pairs in the price-based PLS offer be exactly equal to the price-based non-PLS offer. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that in order to ensure effective market power mitigation, PJM always enforce parameter limited values by committing units only on parameter limited schedules, when the TPS test is failed or during high load conditions such as cold and hot weather alerts or more severe emergencies. (Priority: High. New recommendation. Status: Not adopted.)
- The MMU recommends that PJM retain the $1,000 per MWh offer cap in the PJM energy market except when cost-based offers exceed $1,000 per MWh, and retain other existing rules that limit incentives to exercise market power. (Priority: High. First reported 1999. Status: Partially adopted, 1999, 2017.)
- The MMU recommends the elimination of FMU and AU adders. FMU and AU adders no longer serve the purpose for which they were created and interfere with the efficient operation of PJM markets. (Priority: Medium. First reported 2012. Status: Partially adopted, 2014.)
- The MMU recommends that market sellers not be allowed to designate any portion of an available Capacity Resource's ICAP equivalent of cleared UCAP capacity commitment as a Maximum Emergency offer at any time during the delivery year.[71] (Priority: Medium. First reported 2012. Status: Not adopted.)

Capacity Performance Resources

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

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

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

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

Accurate System Modeling

- The MMU recommends that PJM explicitly state its policy on the use of transmission penalty factors including: the level of the penalty factors; the triggers for the use of the penalty factors; the appropriate line ratings to trigger the use of penalty factors; the allowed duration of the violation; the use of constraint relaxation logic; and when the transmission penalty factors will be used to set the shadow price. (Priority: Medium. First reported 2015. Status: Partially adopted.)
- The MMU recommends that PJM routinely review all transmission facility ratings and any changes to those ratings to ensure that the normal, emergency and load dump ratings used in modeling the transmission system are accurate and reflect standard ratings practice. (Priority: Low. First reported 2013. Status: Partially adopted.)
- The MMU recommends that PJM update the outage impact studies, the reliability analyses used in RPM for capacity deliverability, and the reliability analyses used in RTEP for transmission upgrades to be consistent with the more conservative emergency operations (post contingency load dump limit exceedance analysis) in the energy market that were implemented in June 2013. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM include in the tariff or appropriate manual an explanation of the initial creation of hubs, the process for modifying hub definitions and a description of how hub definitions have changed.[72] [73] (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that all buses with a net withdrawal be treated as load for purposes of calculating load and load-weighted LMP, even if the MW are settled to the generator. The MMU recommends that during hours when a load bus shows a net injection, the energy injection be treated as generation, not negative load, for purposes of calculating generation and load-weighted LMP, even if the injection MW are settled to the load serving entity. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM identify and collect data on available behind the meter generation resources, including nodal location information and relevant operating parameters. (Priority: Low. First reported 2013. Status: Partially adopted.)
- The MMU recommends that PJM document how LMPs are calculated when demand response is marginal. (Priority: Low. First reported 2014. Status: Not Adopted.)
- The MMU recommends that PJM not allow nuclear generators which do not respond to prices or which only respond to manual instructions from the operator to set the LMPs in the real-time market. (Priority: Low. First reported 2016. Status: Not adopted.)
- The MMU recommends that PJM increase the interaction of outage and operational restrictions data submitted by market participants via eDART/eGADs and offer data submitted via Markets Gateway. (Priority: Low. First reported 2017. Status: Not adopted.)

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

73 There is currently no PJM documentation in the tariff or manuals explaining how hubs are created and how their definitions are changed. The general definition of a hub can be found in the PJM.com Glossary <http://www.pjm.com/Glossary.aspx>.

- The MMU recommends that PJM model generators' operating transitions and peak operating modes. (Priority: Medium. New recommendation. Status: Not adopted.)

Transparency

- The MMU recommends that PJM market rules require the fuel type be identified for every price and cost schedule on an hourly basis and PJM market rules remove nonspecific fuel types such as other or co-fire other from the list of fuel types available for market participants to identify the fuel type associated with their price and cost schedules. (Priority: Medium. First reported 2015. Status: Partially adopted.)
- The MMU recommends that PJM continue to enhance its posting of market data to promote market efficiency. (Priority: Medium. First reported 2005. Status: Partially adopted.)
- The MMU recommends that PJM clearly define the criteria for operator approval of RT SCED cases used to send dispatch signals to resources and for pricing, to minimize operator discretion and implement a rule based approach. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM approve one RT SCED case for each five minute interval to send dispatch signals, and that PJM calculate prices for that five minute interval using the same approved SCED case. (Priority: High. New recommendation. Status: Not adopted.)

Section 3 Conclusion

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

PJM average real-time cleared generation decreased by 29 MWh, and peak load increased by 1,185 MWh, 0.8 percent, in the first nine months of 2019 compared to the first nine months of 2018. The relationship between supply and demand, regardless of the specific market, balanced by market concentration and the extent of pivotal suppliers, is referred to as the supply-demand fundamentals or economic fundamentals. The market structure of the PJM aggregate energy market is partially competitive because aggregate market power does exist for a significant number of hours. The HHI is not a definitive measure of structural market power. The number of pivotal suppliers in the energy market is a more precise measure of structural market power than the HHI. It is possible to have pivotal suppliers in the aggregate market even when the HHI level is not in the highly concentrated range. The current market power mitigation rules for the PJM energy market rely on the assumption that the ownership structure of the aggregate market ensures competitive outcomes. This assumption requires that the total demand for energy can be met without the supply from any individual supplier or without the supply from a small group of suppliers. This assumption is not correct. There are pivotal suppliers in the aggregate energy market at times. High markups for some units demonstrate the potential to exercise market power both routinely and during high demand conditions. The existing market power mitigation measures do not address aggregate market power. The MMU is developing an aggregate market power test and will propose market power mitigation rules to address aggregate market power.

The three pivotal supplier test is applied by PJM on an ongoing basis for local energy markets in order to determine whether offer capping is required for transmission constraints.[74] However, there are some issues with the application of market power mitigation in the Day-Ahead Energy Market and the Real-Time Energy Market when market sellers fail the TPS test. These issues can be resolved by simple rule changes.

The enforcement of market power mitigation rules is undermined if the definition of a competitive offer is not correct. A competitive offer is equal to short run marginal costs. The significance of competition metrics like markup is also undermined if the definition of a competitive offer is not correct. The definition of a competitive offer, under the PJM Market Rules, is not currently correct. The definition, that energy costs must be related to electric production,

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

is not clear or correct. All costs and investments for power generation are related to electric production. Under this definition, some unit owners include costs that are not short run marginal costs in offers, especially maintenance costs. This issue can be resolved by simple rule changes to incorporate a clear and accurate definition of short run marginal costs.

Prices are a key outcome of markets. Prices vary across hours, days and years for multiple reasons. Price is an indicator of the level of competition in a market although individual prices are not always easy to interpret. In a competitive market, prices are directly related to the marginal cost to serve load in each market interval. The pattern of prices within days and across months and years illustrates how prices are directly related to supply and demand conditions and thus also illustrates the potential significance of the impact of the price elasticity of demand on prices. Energy market results in the first nine months of 2019 generally reflected supply-demand fundamentals, although the behavior of some participants both routinely and during high demand periods represents economic withholding. Economic withholding is the ability to increase markups substantially in tight market conditions. There are additional issues in the energy market including the uncertainties about the pricing and availability of natural gas, the way that generation owners incorporate natural gas costs in offers, and the lack of adequate incentives for unit owners to take all necessary actions to acquire fuel and operate rather than economically withhold or physically withhold.

Prices in PJM are not too low. Prices in PJM are the result of input prices, consistent with a competitive market. Low natural gas prices have been a primary cause of low PJM energy market prices. There is no evidence to support the need for a significant change to the calculation of LMP. The underlying problem that fast start pricing and PJM's reserve pricing approach are attempting to address is actually scarcity pricing, including the impact of operator actions on the definition of scarcity. Prices do not reflect market conditions when the market is tight, because PJM is not implementing scarcity pricing when there is scarcity. Rather than undercutting the basic LMP logic that is core to market efficiency, it would make more sense to directly address scarcity pricing, operator actions and the design of reserve markets. Implementing scarcity pricing when there is scarcity is a basic first step. Targeted increases to the demand for reserves when the market is tight would address price formation in the energy market.

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

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

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

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

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

With or without a capacity market, energy market design must permit scarcity pricing when such pricing is consistent with market conditions and constrained by reasonable rules to ensure that market power is not exercised. Scarcity pricing can serve two functions in wholesale power markets: revenue adequacy and price signals. Scarcity pricing for revenue adequacy, as in PJM's ORDC proposal, is not required in PJM. Scarcity pricing for price signals that reflect market conditions during periods of scarcity is required in PJM. Scarcity pricing is also part of an appropriate incentive structure facing both load and generation owners in a working wholesale electric power market design. Scarcity pricing must be designed to ensure that market prices reflect actual market conditions, that scarcity pricing occurs with transparent triggers based on measured reserve levels and transparent prices, that scarcity pricing only occurs when scarcity exists, and that there are strong incentives for competitive behavior and strong disincentives to exercise market power. Such administrative scarcity pricing is a key link between energy and capacity markets. Administrative scarcity pricing that establishes scarcity pricing in about 85 percent of hours, as PJM's ORDC proposal would, is not scarcity pricing but simply a revenue enhancement mechanism. When combined with PJM's failure to address the energy and ancillary services offset in the capacity market, PJM's ORDC filing is not consistent with efficient market design and is even more clearly just a revenue enhancement mechanism.

The PJM Capacity Market is explicitly designed to provide revenue adequacy and the resultant reliability. However, the explicit balancing mechanism that included net revenues directly in unit offers in the prior capacity market design is not present in the Capacity Performance design. The nature of a direct and explicit energy pricing net revenue true up mechanism in the capacity market should be addressed if energy revenues are expected to increase as a result of scarcity events, as a result of increased demand for reserves, or as a result of PJM's inappropriate proposals related to fast start pricing and the inclusion of maintenance expenses as short run marginal costs. The true up mechanism must address both cleared auctions and subsequent auctions. There are also significant issues with PJM's scarcity pricing rules, including the absence of a clear trigger based on measured reserve levels (the current triggers are based on estimated reserves) and the lack of adequate locational scarcity pricing options.

The overall energy market results support the conclusion that energy prices in PJM are set, generally, by marginal units operating at, or close to, their marginal costs, although this was not always the case in the first nine months of 2019 or prior years. In the first nine months of 2019, marginal units were predominantly combined cycle gas generators with low fuel costs. The frequency of combined cycle gas as the marginal unit type has risen rapidly in the last three years, from 29.3 percent in the first nine months of 2016 to 62.2 percent in the first nine months of 2019. Overdue improvements in generator modeling in the energy market would allow PJM to more efficiently commit and dispatch combined cycle plants and to fully reflect the flexibility of these units. New combined cycle units placed competitive pressure on less efficient generators, and the market reliably served load with less congestion, less uplift, and less markup in marginal offers than in the first nine months of 2018. This is evidence of generally competitive behavior and competitive market outcomes, although the behavior of some participants represents economic withholding. Given the structure of the energy market which can permit the exercise of aggregate market power, the change in some participants' behavior is a source of concern in the energy market and provides a reason to use correctly defined short run marginal cost as the sole basis for cost-based offers and a reason for implementing an aggregate market power test. The MMU concludes that the PJM energy market results were competitive in the first nine months of 2019.

Overview: Section 4, Energy Uplift

Energy Uplift Credits

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

Energy Uplift Charges

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

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

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

Geography of Charges and Credits

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

Section 4 Recommendations

- The MMU recommends that uplift be paid only based on operating parameters that reflect the flexibility of the benchmark new entrant unit (CONE unit) in the PJM Capacity Market. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM not use closed loop interface constraints to artificially override nodal prices based on fundamental LMP logic in order to: accommodate rather than resolve the inadequacies of the demand side resource capacity product; address the inability of the power flow model to incorporate the need for reactive power; accommodate rather than resolve the flaws in PJM's approach to scarcity pricing; or for any other reason. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM not use CT price setting logic to modify transmission line limits to artificially override the nodal prices that are based on fundamental LMP logic in order to reduce uplift. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that if PJM believes it appropriate to implement CT price setting logic, PJM first initiate a stakeholder process to determine whether such modification is appropriate. PJM should file any proposed changes with FERC to ensure review. Any such changes should be incorporated in the PJM tariff. (Priority: Medium. First Reported 2016. Status: Not adopted.)
- The MMU recommends that PJM initiate an analysis of the reasons why a significant number of combustion turbines and diesels scheduled in the Day-Ahead Energy Market are not called in real time when they are economic. (Priority: Medium. First Reported 2012. Status: Not adopted.)
- The MMU recommends eliminating intraday segments from the calculation of uplift payments and returning to calculating the need for uplift based on the entire 24 hour operating day. (Priority: High. First reported 2018. Status: Not adopted.)

- The MMU recommends the elimination of day-ahead operating reserves to ensure that units receive an energy uplift payment based on their real-time output and not their day-ahead scheduled output. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends enhancing the current energy uplift allocation rules to reflect the recommended elimination of day-ahead operating reserves, the timing of commitment decisions and the commitment reasons. (Priority: High. First reported 2012. Status: Not adopted.)
- The MMU recommends reincorporating the use of net regulation revenues as an offset in the calculation of balancing operating reserve credits. (Priority: Medium. First reported 2009. Status: Not adopted. Stakeholder process.)
- The MMU recommends that self scheduled units not be paid energy uplift for their startup cost when the units are scheduled by PJM to start before the self scheduled hours. (Priority: Low. First reported 2013. Status: Not adopted. Stakeholder process.)
- The MMU recommends three modifications to the energy lost opportunity cost calculations:
  - The MMU recommends calculating LOC based on 24 hour daily periods for combustion turbines and diesels scheduled in the Day-Ahead Energy Market, but not committed in real time. (Priority: Medium. First reported 2014. Status: Not adopted.)
  - The MMU recommends that units scheduled in the Day-Ahead Energy Market and not committed in real time should be compensated for LOC based on their real-time desired and achievable output, not their scheduled day-ahead output. (Priority: Medium. First reported 2015. Status: Not adopted.)
  - The MMU recommends that only flexible fast start units (startup plus notification times of 10 minutes or less) and short minimum run times (one hour or less) be eligible by default for the LOC compensation to units scheduled in the Day-Ahead Energy Market and not committed in real time. Other units should be eligible for LOC compensation only if PJM explicitly cancels their day-ahead commitment. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that up to congestion transactions be required to pay energy uplift charges for both the injection and the withdrawal sides of the UTC. (Priority: High. First reported 2011. Status: Not adopted.)
- The MMU recommends eliminating the use of internal bilateral transactions (IBTs) in the calculation of deviations used to allocate balancing operating reserve charges. (Priority: High. First reported 2013. Status: Adopted 2018.[75])
- The MMU recommends allocating the energy uplift payments to units scheduled as must run in the Day-Ahead Energy Market for reasons other than voltage/reactive or black start services as a reliability charge to real-time load, real-time exports and real-time wheels. (Priority: Medium. First reported 2014. Status: Not adopted. Stakeholder process.)
- The MMU recommends that the total cost of providing reactive support be categorized and allocated as reactive services. Reactive services credits should be calculated consistent with the balancing operating reserve credit calculation. (Priority: Medium. First reported 2012. Status: Not adopted. Stakeholder process.)
- The MMU recommends including real-time exports and real-time wheels in the allocation of the cost of providing reactive support to the 500 kV system or above, in addition to real-time load. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends modifications to the calculation of lost opportunity costs credits paid to wind units. The lost opportunity costs credits paid to wind units should be based on the lesser of the desired output, the estimated output based on actual wind conditions and the capacity interconnection rights (CIRs). The MMU recommends that PJM allow wind units to request CIRs that reflect the maximum output wind units want to inject into the transmission system at any time. (Priority: Low. First reported 2012. Status: Not adopted.)

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

- The MMU recommends that PJM clearly identify and classify all reasons for incurring operating reserves in the Day-Ahead and the Real-Time Energy Markets and the associated operating reserve charges in order to make all market participants aware of the reasons for these costs and to help ensure a long term solution to the issue of how to allocate the costs of operating reserves. (Priority: Medium. First reported 2011. Status: Partially adopted.)
- The MMU recommends that PJM revise the current operating reserve confidentiality rules in order to allow the disclosure of complete information about the level of operating reserve charges by unit and the detailed reasons for the level of operating reserve credits by unit in the PJM region. (Priority: High. First reported 2013. Status: Partially adopted.[76])
- The MMU recommends that PJM pay uplift based on the offer at the lower of the actual unit output or the dispatch signal MW. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM develop and implement an accurate metric to define when a unit is following dispatch to determine eligibility to receive balancing operating reserve credits and for assessing generator deviations. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM eliminate the exemption for fast start resources (CTs and diesels) from the requirement to follow dispatch. The performance of these resources should be evaluated in a manner consistent with all other resources (Priority: Medium. First reported 2018. Status: Not adopted.)

Conclusion

Competitive market outcomes result from energy offers equal to short run marginal costs that incorporate flexible operating parameters. When PJM permits a unit to include inflexible operating parameters in its offer and pays uplift based on those inflexible parameters, there is an incentive for the unit to remain inflexible. The rules regarding operating parameters should be implemented in a way that creates incentives for flexible operations rather than inflexible operations. The standard for paying uplift should be the maximum achievable flexibility, based on OEM standards for the benchmark new entrant unit (CONE unit) in the PJM Capacity Market. Applying a weaker standard effectively subsidizes inflexible units by paying them based on inflexible parameters that result from lack of investment and that could be made more flexible. The result both inflates uplift costs and suppresses energy prices.

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

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

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

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

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

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

When units receive substantial revenues through energy uplift payments, these payments are not transparent to the market because of the current confidentiality rules. As a result, other market participants, including generation and transmission developers, do not have the opportunity to compete to displace them. As a result, substantial energy uplift payments to a concentrated group of units and organizations have persisted for more than 10 years. FERC Order No. 844 authorized the publication of unit specific uplift payments for credits incurred after July 1, 2019.[77]

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

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

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

While energy uplift charges are an appropriate part of the cost of energy, market efficiency would be improved by ensuring that the level and variability of these charges are as low as possible consistent with the reliable operation of the system and consistent with pricing at short run marginal cost. The goal should be to minimize the total incurred energy uplift charges and to increase the transactions over which those charges are spread in order to reduce the impact of energy uplift charges on markets. The result would be to reduce the level of per MWh charges, to reduce the uncertainty associated with uplift charges and to reduce the impact of energy uplift charges on decisions about how and when to participate in PJM markets.

Overview: Section 5, Capacity Market

RPM Capacity Market

Market Design

The Reliability Pricing Model (RPM) Capacity Market is a forward-looking, annual, locational market, with a must offer requirement for Existing Generation Capacity Resources and mandatory participation by load, with performance incentives, that includes clear market power mitigation rules and that permits the direct participation of demand-side resources.[79]

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

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

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

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

the 2012/2013 Delivery Year, First, Second and Third Incremental Auctions (IA) are held for each delivery year.[80] Prior to the 2012/2013 Delivery Year, the Second Incremental Auction was conducted if PJM determined that an unforced capacity resource shortage exceeded 100 MW of unforced capacity due to a load forecast increase. Effective January 31, 2010, First, Second, and Third Incremental Auctions are conducted 20, 10, and three months prior to the delivery year.[81] Also effective for the 2012/2013 Delivery Year, a Conditional Incremental Auction may be held if there is a need to procure additional capacity resulting from a delay in a planned large transmission upgrade that was modeled in the BRA for the relevant delivery year.[82]

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

On June 9, 2015, FERC accepted changes to the PJM capacity market rules proposed in PJM's Capacity Performance (CP) filing.[85] For a transition period during the 2018/2019 and 2019/2020 delivery years, PJM will procure two product types, Capacity Performance and Base Capacity. PJM also procured Capacity Performance resources in two transition auctions for the 2016/2017 and 2017/2018 delivery years. Effective with the 2020/2021 Delivery Year, PJM will procure a single capacity product, Capacity Performance. CP Resources are expected to be available and capable of providing energy and reserves when needed at any time during the delivery year.[86] Effective for the 2018/2019 through the 2019/2020 delivery years, a Base Capacity Demand Resource Constraint and a Base Capacity Resource Constraint are established for each modeled LDA. These maximum quantities are set for reliability purpose to limit the quantity procured of the less available products, including Base Capacity Generation Resources, Base Capacity Demand Resources, and Base Capacity Energy Efficiency Resources. The Capacity Performance (CP) Transition Incremental Auctions (IAs) were held as part of a five year transition to a single capacity product type in the 2020/2021 Delivery Year. Participation in the CP Transition IAs was voluntary. If a resource cleared a CP Transition IA and had a prior commitment for the relevant delivery year, the existing commitment was converted to a CP commitment, which is subject to the CP performance requirements and nonperformance charges. The Transition IAs were not designed to minimize the cost of purchasing Capacity Performance resources for the two delivery years and were not designed to maximize economic welfare for the two delivery years.

RPM prices are locational and may vary depending on transmission constraints.[87] Existing generation capable of qualifying as a capacity resource must be offered into RPM auctions, except for resources owned by entities that elect the fixed resource requirement (FRR) option. Participation by LSEs is mandatory, except for those entities that elect the FRR option. There is an administratively determined demand curve that defines scarcity pricing levels and that, with the supply curve derived from capacity offers, determines market prices in each BRA. RPM rules provide performance incentives for generation, including the requirement to submit generator outage data and the linking of capacity payments to the level of unforced capacity, and the performance incentives have been strengthened significantly under the Capacity Performance modifications to RPM. Under RPM there are explicit market power mitigation rules that define the must offer requirement, that define structural market power based on the marginal cost of capacity, that define offer caps, that define the minimum offer price, and that have flexible criteria for competitive offers by new entrants. Market power mitigation is effective only when these definitions are up to date and accurate. Demand resources and energy efficiency resources may be offered directly into RPM auctions and receive the clearing price without mitigation.

80 See 126 FERC ¶ 61,275 at P 86 (2009).
81 See Letter Order, FERC Docket No. ER10-366-000 (January 22, 2010).
82 See 126 FERC ¶ 61,275 at P 88 (2009).
83 See 164 FERC ¶ 61,153 (2018).
84 See 168 FERC ¶ 61,051 (2019).
85 See 151 FERC ¶ 61,208 (2015).
86 See "PJM Manual 18: PJM Capacity Market," § 1.5 Transition to Capacity Performance, Rev. 42 (July 25, 2019).
87 Transmission constraints are local capacity import capability limitations (low capacity emergency transfer limit (CETL) margin over capacity emergency transfer objective (CETO)) caused by transmission facility limitations, voltage limitations or stability limitations.

Market Structure

- **RPM Installed Capacity.** During the first nine months of 2019, RPM installed capacity increased 6.8 MW or 0.0 percent, from 186,496.1 MW on January 1 to 186,502.9 MW on September 30. Installed capacity includes net capacity imports and exports and can vary on a daily basis.
- **RPM Installed Capacity by Fuel Type.** Of the total installed capacity on September 30, 2019, 42.1 percent was gas; 31.0 percent was coal; 17.3 percent was nuclear; 4.8 percent was hydroelectric; 3.4 percent was oil; 0.6 percent was wind; 0.4 percent was solid waste; and 0.4 percent was solar.
- **Market Concentration.** In the 2020/2021 RPM Second Incremental Auction all participants in the total PJM market as well as the LDA RPM markets failed the three pivotal supplier (TPS) test.[88] In the 2021/2022 RPM First Incremental Auction, two participants in the EMAAC LDA market passed the TPS test. Offer caps were applied to all sell offers for resources which were subject to mitigation when the capacity market seller did not pass the test, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, increased the market clearing price.[89] [90] [91]
- **Imports and Exports.** Of the 4,470.4 MW of imports in the 2021/2022 RPM Base Residual Auction, 4,051.8 MW cleared. Of the cleared imports, 1,909.9 MW (47.1 percent) were from MISO.
- **Demand-Side and Energy Efficiency Resources.** Capacity in the RPM load management programs was 11,042.8 MW for June 1, 2019, as a result of cleared capacity for demand resources and energy efficiency resources in RPM auctions for the 2019/2020 Delivery Year (13,231.6 MW) less replacement capacity (2,188.8 MW).

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

89 See OATT Attachment DD § 6.5.

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

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

Market Conduct

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

Market Performance

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

Reliability Must Run Service

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

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

Generator Performance

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

Section 5 Recommendations[94]

The MMU recognizes that PJM has implemented the Capacity Performance Construct to replace some of the existing core market rules and to address fundamental performance incentive issues. The MMU recognizes that the Capacity Performance Construct addresses many of the MMU's recommendations. The MMU's recommendations are based on the existing capacity market rules. The status is reported as adopted if the recommendation was included in FERC's order approving PJM's Capacity Performance filing.[95]

Definition of Capacity

- The MMU recommends the enforcement of a consistent definition of capacity resource. The MMU recommends that the requirement to be a physical resource be enforced and enhanced. The requirement to be a physical resource should apply at the time of auctions and should also constitute a commitment to be physical in the relevant delivery year. The requirement to be a physical resource should be applied to all resource types, including planned generation, demand resources and imports.[96] [97] (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that DR providers be required to have a signed contract with specific customers for specific facilities for specific levels of DR at least six months prior to any capacity auction in which the DR is offered. (Priority: High. First reported 2016. Status: Not adopted.)

Market Design and Parameters

- The MMU recommends that the test for determining modeled Locational Deliverability Areas (LDAs) in RPM be redefined. A detailed reliability analysis of all at risk units should be included in the redefined model. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that the net revenue calculation used by PJM to calculate the net Cost of New Entry (CONE) VRR parameter reflect the actual flexibility of units in responding to price signals rather than using assumed fixed operating blocks that are not a result of actual unit limitations.[98] [99] The result of reflecting the actual flexibility is higher net revenues, which affect the parameters of the RPM demand curve and market outcomes. (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that energy efficiency resources (EE) not be included on the supply side of the capacity market, because PJM's load forecasts now account for future EE, unlike the situation when EE was first added to the capacity market. However, the MMU recommends that the PJM load forecast method should be modified so that EE impacts immediately affect the forecast without the long lag times incorporated in the current forecast method. If EE is not included on the supply side, there is no reason to have an add back mechanism. If EE remains on the supply side, the implementation of the EE add back mechanism should be modified to ensure that market clearing prices are not affected. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that PJM reduce the number of incremental auctions to a single incremental auction held three months prior to the start of the delivery year and reevaluate the triggers for holding

93 The generator performance analysis includes all PJM capacity resources for which there are data in the PJM generator availability data systems (GADS) database. This set of capacity resources may include generators in addition to those in the set of generators committed as capacity resources in RPM. Data was downloaded from the PJM GADS database on November 1, 2019. EFORd data presented in state of the market reports may be revised based on data submitted after the publication of the reports as generation owners may submit corrections at any time with permission from PJM GADS administrators.

94 The MMU has identified serious market design issues with RPM and the MMU has made specific recommendations to address those issues. These recommendations have been made in public reports. See Table 52.

95 151 FERC ¶ 61,208 (2015).

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

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

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

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

conditional incremental auctions. (Priority: Medium. First reported 2013. Status: Not adopted.)

- The MMU recommends that PJM offer to sell back capacity in incremental auctions only at the BRA clearing price for the relevant delivery year. (Priority: Medium. First reported 2017. Status: Not adopted.)
- The MMU recommends changing the RPM solution method to explicitly incorporate the cost of make whole payments in the objective function. (Priority: Medium. First reported 2014. Status: Not adopted.)
- The MMU recommends that PJM clear the capacity market based on nodal capacity resource locations and the characteristics of the transmission system consistent with the actual electrical facts of the grid. The current nested LDA structure used in the capacity market does not adequately represent all the capacity transfers that are feasible among LDAs. Absent a fully nodal capacity market clearing process, the MMU recommends that PJM use a nonnested model for all LDAs and specify a VRR curve for each LDA separately. Each LDA requirement should be met with the capacity resources located within the LDA and exchanges from neighboring LDAs up to the transmission limit. LDAs should price separate if that is the result of the LDA supply curves and the transmission constraints. (Priority: Medium. First reported 2017. Status: Not adopted.)
- The MMU recommends that the maximum price on the VRR curve be defined as net CONE. (Priority: Medium. First reported Q1, 2019. Status: Not adopted.)

Offer Caps, Offer Floors, and Must Offer

- The MMU recommends use of the Sustainable Market Rule (SMR) in order to protect competition in the capacity market from nonmarket revenues.[100] (Priority: High. First reported 2016. Status: Not adopted.)
- The MMU recommends that, as part of the MOPR unit specific standard of review, all projects be required to use the same basic modeling assumptions. That is the only way to ensure that projects compete on the basis of actual costs rather than on the basis of modeling assumptions.[101] (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that modifications to existing resources not be treated as new resources for purposes of market power related offer caps or MOPR offer floors. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that the RPM market power mitigation rule be modified to apply offer caps in all cases when the three pivotal supplier test is failed and the sell offer is greater than the offer cap. This will ensure that market power does not result in an increase in make whole payments. (Priority: Medium. First reported 2017. Status: Not adopted.)
- The MMU recommends that the offer cap for capacity resources be defined as the net avoidable cost rate (ACR) of each unit so that the clearing prices are a result of such net ACR offers, consistent with the fundamental economic logic for a competitive offer of a CP resource. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends that PJM develop a process for calculating a forward looking estimate for the expected number of Performance Assessment Intervals (H) to use in calculating the Market Seller Offer Cap (MSOC). The MMU recommends that the Nonperformance Charge Rate be left at its current level. The MMU recommends that PJM develop a forward looking estimate for the Balancing Ratio (B) during Performance Assessment Intervals (PAIs) to use in calculating the MSOC. Both H and B parameters should be included in the annual review of planning parameters for the Base Residual Auction, and should incorporate the actual observed reserve margins, and other assumptions consistent with the annual IRM study. (Priority: High. First reported 2017. Status: Not adopted.)

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

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

- The MMU recommends that capacity market sellers be required to request the use of minimum MW quantities greater than 0 MW (inflexible sell offer segments) and that the requests should only be permitted for defined physical reasons. (Priority: Medium. First reported 2018. Status: Not adopted.)

Performance Incentive Requirements of RPM

- The MMU recommends that a unit which is not capable of supplying energy consistent with its day-ahead offer reflect an appropriate outage. (Priority: Medium. First reported 2009. Status: Not adopted.)
- The MMU recommends that retroactive replacement transactions associated with a failure to perform during a PAH not be allowed and that, more generally, retroactive replacement capacity transactions not be permitted. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that there be an explicit requirement that capacity resource offers in the Day-Ahead Energy Market be competitive, where competitive is defined to be the short run marginal cost of the units. (Priority: Low. First reported 2013. Status: Not adopted.)

Capacity Imports and Exports

- The MMU recommends that all capacity imports be required to be deliverable to PJM load prior to the relevant delivery year to ensure that they are full substitutes for internal, physical capacity resources. Pseudo ties alone are not adequate to ensure deliverability. (Priority: High. First reported 2016. Status: Not adopted.)
- The MMU recommends that all costs incurred as a result of a pseudo tied unit be borne by the unit itself and included as appropriate in unit offers in the capacity market. (Priority: High. First reported 2016. Status: Not adopted.)
- The MMU recommends clear, explicit and detailed rules that define the conditions under which PJM will and will not recall energy from PJM capacity resources and prohibit new energy exports from PJM capacity resources. The MMU recommends that those rules define the conditions under which PJM will purchase emergency energy while at the same time not recalling energy exports from PJM capacity resources. PJM has modified these rules, but the rules need additional clarification and operational details. (Priority: Low. First reported 2010. Status: Partially adopted.)

Deactivations/Retirements

- The MMU recommends that the notification requirement for deactivations be extended from 90 days prior to the date of deactivation to 12 months prior to the date of deactivation and that PJM and the MMU be provided 60 days rather than 30 days to complete their reliability and market power analyses. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that RMR units recover all and only the incremental costs, including incremental investment costs, required by the RMR service that the unit owner would not have incurred if the unit owner had deactivated its unit as it proposed. Customers should bear no responsibility for paying previously incurred costs, including a return on or of prior investments. (Priority: Low. First reported 2010. Status: Not adopted.)
- The MMU recommends elimination of the cost of service recovery rate in OATT Section 119, and that RMR service should be provided under the deactivation avoidable cost rate in Part V. The MMU also recommends specific improvements to the DACR provisions. (Priority: Medium. First reported 2017. Status: Not adopted.)

Section 5 Conclusion

The analysis of PJM Capacity Markets begins with market structure, which provides the framework for the actual behavior or conduct of market participants. The analysis examines participant behavior within that market structure. In a competitive market structure, market participants are constrained to behave competitively. The analysis examines market performance, measured by price and the relationship between price and marginal cost, that results from the interaction of market structure and participant behavior. Market power is and will remain endemic to the structure of the PJM Capacity Market. Nonetheless a competitive outcome can be assured by appropriate market power mitigation rules.

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

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

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

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

The MMU has identified serious market design issues with RPM and the MMU has made specific recommendations to address those issues.[102] [103] [104] [105] [106] [107] In 2018 and 2019, the MMU prepared a number of RPM related reports and testimony, shown in Table 5-2. The capacity performance modifications to the RPM construct have significantly improved the capacity market and addressed many of the issues identified by the MMU. The MMU will continue to publish more detailed reports on the CP auctions which include more specific issues and suggestions for improvements.

The PJM markets have worked to provide incentives to entry and to retaining capacity. PJM had excess reserves of more than 11,000 ICAP MW on June 1, 2019, and will have excess reserves of more than 17,000 ICAP MW on June 1, 2020, based on current positions.[108] A majority of capacity investments in PJM were financed by market sources.[109] Of the 36,859.2 MW of additional capacity that cleared in RPM auctions for the 2007/2008 through 2018/2019 delivery years, 27,306.6 MW (74.1 percent) were based on market funding. Of the 7,171.2 MW of additional capacity that cleared in RPM auctions for the 2019/2020 through 2021/2022 delivery years, 7,014.7 MW (97.8 percent) are based on market funding. Those investments were made based on the assumption that markets would be allowed to work and that inefficient units would exit.

The issue of external subsidies, particularly for economic nuclear power plants, continued to evolve. The subsidies are not part of the PJM market

102 See "Analysis of the 2018/2019 RPM Base Residual Auction Revised," <http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Analysis_of_the_20182019_RPM_Base_Residual_Auction_20160706.pdf> (July 6, 2016).
103 See "Analysis of the 2019/2020 RPM Base Residual Auction Revised," <http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Analysis_of_the_20192020_RPM_BRA_20160831-Revised.pdf> (August 31, 2016).
104 See "Analysis of the 2020/2021 RPM Base Residual Auction," <http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Analysis_of_the_20202021_RPM_BRA_20171117.pdf> (November 11, 2017).
105 See "Analysis of the 2021/2022 RPM Base Residual Auction - Revised," <http://www.monitoringanalytics.com/reports/Reports/2018/IMM_Analysis_of_the_20212022_RPM_BRA_Revised_20180824.pdf> (August 24, 2018).
106 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2017," <http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Report_on_Capacity_Replacement_Activity_4_20171214.pdf> (December 14, 2017).
107 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2019," <http://www.monitoringanalytics.com/reports/Reports/2019/IMM_Analysis_of_Replacement_Capacity_for_RPM_Commitments_June_1_2007_to_June_1_2019_20190913.pdf> (September 13, 2019).
108 The calculated reserve margin for June 1, 2020, does not account for cleared buy bids that have not been used in replacement capacity transactions.
109 "PJM Generation and Funding Sources 2007/2008 through 2021/2022 Delivery Years," <http://www.monitoringanalytics.com/reports/Reports/2019/IMM_PJM_Generation_Capacity_and_Funding_Sources_20072008_through_20212022_Delivery_Years_20190912.pdf> (September 12, 2019).

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

The Ohio subsidy legislation to subsidize both nuclear and coal plants and to eliminate the RPS, the Illinois ZEC legislation to subsidize the Quad Cities nuclear power plant and the requests for additional subsidies, the request in Pennsylvania to subsidize the Three Mile Island and other nuclear power plants, the New Jersey legislation to subsidize the Salem and Hope Creek nuclear power plants, the potential U.S. DOE proposal to subsidize coal and nuclear power plants, and the request by FirstEnergy to the U.S. DOE for subsidies consistent with the DOE Grid Resilience Proposal, all originate from the fact that competitive markets result in the exit of uneconomic and uncompetitive generating units. Regardless of the specific rationales offered by unit owners, the proposed solution for all such generating units has been to provide out of market subsidies in order to retain such units. The proposed solution in all cases ignores the opportunity cost of subsidizing uneconomic units, which is the displacement of new resources and technologies that would otherwise be economic. These subsidies are not accurately characterized as state subsidies. These subsidies were all requested by the owners of specific uneconomic generating units in order to improve the profitability of those specific units. These subsidies were not requested to accomplish broader social goals. Broader social goals can all be met with market-based mechanisms available to all market participants on a competitive basis and without discrimination.

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

It is essential that any approach to the PJM markets incorporate a consistent view of how the preferred market design is expected to provide competitive results in a sustainable market design over the long run. A sustainable market design means a market design that results in appropriate incentives to competitive market participants to retire units and to invest in new units over time such that reliability is ensured as a result of the functioning of the market. The MMU calls this approach the Sustainable Market Rule (SMR). The SMR is fully consistent with the renewables targets of many states in the PJM footprint. The SMR is also consistent with incorporating economic nuclear power plants in the capacity market.

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

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

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

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

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

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

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

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

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

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

Overview: Section 6, Demand Response

- **Demand Response Activity.** Demand response activity includes economic demand response (economic resources), emergency and pre-emergency demand response (demand resources), synchronized reserves and regulation. Economic demand response participates in the energy market. Emergency and pre-emergency demand response participates in the capacity market and energy market.[110] Demand response resources participate in the Synchronized Reserve Market. Demand response resources participate in the Regulation Market.

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

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

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

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

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

- **Demand Response Energy Payments are Uplift.** Energy payments to emergency and economic demand response resources are uplift. LMP does not cover energy payments although emergency and economic demand response can and does set LMP. Energy payments to emergency demand resources are paid by PJM market participants in proportion to their net purchases in the real-time market. Energy payments to economic demand resources are paid by real-time exports from PJM and real-time loads in each zone for which the load-weighted, average real-time LMP for the hour during which the reduction occurred is greater than or equal to the net benefits test price for that month.[113]

- **Demand Response Market Concentration.** The ownership of economic demand response resources was highly concentrated in 2018 and the first nine months of 2019. The HHI for economic resource reductions increased by 535 points from 7541 in the first nine months 2018 to 8076 in the first nine months of 2019. The ownership of emergency demand response resources was moderately concentrated in the first nine months of 2019. The HHI for emergency demand response committed MW was 1808 for the 2018/2019 Delivery Year and 1838 for the 2019/2020 Delivery Year. In the 2018/2019 Delivery Year, the four largest companies owned 78.1 percent of all committed demand response UCAP MW. In the 2019/2020 Delivery Year, the four largest companies owned 78.8 percent of all committed demand response UCAP MW.

- **Limited Locational Dispatch of Demand Resources.** Beginning with the 2014/2015 Delivery Year, demand resources that are not Capacity Performance, are dispatchable for mandatory reductions on a subzonal basis, defined by zip codes, but only if the subzone is defined at least one day before it is dispatched and only until PJM removes the definition of the subzone. Nodal dispatch of demand resources in a nodal market would improve market efficiency. The goal should be nodal dispatch of demand resources with no advance notice required, as is the case for generation resources. With full implementation of the Capacity Performance rules in the capacity market starting with the 2020/2021 Delivery Year, PJM will be able to individually dispatch demand resources with no advanced notice, although PJM does not know the nodal location of demand resources.

Section 6 Recommendations

The MMU recognizes that PJM incorporated some of the recommendations related to demand response in the Capacity Performance filing. The status of each recommendation reflects the status at September 30, 2019.

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

- The MMU recommends that the option to specify a minimum dispatch price (strike price) for demand resources be eliminated and that participating resources receive the hourly real-time LMP less any generation component

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

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

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

of their retail rate. (Priority: Medium. First reported 2010. Status: Not adopted.)

- The MMU recommends that the maximum offer for demand resources be the same as the maximum offer for generation resources. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that the demand resources be treated as economic resources, responding to economic price signals like other capacity resources. The MMU recommends that demand resources not be treated as emergency resources, not trigger a PJM emergency and not trigger a Performance Assessment Interval. (Priority: High. First reported 2012. Status: Not adopted.)
- The MMU recommends that the Emergency Program Energy Only option be eliminated because the opportunity to receive the appropriate energy market incentive is already provided in the economic program. (Priority: Low. First reported 2010. Status: Not adopted.)
- The MMU recommends that, if demand resources remain in the capacity market, a daily energy market must offer requirement apply to demand resources, comparable to the rule applicable to generation capacity resources.[114] (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that demand resources be required to provide their nodal location, comparable to generation resources. (Priority: High. First reported 2011. Status: Not adopted.)
- The MMU recommends that PJM require nodal dispatch of demand resources with no advance notice required or, if nodal location is not required, subzonal dispatch of demand resources with no advance notice required. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM not remove any defined subzones and maintain a public record of all created and removed subzones. (Priority: Low. First reported 2016. Status: Not adopted.)
- The MMU recommends that PJM eliminate the measurement of compliance across zones within a compliance aggregation area (CAA). The multiple zone approach is less locational than the zonal and subzonal approach and creates larger mismatches between the locational need for the resources and the actual response. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that measurement and verification methods for demand resources be modified to reflect compliance more accurately. (Priority: Medium. First reported 2009. Status: Not adopted.)
- The MMU recommends that compliance rules be revised to include submittal of all necessary hourly load data, and that negative values be included when calculating event compliance across hours and registrations. (Priority: Medium. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM adopt the ISO-NE five-minute metering requirements in order to ensure that operators have the necessary information for reliability and that market payments to demand resources be calculated based on interval meter data at the site of the demand reductions.[115] (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends limited, extended summer and annual demand response event compliance be calculated on an hourly basis for noncapacity performance resources and on a five minute basis for all capacity performance resources and that the penalty structure reflect five minute compliance. (Priority: Medium. First reported 2013. Status: Partially adopted.)
- The MMU recommends that load management testing be initiated by PJM with limited warning to CSPs in order to more accurately represent the conditions of an emergency event. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that shutdown cost be defined as the cost to curtail load for a given period that does not vary with the measured reduction or, for behind the meter generators, be the start cost defined in Manual 15 for generators. (Priority: Low. First reported 2012. Status: Not adopted.)

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

115 See ISO-NE Tariff, Section III, Market Rule 1, Appendix E1 and Appendix E2, "Demand Response," <http://www.iso-ne.com/regulatory/tariff/sect_3/mr1_append-e.pdf>. (Accessed October 17, 2017) ISO-NE requires that DR have an interval meter with five-minute data reported to the ISO and each behind the meter generator is required to have a separate interval meter. After June 1, 2017, demand response resources in ISO-NE must also be registered at a single node.

- The MMU recommends that the Net Benefits Test be eliminated and that demand response resources be paid LMP less any generation component of the applicable retail rate. (Priority: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that the tariff rules for demand response clarify that a resource and its CSP, if any, must notify PJM of material changes affecting the capability of the resource to perform as registered and must terminate or modify registrations that are no longer capable of responding to PJM dispatch directives at defined levels because load has been reduced or eliminated, as in the case of bankrupt and/or out of service facilities. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that there be only one demand response product in the capacity market, with an obligation to respond when called for any hour of the delivery year. (Priority: High. First reported 2011. Status: Partially adopted.[116])
- The MMU recommends that the lead times for demand resources be shortened to 30 minutes with an hour minimum dispatch for all resources. (Priority: Medium. First reported 2013. Status: Partially adopted.)
- The MMU recommends setting the baseline for measuring capacity compliance under winter compliance at the customers' PLC, similar to GLD, to avoid double counting. (Priority: High. First reported 2010. Status: Partially adopted.)
- The MMU recommends the Relative Root Mean Squared Test be required for all demand resources with a CBL. (Priority: Low. First reported 2017. Status: Partially adopted.)
- The MMU recommends that PRD be required to respond during a PAI to be consistent with all CP resources. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends that the limits imposed on the pre-emergency and emergency demand response share of the Synchronized Reserve Market be eliminated. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that 30 minute pre-emergency and emergency demand response be considered to be 30 minute reserves. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that energy efficiency MW not be included in the PJM capacity market and that PJM should ensure that the impact of EE measures on the load forecast is incorporated immediately rather than with the existing lag. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that demand reductions based entirely on behind the meter generation be capped at the lower of economic maximum or actual generation output. (Priority: High. First reported Q2, 2019. Status: Not adopted.)

Section 6 Conclusion

A fully functional demand side of the electricity market means that end use customers or their designated intermediaries will have the ability to see real-time energy price signals in real time, will have the ability to react to real-time prices in real time and will have the ability to receive the direct benefits or costs of changes in real-time energy use. In addition, customers or their designated intermediaries will have the ability to see current capacity prices, will have the ability to react to capacity prices and will have the ability to receive the direct benefits or costs of changes in the demand for capacity in the same year in which demand for capacity changes. A functional demand side of these markets means that customers will have the ability to make decisions about levels of power consumption based both on how customers value the power and on the actual cost of that power.

In the energy market, if there is to be a demand side program, demand resources should be paid the value of energy, which is LMP less any generation component of the applicable retail rate. There is no reason to have the net benefits test. The necessity for the net benefits test is an illustration of the illogical approach to demand side compensation embodied in paying full LMP to demand resources. The benefit of demand side resources is not that they suppress market prices, but that customers can choose not to consume

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

at the current price of power, that individual customers benefit from their choices and that the choices of all customers are reflected in market prices. If customers face the market price, customers should have the ability to not purchase power and the market impact of that choice does not require a test for appropriateness.

If demand resources are to continue competing directly with generation capacity resources in the PJM Capacity Market, the product must be defined such that it can actually serve as a substitute for generation. This is a prerequisite to a functional market design. The Capacity Performance demand response product definition in the PJM Capacity Performance capacity market design is a significant step in that direction, although performance obligations are still not identical to other capacity resources. Demand resources do not have a must offer requirement into the day-ahead energy market, are able to offer above $1,000 per MWh without providing a fuel cost policy, or any rationale for the offer. PJM automatically triggers a PAI when demand resources are dispatched and demand resources do not have telemetry requirements similar to other Capacity Performance resources.

In order to be a substitute for generation, demand resources should be defined in PJM rules as an economic resource, as generation is defined. Demand resources should be required to offer in the Day-Ahead Energy Market and should be called when the resources are required and prior to the declaration of an emergency. Demand resources should be available for every hour of the year. The fact that PJM currently defines demand resources as emergency resources and the fact that calling on demand resources triggers a performance assessment interval (PAI) under the Capacity Performance design, both serve as a significant disincentive to calling on demand resources and mean that demand resources are underused. Demand resources should be treated as economic resources like any other capacity resource. Demand resources should be called when economic and paid the LMP rather than an inflated strike price up to $1,849 per MWh that is set by the seller.

In order to be a substitute for generation, demand resources should be subject to robust measurement and verification techniques to ensure that transitional DR programs incent the desired behavior. The methods used in PJM programs today are not adequate to determine and quantify deliberate actions taken to reduce consumption.

In order to be a substitute for generation, demand resources should provide a nodal location and should be dispatched nodally to enhance the effectiveness of demand resources and to permit the efficient functioning of the energy market. Both subzonal and multi-zone compliance should be eliminated because they are inconsistent with an efficient nodal market.

In order to be a substitute for generation, compliance by demand resources with PJM dispatch instructions should include both increases and decreases in load. The current method applied by PJM simply ignores increases in load and thus artificially overstates compliance.

In order to be a substitute for generation, reductions should be calculated hourly for dispatched DR. The current rules use the average reduction for the duration of an event. The average reduction across multiple hours does not provide an accurate metric for each hour of the event and is inconsistent with the measurement of generation resources. Measuring compliance hourly would provide accurate information to the PJM system. Under the new CP rules, the performance of demand response during Performance Assessment Interval (PAI) will be measured on a five-minute basis.

In order to be a substitute for generation, any demand resource and its Curtailment Service Provider (CSP), should be required to notify PJM of material changes affecting the capability of the resource to perform as registered and to terminate or modify registrations that are no longer capable of responding to PJM dispatch directives at the specified level, such as in the case of bankrupt and out of service facilities. Generation resources are required to inform PJM of any change in availability status, including outages and shutdown status.

As a preferred alternative, demand response resources should be on the demand side of the capacity market rather than on the supply side. Rather than detailed demand response programs with their attendant complex and difficult to administer rules, customers would be able to avoid capacity and energy charges by not using capacity and energy at their discretion and the level of usage paid for would be defined by metered usage rather than a complex and inaccurate measurement protocol.

The MMU peak shaving proposal at the Summer-Only Demand Response Senior Task Force (SODRSTF) is an example of how to create a demand side product that is on the demand side of the market and not on the supply side.[117] The MMU proposal was based on the BGE load forecasting program and Pennsylvania Act 129 Utility Program.[118] [119] Under the MMU proposal, participating load would inform PJM prior to an RPM auction of the MW participating, the months and hours of participation and the temperature humidity index (THI) threshold at which load would be reduced. PJM would reduce the load forecast used in the RPM auction based on the designated reductions. Load would agree to curtail demand to at or below a defined FSL, less than the customer PLC, when the THI exceeds a defined level or load exceeds a specified threshold. By relying on metered load and the PLC, load can reduce its demand for capacity and that reduction can be verified without complicated and inaccurate metrics to estimate load reductions. Under PJM's weakened version of the program, performance will be measured under the current economic demand response CBL rules which means relying on load estimates rather than actual metered load.[120] PJM's proposal includes only a THI curtailment trigger and not an overall load curtailment trigger.

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

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

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

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

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

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

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

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

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

Overview: Section 7, Net Revenue

Net Revenue

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

Historical New Entrant CT and CC Revenue Adequacy

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

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

Section 7 Conclusion

Wholesale electric power markets are affected by externally imposed reliability requirements. A regulatory authority external to the market makes a determination as to the acceptable level of reliability which is enforced through a requirement to maintain a target level of installed or unforced capacity. The requirement to maintain a target level of installed capacity can be enforced via a variety of mechanisms, including government construction of generation, full-requirement contracts with developers to construct and operate generation, state utility commission mandates to construct capacity, or capacity markets of various types. Regardless of the enforcement mechanism, the exogenous requirement to construct capacity in excess of what is constructed in response to energy market signals has an impact on energy markets. The reliability requirement results in maintaining a level of capacity in excess of the level that would result from the operation of an energy market alone. The result of that additional capacity is to reduce the level and volatility of energy market prices and to reduce the duration of high energy market prices. This, in turn, reduces net revenue to generation owners which reduces the incentive to invest. The exact level of both aggregate and locational excess capacity is a function of the calculation methods used by RTOs and ISOs.

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

Overview: Section 8, Environmental and Renewables

Federal Environmental Regulation

- **MATS.** The U.S. Environmental Protection Agency's (EPA) Mercury and Air Toxics Standards rule (MATS) applies the Clean Air Act (CAA) maximum achievable control technology (MACT) requirement to new or modified sources of emissions of mercury and arsenic, acid gas, nickel, selenium and cyanide.[122] All coal steam units in PJM are compliant with the state and federal emissions limits established by MATS.
- **Air Quality Standards (NO_x and SO_2 Emissions).** The CAA requires each state to attain and maintain compliance with fine particulate matter (PM) and ozone national ambient air quality standards (NAAQS). The CAA also requires that each state prohibit emissions that significantly interfere with the ability of another state to meet NAAQS.[123]
- **NSR.** On August 1, 2019, the EPA proposed to reform the New Source Review (NSR) permitting program.[124] NSR requires new projects and existing projects receiving major overhauls that significantly increase emissions to obtain permits under State Implementation Programs.
- **RICE.** Stationary reciprocating internal combustion engines (RICE) are electrical generation facilities like diesel engines typically used for backup, emergency or supplemental power. RICE must be tested annually.[125] Emergency stationary RICE participating in demand response programs are allowed to operate for up to 100 hours/calendar year providing emergency demand response during periods when there is a NERC declared Energy Emergency Alert Level 2 or there is a five percent voltage/frequency deviations, and for an unlimited time during emergency situations.
- **Greenhouse Gas Emissions.** On June 19, 2019, the EPA repealed the Clean Power Plan[126] and replaced it with the Affordable Clean Energy (ACE) rule, which establishes guidelines for states to develop plans to address greenhouse gas emissions from existing coal fired power plants.[127] Under the ACE Rule some states may permit more CO_2 emissions than under the Clean Power Plan.
- **Cooling Water Intakes.** An EPA rule implementing Section 316(b) of the Clean Water Act (CWA) requires that cooling water intake structures reflect the best technology available for minimizing adverse environmental impacts.[128]
- **Coal Ash.** The EPA administers the Resource Conservation and Recovery Act (RCRA), which governs the disposal of solid and hazardous waste.[129]

State Environmental Regulation

- **Regional Greenhouse Gas Initiative (RGGI).** The Regional Greenhouse Gas Initiative (RGGI) is a CO_2 emissions cap and trade agreement among Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont that applies to power generation facilities. New Jersey is rejoining.[130] Virginia and Pennsylvania are preparing to join.[131] [132] The auction price in the September 4, 2019, auction for the 2018/2020 compliance period was $5.02 per ton. The clearing price is equivalent to a price of $5.73 per metric tonne, the unit used in other carbon markets. The price decreased by $0.60 per ton, 7.5 percent, from $5.62 per ton from June 5, 2019, to $5.02 per ton for September 4, 2019.
- **Carbon Price.** If the price of carbon were $50.00 per metric tonne, the short run marginal costs would increase by $24.52 per MWh for a new

122 National Emission Standards for Hazardous Air Pollutants From Coal and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil Fuel Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units, EPA Docket No. EPA-HQ-OAR-2009-0234, 77 Fed. Reg. 9304 (Feb. 16, 2012).
123 CAA § 110(a)(2)(D)(i)(I).
124 Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NNSR): Project Emissions Accounting, EPA Docket No. EPA-HQ-OAR-2018-0048; FRL-9997-95-OAR, 84 Fed. Reg. 39244 (Aug. 9, 2019).
125 See 40 CFR § 63.6640(f).
126 Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, EPA-HQ-OAR-2013-0602, Final Rule mimeo (Aug. 3, 2015) (Clean Power Plan). The Clean Power Plan never took effect because it was subject to a stay issued by the U.S. Supreme Court.
127 See Repeal of the Clean Power Plan; Emission Guidelines for Greenhouse Gas Emissions From Existing Electric Utility Generating Units; Revisions to Emission Guidelines Implementing Regulations, EPA Docket No. EPA-HQ-OAR-2017-0355, et al., 84 Fed. Reg. 32520 (July 8, 2019).
128 See EPA, National Pollutant Discharge Elimination System—Final Regulations to Establish Requirements for Cooling Water Intake Structures at Existing Facilities and Amend Requirements at Phase I Facilities, EPA-HQ-OW-2008-0667, 79 Fed. Reg. 48300 (Aug. 15, 2014).
129 42 U.S.C. §§ 6901 et seq.
130 Executive Order 7; see Regional Greenhouse Gas Initiative, State of New Jersey Department of Environmental Protection <http://www.state.nj.us/dep/aqes/rggi.html>.
131 See Regulation for Emissions Trading, 9 VAC 5-140. The Virginia Air Pollution Control Board is developing the regulation and considering public comments.
132 Executive Order – 2019-07- Commonwealth Leadership in Addressing Climate Change through Electric Sector Emissions Reductions, Tom Wolf, Governor, October 3, 2019, <https://www.governor.pa.gov/newsroom/executive-order-2019-07-commonwealth-leadership-in-addressing-climate-change-through-electric-sector-emissions-reductions/>.

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

State Renewable Portfolio Standards

- **RPS.** In PJM, nine of 14 jurisdictions have enacted legislation requiring that a defined percentage of retail suppliers' load be served by renewable resources, for which definitions vary. These are typically known as renewable portfolio standards, or RPS. As of September 30, 2019, Delaware, Illinois, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, and Washington D.C. had renewable portfolio standards. Virginia and Indiana had voluntary renewable portfolio standards. Kentucky, Tennessee and West Virginia did not have renewable portfolio standards.
- **RPS Cost.** The cost of complying with RPS, as reported by the states, was $3.4 billion over the four year period from 2014 through 2017, or an average annual RPS compliance cost of $840.4 million.[133]

Emissions Controls in PJM Markets

- **Regulations.** Environmental regulations affect decisions about emission control investments in existing units, investment in new units and decisions to retire units. As a result of environmental regulations and agreements to limit emissions, many PJM units burning fossil fuels have installed emission control technology.
- **Emissions Controls.** As of September 30, 2019, 93.5 percent of coal steam MW had some type of flue-gas desulfurization (FGD) technology to reduce SO_2 emissions, while 99.6 percent of coal steam MW had some type of particulate control, and 93.6 percent of fossil fuel fired capacity in PJM had NO_x emission control technology. All coal steam units in PJM are compliant with the state and federal emissions limits established by MATS.

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

Renewable Generation

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

Section 8 Recommendations

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

Section 8 Conclusion

Environmental requirements and renewable energy mandates at both the federal and state levels have a significant impact on the cost of energy and capacity in PJM markets. Renewable energy credit (REC) markets are markets related to the production and purchase of wholesale power, but FERC has determined that RECs are not regulated under the Federal Power Act unless the REC is sold as part of a transaction that also includes a wholesale sale of electric energy in a bundled transaction.[134] The MMU recommends that the Commission reconsider its disclaimer of jurisdiction over RECs markets because, given market changes since that decision, it is clear that RECs materially affect jurisdictional rates.

RECs clearly affect prices in the PJM wholesale power market. Some resources are not economic except for the ability to purchase or sell RECs. RECs provide out of market payments to qualifying renewable resources, primarily wind and solar. The credits provide an incentive to make negative energy offers and more generally provide an incentive to enter the market, to remain in the market and to operate whenever possible. These subsidies affect the offer behavior and the operational behavior of these resources in PJM markets and in some cases the existence of these resources and thus the market prices and the mix of clearing resources.

RECs markets are, as an economic fact, integrated with PJM markets including energy and capacity markets, but are not formally recognized as part of PJM markets. It would be preferable to have a single, transparent market for RECs operated by the PJM RTO that would meet the standards and requirements of all states in the PJM footprint including those with no RPS. This would provide better information for market participants about supply and demand and prices and contribute to a more efficient and competitive market and to better price formation. This could also facilitate entry by qualifying renewable resources by reducing the risks associated with lack of transparent market data. The MMU recommends that PJM states consider the development of a multistate framework for REC markets, for potential agreement on carbon pricing, and for coordination with PJM wholesale markets.

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

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

PJM markets provide a flexible mechanism for incorporating the costs of environmental controls and meeting environmental requirements in a cost effective manner. Costs for environmental controls are part of offers for capacity resources in the PJM Capacity Market. The costs of emissions credits are included in energy offers. PJM markets also provide a flexible mechanism that incorporates renewable resources and the impacts of renewable energy credit markets, and ensures that renewable resources have access to a broad market. PJM markets provide efficient price signals that permit valuation of resources with very different characteristics when they provide the same product.

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

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

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

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

to limit carbon output, a consistent carbon price would be the most efficient way to implement that decision. The states in PJM could agree, if they decided it was in their interests, with the appropriate information, on a carbon price and on how to allocate the revenues from a carbon price that would make all states better off. The MMU continues to recommend that PJM provide modeling information to the states adequate to inform such a decision making process. A carbon price would also be an alternative to specific subsidies to individual nuclear power plants and to the current wide range of implied carbon prices embedded in RPS programs and instead provide a market signal to which any resource could respond. The imposition of specific and prescriptive environmental dispatch rules would, in contrast, pose a threat to economic dispatch and efficient markets and create very difficult market power monitoring and mitigation issues. The provision of subsidies to individual units creates a discriminatory regime that is not consistent with competition. The use of inconsistent implied carbon prices by state is also inconsistent with an efficient market and inconsistent with the least cost approach to meeting state environmental goals.

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

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

Overview: Section 9, Interchange Transactions

Interchange Transaction Activity

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

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

138 Calculated values shown in Section 9, "Interchange Transactions," are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

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

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

Interactions with Bordering Areas

PJM Interface Pricing with Organized Markets

- **PJM and MISO Interface Prices.** In the first nine months of 2019, the direction of the hourly flow was consistent with the real-time hourly price differences between the PJM/MISO Interface and the MISO/PJM Interface in 61.5 percent of the hours.
- **PJM and New York ISO Interface Prices.** In the first nine months of 2019, the direction of the hourly flow was consistent with the real-time hourly price differences between the PJM/NYIS Interface and the NYISO/PJM proxy bus in 57.9 percent of the hours.
- **Neptune Underwater Transmission Line to Long Island, New York.** In the first nine months of 2019, the hourly flow (PJM to NYISO) was consistent with the real-time hourly price differences between the PJM Neptune Interface and the NYISO Neptune bus in 73.1 percent of the hours.
- **Linden Variable Frequency Transformer (VFT) Facility.** In the first nine months of 2019, the hourly flow (PJM to NYISO) was consistent with the real-time hourly price differences between the PJM Linden Interface and the NYISO Linden bus in 68.3 percent of the hours.
- **Hudson DC Line.** In the first nine months of 2019, the hourly flow (PJM to NYISO) was consistent with the real-time hourly price differences between the PJM Hudson Interface and the NYISO Hudson bus in 66.3 percent of the hours.

Interchange Transaction Issues

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

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

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

Section 9 Recommendations

- The MMU recommends that PJM implement rules to prevent sham scheduling. The MMU recommends that PJM apply after the fact market settlement adjustments to identified sham scheduling segments to ensure that market participants cannot benefit from sham scheduling. (Priority: High. First reported 2012. Status: Not adopted. Stakeholder process.)
- The MMU recommends that PJM implement a validation method for submitted transactions that would prohibit market participants from breaking transactions into smaller segments to defeat the interface pricing rule by concealing the true source or sink of the transaction. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM implement a validation method for submitted transactions that would require market participants to submit transactions on paths that reflect the expected actual power flow in order to reduce unscheduled loop flows. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM end the practice of maintaining outdated definitions of interface pricing points, eliminate the NIPSCO, Southeast and Southwest interface pricing points from the Day-Ahead and Real-Time Energy Markets and, with VACAR, assign the transactions created under the reserve sharing agreement to the SouthIMP/EXP pricing point. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM eliminate the IMO interface pricing point, and assign the transactions that originate or sink in the IESO balancing authority to the MISO interface pricing point. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM monitor, and adjust as necessary, the weights applied to the components of the interfaces to ensure that the interface prices reflect ongoing changes in system conditions. The MMU also recommends that PJM review the mappings of external balancing authorities to individual interface pricing points to reflect changes to the impact of the external power source on PJM tie lines as a result of system topology changes. The MMU recommends that this review occur at least annually. (Priority: Low. First reported 2009. Status: Not adopted.)
- The MMU recommends that, in order to permit a complete analysis of loop flow, FERC and NERC ensure that the identified data are made available to market monitors as well as other industry entities determined appropriate by FERC. (Priority: Medium. First reported 2003. Status: Not adopted.)
- The MMU recommends that PJM explore an interchange optimization solution with its neighboring balancing authorities that would remove the need for market participants to schedule physical transactions across seams. Such a solution would include an optimized, but limited, joint dispatch approach that uses supply curves and treats seams between balancing authorities as constraints, similar to other constraints within an LMP market. (Priority: Medium. First reported 2014. Status: Not adopted.)
- The MMU recommends that PJM permit unlimited spot market imports as well as unlimited nonfirm point-to-point willing to pay congestion imports and exports at all PJM interfaces in order to improve the efficiency of the market. (Priority: Medium. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM immediately provide the required 12-month notice to Duke Energy Progress (DEP) to unilaterally terminate the Joint Operating Agreement. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM Settlement Inc. immediately request a credit evaluation from all companies that engaged in up to congestion transactions between September 8, 2014, and December 31, 2015. If PJM has the authority, PJM should ensure that the potential exposure to uplift for that period be included as a contingency in the companies' calculations for credit levels and/or collateral requirements. If PJM does

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

not have the authority to take such steps, PJM should request guidance from FERC. (Priority: Low. First reported 2015. Status: Not adopted.)

- The MMU recommends that the emergency interchange cap be replaced with a market based solution. (Priority: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that the submission deadline for real-time dispatchable transactions be modified from 1800 on the day prior, to three hours prior to the requested start time, and that the minimum duration be modified from one hour to 15 minutes. These changes would give PJM a more flexible product that could be used to meet load in the most economic manner. (Priority: Medium. First reported 2014. Status: Partially adopted, 2015.)
- The MMU recommends that the Commission require that the open FFE/FFL freeze date issues be addressed at a Commission technical conference, and that the Commission set a deadline to resolve the significant issues that result from the freeze date. (Priority: Medium. First reported Q2, 2019. Status: Not adopted.)

Section 9 Conclusion

Transactions between PJM and multiple balancing authorities in the Eastern Interconnection are part of a single energy market. While some of these balancing authorities are termed market areas and some are termed nonmarket areas, all electricity transactions are part of a single energy market. Nonetheless, there are significant differences between market and nonmarket areas. Market areas, like PJM, include essential features such as locational marginal pricing, financial congestion offsets (FTRs and ARRs in PJM) and transparent, least cost, security constrained economic dispatch for all available generation. Nonmarket areas do not include these features. Pricing in the market areas is transparent and pricing in the nonmarket areas is not transparent.

The MMU's recommendations related to transactions with external balancing authorities all share the goal of improving the economic efficiency of interchange transactions. The standard of comparison is an LMP market. In an LMP market, redispatch based on LMP and competitive generator offers results in an efficient dispatch and efficient prices. The goal of designing interface transaction rules should be to match the outcomes that would exist in an LMP market across the interfaces.

Overview: Section 10, Ancillary Services

Primary Reserve

PJM's primary reserves are made up of resources, both synchronized and nonsynchronized, that can provide energy within 10 minutes. Primary reserve is PJM's implementation of the NERC 15-minute contingency reserve requirement.[143]

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

Market Structure

- **Supply.** Primary reserve is satisfied by both synchronized reserve (generation or demand response currently synchronized to the grid and available within 10 minutes), and nonsynchronized reserve (generation currently off line but available to start and provide energy within 10 minutes).
- **Demand.** The PJM primary reserve requirement is 150 percent of the most severe single contingency. In the first nine months of 2019, the average primary reserve requirement was 2,474.8 MW in the RTO Zone and 2,530.9 MW in the MAD Subzone.

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

Tier 1 Synchronized Reserve

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

Tier 1 synchronized reserve is the capability of online resources following economic dispatch to ramp up in 10 minutes from their current output in response to a synchronized reserve event. There is no formal market for tier 1 synchronized reserve.

- **Supply.** No offers are made for tier 1 synchronized reserves. The market solution estimates tier 1 synchronized reserve as available 10 minute ramp from the energy dispatch. In the first nine months of 2019, there was an average hourly supply of 2,185.1 MW of tier 1 available in the RTO Zone. In the first nine months of 2019, there was an average hourly supply of 1,574.7 MW of tier 1 synchronized reserve available within the MAD Subzone.
- **Demand.** The synchronized reserve requirement is calculated for each five minute interval as the most severe single contingency within both the RTO Zone and the MAD Subzone. The requirement can be met with tier 1 or tier 2 synchronized reserves.
- **Tier 1 Synchronized Reserve Event Response.** Tier 1 synchronized reserve is paid when a synchronized reserve event occurs and it responds. When a synchronized reserve event is called, all tier 1 response is paid for increasing its output (or reducing load for demand response) at the rate of $50 per MWh in addition to LMP.[144] This is the Synchronized Energy Premium Price.
- **Issues.** The competitive offer for tier 1 synchronized reserves is zero, as there is no incremental cost associated with the ability to ramp up from the current economic dispatch point and the appropriate payment for responding to an event is synchronized energy premium price of $50 per MWh. The tariff requires payment of the tier 2 synchronized reserve market clearing price to tier 1 resources whenever the nonsynchronized reserve market clearing price rises above zero. This requirement is unnecessary and inconsistent with efficient markets. This change had a significant impact on the cost of tier 1 synchronized reserves, resulting in a windfall payment of $89,719,045 to tier 1 resources in 2014, $34,397,441 in 2015, $4,948,084 in 2016, $2,197,514 in 2017, $4,732,025 in 2018, and $2,295,217 in the first nine months of 2019.

Tier 2 Synchronized Reserve Market

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

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

Market Structure

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

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

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

synchronized reserve was 280.6 MW in the MAD Subzone and 536.9 MW in the RTO.

- **Market Concentration.** Both the Mid-Atlantic Dominion Subzone Tier 2 Synchronized Reserve Market and the RTO Synchronized Reserve Zone Market were characterized by structural market power in the first nine months 2019.

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

Market Conduct

- **Offers.** There is a must offer requirement for tier 2 synchronized reserve. All nonemergency generation capacity resources are required to submit a daily offer for tier 2 synchronized reserve, unless the unit type is exempt. Tier 2 synchronized reserve offers from generating units are subject to an offer cap of marginal cost plus $7.50 per MW, plus opportunity cost which is calculated by PJM. PJM automatically enters an offer of $0 for tier 2 synchronized reserve when an offer is not entered by the owner.

Market Performance

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

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

Nonsynchronized Reserve Market

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

Market Structure

- **Supply.** In the first nine months of 2019, the average hourly supply of eligible nonsynchronized reserve was 3,953.1 MW in the RTO Zone.
- **Demand.** Demand for nonsynchronized reserve equals the primary reserve requirement minus the tier 1 synchronized reserve estimate and minus the scheduled tier 2 synchronized reserve.[146] The actual amount of nonsynchronized reserve scheduled often exceeds the demand and the corresponding price is $0.00. In the RTO Zone, the market scheduled an hourly average of 1,461.9 MW of nonsynchronized reserve in the first nine months of 2019.
- **Market Concentration.** The MMU calculates that the three pivotal supplier test would have been failed in 61.3 percent of hours in the first nine months of 2019.

Market Conduct

- **Offers.** Generation owners do not submit supply offers. Nonemergency generation resources that are available to provide energy and can start in 10 minutes or less are considered available for nonsynchronized reserves by the market solution software. PJM calculates the associated offer prices based on PJM calculations of resource specific opportunity costs.

Market Performance

- **Price.** The nonsynchronized reserve price is determined by the opportunity cost of the marginal nonsynchronized reserve unit. The nonsynchronized

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

reserve weighted average price for all hours in the RTO Reserve Zone was $0.20 per MW in the first nine months of 2019. The price cleared above $0.00 in 0.9 percent of hours.

Secondary Reserve

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

PJM maintains a day-ahead, offer-based market for 30 minute day-ahead secondary reserve. The Day-Ahead Scheduling Reserve Market (DASR) has no performance obligations except that a unit which clears the DASR Market may not be on an outage in real time.[147] If DASR units are on an outage in real-time or cleared DASR MW are not available, the DASR payment is not made.

Market Structure

- **Supply.** The DASR Market is a must offer market. Any resources that do not make an offer have their offer set to $0.00 per MW. DASR is calculated by the day-ahead market solution as the lesser of the 30 minute energy ramp rate or the economic maximum MW minus the day-ahead dispatch point for all online units. In the first nine months of 2019, the average available hourly DASR was 44,547.9 MW.
- **Demand.** The DASR requirement for 2019 is 5.29 percent of peak load forecast, which is up 0.01 percent from in 2018. The average hourly DASR MW purchased in the first nine months of 2019 was 5,511.0 MW. This is a reduction from the 5,625.4 hourly MW in 2018.
- **Concentration.** In the first nine months of 2019, the DASR Market failed the three pivotal supplier test in less than one percent of hours.

Market Conduct

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

Market Performance

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

Regulation Market

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

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

Market Structure

- **Supply.** In the first nine months of 2019, the average hourly eligible supply of regulation for nonramp hours was 1,062.1 performance adjusted MW (801.2 effective MW). This was a decrease of 37.2 performance adjusted MW (a decrease of 56.5 effective MW) from the first nine months of 2018, when the average hourly eligible supply of regulation was 1,099.3 performance adjusted MW (857.7 effective MW). In the first nine months of 2019, the average hourly eligible supply of regulation for ramp hours was 1,357.8 performance adjusted MW (1,127.6 effective MW). This was a decrease of 53.3 performance adjusted MW (a decrease of 64.1 effective MW) from the first nine months of 2018, when the average hourly eligible supply of regulation was 1,411.1 performance adjusted MW (1,191.8 effective MW).
- **Demand.** The hourly regulation demand is 525.0 effective MW for nonramp hours and 800.0 effective MW for ramp hours.
- **Supply and Demand.** The nonramp regulation requirement of 525.0 effective MW was provided by a combination of RegA and RegD resources equal to 470.7 hourly average performance adjusted actual MW in the first nine months of 2019. This is a decrease of 16.1 performance adjusted actual MW from the first nine months of 2018, when the average hourly total regulation cleared performance adjusted actual MW for nonramp hours were 486.8 performance adjusted actual MW. The ramp regulation requirement of 800.0 effective MW was provided by a combination of RegA and RegD resources equal to 722.8 hourly average performance adjusted actual MW in the first nine months of 2019. This is a decrease of 27.1 performance adjusted actual MW from the first nine months of 2018, where the average hourly regulation cleared MW for ramp hours were 750.0 performance adjusted actual MW.

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

Market Conduct

- **Offers.** Daily regulation offer prices are submitted for each unit by the unit owner. Owners are required to submit a cost-based offer and may submit a price-based offer. Offers include both a capability offer and a performance offer. Owners must specify which signal type the unit will be following, RegA or RegD.[149] In the first nine months of 2019, there were 213 resources following the RegA signal and 59 resources following the RegD signal.

Market Performance

- **Price and Cost.** The weighted average clearing price for regulation was $14.97 per MW of regulation in the first nine months of 2019. This is a decrease of $13.25 per MW, or 47.0 percent, from the weighted average clearing price of $28.21 per MW in the first nine months of 2018. The weighted average cost of regulation in the first nine months of 2019 was $19.14 per MW of regulation. This is a decrease of $15.91 per MW, or 45.4 percent, from the weighted average cost of $35.05 per MW in the first nine months of 2018.
- **Prices.** RegD resources continue to be incorrectly compensated relative to RegA resources due to an inconsistent application of the marginal benefit factor in the optimization, assignment and settlement processes. If the Regulation Market were functioning efficiently, RegD and RegA resources would be paid the same price per effective MW. RegA resources are paid

148 HHI results are based on market shares of effective MW, defined as regulation capability MW adjusted by performance score and resource specific benefit factor, consistent with the way the regulation market is cleared.
149 See the 2018 State of the Market Report for PJM, Vol. 2, Appendix F "Ancillary Services Markets."

on the basis of dollars per effective MW of RegA. RegD resources are not paid in terms of dollars per effective MW of RegA because the marginal benefit factor is not used in settlements. When the marginal benefit factor is above 1.0, RegD resources are generally (depending on the mileage ratio) underpaid on a per effective MW basis. When the MBF is less than one, RegD resources are generally overpaid on a per effective MW basis.

- **Marginal Benefit Factor.** The marginal benefit factor (MBF) is intended to measure the operational substitutability of RegD resources for RegA resources. The marginal benefit factor is incorrectly defined and applied in the PJM market clearing. Correctly defined, the MBF represents the Marginal Rate of Technical Substitution (MRTS) between RegA and RegD. Correctly implemented, the MBF would be consistently applied in the Regulation Market clearing and settlement. The current incorrect and inconsistent implementation of the MBF has resulted in the PJM Regulation Market over procuring RegD relative to RegA in most hours and in a consistently inefficient market signal to participants regarding the value of RegD to the market in every hour. This over procurement of RegD can also degrade the ability of PJM to control ACE.
- **Changes to the Regulation Market.** The MMU and PJM developed a joint proposal to address the significant flaws in the regulation market design which was approved by the PJM Members Committee on July 27, 2017, and filed with FERC on October 17, 2017. The proposal addresses issues with the inconsistent application of the marginal benefit factor throughout the optimization and settlement process in the PJM Regulation Market. On March 30, 2018, this joint proposal was rejected by FERC.[150] The MMU and PJM filed requests for rehearing.[151]

Black Start Service

Black start service is required for the reliable restoration of the grid following a blackout. Black start service is the ability of a generating unit to start without an outside electrical supply, or is the demonstrated ability of a generating unit to automatically remain operating at reduced levels when disconnected from the grid (automatic load rejection or ALR).[152]

In the first nine months of 2019, total black start charges were $48.37 million, including $48.21 million in revenue requirement charges and $0.160 million in operating reserve charges. Black start revenue requirements consist of fixed black start service costs, variable black start service costs, training costs, fuel storage costs, and an incentive factor. Black start operating reserve charges are paid to units scheduled in the Day-Ahead Energy Market or committed in real time to provide black start service under the ALR option or for black start testing. Black start zonal charges in the first nine months of 2019 ranged from $0.04 per MW-day in the DLCO Zone (total charges were $33,657) to $4.03 per MW-day in the PENELEC Zone (total charges were $3,299,265).

Reactive

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

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

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

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

Frequency Response

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

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

Section 10 Recommendations

- The MMU recommends that all data necessary to perform the regulation market three pivotal supplier test be saved so that the test can be replicated. (Priority: Medium. First reported 2016. Status: Not Adopted.)
- The MMU recommends that the Regulation Market be modified to incorporate a consistent application of the marginal benefit factor (MBF) throughout the optimization, assignment and settlement process. The MBF should be defined as the Marginal Rate of Technical Substitution (MRTS) between RegA and RegD. (Priority: High. First reported 2012. Status: Not adopted. FERC rejected, pending rehearing request before FERC.[157])
- The MMU recommends that the lost opportunity cost in the ancillary services markets be calculated using the schedule on which the unit was scheduled to run in the energy market. (Priority: High. First reported 2010. Status: Not adopted.[158] FERC rejected, pending rehearing request before FERC.[159])
- The MMU recommends that the lost opportunity cost calculation used in the Regulation Market be based on the resource's dispatched energy offer schedule, not the lower of its price or cost offer schedule. (Priority: Medium. First reported 2010. Status: Not adopted. FERC rejected, pending rehearing request before FERC.[160])
- The MMU recommends that, to prevent gaming, there be a penalty enforced in the Regulation Market as a reduction in performance score and/or a forfeiture of revenues when resource owners elect to deassign assigned regulation resources within the hour. (Priority: Medium. First reported 2016. Status: Not adopted. FERC rejected, pending rehearing request before FERC.[161])
- The MMU recommends enhanced documentation of the implementation of the Regulation Market design. (Priority: Medium. First reported 2010. Status: Not adopted. FERC rejected, pending rehearing request before FERC.[162])
- The MMU recommends that all data necessary to perform the regulation market three pivotal supplier test be saved so that the test can be replicated. (Priority: Medium. First reported 2016. Status: Adopted, 2018.)
- The MMU recommends that PJM be required to save data elements necessary for verifying the performance of the Regulation Market. (Priority: Medium. First reported 2010. Status: Not adopted.)

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

- The MMU recommends that the $7.50 margin be eliminated from the definition of the cost of tier 2 synchronized reserve because it is a markup and not a cost. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that the rule requiring that tier 1 synchronized reserve resources are paid the tier 2 price when the nonsynchronized reserve price is above zero be eliminated immediately and that, under the current rule, tier 1 synchronized reserve resources not be paid the tier 2 price when they do not respond. (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that the tier 2 synchronized reserve must offer requirement be enforced on a daily and hourly basis. The MMU recommends that PJM define a set of acceptable reasons why a unit can be made unavailable daily or hourly and require unit owners to select a reason in Markets Gateway whenever making a unit unavailable either daily or hourly or setting the offer MW to 0 MW. (Priority: Medium. First reported 2013. Status: Partially adopted.)
- The MMU recommends that PJM be more explicit and transparent about why tier 1 biasing is used in defining demand in the Tier 2 Synchronized Reserve Market. The MMU recommends that PJM define rules for estimating tier 1 MW, define rules for the use and amount of tier 1 biasing and identify the rule based reasons for each instance of biasing. (Priority: Medium. First reported 2012. Status: Not adopted.)
- The MMU recommends that, for calculating the penalty for a tier 2 resource failing to meet its scheduled obligation during a spinning event, the definition of the IPI be changed from the average number of days between events to the actual number of days since the last event greater than 10 minutes. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that aggregation not be permitted to offset unit specific penalties for failure to respond to a synchronized reserve event. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM eliminate the use of Degree of Generator Performance (DGP) in the synchronized reserve market solution and improve the actual tier 1 estimate. If PJM continues to use DGP, DGP should be documented in PJM's manuals. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that a reason code be attached to every hour in which PJM market operations adds additional DASR MW. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM modify the DASR Market to ensure that all resources cleared incur a real-time performance obligation. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that offers in the DASR Market be based on opportunity cost only in order to eliminate market power. (Priority: Low. First reported 2009. Modified, 2018. Status: Not adopted.)
- The MMU recommends that separate cost of service payments for reactive capability be eliminated and the cost of reactive capability be recovered in the capacity market. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that payments for reactive capability, if continued, be based on the 0.90 power factor that PJM has determined is necessary. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that all resources, new and existing, have a requirement to include and maintain equipment for primary frequency response capability as a condition of interconnection service and that compensation is provided through the capacity and energy markets. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends for oil tanks shared with other resources that only a proportionate share of the minimum tank suction level (MTSL) be allocated to black start service. The MMU further recommends that the PJM tariff be updated to clearly state how the MTSL will be calculated for black start units sharing oil tanks. (Priority: Medium. First reported 2017. Status: Not adopted.)

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

Section 10 Conclusion

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

The design of the PJM Regulation Market is significantly flawed. The market design does not correctly incorporate the marginal rate of technical substitution (MRTS) in market clearing and settlement. The market design uses the marginal benefit factor (MBF) to incorrectly represent the MRTS and uses a mileage ratio instead of the MBF in settlement. This failure to correctly and consistently incorporate the MRTS into the regulation market design has resulted in both underpayment and overpayment of RegD resources and in the over procurement of RegD resources in all hours. The market results continue to include the incorrect definition of opportunity cost. These issues are the basis for the MMU's conclusion that the regulation market design is flawed.

To address these flaws, the MMU and PJM developed a joint proposal which was approved by the PJM Members Committee on July 27, 2017, and filed with FERC on October 17, 2017.[165] The PJM/MMU joint proposal addresses issues with the inconsistent application of the marginal benefit factor throughout the optimization and settlement process in the PJM Regulation Market. FERC rejected the joint proposal on March 30, 2018, as being noncompliant with Order No. 755.[166] The MMU and PJM separately filed requests for rehearing.[167]

The structure of the Tier 2 Synchronized Reserve Market has been evaluated and the MMU has concluded that these markets are not structurally competitive as they are characterized by high levels of supplier concentration and inelastic demand. As a result, these markets are operated with market clearing prices and with offers based on the marginal cost of producing the product plus a margin. As a result of these requirements, the conduct of market participants within these market structures has been consistent with competition, and the market performance results have been competitive. However, the $7.50 margin is not a cost. The margin is effectively a rule-based form of market power and is therefore not consistent with a competitive outcome. The $7.50 margin should be eliminated. Participant performance has not been adequate. Compliance with calls to respond to actual synchronized reserve events remains less than 100 percent. For the spinning events 10 minutes or longer in 2016, the average tier 2 synchronized reserve response was 85.5 percent of all scheduled MW. For the six spinning events 10 minutes or longer in 2017, the response was 87.6 percent of scheduled tier 2 MW. For the seven spinning events longer than 10 minutes in 2018, the response was 74.2 percent of scheduled tier 2 MW. There was only one spinning event that lasted longer than 10 minutes in the first nine months of 2019. This one spinning event in the first nine months of 2019 occurred on September 23. In the September 23 event, tier 2 response was 87.4 percent of the amount scheduled and tier 1 response was 71.8 percent of DGP estimated amount. Actual participant performance means that the penalty structure is not adequate to incent performance.

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

The rule that requires payment of the tier 2 synchronized reserve price to tier 1 synchronized reserve resources when the nonsynchronized reserve price is greater than zero, is inefficient and results in a substantial windfall payment to the holders of tier 1 synchronized reserve resources. Tier 1 resources have no obligation to perform and pay no penalties if they do not perform, and tier 1 resources do not incur any costs when they are part of the tier 1 estimate in the market solution. Tier 1 resources are already paid for their response if they do respond. Tier 1 resources require no additional payment. If tier 1 resources wish to be paid as tier 2 resources, the rules provide the opportunity to make competitive offers in the tier 2 market and take on the associated obligations. Overpayment of tier 1 resources based on this rule added $89.7 million to the cost of primary reserve in 2014, $34.1 million in 2015, $4.9 million in 2016, $2.2 million in 2017, $4.7 million in 2018, and $2.3 million in the first nine months of 2019.

The benefits of markets are realized under these approaches to ancillary service markets. Even in the presence of structurally noncompetitive markets, there can be transparent, market clearing prices based on competitive offers that account explicitly and accurately for opportunity cost. This is consistent with the market design goal of ensuring competitive outcomes that provide appropriate incentives without reliance on the exercise of market power and with explicit mechanisms to prevent the exercise of market power.

The MMU concludes that the regulation market results were competitive, although the market design is significantly flawed. The MMU concludes that the synchronized reserve market results were competitive, although the $7.50 margin should be removed. The MMU concludes that the DASR market results were competitive, although offers above the competitive level continue to affect prices.

Overview: Section 11, Congestion and Marginal Losses

Congestion Cost

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

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

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

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

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

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

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

168 162 FERC ¶ 61,139.

Marginal Loss Cost

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

Energy Cost

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

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

Section 11 Recommendations

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

Section 11 Conclusion

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

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

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

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

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

Overview: Section 12, Planning

Generation Interconnection Planning

Existing Generation Mix

- As of September 30, 2019, PJM had a total installed capacity of 198,501.1 MW, of which 54,856.6 MW (27.6 percent) are coal fired steam units, 48,641.6 MW (24.5 percent) are combined cycle units and 34,257.6 MW (17.3 percent) are nuclear units. This measure of installed capacity differs from capacity market installed capacity because it includes energy only units, excludes all external units, and uses nameplate values for solar and wind resources.
- The AEP Zone has the most total installed capacity of any PJM zone. Of the 198,501.1 MW of PJM total installed capacity, 30,843.0 MW (15.5 percent) are in the AEP Zone, of which 13,927.8 MW (45.2 percent) are coal fired steam units, 6,990.0 MW (22.7 percent) are combined cycle units and 2,071.0 MW (6.7 percent) are nuclear units.

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

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

Generation Retirements[170]

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

Generation Queue[171]

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

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

Regional Transmission Expansion Plan (RTEP)

Market Efficiency Process

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

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

- PJM and MISO developed a process to facilitate the construction of interregional projects in response to the Commissions concerns about interregional coordination along the PJM-MISO seam, called the Targeted Market Efficiency Process (TMEP).[173] The allocation of costs to each RTO for TMEPs will be in proportion to the benefits received.[174]

Supplemental Transmission Projects

- Supplemental projects are defined to be "transmission expansions or enhancements that are not required for compliance with PJM criteria and are not state public policy projects according to the PJM Operating Agreement. These projects are used as inputs to RTEP models, but are not required for reliability, economic efficiency or operational performance criteria, as determined by PJM."[175] Supplemental projects are exempt from the competitive planning process.
- The average number of supplemental projects in each expected in service year increased by 600.0 percent, from 20 for years 1998 through 2007 (pre Order No. 890) to 140 for years 2008 through 2019 (post Order 890).
- The process for designating projects as supplemental projects should be reviewed and modified to ensure that the supplemental project designation is not used to exempt transmission projects from a transparent, robust and clearly defined mechanism to permit competition to build the project or to effectively replace the RTEP process.

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

End of Life Transmission Projects

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

Board Authorized Transmission Upgrades

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

Transmission Competition

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

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

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

Qualifying Transmission Upgrades (QTU)

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

Transmission Facility Outages

- PJM maintains a list of reportable transmission facilities. When the reportable transmission facilities need to be taken out of service, PJM transmission owners are required to report planned transmission facility outages as early as possible. PJM processes the transmission facility outage requests according to rules in PJM's Manual 3 to decide if the outage is on time or late and whether or not they will allow the outage.[178]
- There were 6,601 transmission outage requests submitted in the first four months of the 2019/2020 planning period. Of the requested outages, 73.3 percent of the requested outages were planned for less than or equal to five days and 12.5 percent of requested outages were planned for greater than 30 days. Of the requested outages, 50.9 percent were late according to the rules in PJM's Manual 3.

Section 12 Recommendations

Generation Retirements

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

Generation Queue

- The MMU recommends that barriers to entry be addressed in a timely manner in order to help ensure that the capacity market will result in the entry of new capacity to meet the needs of PJM market participants and reflect the uncertainty and resultant risks in the cost of new entry used to establish the capacity market demand curve in RPM. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends improvements in queue management including that PJM establish a review process to ensure that projects are removed from the queue if they are not viable, as well as a process to allow commercially viable projects to advance in the queue ahead of projects which have failed to make progress, subject to rules to prevent gaming. (Priority: Medium. First reported 2013. Status: Partially adopted.)
- The MMU recommends continuing analysis of the study phase of PJM's transmission planning to reduce the need for postponements of study results, to decrease study completion times, and to improve the likelihood that a project at a given phase in the study process will successfully

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

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

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

- The MMU recommends outsourcing interconnection studies to an independent party to avoid potential conflicts of interest. Currently, these studies are performed by incumbent transmission owners under PJM's direction. This creates potential conflicts of interest, particularly when transmission owners are vertically integrated and the owner of transmission also owns generation. (Priority: Low. First reported 2013. Status: Not adopted.)

Market Efficiency Process

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

Transmission Competition

- The MMU recommends, to increase the role of competition, that the exemption of supplemental projects from the Order No. 1000 competitive process be terminated and that the basis for all such exemptions be reviewed and modified to ensure that the supplemental project designation is not used to exempt transmission projects from a transparent, robust and clearly defined mechanism to permit competition to build such projects or to effectively replace the RTEP process. (Priority: Medium. First reported 2017. Status: Not adopted.)
- The MMU recommends, to increase the role of competition, that the exemption of end of life projects from the Order No. 1000 competitive process be terminated and that end of life transmission projects should be included in the RTEP process and should be subject to a transparent, robust and clearly defined mechanism to permit competition to build such projects. (Priority: Medium. First reported Q1, 2019. Status: Not adopted.)
- The MMU recommends that PJM enhance the transparency and queue management process for nonincumbent transmission investment. Issues related to data access and complete explanations of cost impacts should be addressed. The goal should be to remove barriers to competition from nonincumbent transmission providers. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM continue to incorporate the principle that the goal of transmission planning should be the incorporation of transmission investment decisions into market driven processes as much as possible. (Priority: Low. First reported 2001. Status: Not adopted.)
- The MMU recommends the creation of a mechanism to permit a direct comparison, or competition, between transmission and generation alternatives, including which alternative is less costly and who bears the risks associated with each alternative. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM establish fair terms of access to rights of way and property, such as at substations, in order to remove any barriers to entry and permit competition between incumbent transmission providers and nonincumbent transmission providers in the RTEP. (Priority: Medium. First reported 2014. Status: Not adopted.)
- The MMU recommends that rules be implemented to permit competition to provide financing for transmission projects. This competition could reduce the cost of capital for transmission projects and significantly

reduce total costs to customers. (Priority: Low. First reported 2013. Status: Not adopted.)

- The MMU recommends that rules be implemented to require that project cost caps on new transmission projects be part of the evaluation of competing projects. (Priority: Medium. First reported 2015. Status: Not adopted.)

Cost Allocation

- The MMU recommends consideration of changing the minimum distribution factor in the allocation from 0.01 to 0.00 and adding a threshold minimum usage impact on the line.[180] (Priority: Medium. First reported 2015. Status: Not adopted.)

Transmission Facility Outages

- The MMU recommends that PJM reevaluate all transmission outage tickets as on time or late as if they were new requests when an outage is rescheduled and apply the standard rules for late submissions to any such outages. (Priority: Low. First reported 2014. Status: Not adopted.)
- The MMU recommends that PJM draft a clear definition of the congestion analysis required for transmission outage requests to include in Manual 3 after appropriate review. (Priority: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM modify the rules to reduce or eliminate the approval of late outage requests submitted or rescheduled after the FTR auction bidding opening date. (Priority: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM not permit transmission owners to divide long duration outages into smaller segments to avoid complying with the requirements for long duration outages. (Priority: Low. First reported 2015. Status: Not adopted.)

Section 12 Conclusion

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

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

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

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

generation assets built under the competitive market paradigm. The MMU recommends that the market efficiency process be eliminated.

Managing the generation queues is a highly complex process. The PJM queue evaluation process has been substantially improved in recent years and it is more efficient and effective as a result. The PJM queue evaluation process should continue to be improved to help ensure that barriers to competition for new generation investments are not created. Issues that need to be addressed include the ownership rights to CIRs, whether transmission owners should perform interconnection studies, and improvements in queue management to ensure that projects are removed from the queue if they are not viable, as well as a process to allow commercially viable projects to advance in the queue ahead of projects which have failed to make progress.

The PJM rules for competitive transmission development through the RTEP should build upon FERC Order No. 1000 to create real competition between incumbent transmission providers and nonincumbent transmission providers. The ability of transmission owners to block competition for supplemental projects and end of life projects and reasons for that policy should be reevaluated. PJM should enhance the transparency and queue management process for nonincumbent transmission investment. Issues related to data access and complete explanations of cost impacts should be addressed. The goal should be to remove barriers to competition from nonincumbent transmission. Another element of opening competition would be to consider transmission owners' ownership of property and rights of way at or around transmission substations. In many cases, the land acquired included property intended to support future expansion of the grid. Incumbents have included the costs of the property in their rate base, paid for by customers. Because PJM now has the responsibility for planning the development of the grid under its RTEP process, property bought to facilitate future expansion should be a part of the RTEP process and be made available to all providers on equal terms.

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

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

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

There are currently no market incentives for transmission owners to submit and complete transmission outages in a timely and efficient manner. Requiring transmission owners to pay does not create an effective incentive when those payments are passed through to transmission customers. The process for the submission of planned transmission outages needs to be carefully reviewed and redesigned to limit the ability of transmission owners to submit transmission outages that are late for FTR auction bid submission dates and are late for the Day-Ahead Energy Market. The submission of late transmission outages can inappropriately affect market outcomes when market participants do not have the ability to modify market bids and offers.

Overview: Section 13, FTRs and ARRs

Auction Revenue Rights

Market Structure

- **Residual ARRs.** If ARR allocations are reduced as the result of a modeled transmission outage and the transmission outage ends during the relevant planning year, the result is that residual ARRs may be available. These residual ARRs are automatically assigned to eligible participants the month before the effective date. Residual ARRs are only available on paths prorated in Stage 1 of the annual ARR allocation, are only effective for single, whole months and cannot be self scheduled. Residual ARR clearing prices are based on monthly FTR auction clearing prices. Residual ARRs with negative target allocations are not allocated to participants. Instead they are removed and the model is rerun.

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

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

Market Performance

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

- **ARRs as an Offset to Congestion.** ARRs did not serve as an effective way to return congestion revenues to load. Total ARR and self scheduled FTR revenue offset only 74.5 percent of total congestion costs, which include congestion in the Day-Ahead Energy Market and the balancing energy market, for the 2011/2012 planning period through the 2016/2017 planning period, under the previous allocation of balancing congestion. In the 2017/2018 planning period, in which balancing congestion and M2M payments were directly assigned to load, total ARR and self scheduled FTR revenues offset 50.0 percent of total congestion costs. Under the new rules for surplus congestion revenue allocation beginning in the 2018/2019 planning periods, for the first four months of the 2019/2020 planning period, over 100 percent of total congestion was offset by ARR credit allocations to ARR holders including FTR auction revenues, self scheduled FTR revenue, surplus from the FTR auction, and day-ahead congestion in excess of target allocations. The goal of the FTR market design should be to ensure that load has the rights to 100 percent of the congestion revenues.

Financial Transmission Rights

Market Structure

- **Supply.** In a given auction, market participants can sell FTRs that they have acquired in preceding auctions or preceding rounds of auctions. In the Monthly Balance of Planning Period FTR Auctions for the first four months of the 2019/2020 planning period, total participant FTR sell offers were 3,881,264 MW, up from 3,320,461 MW for the same period during the 2018/2019 planning period.

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

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

Market Behavior

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

Market Performance

- **Volume.** In the first four months of the 2019/2020 planning period Monthly Balance of Planning Period FTR Auctions cleared 1,588,345 MW (16.6 percent) of FTR buy bids and 832,832 MW (21.5 percent) of FTR sell offers.
- **Price.** The weighted average buy bid cleared FTR price in the Monthly Balance of Planning Period FTR Auctions for the first four months of the 2019/2020 planning period was $0.17, up from $0.12 per MW for the same period in the 2018/2019 planning period.
- **Revenue.** The Monthly Balance of Planning Period FTR Auctions generated $27.9 million in net revenue for all FTRs of the first four months of the 2019/2020 planning period, down from $33.5 million for the same time period in the 2018/2019 planning period.
- **Revenue Adequacy.** FTRs were paid at 100.0 percent of the target allocation level for the first four months of the 2019/2020 planning period, assuming the distribution of the current (as of September) existing surplus revenue. This level of FTR funding was at least partially a result of FERC redefining the FTR congestion calculation to exclude balancing congestion and M2M payments.
- **Profitability.** FTR profitability is the difference between the revenue received for an FTR and the cost of the FTR. In the first four months of the 2019/2020 planning period, physical entities made -$22.6 million in profits on FTRs purchased directly (not self scheduled), while receiving $39.5 million in returned congestion from self scheduled FTRs, and financial entities made -$3.1 million in profits.

Section 13 Recommendations

- The MMU recommends that the ARR/FTR design be modified to ensure that the rights to all congestion revenues are assigned to load. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that the Long Term FTR product be eliminated. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that, if the Long Term FTR product is not eliminated, the Long Term FTR Market be modified so that the supply of prevailing flow FTRs in the Long Term FTR Market is based solely on counter flow offers in the Long Term FTR Market. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends that, under the current FTR design, the full capability of the transmission system be allocated as ARRs prior to sale as FTRs. Reductions for outages and increased system capability should be reserved for ARRs rather than sold in the Long Term FTR Auction. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends that all FTR auction revenue be distributed to ARR holders monthly, regardless of FTR funding levels. (Priority: High. First reported 2015. Status: Not adopted.)

- The MMU recommends that, under the current FTR design, all congestion revenue in excess of FTR target allocations be distributed to ARR holders on a monthly basis. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that FTR auction revenues not be used to buy counter flow FTRs for the purpose of improving FTR payout ratios.[181] (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that all historical generation to load paths be eliminated as a basis for allocating ARRs. (Priority: High. First reported 2015. Status: Partially adopted.)
- The MMU recommends that PJM eliminate portfolio netting to eliminate cross subsidies among FTR market participants. (Priority: High. First reported 2012. Status: Not adopted. Rejected by FERC.)
- The MMU recommends that PJM eliminate subsidies to counter flow FTRs by applying the payout ratio to counter flow FTRs in the same way the payout ratio is applied to prevailing flow FTRs. (Priority: High. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM eliminate geographic cross subsidies. (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM examine the mechanism by which self scheduled FTRs are allocated when load switching among LSEs occurs throughout the planning period. (Priority: Low. First reported 2011. Status: Not adopted.)
- The MMU recommends that PJM improve transmission outage modeling in the FTR auction models, including the use of probabilistic outage modeling. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM reduce FTR sales on paths with persistent overallocation of FTRs including clear rules for what defines persistent overallocation and how the reduction will be applied. (Priority: High. First reported 2013. Status: Partially adopted, 2014/2015 planning period.)
- The MMU recommends that PJM and its members continue to review the management of a defaulted member's FTR portfolio, including options other than immediate liquidation. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM continue to evaluate the bilateral indemnification rules and any asymmetries they may create. (Priority: Low. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM examine the source and sink node combinations available in the FTR market and eliminate generation to generation paths and all other paths that do not represent the delivery of power to load. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that the forfeiture amount from the FTR forfeiture rule be based on the correct hourly cost of an FTR, rather than a simple daily price divided by 24. (Priority: High. First reported 2018. Status: Pending at FERC.)
- The MMU recommends that the direct customer request approach for creating and allocating IARRs be eliminated from PJM's tariff. (Priority: Low. First reported 2018. Status: Not adopted.)

Section 13 Conclusion

The annual ARR allocation should be designed to ensure that the rights to all congestion revenues are assigned to firm transmission service customers, without requiring contract path physical transmission rights that are inconsistent with the network based delivery of power and the actual way congestion is generated in security constrained LMP markets. The fixed charges paid for firm transmission services result in the transmission system which provides physically firm transmission service, which results in the delivery of low cost generation, which results in load paying congestion revenues, in an LMP market.

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

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

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

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

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

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

Load should never be required to subsidize payments to FTR holders, regardless of the reason. Such subsidies have been suggested repeatedly.[182] The FERC order of September 15, 2016, introduced a subsidy to FTR holders at the expense of ARR holders.[183] The order requires PJM to ignore balancing congestion when calculating total congestion dollars available to fund FTRs. As of the 2017/2018 planning period, as a result of the FERC order, balancing congestion and M2M payments are assigned to load, rather than to FTR holders. The Commission's order shifts substantial revenue from load to the holders of FTRs and reduces the ability of load to offset congestion. This approach ignores the fact that loads must pay both day-ahead and balancing congestion, and that congestion is defined, in an accounting sense, to equal the sum of day-ahead and balancing congestion. Eliminating balancing congestion from the FTR revenue calculation requires load to pay twice for congestion. Load pays for the physical transmission system, pays in excess of generator revenues and pays negative balancing congestion again. The result is that load gets back less than total congestion. Based on a recent rule change, balancing congestion is allocated to load on a load ratio share, rather than on the basis of location or source of the balancing congestion. This rule creates inappropriate cross subsidies among loads.

These changes were made in order to increase the payout to holders of FTRs who are not loads. Load will continue to be the source of all the funding for FTRs, while payments to FTR holders who did not receive ARRs exceed total congestion on their FTR paths and result in profits to FTR holders. Increasing

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

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

Load was made significantly worse off as a result of the changes made to the FTR/ARR process by PJM based on the FERC order of September 15, 2016. ARR revenues were significantly reduced for the 2017/2018 FTR Auction, the first auction under the new rules. ARRs and self scheduled FTRs offset 50.0 percent of total congestion costs for the 2017/2018 planning period rather than the 60.5 percent offset that would have occurred under the prior rules, a difference of $125.8 million. There was a significant amount of congestion in January 2018 which adversely affected the congestion offset value of ARRs. ARR revenue is fixed at annual auction prices, but congestion revenue varies with market conditions. If these allocation rules had been in place beginning with the 2011/2012 planning period, ARR holders would have received a total of $1,160.0 million less in congestion offsets from the 2011/2012 through the 2017/2018 planning period. The total overpayment to FTR holders for the 2011/2012 through 2018/2019 planning period would have been $1,427.4 million.

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

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

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

The overallocation of Stage 1A ARRs results in FTR overallocations on the same facilities. While Stage 1A overallocation has been reduced, Stage 1A ARR overallocation is a source of reduced revenue and cross subsidy.

The MMU recommends that the basis for the Stage 1A assignments be reviewed and made explicit and that the role of out of date generation to load paths be reviewed beyond the replacement of retired generation that was implemented. There is a reason that transmission is not built to address the Stage 1A overallocation issue. PJM's transmission planning process (RTEP) does not identify a need for new transmission because many of the over allocations are due to outages in the FTR model, or are not actual system limitations. Capacity issues do not persist if the modeled outages are removed, so there is no need to expand the transmission system to support them. The Stage 1A overallocation issue is a fiction based on the use of outdated and irrelevant generation to load paths to assign Stage 1A rights that have nothing to do with actual power flows.

184 163 FERC ¶61,165 (2018).

In addition to addressing these issues, the approach to the question of FTR funding should also examine the fundamental reasons that there has been a significant and persistent difference between day-ahead and balancing congestion. The MMU recommends that the transmission modeling in the FTR auction and persistent FTR path overallocation issues be reviewed and modifications implemented. Regardless of how these issues are addressed, funding issues that persist as a result of modeling differences and flaws in the design of the FTR Market should be borne by FTR holders operating in the voluntary FTR Market and not imposed on load through the mechanism of balancing congestion.

It is not clear, in a competitive market, why participation in the Long Term FTR Auction continues to be very low for the second and third year long term product. In a competitive market the price of Long Term FTRs would be expected to converge with the prices of Annual FTRs, but there has been a persistent, wide divergence that has made the purchase of Long Term FTRs persistently very profitable. Recent changes to improve the modeling of the next year's auction model and include an offline ARR allocation model are steps in the right direction, but do not do enough to guarantee ARR holders' rights to the congestion being auctioned in the Long Term FTR Auction.

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

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