Introduction

Q1 – Q3 2022 in Review

Reliability is a core goal of PJM. Maintaining and improving competitive markets should also be a core goal of PJM. The goal of competition in PJM is to provide customers reliable 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 PJM markets were reliable in the first nine months of 2022. The results of the energy market were competitive in the first nine months of 2022. As a result of FERC's resolving a core underlying issue in the capacity market, the overstated market seller offer cap, the results of the 2023/2024 capacity auction were competitive, although the results of the two prior base capacity auctions were not competitive. The PJM markets bring customers the benefits of competition when the market rules allow competition to work and prevent the exercise of market power.

Markets provide incentives for innovation and efficiency. Organized, competitive wholesale power markets are the best way to facilitate the least cost path to decarbonization. Renewables can compete, without guaranteed long term contracts. Innovation will occur in renewable technologies in unpredictable and beneficial ways. But the PJM markets are not perfect. Significant changes to the market design continue, including some that improve markets and some that do not. Significant issues with the market design remain. It is not guaranteed that the market design will successfully adapt to the changing realities, including the role of renewable and intermittent resources, the role of distributed resources, the role of regulated EDCs in competitive wholesale power markets, and the role of states in subsidizing resources.

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 for both price decreases and price increases. Energy prices increased significantly in the first nine months of 2022 from the first nine months of 2021. The real-time load-weighted average LMP in the first nine months of 2022 increased 118.2 percent from the first nine months of 2021, from $35.68 per MWh to $77.84 per MWh. This is the highest average PJM price ($77.84 per MWh), the highest price increase ($42.16 per MWh) and the highest percent price increase (118.2 percent) for the first nine months of a year since the creation of PJM markets in 1999.

Of the $42.16 per MWh increase, 74.5 percent was a direct result of the costs of fuel, emissions, and consumables. Both coal and natural gas prices were higher in the first nine months of 2022 compared to 2021, although fuel prices varied by time period and area. Coal prices and gas prices in the eastern part of PJM doubled. The real-time hourly average load in the first nine months of 2022 increased by 1.1 percent from the first nine months of 2021, from 89,515 MWh to 90,514 MWh. The load change included increases in data center load and decreases in load due to the growth in behind the meter solar.

More specifically, of the $42.16 per MWh increase in the real-time load weighted average LMP, $26.45 per MWh (62.7 percent) was an increase in the fuel and consumables cost components of LMP, $4.98 per MWh (11.8 percent) was an increase in the emissions cost components of LMP, $5.49 per MWh (13.0 percent) was an increase in the sum of the markup, maintenance, and ten percent adder components of LMP, $1.10 per MWh (2.6 percent) was an increase in the transmission constraint penalty factor component of LMP, and $1.15 per MWh (2.7 percent) was an increase in the scarcity component of LMP.

The total price of wholesale power increased from $61.61 per MWh in the first nine months of 2021 to $103.43 per MWh in the first nine months of 2022, an increase of 67.9 percent. Energy, capacity and transmission charges are the three largest components of the total price of wholesale power, comprising 98.1 percent of the total price per MWh in the first nine months of 2022. Starting in the third quarter of 2019, the cost of transmission per MWh of wholesale power has been higher than the cost of capacity.

In the first nine months of 2022, generation from coal units decreased 12.1 percent, generation from natural gas units increased 8.7 percent, and generation from wind and solar units increased 17.1 percent compared to the first nine months of 2021. The steadily increasing role of gas fired generation and the declining role of coal highlight the importance of ensuring that PJM has real time, detailed and complete information on the gas supply arrangements of all generators, that PJM consider rules requiring capacity resources to have firm fuel supplies and that PJM evaluate the extent to which new gas-fired generators will have access to firm gas. It is also essential that FERC consider and address the implications of the inconsistencies between the gas pipeline business model and the power producer business model and the issue of market power in the gas markets under extreme weather conditions. PJM will rely on existing and new gas-fired generation in the foreseeable future and it is essential that such resources provide reliability and flexibility.

Net revenue is a key measure of overall market performance as well as a measure of the incentive to invest in generation to serve PJM markets. Theoretical net revenues from the energy market increased for all unit types in the first nine months of 2022 compared to the first nine months of 2021. Theoretical energy net revenues increased by 161 percent for a new combustion turbine, 148 percent for a new combined cycle, 44 percent for a new coal unit, and 117 percent for a new nuclear plant.

Changes in forward energy market prices significantly affect the expected profitability of nuclear plants in PJM. Based on forward prices as of October 1, 2022, for energy, and known forward prices for capacity, all the nuclear plants in PJM are expected to cover their annual avoidable costs in 2022, 2023, and 2024, based on NEI average costs. As a result, none of the currently subsidized nuclear plants in PJM need a subsidy for those years in order to cover their avoidable costs.

If more 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 that in some cases subsidize carbon emitting resources. Delaware, Maryland, New Jersey and Virginia were members of RGGI in the first nine months of 2022. Virginia has taken preliminary steps to leave RGGI. Pennsylvania joined RGGI on April 23, 2022, effective on July 1, 2022, but the state's participation has been enjoined by court order while the state action is under review. Implementation of a carbon price is a market approach that 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.

Assertions that customers pay more for energy when there is a carbon price generally do not account for the return of carbon pricing revenues to customers and generally do not recognize the costs of alternative carbon reduction strategies. The MMU continues to recommend that PJM provide a full analysis of the impact of carbon pricing on PJM generating units and carbon pricing revenues to all PJM states in order to permit states to consider the development of a multistate framework that could benefit all states: for REC market design; for potential agreement on carbon pricing; for potential agreement on the distribution of carbon pricing revenues; and for coordination with PJM wholesale markets.

A number of PJM states are pursuing direct approaches to environmental issues including mandating the closure of emitting resources and capping emissions from existing and new resources, in addition to creating renewable portfolio standards (RPS). RECs (renewable energy credits) are an important mechanism used by many PJM states to implement environmental policy under a range of RPS approaches. RECs affect prices in the PJM wholesale power market. RECs provide out of market payments to qualifying renewable resources, primarily wind and solar, as well as some nonrenewable resources. Some resources are not economic without revenue from RECs.

In the absence of a PJM market carbon price, a single, transparent PJM market for RECs would contribute significantly to market efficiency and to the procurement of renewable resources in a least cost manner, if some or all of the PJM states with RPS decided to use that option. Ideally, there would be a single PJM operated forward market for RECs, for a single product based on a common set of state definitions of renewable technologies, with a single clearing price, trued up to real-time delivery, that includes market power mitigation rules. The product definition is a state decision. States would continue to have the option to create separate RECs for additional products that did not fit the product definition, e.g. waste coal or trash incinerators. Such a market 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. The market could also facilitate entry by renewable resources by reducing the risks associated with lack of transparent REC market data and ensuring competitive prices. But it is also important, given that PJM states have a range of approaches to climate policy, to not integrate the REC market into the PJM energy or capacity market so tightly that it affects the prices of energy and capacity for all market participants. Investors would have the responsibility to evaluate and manage their own strategies with a standalone REC market.

Despite suggestions that PJM needs a flexibility product, the PJM fleet already includes the flexibility needed to offset the fluctuations in output assumed to be inherent in renewable energy. Gas fired combined cycles can provide significant flexibility if the market design and rules can account for their characteristics appropriately. But it should not simply be assumed that renewable resources require flexible resources to offset their output fluctuations. PJM markets should provide incentives, especially in the capacity market, for renewable resources to provide higher quality capacity and more stable output by creating hybrid resources. For example, if the ELCC calculations reflected the relatively low marginal value of standalone renewables, as they should, and the significantly higher marginal value of hybrids, there would be a strong incentive to combine resources into hybrids. There would be a related incentive to invest in longer duration hybrids over shorter duration hybrids. PJM does not need a flexibility product. PJM needs to provide incentives to existing and new entrant resources to unlock the significant flexibility potential that already exists and to stop creating incentives for inflexibility. This means enforcing parameter limited schedules, enforcing must offer requirements, enhancing generator modelling to support combined cycle resources without weakening market power mitigation rules, enforcing the correct definition of maximum emergency status, and requiring resources to follow PJM's dispatch instructions in order to be eligible for uplift payments. There is no reason to consider a new flexibility product until the existing rules are enforced and refined, including the elimination of current incentives to be inflexible.

PJM interventions in the market have substantial effects on energy market outcomes. For example, 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 significant price increases through transmission line limit violations or restrictions on the resources available to resolve constraints. PJM interventions to reduce line ratings unnecessarily trigger transmission constraint penalty factors and significantly increase power prices. In the first nine months of 2022, $4.18 per MWh (5.4 percent) of the PJM real-time, load weighted LMP was the result of the transmission constraint violation penalty factors. The increase in the transmission constraint penalty factor component of LMP accounted for $1.10 per MWh (2.6 percent) of the overall increase in LMP in the first nine months of 2022. In the first nine months of 2022, there were 17,472 intervals affected by PJM's use of transmission constraint penalty factors in the real-time market. PJM reduced transmission line ratings in the market clearing process in 86 percent of these cases, by an average of 5.5 percent, below the level that PJM used in actual operations. PJM should limit its interventions in the market and provide greater transparency about the reasons and impacts, if any such interventions continue, in order to enhance market efficiency. PJM's actions should be defined by rules and should be transparent. The MMU continues to recommend that PJM end the practice of discretionary reductions in transmission line ratings modeled in the market clearing and included in LMP.

Fast start pricing significantly increases energy market prices in ways not consistent with competitive markets. Fast start pricing, implemented on September 1, 2021, creates an inefficient wedge between the competitive price and the actual price paid to generators and charged to customers. Fast start pricing increased average real-time energy market prices in the first nine months of 2022 by 6.3 percent compared to competitive energy market prices. This is a significant increase to energy prices given that it does not result from any change to the underlying market supply and demand fundamentals.

The competitiveness of energy market prices cannot be taken for granted. In the first nine months of 2022, 6.2 percent of marginal units set price with positive markups, in some cases over $150 per MWh, despite failing the Three Pivotal Supplier (TPS) test for market power in the real-time energy market. This was the result of documented flaws in the application of offer capping when units fail the TPS test. PJM also schedules and pays uplift to units that fail the TPS test without requiring that units use flexible operating parameters, an issue that FERC raised in a June 17, 2021, Order to Show Cause. In addition to the existing issues with market power mitigation, the current tariff definition of a competitive energy offer results in overstated cost-based offers through the inclusion of major maintenance costs which do not vary in the short run with energy output and are not short run marginal costs. Further, the use of and applicability of fuel cost policies have been undermined. Fuel cost policies should ensure that the costs in generator offers are clearly defined and are verifiable and systematic. Fuel cost policies are required for effective and accurate market power mitigation. Some generation owners prefer to not have clearly defined costs in order to exercise market power and in order to avoid taking responsibility for the accuracy of their offers.

The crisis in ERCOT in February 2021 raised questions about the maximum level of prices in the PJM energy market and whether a circuit breaker is appropriate in order to avoid inefficient wealth transfers. Inefficient wealth transfers from load to generation, among generators, or from physical to financial market participants occur when administrative pricing creates arbitrarily high price signals to which participants cannot respond. The first goal should be to ensure that the energy market design results in prices that reflect market fundamentals and that are not punitive, by design or accident. If, nonetheless, a circuit breaker is implemented, it should be based on the same principles. Prices should reflect market fundamentals and not be suppressed below that level. For example, if gas market prices imply energy market prices of $2,000 per MWh, attempting to suppress the energy market prices below $2,000 per MWh would cause inefficient dislocations, and could exacerbate shortage conditions including the transfer of gas to higher value uses. But prices should not be inflated by the application of administrative pricing measures including those based on ORDCs and transmission constraint penalty factors. The trigger for a circuit breaker is a matter of judgment for those who buy and sell energy in the PJM markets and ultimately FERC. But an effective trigger would be objective, transparent, algorithmic and verifiable in real time. One such metric would be the energy market price. For example, if the energy market price is greater than or equal to $3,000 per MWh for two hours in a day, the circuit breaker would be triggered. The effect of the trigger would be that PJM would set the administrative pricing elements to zero and that the markets would otherwise continue to function as designed.

The design and functioning of the capacity market also cannot be taken for granted. The ongoing stakeholder review of many key elements of the capacity market design includes some proposals that would undermine the role that the capacity market has played to date in the overall PJM market design.

The only purpose of the capacity market is to make the energy market work. The PJM capacity market has played a central role in the evolution of the self sustaining overall PJM market design. If PJM markets are going to continue to be sustainable, it is essential that the basic design of the current capacity market remain. It is essential that the goal of any changes to the capacity market design be explicitly and demonstrably to improve the competitiveness of the market so that the capacity market can continue to use competitive forces to contribute to the success of the energy market, at the lowest possible cost.

The key elements of the capacity market design include: the market is a security constrained single clearing price market; the market is for a single homogeneous and substitutable product; the market is locational; the market is forward looking; the market is annual; all capacity resources must be offered in the market; load must buy all the capacity resources needed to meet the defined reliability goals; and the market includes effective market power mitigation rules.

The key elements of the definition of the homogeneous and substitutable capacity product include: capacity resources are physical; generators must pay for their interconnection costs; the energy from capacity resources is deliverable; the energy from capacity resources is recallable in an emergency; capacity resources must formally track and report outages; and capacity resources must offer their full capacity in the energy market every hour of every day. All capacity resources must supply the homogeneous product with these elements or be convertible into units of the homogeneous product.

Derating factors and ELCC values are used in capacity auctions to convert the nameplate capacity of intermittent and storage resources into MW of capacity equivalent to resources that can produce for any of the 8,760 hours in a year. In order for the capacity market to provide competitive price signals, particularly with more renewable and intermittent and storage resources, the ELCC values must be accurate. PJM has replaced default derating factors by technology type with the Effective Load Carrying Capability (ELCC) approach. But PJM's approach to calculating ELCC values by technology is badly flawed. Fixing the PJM approach to ELCC is a manageable task if there is a shared goal of letting markets reflect the actual, marginal contribution of all types of capacity (including thermal resources) to reliability without assumptions that arbitrarily favor some resource types. ELCC is also not a complete answer to defining a homogeneous product. Regardless of the ELCC value, solar energy will not be available at night and wind energy will not be available when the wind is not blowing. Reliability is not correctly defined as supplying energy during only a limited number of hours. The obligation of capacity resources is to offer energy in all 8,760 hours of the year.

Renewable energy was a relatively small share of PJM total energy and capacity in the first nine months of 2022 but the share is increasing and many renewable projects are under development. While renewables currently make up the majority of both projects and nameplate MW in the interconnection queue, historical completion rates and derating factors must be accounted for when evaluating the share of capacity resources that are likely to be contributed by renewables and by thermal resources and when evaluating the associated required transmission. Of the 12,727.4 MW of combined cycle projects in the queue, 7,478.1 MW (58.8 percent) are expected to go in service based on historical completion rates as of September 30, 2022, providing both energy and capacity at that level. Of the 209,039.6 MW of renewable projects in the queue, only 25,713.2 MW (12.3 percent) are expected to go in service based on historical completion rates and be available to supply energy. Of those 25,713.2 MW, only 11,631.3 MW (5.6 percent of the total) are expected to be capacity resources, based on the average derate factors for storage, wind and solar.

PJM has regularly procured capacity in excess of the reserve requirement at significant cost to customers, both as a result of over forecasted demand and the shape and location of the capacity market demand (VRR) curve. But the quality and significance of PJM reserves needs to be analyzed carefully.

For the 2023/2024 capacity market Base Residual Auction, the level of committed demand resources (8,203.3 MW) exceeds the entire level of excess capacity (7,835.3 MW). This is consistent with PJM effectively not relying on demand response for reserves or reliability in actual operations. The excess is a result of the flawed rules permitting the participation of inferior demand side resources in the capacity market. Maintaining the persistent excess capacity has meant that PJM markets have never experienced the results of reliance on demand side resources as part of the required reserve margin, rather than as excess above the required reserve margin. PJM markets have never experienced the implications of the definition of demand side resources as a purely emergency capacity resource that triggers a PAI whenever called. If demand side capacity resources were part of the required reserves and there were no excess capacity, the probability of PAI would increase, potentially significantly, with correspondingly significant impacts on market prices.

In addition, the sum of cleared MW that were considered categorically exempt from the capacity market must offer requirement is 7,534.3 MW, or 44.4 percent of the required reserves and 30.4 percent of total reserves. The sum of cleared MW that were categorically exempt from the must offer requirement and the cleared MW of DR is 15,737.7 MW, or 92.8 percent of required reserves and 63.5 percent of total reserves.

These results suggest that the required reserve margin and the actual reserve margin be considered carefully along with the obligations of the resources that the reserve margin assumes will be available. The excess reserve margins should be reduced, but only if the related issues are addressed. Demand side resources should either be required to provide the homogeneous capacity product as an actual substitute for other capacity resources or it should be on the demand side of the market where it can participate more effectively and flexibly without the need to meet the requirements to be a supply side capacity resource. Intermittent resources should have the same must offer requirement as all other capacity resources. The capacity market cannot work without a uniformly applied must offer requirement. As the role of intermittent and storage resources increases in PJM markets, the need to establish the uniform must offer requirement is urgent.

The significant level of expected coal plant retirements over the next five years, largely as a result of state and federal regulatory actions but also reflecting economic factors and coal availability, will also have an effect on overall reserve margins and on locational resource adequacy. There is the potential for additional RMR units that PJM requires to remain in service for reliability reasons after the units' target retirement date. PJM's RMR tariff is badly flawed and needs immediate reform. Among many flaws, the RMR tariff is interpreted by many RMR generation owners to permit the recovery from customers of investment costs associated with assets that had previously been written off on the owners' books. RMR units are intended to be a short term, nonmarket solution to a reliability problem. But the need for an RMR solution suggests that the locational capacity market signals are not effective because they cannot incorporate the retirement before it is announced. Known retirements for regulatory reasons should be identified in advance and excluded from the forward capacity markets following desired retirement dates. More granular locational capacity market price signals are needed to provide appropriate incentives for entry to replace retiring units. PJM's CETO/CETL analysis should be reviewed in order to ensure that it is correctly reflecting locational reliability requirements and resources. PJM should do transmission planning to ensure that the transmission system will be adequate to ensure reliability after the expected retirements and without RMRs.

The challenge for reliability in the next five years will be to ensure that the market design provides energy and capacity market signals based on market fundamentals and avoids attempts to suppress or inflate market prices. This return to market design basics is difficult as the temptation to add complexity is apparently overwhelming at times. The capacity market return to basics should include elimination of the remaining formal elements of the Capacity Performance model while retaining the essential insight that rules and incentives for performance are essential. Use of EFORd as a performance metric is outdated. A combination of ELCC for renewables and equivalent availability factors (EAF) for thermal resources is needed.

The MMU supported PJM's Capacity Performance (CP) filing. But, after evaluating the offer behavior and results of the capacity market auctions under CP, the underlying assumptions and logic of CP, and the actual PAI evidence and the failure to include updated PAI data in the definition of the offer cap, it became clear to the MMU that the CP model was a mistake.

The market seller offer cap of Net CONE times B was ultimately a failed experiment based on three key counterfactual assumptions. It was explicitly assumed that Net CONE was the target clearing price for the capacity market. That assumption and/or assertion was the basis for using Net CONE as the penalty rate. The penalty rate, adjusted for the reduced obligation defined by B, became the market seller offer cap. The circular logic of the mathematical derivation inevitably concluded that Net CONE times B was the competitive offer. It was assumed that capacity resources have the ability to costlessly switch between capacity resource status and energy only status. Finally, it was assumed that competitive forces in the capacity market would produce competitive outcomes, even if the prior assumptions led to an offer cap that was above the competitive level.

The mathematical derivation also included some additional unsupported and incorrect assumptions: there are a reasonably expected number of PAI; the number of PAI used in the calculation of the nonperformance charge rate is the same as the expected PAI (360); the number of performance intervals that define the total payments must equal the denominator of the performance penalty rate; the bonus payment rate for units that overperform equals the penalty rate for units that underperform; and penalties are imposed by PJM for all cases of noncompliance as defined in the tariff and there are no excuses.

The structure of the PJM Capacity Market is not competitive and the purpose of market power mitigation is to produce competitive results despite that fact. The correct definition of a competitive offer is the marginal cost of capacity, net ACR, where ACR includes an explicit accounting for the costs of mitigating risk, including the risk associated with capacity market nonperformance penalties, and the relevant costs of acquiring fuel, including natural gas.

The MMU recommends elimination of the key remaining components of the Capacity Performance model because they interfere with competitive outcomes in the capacity market and create unnecessary complexity and risk. The use of Net CONE to define the penalty rate is a form of arbitrary administrative pricing that creates high risk for generators, creates complexity in the calculation of the cost to mitigate risk (CPQR) and ultimately raises the price of capacity. Rather than penalizing capacity resources for nonperformance, capacity resources should be paid the daily price of capacity only to the extent that they are available to produce energy or provide reserves, as required by PJM on a daily/hourly basis, based on their cleared capacity (ICAP). This is a positive performance incentive based on the market price of capacity rather than a penalty based on an arbitrary and incorrect assumption.

The evolution of wholesale power markets is far from complete. The PJM markets need rules in order to provide reliable energy through competition. The foundational principle of using markets, with rules to prevent the exercise of market power and provide competitive results, is essential. Private investors, regardless of technology or subsidies, will put capital at risk and earn compensatory returns that are not skewed in favor of any specific technology. The core elements of the PJM market design remain robust. The use of locational marginal prices (LMP) in the energy market and locational prices in the capacity market continue to be essential to getting the price signals right. Technological and policy changes do not require that the core elements change. But the market design can be improved and made more reliable and 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, 2021 and 2022[1]

	2021 (Jan-Sep)	2022 (Jan-Sep)	Percent Change
Average Hourly Load Plus Exports (MWh)	94,746	96,196	1.5%
Average Hourly Generation Plus Imports (MWh)	96,519	98,064	1.6%
Peak Load Plus Export (MWh)	151,680	149,531	(1.4%)
Installed Capacity at September 30 (MW)	184,623	181,346	(1.8%)
Load Weighted Average Real Time LMP ($/MWh)	$35.68	$77.84	118.2%
Total Congestion Costs ($ Million)	$614.6	$1,863.2	203.2%
Total Uplift Credits ($ Million)	$131.1	$180.5	37.7%
Total PJM Billing ($ Billion)	$37.55	$66.10	76.0%

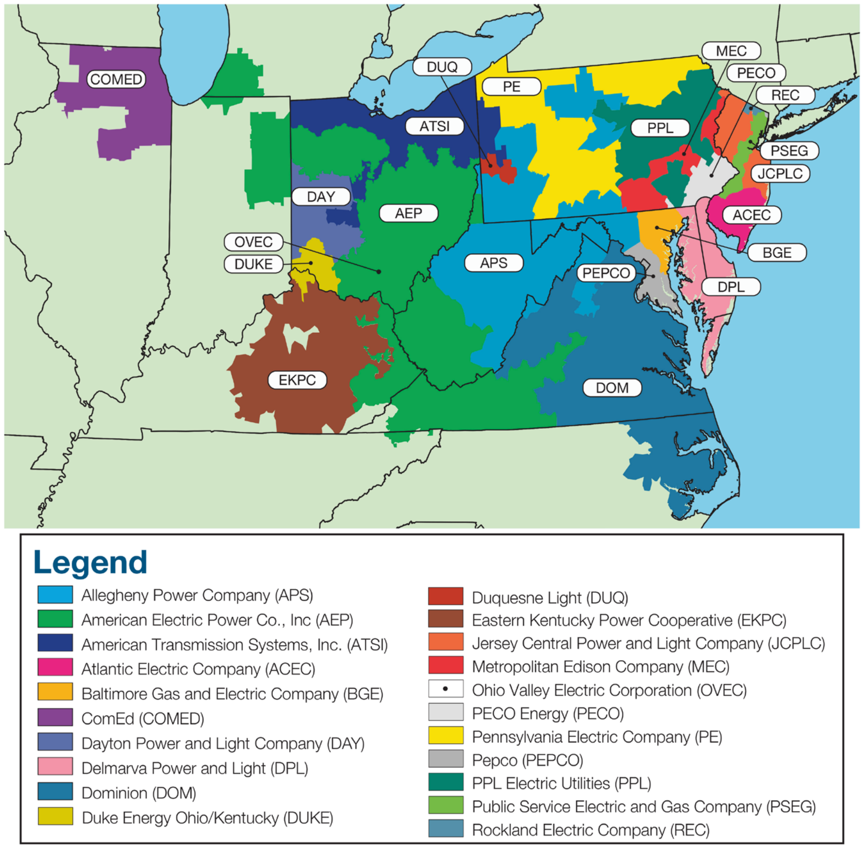
PJM Market Background

The PJM Interconnection, L.L.C. (PJM) operates a centrally dispatched, competitive wholesale electric power market that, as of September 30, 2022, had installed generating capacity of 181,346 megawatts (MW) and 1,095 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).[2 3 4]

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

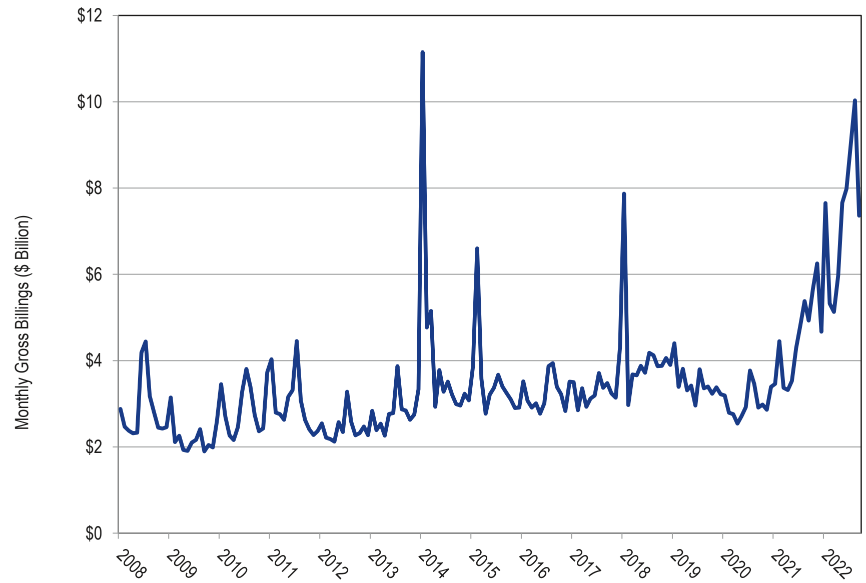
1 In Table 01, the MMU uses Total PJM Billing values provided by PJM. For 2019 and after, the Total PJM Billing calculation was modified to better reflect PJM total billing through the PJM settlement process.
2 See PJM. "Member List," which can be accessed at: <http://pjm.com/about-pjm/member-services/member-list.aspx>.
3 See PJM. "Who We Are," which can be accessed at: <http://pjm.com/about-pjm/who-we-are.aspx>.
4 See the *2021 State of the Market Report for PJM*, Volume II, Appendix A: "PJM Overview" for maps showing the PJM footprint and its evolution prior to 2022.

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



In the first nine months of 2022, PJM had net gross billings of $66.10 billion, an increase of 76.0 percent from $37.55 billion in the first nine months of 2021. The $66.10 billion of gross billings in the first nine months of 2022 was larger than any PJM annual total reported. (Figure 1-2).

Figure 1-2 PJM reported monthly billings ($ Billion): January 2008 through September 2022[5]



PJM operates the day-ahead energy market, the real-time energy market, the Reliability Pricing Model (RPM) capacity market, the regulation market, the synchronized reserve market, the day-ahead scheduling reserve (DASR) market and the financial transmission rights (FTRs) markets.

PJM introduced energy pricing with cost-based offers and market-clearing nodal prices on April 1, 1998, and market-clearing nodal prices with market-based offers on April 1, 1999. PJM introduced the Daily Capacity Market on January 1, 1999, and the Monthly and Multimonthly Capacity Markets for the January through May 1999 period. PJM implemented FTRs on May 1, 1999. PJM implemented the day-ahead energy market and the regulation market on June 1, 2000. PJM modified the regulation market design and added a market in Synchronized Reserve on December 1, 2002. PJM introduced an

5 In Figure 1-2, the MMU uses Total PJM Billing values provided by PJM. For 2019 and after, the Total PJM Billing calculation was modified to better reflect PJM total billing through the PJM settlement process.

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.[6 7]

Conclusions

This report assesses the competitiveness of the markets managed by PJM in the first nine months of 2022, 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, markup, and price. The MMU concludes that the PJM energy market results were competitive in the first nine months of 2022.

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**

6 See also the *2021 State of the Market Report for PJM*, Volume II, Appendix A: "PJM Overview."

7 Analysis of 2022 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 (DUQ) and Dominion (DOM). In June 2011, PJM integrated the American Transmission Systems, Inc. (ATSI) Control Zone. In January 2012, PJM integrated the Duke Energy Ohio/Kentucky (DUKE) 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 2022, see *2021 State of the Market Report for PJM*, Volume 2, Appendix A: "PJM Overview."

- 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 aggregate energy market in the first nine months of 2022 was, on average, unconcentrated by FERC HHI standards. Average HHI was 690 with a minimum of 554 and a maximum of 1012 in the first nine months of 2022. The intermediate segment was moderately concentrated. The peaking segment of supply was highly concentrated. The fact that the average HHI is in the unconcentrated 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 require 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 the day-ahead and real-time energy markets, although the behavior of some participants both routinely and during periods of high demand represents economic withholding. The ownership of marginal units is concentrated. The markups of pivotal suppliers in the aggregate market and of many pivotal suppliers in local markets remain unmitigated due to the lack of aggregate market power mitigation and the flawed implementation of offer caps for resources that fail the TPS test. 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 resolved the problems with real-time dispatch and pricing on November 1, 2021. The implementation of fast start pricing on September 1, 2021 undermined market efficiency by setting inefficient prices that are inconsistent with the dispatch signals.
- 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 core functions is to identify actual or potential market design flaws.[8] The approach to market power mitigation in PJM has focused on market designs that promote competition (a structural basis for competitive outcomes) and on mitigating market power in instances where the market structure is not competitive and thus where market design alone cannot mitigate market power. FERC relies on effective market power mitigation when it approves market sellers to participate in the PJM market at market based rates.[9] In the PJM energy market, market power mitigation 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. FERC recognized these issues in its June 17, 2021 order.[11] Some units with market power have positive markups and some have inflexible parameters, which means that the cost-based offer was not used and that the process for offer capping units that fail the TPS test does not consistently result in competitive market outcomes in the presence of market power. 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. 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 rules permitting cost-based offers in excess of $1,000 per MWh.

Capacity Market Conclusion

The Market Monitoring Unit (MMU) analyzed market structure, participant conduct and market performance in the PJM Capacity Market, including supply, demand, concentration ratios, pivotal suppliers, volumes, prices, outage rates and reliability.[12] The conclusions are a result of the MMU's evaluation of the 2023/2024 Base Residual Auction.

Table 1-3 The capacity market results were competitive

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

- The aggregate market structure was evaluated as not competitive. For almost all auctions held from 2007 to the present, the PJM Capacity Market failed the three pivotal supplier test (TPS), which is conducted at the time of the auction.[13] 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.[14]
- Participant behavior was evaluated as competitive in the 2023/2024 BRA after the Commission order addressed the definition of the market seller

8 OATT Attachment M (PJM Market Monitoring Plan).
9 See *Refinements to Horizontal Market Power Analysis for Sellers in Certain Regional Transmission Organization and Independent System Operator Markets*, Order No. 861, 168 FERC ¶ 61,040 (2019); *order on reh'g*, Order No. 861-A; 170 FERC ¶ 61,106 (2020).
10 The market performance test means that offer capping is not applied if the offer does not exceed the competitive level and therefore market power would not affect market performance.
11 175 FERC ¶ 61,231 (2021).
12 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.
13 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.
14 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. In the 2021/2022 RPM Second Incremental Auction, two participants in the incremental supply in EMAAC passed the TPS test.

offer cap by eliminating the Net CONE times B offer cap and establishing a competitive market seller offer cap of net ACR, effective September 2, 2021.[15] Market power mitigation measures were applied when the capacity market seller failed the market power test for the auction, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, would increase the market clearing price.

- Market performance was evaluated as competitive based on the 2023/2024 Base Residual Auction after the Commission order eliminating the Net CONE times B offer cap and establishing a competitive market seller offer cap of net ACR, effective September 2, 2021. Although structural market power exists in the capacity market, a competitive outcome can result from the application of market power mitigation rules.
- Market design was evaluated as mixed because while there are many positive features of the Reliability Pricing Model (RPM) design and the capacity performance modifications to RPM, there are several features of the RPM design which still threaten competitive outcomes. These include the definition of DR which permits inferior products to substitute for capacity, the replacement capacity issue, the definition of unit offer parameters, and the inclusion of imports which are not substitutes for internal capacity resources.
- As a result of the fact that the capacity market design was found to be not just and reasonable by FERC and a final market design had not been approved, the 2022/2023 Base Residual Auction was delayed and held in May 2021, and for a number of additional reasons, the 2023/2024 Base Residual Auction was delayed and held in June 2022, and first and second incremental auctions for the 2022/2023 through 2026/2027 Delivery Years are canceled if within 10 months of the revised BRA schedule.[16]

15 176 FERC ¶ 61,137 (2021), *order denying reh'g*, 178 FERC ¶ 61,121 (2022), *appeal pending*, EPSA, et al. v. FERC, Case No. 21-1214, et al. (DC Cir. 2022) . The Commission recognized the market power problem and issued an order correcting the PJM tariff, eliminating the prior offer cap and establishing a competitive market seller offer cap set at net ACR, effective September 2, 2021.

16 174 FERC ¶ 61,036 (2021), 177 FERC ¶ 61,050 (2021), 177 FERC ¶ 61,209 (2021).

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 2022.

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 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 overcompensated when the nonsynchronized reserve market clears with a nonzero price. This settlement rule is scheduled to be removed on October 1, 2022, with the consolidation of tier 1 and tier 2 reserves.

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 2022.

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 structure was evaluated as not competitive because the DASR market failed the three pivotal supplier (TPS) test in 86.7 percent of the intervals in which the price was greater than $0.01 per MWh.
- Participant behavior was evaluated as mixed because while most offers were equal to marginal costs, a significant proportion of offers reflected economic withholding. The ability to withhold 30 minute reserves using offers is scheduled to be removed on October 1, 2022, with the implementation of a secondary reserve market.
- Market performance was evaluated as competitive because there were adequate offers in every hour to satisfy the requirement and the clearing prices reflected in those offers, although there is concern about offers above the competitive level affecting prices. The day-ahead scheduling reserve market clearing price was above $0 in 12.6 percent of hours in the first nine months of 2022. In 98.4 percent of hours when the clearing price was above $0, the clearing price was the offer price of the marginal unit. The price included lost opportunity cost in 1.6 percent of hours when the clearing price was above $0. After October 1, 2022, clearing prices for 30 minute reserves will include only lost opportunity cost.
- 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. After October 1, 2022, offers will contain only opportunity cost and day-ahead 30 minute reserves will have a corresponding real-time product.

Regulation Market Conclusion

The MMU analyzed measures of market structure, conduct and performance for the PJM Regulation Market for the first nine months of 2022.

Table 1-6 The regulation market results were not competitive

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

- The regulation market structure was evaluated as not competitive because the PJM Regulation Market failed the three pivotal supplier (TPS) test in 88.8 percent of the hours in the first nine months of 2022.
- Participant behavior in the PJM Regulation Market was evaluated as competitive in the first nine months of 2022 because market power mitigation requires competitive offers when the three pivotal supplier test is failed, although the inclusion of a positive margin raises questions.
- Market performance was evaluated as not competitive, because all units are not paid the same price on an equivalent MW basis.
- 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 *2022 Quarterly State of the Market Report for PJM: January through September* focuses on the 2022/2023 Monthly Balance of Planning Period FTR Auctions, specifically covering January 1, 2022, through September 30, 2022. 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 partially competitive in the first nine months of 2022.

Table 1-7 The FTR auction markets results were partially competitive

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

- Market structure was evaluated as competitive. The ownership of FTR obligations is unconcentrated for the individual years of the 2022/2025 Long Term FTR Auction, the 2022/2023 Annual FTR Auction and each period of the Monthly Balance of Planning Period Auctions. The ownership of FTR options is moderately or highly concentrated for every Monthly FTR Auction period and moderately concentrated for the 2022/2023 Annual FTR Auction. Ownership of FTRs is disproportionately (85.2 percent) by financial participants. The ownership of ARRs is unconcentrated.

- Participant behavior was evaluated as partially competitive because ARR holders who are the sellers of FTRs are not permitted to participate in the market clearing.
- Market performance was evaluated as partially competitive because of the flaws in the market design. Sellers, the ARR holders, cannot set a sale price. Buyers can reclaim some of their purchase price after the market clears if the product does not meet a profitability target. The market resulted in a substantial shortfall in congestion payments to load and significant and unsupportable disparities among zones in the share of congestion returned to load. FTR purchases by financial entities remain persistently profitable in part as a result of the flaws in the market design.
- Market design was evaluated as flawed because there are significant and fundamental flaws with the basic ARR/FTR design. The FTR auction market is not actually a market because the sellers have no independent role in the process. ARR holders cannot determine the price at which they are willing to sell rights to congestion revenue. Buyers have the ability to reclaim some of the price paid for FTRs after the market clears. The market design is not an efficient or effective way to ensure that the rights to all congestion revenues are assigned to load. The product sold to FTR buyers is incorrectly defined as target allocations rather than a share of congestion revenue. ARR holders' rights to congestion revenues are not correctly defined because the contract path based assignment of congestion rights is inadequate and incorrect. Ongoing PJM subjective intervention in the FTR market that affects market fundamentals is also an issue and a symptom of the fundamental flaws in the design. The product, the quantity of the product and the price of the product are all incorrectly defined.
- 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 and the fact that sellers are required to return some of the cleared auction revenue to FTR buyers when FTR profits are not adequate, means that the FTR design does not actually function as a market and is evidence of basic flaws in the market design.

Role of MMU

FERC assigns three core functions to MMUs: reporting, monitoring and market design.[17] 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.[18]

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.

17 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).
18 OATT Attachment M § IV; 18 CFR § 1c.2.

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

Monitoring

To perform its monitoring function, the MMU screens and monitors the conduct of Market Participants under the MMU's broad purview to monitor, investigate, evaluate and report on the PJM Markets.[19] The MMU has direct, confidential access to FERC.[20] The MMU may also refer matters to the attention of state commissions.[21]

The MMU monitors market behavior for violations of FERC Market Rules and PJM Market Rules, including the actual or potential exercise of market power.[22] 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…"[23] [24] [25] The MMU also monitors PJM for compliance with the rules, in addition to market participants.[26]

19 OATT Attachment M § IV.
20 OATT Attachment M § IV.K.3.
21 OATT Attachment M § IV.H.
22 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.")
23 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.
24 OATT § I.1.
25 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 initiate, participate as a party or provide information or testimony in regulatory or other proceedings.
26 OATT Attachment M § IV.C.

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

If cost-based offers do 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 cap in each capacity market (RPM) auction using data submitted to the MMU through web-based data input systems developed by the MMU.[27]

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.[28] [29] [30] [31]

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

27 OATT Attachment M–Appendix § II.E.
28 OATT Attachment M–Appendix § II.B.
29 OATT Attachment M–Appendix § II.C.
30 OATT Attachment M–Appendix § IV.
31 OATT Attachment M–Appendix § VII.

reviews offers, but it does so in order to determine whether offers comply with the PJM tariff and manuals. PJM, in its role as the market operator, may reject an offer that fails to comply with the market rules. The respective reviews performed by the MMU and PJM are separate and non-sequential.

The PJM markets monitored by the MMU include market related procurement processes conducted by PJM, such as for Black Start resources included in the PJM system restoration plan.[32] [33]

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.[34]

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.[35] The MMU initiates and proposes changes to the design of such markets or the PJM Market Rules in stakeholder or regulatory proceedings.[36] 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, market rules and market rule implementation issues, including complaints or petitions.[37] 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.[38] The MMU may provide in its annual, quarterly and other reports "recommendations regarding any matter within its purview."[39]

32 OATT Attachment M–Appendix § II(p).
33 OATT Attachment M–Appendix § III.
34 OA Schedule 6 § 1.5.
35 OATT Attachment M § IV.D.
36 *Id.*
37 *Id.*; see also, e.g., 171 FERC ¶ 61,039; 167 FERC ¶ 61,084 at PP 70–76, *reh'g denied*, 168 FERC ¶ 61,141.
38 *Id.*
39 OATT Attachment M § VI.A.

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," the MMU recommends specific enhancements to existing market rules and implementation of new rules that are required for competitive results in PJM markets and for continued improvements in the functioning of PJM markets.[40]

In this *2022 Quarterly State of the Market Report for PJM: January through September*, the MMU includes one new recommendation.

New Recommendation from Section 5, Capacity Market

- The MMU recommends elimination of the key remaining components of the Capacity Performance model because they interfere with competitive outcomes in the capacity market and create unnecessary complexity and risk. (Priority: High. New recommendation. Status: Not adopted.)

Total Price of Wholesale Power

The total price of wholesale power is the total price per MWh of wholesale electricity in PJM markets.[41] The total price is an average price. Prices vary by location and time period. The total price includes the price of energy, capacity, transmission service, ancillary services, and 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 2021 and 2022.

The total costs for each year shown in Table 1-8 equal the total price per MWh, by category, multiplied by the total load. The total costs are different from the total billing values that PJM reports as shown in Figure 1-2. PJM's reported total billing values represent the total dollars that pass through the PJM settlement process.

40 18 CFR § 35.28(g)(3)(ii)(A); see also OATT Attachment M § IV.D.
41 Accounting load is used in the calculation of total price because accounting load is the load customers pay for in PJM settlements. The use of accounting load with losses before June 1, 2007 and without losses after June 1, 2007, is consistent with PJM's calculation of LMP. Before June 1, 2007, transmission losses were included in accounting load. After June 1, 2007, transmission losses were excluded from accounting load and losses were addressed through the incorporation of marginal loss pricing in LMP.

Each of the components in Table 1-8 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.[42]
- The Energy Uplift (Operating Reserves) component is the average price per MWh of day-ahead and balancing operating reserves and synchronous condensing charges.[43]
- The Reactive component is the average cost per MWh of reactive supply and voltage control from generation and other sources.[44]
- The Regulation component is the average cost per MWh of regulation procured through the PJM Regulation Market.[45]
- 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.[46]
- 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.[47]
- The Emergency Load Response component is the average cost per MWh of the PJM Emergency Load Response Program.[48]
- 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.[49]
- 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.[50]
- The Synchronized Reserve component is the average cost per MWh of synchronized reserve procured through the Synchronized Reserve Market.[51]
- The Black Start component is the average cost per MWh of black start service.[52]
- The RTO Startup and Expansion component is the average cost per MWh of charges to recover AEP, COMED and DAY's integration expenses.[53]
- The NERC/RFC component is the average cost per MWh of NERC and RFC charges, plus any reconciliation charges.[54]
- The Economic Load Response component is the average cost per MWh of day-ahead and real-time economic load response program charges to LSEs.[55]
- The Transmission Facility Charges component is the average cost per MWh of Ramapo Phase Angle Regulators charges allocated to PJM Mid-Atlantic transmission owners.[56]
- The Nonsynchronized Reserve component is the average cost per MWh of non-synchronized reserve procured through the Non-Synchronized Reserve Market.[57]
- The Emergency Energy component is the average cost per MWh of emergency energy.[58]

42 OATT §§ 13.7, 14.5, 27A & 34.
43 OA Schedules 1 §§ 3.2.3 & 3.3.3.
44 OATT Schedule 2 and OA Schedule 1 § 3.2.3B. The line item in Table 08 includes all reactive services charges.
45 OA Schedules 1 §§ 3.2.2, 3.2.2A, 3.3.2, & 3.3.2A; OATT Schedule 3.
46 OATT Schedule 12.
47 RAA Schedule 8.1.
48 OATT PJM Emergency Load Response Program.
49 OA Schedules 1 §§ 3.2.3A.01 & OATT Schedule 6.
50 OATT Schedule 1A.
51 OA Schedule 1 § 3.2.3A.01; PJM OATT Schedule 6.
52 OATT Schedule 6A. The line item in Table 08 includes all Energy Uplift (Operating Reserves) charges for Black Start.
53 OATT Attachments H-13, H-14 and H-15 and Schedule 13.
54 OATT Schedule 10-NERC and OATT Schedule 10-RFC.
55 OA Schedule 1 § 3.6.
56 OA Schedule 1 § 5.3b.
57 OA Schedule 1 § 3.2.3A.001.
58 OA Schedule 1 § 3.2.6.

Table 1-8 shows that energy, capacity and transmission charges are the three largest components of the total price per MWh of wholesale power, comprising 98.1 percent of the total price per MWh in the first nine months of 2022. The total price per MWh of wholesale power increased from $61.61 in the first nine months of 2021 to $103.43 in the first nine months of 2022, an increase of 67.9 percent. Starting in the third quarter of 2019, the cost of transmission per MWh of wholesale power has been higher than the cost of capacity.

Table 1-8 Total price per MWh by category: January through September, 2021 and 2022[59 60 61 62]

Category	2021 (Jan - Sep) $/MWh	2021 (Jan - Sep) ($ Millions)	2021 (Jan - Sep) Percent of Total	2022 (Jan - Sep) $/MWh	2022 (Jan - Sep) ($ Millions)	2022 (Jan - Sep) Percent of Total	Percent Change
Load Weighted Energy	$35.68	$20,923	57.9%	$77.84	$46,155	75.3%	118.2%
Capacity	$10.29	$6,036	16.7%	$8.82	$5,228	8.5%	(14.3%)
Capacity	$10.29	$6,035	16.7%	$8.78	$5,205	8.5%	(14.7%)
Capacity (FRR)	$0.00	$1	0.0%	$0.01	$3	0.0%	354.5%
Capacity (RMR)	$0.00	$0	0.0%	$0.03	$21	0.0%	0.0%
Transmission	$14.07	$8,250	22.8%	$14.83	$8,793	14.3%	5.4%
Transmission Service Charges	$11.72	$6,875	19.0%	$12.51	$7,419	12.1%	6.7%
Transmission Enhancement Cost Recovery	$2.25	$1,322	3.7%	$2.24	$1,328	2.2%	(0.6%)
Transmission Owner (Schedule 1A)	$0.09	$53	0.1%	$0.08	$45	0.1%	(16.5%)
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	$0.79	$462	1.3%	$1.11	$657	1.1%	40.7%
Reactive	$0.46	$272	0.8%	$0.49	$290	0.5%	5.3%
Regulation	$0.15	$88	0.2%	$0.36	$212	0.3%	138.3%
Black Start	$0.09	$50	0.1%	$0.09	$52	0.1%	1.3%
Synchronized Reserves	$0.05	$31	0.1%	$0.13	$78	0.1%	144.9%
Non-Synchronized Reserves	$0.02	$11	0.0%	$0.03	$15	0.0%	40.4%
Day Ahead Scheduling Reserve (DASR)	$0.02	$9	0.0%	$0.02	$11	0.0%	19.1%
Administration	$0.55	$323	0.9%	$0.51	$305	0.5%	(6.7%)
PJM Administrative Fees	$0.52	$303	0.8%	$0.48	$284	0.5%	(7.3%)
NERC/RFC	$0.04	$21	0.1%	$0.04	$21	0.0%	2.0%
RTO Startup and Expansion	$0.00	$0	0.0%	$0.00	$0	0.0%	0.0%
Energy Uplift (Operating Reserves)	$0.22	$130	0.4%	$0.30	$179	0.3%	35.9%
Demand Response	$0.00	$1	0.0%	$0.02	$10	0.0%	962.5%
Load Response	$0.00	$1	0.0%	$0.01	$7	0.0%	687.5%
Emergency Load Response	$0.00	$0	0.0%	$0.00	$3	0.0%	0.0%
Emergency Energy	$0.00	$0	0.0%	$0.00	$0	0.0%	0.0%
Other	$0.01	$4	0.0%	$0.00	$3	0.0%	(37.8%)
Total Price	$61.61	$36,129	100.0%	$103.43	$61,330	100.0%	67.9%
Total Load (GWh)	586,415			592,959			1.1%
Total Cost ($ Billions)	$36.13			$61.33			69.8%

59 The totals in the Transmission section of this table include corrections to previously reported totals which did not include a full accounting of Transmission Enhancement Cost Recovery costs. The MMU is currently reevaluating the total cost of wholesale power calculation.
60 Note: The totals in this table include after the fact billing adjustments and may not match totals presented in past reports.
61 The total cost in this table does not match the PJM reported total billing due to differences in calculation methods. The total prices in this table are load weighted average system prices per MWh by category, even if each category is not charged on a per MWh basis. PJM's reported total billing represents the total dollars that pass through the PJM settlement process.
62 The MMU publishes monthly detail of these components of PJM price. See <http://www.monitoringanalytics.com/data/pjm_price.shtml>.

Table 1-9 shows the inflation adjusted average price, by component, for the first nine months of 2021 and 2022. To calculate 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).[63]

Table 1-9 Inflation adjusted total price per MWh by category: January through September, 2021 and 2022[64 65]

Category	2021 (Jan - Sep) $/MWh	2021 (Jan - Sep) ($ Millions)	2021 (Jan - Sep) Percent of Total	2022 (Jan - Sep) $/MWh	2022 (Jan - Sep) ($ Millions)	2022 (Jan - Sep) Percent of Total	Percent Change
Load Weighted Energy	$21.39	$12,545	57.3%	$43.04	$25,523	74.8%	101.2%
Capacity	$6.54	$3,833	17.5%	$5.19	$3,075	9.0%	(20.7%)
Capacity	$6.54	$3,833	17.5%	$5.16	$3,062	9.0%	(21.0%)
Capacity (FRR)	$0.00	$0	0.0%	$0.00	$2	0.0%	300.0%
Capacity (RMR)	$0.00	$0	0.0%	$0.02	$11	0.0%	0.0%
Transmission	$8.46	$4,961	22.7%	$8.23	$4,883	14.3%	(2.7%)
Transmission Service Charges	$7.05	$4,134	18.9%	$6.95	$4,120	12.1%	(1.4%)
Transmission Enhancement Cost Recovery	$1.36	$795	3.6%	$1.24	$738	2.2%	(8.2%)
Transmission Owner (Schedule 1A)	$0.05	$32	0.1%	$0.04	$25	0.1%	(22.7%)
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	$0.47	$277	1.3%	$0.61	$365	1.1%	30.0%
Reactive	$0.28	$164	0.7%	$0.27	$161	0.5%	(2.8%)
Regulation	$0.09	$53	0.2%	$0.20	$118	0.3%	120.5%
Black Start	$0.05	$30	0.1%	$0.05	$29	0.1%	(6.4%)
Synchronized Reserves	$0.03	$19	0.1%	$0.07	$43	0.1%	125.6%
Non-Synchronized Reserves	$0.01	$6	0.0%	$0.01	$9	0.0%	31.8%
Day Ahead Scheduling Reserve (DASR)	$0.01	$5	0.0%	$0.01	$6	0.0%	10.0%
Administration	$0.33	$194	0.9%	$0.29	$169	0.5%	(14.0%)
PJM Administrative Fees	$0.31	$182	0.8%	$0.27	$157	0.5%	(14.5%)
NERC/RFC	$0.02	$12	0.1%	$0.02	$12	0.0%	(5.7%)
RTO Startup and Expansion	$0.00	$0	0.0%	$0.00	$0	0.0%	0.0%
Energy Uplift (Operating Reserves)	$0.13	$78	0.4%	$0.17	$99	0.3%	24.8%
Demand Response	$0.00	$1	0.0%	$0.01	$6	0.0%	830.0%
Load Response	$0.00	$1	0.0%	$0.01	$4	0.0%	590.0%
Emergency Load Response	$0.00	$0	0.0%	$0.00	$1	0.0%	0.0%
Emergency Energy	$0.00	$0	0.0%	$0.00	$0	0.0%	0.0%
Other	$0.00	$3	0.0%	$0.00	$2	0.0%	(42.2%)
Total Price	$37.33	$21,892	100.0%	$57.54	$34,120	100.0%	54.1%
Total Load (GWh)	586,415			592,959			1.1%
Total Cost ($ Billions)	$21.89			$34.12			55.9%

63 US Consumer Price Index for all items, Urban Consumers (base period: January 1998), published by *Bureau of Labor Statistics*. <http://download.bls.gov/pub/time.series/cu/cu.data.1.AllItems> (October 13, 2022).
64 The totals in the Transmission section of this table include corrections to previously reported totals which did not include a full accounting of Transmission Enhancement Cost Recovery costs. The MMU is currently reevaluating the total cost of wholesale power calculation.
65 Note: The totals in this table include after the fact billing adjustments and may not match totals presented in past reports.

Section Overviews

Overview: Section 3, Energy Market

Supply and Demand

Market Structure

- **Supply.** In the first nine months of 2022, 2,666.5 MW of new resources were added in the energy market, and 6,069.6 MW of resources were retired.
- The real-time hourly on peak average offered supply was 152,828 MW in the summer of 2021, and 152,027 MW in the summer of 2022. The day-ahead hourly on peak average offered supply was 164,847 MW in the summer of 2021, and 161,651 MW in the summer of 2022.
- The real-time hourly average cleared generation in the first nine months of 2022 increased by 0.6 percent from the first nine months of 2021, from 95,792 MWh to 96,397 MWh.
- The day-ahead hourly average supply in the first nine months of 2022, including INCs and UTCs, increased by 5.5 percent from the first nine months of 2021, from 104,785 MWh to 110,598 MWh.
- **Demand.** The real-time hourly peak load plus exports in the first nine months of 2022 was 149,531 MWh (144,356 MWh of load plus 5,175 MWh of gross exports) in the HE 1800 on July 20, 2022, which was 1.4 percent, 2,150 MWh, lower than the PJM peak load plus exports in first nine months of 2021, which was 151,680 MWh in the HE 1800 on August 24, 2021.
- The real-time hourly average load in the first nine months of 2022 increased by 1.1 percent from the first nine months of 2021, from 89,515 MWh to 90,514 MWh.
- The day-ahead hourly average demand in the first nine months of 2022, including DECs and UTCs, increased by 5.4 percent from the first nine months of 2021, from 99,788 MWh to 105,195 MWh.

Market Behavior

- **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. The hourly average submitted increment offer MW increased by 33.9 percent and cleared increment MW increased by 50.5 percent in the first nine months of 2022 compared to the first nine months of 2021. The hourly average submitted decrement bid MW increased by 22.8 percent and cleared decrement MW increased by 27.1 percent in the first nine months of 2022 compared to the first nine months of 2021. The hourly average submitted up to congestion bid MW increased by 89.3 percent and cleared up to congestion bid MW increased by 49.1 percent in the first nine months of 2022 compared to the first nine months of 2021.

Market Performance

- **Generation Fuel Mix.** In the first nine months of 2022, generation from coal units decreased 12.1 percent, generation from natural gas units increased 8.7 percent, and generation from oil increased 1.3 percent compared to the first nine months of 2021. Wind and solar output rose by 17.1 percent compared to the first nine months of 2021, supplying 4.6 percent of PJM energy in the first nine months of 2022.
- **Fuel Diversity.** The fuel diversity of energy generation in the first nine months of 2022, measured by the fuel diversity index for energy (FDI_e), decreased 0.9 percent compared to the first nine months of 2021.
- **Marginal Resources.** In the PJM Real-Time Energy Market in the first nine months of 2022, coal units were 10.7 percent and natural gas units were 74.3 percent of marginal resources. In the first nine months of 2021, coal units were 16.9 percent and natural gas units were 71.0 percent of marginal resources.

  In the PJM Day-Ahead Energy Market in the first nine months of 2022, UTCs were 44.1 percent, INCs were 18.3 percent, DECs were 20.8 percent, and generation resources were 16.5 percent of marginal resources. In the first nine months of 2021, UTCs were 36.1 percent, INCs were 17.3 percent, DECs were 26.5 percent, and generation resources were 19.7 percent of marginal resources.

- **Prices.** The real-time load-weighted average LMP in the first nine months of 2022 increased 118.2 percent from the first nine months of 2021, from $35.68 per MWh to $77.84 per MWh.
- The day-ahead load-weighted average LMP in the first nine months of 2022 increased 116.7 percent from the first nine months of 2021, from $35.51 per MWh to $76.97 per MWh.
- **Fast Start Pricing.** The real-time load-weighted average PLMP was $77.84 per MWh for the first nine months of 2022, which was 6.3 percent, $4.61 per MWh, higher than the real-time load-weighted average DLMP of $73.23 per MWh.
- **Components of LMP.** In the PJM Real-Time Energy Market in the first nine months of 2022, 7.8 percent of the load-weighted LMP was the result of coal costs, 55.4 percent was the result of gas costs and 6.1 percent was the result of the cost of emission allowances. In the first nine months of 2022, 5.4 percent of load-weighted LMP was the result of the transmission constraint violation penalty factor. In the first nine months of 2022, 3.1 percent of the real-time load-weighted average LMP was the result of the commitment costs of fast start units.
- Of the $42.16 per MWh increase in the real-time load weighted average LMP, $26.45 per MWh (62.7 percent) was in the fuel and consumables cost components of LMP, $4.98 per MWh (11.8 percent) was in the emissions cost components of LMP, $5.49 per MWh (13.0 percent) was in the sum of the markup, maintenance, and ten percent adder components of LMP, $1.10 per MWh (2.6 percent) was in the transmission constraint penalty factor component of LMP, and $1.15 per MWh (2.7 percent) was in the scarcity component of LMP.

  In the PJM Day-Ahead Energy Market in the first nine months of 2022, 22.2 percent of the load-weighted LMP was the result of gas costs, 7.4 percent was the result of coal costs, 30.2 percent was the result of DEC bids, 22.0 percent was the result of INC offers, 5.7 percent was the result of positive markup, and 2.4 percent was the result of UTCs. In the first nine months of 2022, 0.4 percent of the day-ahead load-weighted average LMP was the result of commitment costs.
- **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 day-ahead and real-time average prices was $0.21 per MWh in the first nine months of 2022, and $0.15 per MWh in the first nine months of 2021. The difference between day-ahead and real-time average prices, by itself, is not a measure of the competitiveness or effectiveness of the day-ahead energy market.

Scarcity

- There were 62 intervals with five minute shortage pricing on 17 days in the first nine months of 2022. There were local load shed directives and dispatch of pre-emergency and emergency load management reduction actions in the Marion area of AEP that resulted in Performance Assessment Intervals on three days in the first nine months of 2022.
- There were 8,033 five minute intervals, or 10.2 percent of all five minute intervals, in the first nine months of 2022 for which at least one RT SCED solution showed a shortage of reserves, and 2,261 five minute intervals, or 2.9 percent of all five minute intervals, in the first nine months of 2022 for which more than one RT SCED solution showed a shortage of reserves. PJM triggered shortage pricing for 62 five minute intervals, or 0.08 percent of all five minute intervals.

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. Three suppliers were jointly pivotal in the day-ahead market on 215 days, 78.8 percent of days, in the first nine months of 2022 and 239 days, 87.5 percent of days, in the first nine months of 2021.

- **Local Market Power.** In the first nine months of 2022, 11 control zones experienced congestion resulting from one or more constraints binding for 75 or more hours. For six out of the top 10 congested facilities (by real-time binding hours) in the first nine months of 2022, the average number of suppliers providing constraint relief was three or less. There was a high level of concentration within the local markets for providing relief to the most congested facilities in the PJM Real-Time Energy Market. The local market structure was not competitive.

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 remained unchanged from the first nine months of 2021 to the first nine months of 2022 at 1.4 percent. In the real-time energy market, for units committed to provide energy for local constraint relief, offer-capped unit hours remained unchanged from the first nine months of 2021 to the first nine months of 2022 at 1.3 percent. While overall offer capping levels have been low, there are a significant number of units with persistent structural local market power that would have had a significant impact on prices in the absence of local market power mitigation.

  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 increased from 0.02 percent in the first nine months of 2021 to 0.06 percent in the first nine months of 2022. In the real-time energy market, for units committed for reliability reasons, offer-capped unit hours increased from 0.02 percent in the first nine months of 2021 to 0.15 percent in the first nine months of 2022. The low offer cap percentages do not mean that units manually committed for reliability reasons do not have market power. All units manually committed for reliability have market power and all are treated as if they had market power. These units are not capped to their cost-based offers because they tend to offer with a negative markup in their price-based offers, particularly at the economic minimum level, which means that PJM's offer capping process results in the use of the price-based offer for commitment even if it has less flexible operating parameters.

- **Parameter Mitigation.** In the first nine months of 2022, 30.9 percent of unit hours for units that failed the TPS test in the day-ahead market were committed on price-based schedules that were less flexible than their cost-based schedules. In the first nine months of 2022, on days when cold weather alerts and hot weather alerts were declared, 18.4 percent of unit hours in the day-ahead energy market were committed on price-based schedules that were less flexible than their price PLS schedules.

- **Frequently Mitigated Units (FMU) and Associated Units (AU).** In the first nine months of 2022, no units qualified for an FMU adder. In the first nine months of 2021, one unit qualified for an FMU adder.

- **Markup Index.** The markup index is a summary measure of participant offer behavior for individual marginal units. While the average markup index in the real-time market was 0.92 in the first nine months of 2022, some marginal units did have substantial markups. The highest markup for any marginal unit in the real-time market in the first nine months of 2022 was more than $900 per MWh when using unadjusted cost-based offers.

  While the average markup index in the day-ahead market was 0.49 in the first nine months of 2022, some marginal units did have substantial markups. The highest markup for any marginal unit in the day-ahead market in the first nine months of 2022 was more than $300 per MWh when using unadjusted cost-based offers.

- **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.

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 2022, the unadjusted markup component of LMP was $3.08 per MWh or 4.0 percent of the PJM load-weighted average LMP. July had the highest unadjusted peak markup component, $7.52 per MWh, or 6.6 percent of the real-time peak hour load-weighted average LMP for July.

  In the PJM Day-Ahead Energy Market, INCs, DECs and UTCs have zero markups. In the first nine months of 2022, the unadjusted markup component of LMP was $3.27 per MWh or 4.2 percent of the PJM day-ahead load-weighted average LMP. June had the highest unadjusted peak markup component, $7.21 per MWh, or 6.4 percent of the day-ahead peak hour load-weighted average LMP for June.

  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.

- **Markup and Local Market Power.** Comparison of the markup behavior of marginal units with TPS test results shows that for 6.2 percent of all real-time marginal unit intervals in the first nine months of 2022, the marginal unit had both local market power as determined by the TPS test and a positive markup. The fact that units with market power had a positive markup means that the cost-based offer was not used, that a higher price-based offer was used, and that the process for offer capping units that fail the TPS test does not consistently result in competitive market outcomes in the presence of market power.

- **Markup and Aggregate Market Power.** In the first nine months of 2022, pivotal suppliers in the aggregate market, committed in the day-ahead market and identified as one of three day-ahead aggregate pivotal suppliers, set real-time market prices with markups over $100 per MWh on 25 days.

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 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.)

Fuel Cost Policies

- 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 temporary cost method be removed and that all units that submit nonzero cost-based offers be required to have an approved fuel cost policy. (Priority: Low. First reported 2020. Status: Not adopted.)

- The MMU recommends that the penalty exemption provision be removed and that all units that submit nonzero cost-based offers be required to follow their approved fuel cost policy. (Priority: Medium. First reported 2020. Status: Not adopted.)

Cost-Based Offers

- The MMU recommends that Manual 15 (Cost Development Guidelines) be replaced or updated with a straightforward description of the components of cost-based offers and the mathematically correct calculation of cost-based offers. (Priority: Medium. First reported 2016. Status: Partially adopted Q1 2022.)[66]
- 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 the removal of all maintenance costs from the Cost Development Guidelines. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that market participants be required to document the amount and cost of consumables used when operating in order to verify that the total operating cost is consistent with the total quantity used and the unit characteristics. (Priority: Medium. First reported 2020. Status: Not adopted.)
- The MMU recommends, given that maintenance costs are currently allowed in cost-based offers, that market participants be permitted to include only variable maintenance costs, linked to verifiable operational events and that can be supported by clear and unambiguous documentation of the operational data (e.g. run hours, MWh, MMBtu) that support the maintenance cycle of the equipment being serviced/replaced. (Priority: Medium. First reported 2020. Status: Not adopted.)
- The MMU recommends explicitly accounting for soak costs and changing the definition of the start heat input for combined cycles to include only the amount of fuel used from first fire to the first breaker close in the Cost Development Guidelines. (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.)

Market Power: TPS Test and Offer Capping

- 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.)[67]
- The MMU recommends that PJM review and fix the process of applying the TPS test in the day-ahead energy market to ensure that all local markets created by binding constraints are tested for market power and to ensure that market sellers with market power are appropriately mitigated to their competitive offers. (Priority: High. First reported Q1 2022. Status: Not adopted.)
- The MMU recommends, in order to ensure effective market power mitigation and to ensure that capacity resources meet their obligations to be flexible, that capacity resources be required to use flexible parameters in all offers at all times. (Priority: High. First reported Q3 2021. Status: Not adopted.)

66 Manual 15 has been updated with the correct calculations and descriptions of the cost components for incremental energy offers and no load costs. The start cost calculations have not been approved.

67 The real-time market formula for determining the lowest cost schedule is currently documented.

- The MMU recommends, if the preferred recommendation is not implemented, that in order to ensure effective market power mitigation, PJM always enforce parameter limited values when the TPS test is failed and during high load conditions such as cold and hot weather alerts and emergency conditions. (Priority: High. First reported 2015. Status: Not 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 consistently positive or negative across the full MWh range of price and cost-based offers. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends, in order to ensure effective market power mitigation when the TPS test is failed, that offer capping be applied to units that fail the TPS test in the real-time market that were not offer capped at the time of commitment in the day-ahead market or at a prior time in the real-time market. (Priority: High. First reported 2020. 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.)[68]

Offer Behavior

- The MMU recommends that resources not be allowed to violate the ICAP must offer requirement. The MMU recommends that PJM enforce the ICAP must offer requirement by assigning a forced outage to any unit that is derated in the energy market below its committed ICAP without an outage that reflects the derate. (Priority: Medium. First reported 2020. Status: Not adopted.)
- The MMU recommends that storage and intermittent resources be subject to an enforceable ICAP must offer rule that reflects the limitations of these resources. (Priority: Medium. First reported 2020. Status: Not adopted.)
- The MMU recommends that capacity resources not be allowed to offer any portion of their capacity market obligation as maximum emergency energy. (Priority: Medium. First reported 2012. Status: Not adopted.)
- The MMU recommends that gas generators be required to check with pipelines throughout the operating day to confirm that nominations are accepted beyond the NAESB deadlines, and that gas generators be required to place their units on forced outage until the time that pipelines allow nominations to consume gas at a unit. (Priority: Medium. First reported Q1 2022. Status: Not adopted.)

Capacity Performance Resources

- The MMU recommends that capacity performance resources 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

68 The applicability of the FMU and AU adders is limited by the rule implemented in 2014 requiring that net revenues must fall below avoidable costs, but the possibility of FMU and AU adders is still part of the PJM Market Rules.

determine capacity performance assessment or uplift payments. (Priority: Medium. First reported 2015. Status: Partially adopted.)[69]

- The MMU recommends, if the capacity market seller offer cap were to be calculated using the historical average balancing ratio, that PJM not include the balancing ratios calculated for localized Performance Assessment Intervals (PAIs), and only include those events that trigger emergencies at a defined zonal or higher level. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM clearly define the business rules that apply to the unit specific parameter adjustment process, including PJM's implementation of the tariff rules in the PJM manuals to ensure market sellers know the requirements for their resources. (Priority: Low. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM update the tariff to clarify that all generation resources are subject to unit specific parameter limits on their cost-based offers using the same standard and process as capacity performance capacity resources. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that resources not be paid the daily capacity payment when unable to operate to their unit specific parameter limits. (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 2019. Status: Not adopted.)
- The MMU recommends that PJM require generators that violate their approved turn down ratio (by either using the fixed gen option or increasing their economic minimum) to use the temporary parameter exception process that requires market sellers to demonstrate that the request is based on a physical and actual constraint. (Priority: Medium. First reported 2021. Status: Not adopted.)
- The MMU recommends: that gas generators be required to confirm, regularly during the operating day, that they can obtain gas if requested to operate at their economic maximum level; that gas generators provide that information to PJM during the operating day; and that gas generators be required to be on forced outage if they cannot obtain gas during the operating day to meet their must offer requirement as a result of pipeline restrictions, and they do not have backup fuel. As part of this, the MMU recommends that PJM collect data on each individual generator's fuel supply arrangements at least annually or when such arrangements change, and analyze the associated locational and regional risks to reliability. (Priority: Medium. First reported Q1 2022. Status: Not adopted.)

Accurate System Modeling

- The MMU recommends that PJM approve one RT SCED case for each five minute interval to dispatch resources during that interval using a five minute ramp time, and that PJM calculate prices using LPC for that five minute interval using the same approved RT SCED case. (Priority: High. First reported 2019. Status: Adopted 2021.)
- 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 and when the transmission penalty factors will be used to set the shadow price. The MMU recommends that PJM end the practice of discretionary reductions in transmission line ratings modeled in the market clearing and included in LMP. (Priority: Medium. First reported 2015. Status: Partially adopted 2020.)[70]
- 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: Not adopted.)

69 Flexible parameter standards are in place for combined cycle and combustion turbine resources when operating on a parameter limited schedule, but not for other schedules or generating technologies.

70 PJM created a more transparent process for transmission constraint penalty factors and added it to the tariff in 2020. Policies on line rating reductions (including limit control percentage) and the duration of violations remain discretionary and undocumented in the PJM Market Rules.

- The MMU recommends that PJM not use closed loop interface or surrogate 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: Adopted 2021.)
- 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.[71] (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 coordination of outage and operational restrictions data submitted by market participants via eDART/eGADs and offer data submitted via Markets Gateway. (Priority: Low. First reported 2017. Status: Not adopted.)
- The MMU recommends that PJM model generators' operating transitions, including soak time for units with a steam turbine, configuration transitions for combined cycles, and peak operating modes. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that PJM clarify, modify and document its process for dispatching reserves and energy when SCED indicates that supply is less than total demand including forecasted load and reserve requirements. The modifications should define: a SCED process to economically convert reserves to energy; a process for the recall of energy from capacity resources; and the minimum level of synchronized reserves that would trigger load shedding. (Priority: Medium. First reported 2020. Status: Not adopted.)
- The MMU recommends that PJM stop capping the system marginal price in RT SCED and instead limit the sum of violated reserve constraint shadow prices used in LPC to $1,700 per MWh. (Priority: Medium. First reported Q1, 2021. Status: Not adopted.)
- The MMU recommends that PJM adjust the ORDCs during spin events to reduce the reserve requirement for synchronized and primary reserves by

71 This recommendation was the result of load shed events in September, 2013. For detailed discussion, please see *2013 State of the Market Report for PJM*, Volume II, Section 3 at 114 – 116.
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 amount of the reserves deployed. (Priority: Medium. First reported 2021. Status: Not adopted.)

Transparency

- The MMU recommends that PJM clearly document the calculation of shortage prices and implementation of reserve price caps in the PJM Manuals, including defining all the components of reserve prices, and all the constraints whose shadow prices are included in reserve prices. (Priority: High. First reported 2021. Status: Not adopted.)
- The MMU recommends that PJM allow generators to report fuel type on an hourly basis in their offer schedules and to designate schedule availability on an hourly basis. (Priority: Medium. First reported 2015. Status: Partially adopted.)[74]
- The MMU recommends that PJM define clear criteria for operator approval of RT SCED cases, including shortage cases, that are used to send dispatch signals to resources, and for pricing, to minimize discretion. (Priority: High. First reported 2018. Status: Partially adopted.)[75]

Virtual Bids and Offers

- The MMU recommends eliminating up to congestion (UTC) bidding at pricing nodes that aggregate only small sections of transmission zones with few physical assets. (Priority: Medium. First reported 2020. Status: Not adopted.)
- The MMU recommends eliminating INC, DEC, and UTC bidding at pricing nodes that allow market participants to profit from modeling issues. (Priority: Medium. First reported 2020. 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 2022, including aggregate supply and demand, concentration ratios, aggregate pivotal supplier results, local three pivotal supplier test results, offer capping, markup, marginal units, participation in demand response programs, virtual bids and offers, loads and prices.

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. In a competitive market, prices are directly related to input prices, the marginal cost to serve load. In the first nine months of 2022, both the price level and the price increase over the first nine months of 2021 were the highest since the PJM market was created in 1999. The largest contributor to increased prices was the cost of fuel, primarily natural gas and coal. The fuel cost components of LMP (the sum gas, coal, oil, landfill gas, variable operations) increased $26.45 per MWh, 62.7 percent of the increase in LMP. The emissions cost components of LMP increased by $4.98 per MWh, 11.8 percent of the increase in LMP, mostly due to high NO_x prices during the summer. New limitations on natural gas plants in Illinois and high NO_x emissions allowance prices contributed to higher LMPs. 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 2022 generally reflected supply-demand fundamentals, although the behavior of some participants both routinely and during high demand periods represents economic withholding. Economic withholding occurs when generator offers are greater than competitive levels. In the first nine months of 2022, economic withholding affected prices through marginal units using increased price markups and a ten percent cost adder applied to a higher fuel cost. The markup, ten percent adder, and maintenance cost components, together increased by $5.49 per MWh or 13.0 percent of the increase in LMP. 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, staff their units, and operate rather than economically withhold or physically withhold.

74 Fuel type is reported by offer schedule, but it can be inaccurate on an hourly basis.
75 The PJM Market Rules clarify that shortage case approval will be based on RT SCED, but does not address RT SCED case choice or load bias.

The extended ORDCs that PJM filed with FERC in 2019 would have created shortage pricing when no reserve shortages exist and, in emergency situations, would have resulted in unjustifiable wealth transfers due to extreme high pricing with no demonstrable market benefit. These changes are unnecessary and distort, rather than improve, price formation. PJM appropriately and directly addressed price formation with the changes that went into effect on November 1, 2021, to resolve the timing mismatch between pricing (LPC) and dispatch instructions (RT SCED). Other potential areas for improvements in price formation include shortage pricing, operator actions and the design of reserve markets. FERC's December 22, 2021, order reversed its prior approval of PJM's proposed extended ORDCs, but accepted other changes to the reserve market design, including the consolidation of tier 1 and tier 2 synchronized reserves and the addition of a day-ahead reserve market. The potential for prolonged and excessively high administrative pricing in the energy market due to reserve penalty factors and transmission constraint penalty factors remains an issue that needs to be addressed.[76] There also continue to be significant issues with PJM's scarcity pricing rules, including the absence of a clear trigger based on accurately estimated reserve levels. In July, August, and September of 2022, PJM approved a shortage case for one RT SCED five minute interval out of 673 intervals with multiple shortage solutions, while the same months in 2021 had only 404 intervals with multiple shortage solutions and nine approved shortage intervals.

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 and ensure no scarcity pricing when such pricing is not consistent with market conditions. 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 have done, is not scarcity pricing but simply a revenue enhancement mechanism, which could have unintended consequences in an emergency, as was the case in ERCOT in February 2021. The Commission recognized that PJM's ORDC changes were not consistent with efficient market design and were just a revenue enhancement mechanism.

The PJM defined inputs to the dispatch tools, particularly the RT SCED, have substantial effects on energy market outcomes. Transmission line ratings, transmission penalty factors, load forecast bias, and hydro resource schedules change the dispatch of the system, affect prices, and can create significant price increases, particularly through transmission line limit violations. PJM operator interventions to reduce line ratings unnecessarily trigger transmission constraint penalty factors and significantly increase prices. Violations of reduced line limits had a direct effect on higher LMP in the first nine months of 2022. If the line limits had not been reduced for the PJM transmission constraints and everything else remained unchanged, fewer constraints would have been violated and the transmission penalty factor's contribution to the load weighted average LMP in the first nine months of 2022 would have decreased by 103.9 percent from $4.18 to -$0.16 per MWh. PJM should evaluate its interventions in the market, consider whether the interventions are appropriate, and provide greater transparency to enhance market efficiency.

Fast start pricing, implemented on September 1, 2021, has disconnected pricing from dispatch instructions and created a greater reliance on uplift rather than price as an incentive to follow PJM's instructions. 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 using

76 177 FERC ¶ 61,209 (2021).

fast start pricing prioritizes minimizing uplift over minimizing production costs.[77] The tradeoff exists 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. Units that start in one hour are not actually 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 is paying new forms of uplift in an attempt to counter the distorted incentives inherent in fast start pricing. While the magnitude of the new payments was small in 2021 and the first nine months of 2022, their effects on behavior are not clear yet.

PJM's arguments for changing energy market price formation asserted that fast start pricing and the extended ORDC would price flexibility in the market, but instead they benefit inflexible units. The fast start pricing and extended ORDC 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? Are units inflexible because the PJM software does not model combined cycle transitions? The question of how to provide market incentives for investment in flexible units, for investment in increased flexibility of existing units, and for operating at the full extent of existing flexibility 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.

The relationship between supply and demand, regardless of the specific market, along with market concentration and the extent of pivotal suppliers, is referred to as the supply-demand fundamentals or economic fundamentals or market structure. 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. Even a low HHI may be consistent with the exercise of market power with a low price elasticity of demand. 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.[78] 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. The Commission recognized some of these issues in its order issued on June 17, 2021.[79] PJM continues to ignore the evidence cited by the Commission and denies the prevalence of these issues, instead of ensuring that market power mitigation works as intended and results in efficient market outcomes.[80] Many of these issues can be resolved by simple rule changes. The MMU proposed these rule changes in its response submitted on October 15, 2021, and continues to recommend them.[81] The MMU recommendations would shorten the solution

77 See 173 FERC ¶ 61,244 (2020).

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

79 See 175 FERC ¶ 61,231 (2021).

80 *See* PJM. "Answer of PJM Interconnection L.L.C.," Docket No. EL21-78 (September 15, 2021).

81 *See* "Comments of the Independent Market Monitor for PJM," Docket No. EL21-78 (October 15, 2021).

time of the day-ahead market software, which would help facilitate enhanced combined cycle modelling.

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 all costs that are related to electric production are short run marginal costs, 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. This rule also had unintended consequences for market seller offer caps in the capacity market. Maintenance costs includable in energy offers cannot be included in capacity market offer caps based on avoidable costs. As a result, capacity market offer caps based on net avoidable costs were lower than they would have been if maintenance costs had been correctly included in avoidable costs rather than incorrectly defined to be part of short marginal costs of producing energy and includable in energy offers.

A competitive market requires that prices increase when fuel costs increase. A competitive market does not require that prices increase when markup increases or when PJM artificially triggers transmission constraint penalty factors. 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 2022 or prior years. Given the structure of the energy market which can permit the exercise of aggregate and local 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 and correcting the offer capping process for resources with local market power. The MMU concludes that the PJM energy market results were competitive in the first nine months of 2022.

Overview: Section 4, Energy Uplift

Energy Uplift Charges

- **Energy Uplift Charges.** Total energy uplift charges increased by $49.4 million, or 37.7 percent, in the first nine months of 2022 compared to the first nine months of 2021, from $131.1 million to $180.5 million.
- **Energy Uplift Charges Categories.** The increase of $49.4 million in 2022 was comprised of a $24.5 million increase in day-ahead operating reserve charges, a $24.2 million increase in balancing operating reserve charges, a $0.5 million increase in reactive services charges and a $0.1 million increase in black start services.
- **Average Effective Operating Reserve Rates in the Eastern Region.** Day-ahead load, exports, DECs and UTCs paid $0.050 per MWh in the Eastern Region. Real-time load and exports paid an average of $0.092 per MWh. Deviations paid $0.515 per MWh in the Eastern Region.
- **Average Effective Operating Reserve Rates in the Western Region.** Day-ahead load, exports, DECs and UTCs paid $0.050 per MWh in the Western Region. Real-time load and exports paid $0.072 per MWh. Deviations paid $0.365 per MWh in the Western Region.

Energy Uplift Credits

- **Types of credits.** In the first nine months of 2022, energy uplift credits were $180.5 million, including $35.3 million in day-ahead generator credits, $113.4 million in balancing generator credits, $25.4 million in lost opportunity cost credits, and $1.2 million in local constraint control credits. Dispatch differential lost opportunity credits, implemented as part of fast start pricing on September 1, 2021, were $3.6 million during the first nine months of 2022.
- **Types of units.** In the first nine months of 2022, coal units received 69.2 percent of day-ahead generator credits, and combustion turbines received

86.4 percent of balancing generator credits and 83.6 percent of lost opportunity cost credits. Combined cycle units and combustion turbines received 68.2 percent of dispatch differential lost opportunity credits.

- **Economic and Noneconomic Generation.** In the first nine months of 2022, 89.0 percent of the day-ahead generation eligible for operating reserve credits was economic and 64.8 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 2022, 0.4 percent of the total day-ahead generation MWh was scheduled as must run for reliability by PJM, of which 58.8 percent received energy uplift payments.
- **Concentration of Energy Uplift Credits.** In the first nine months of 2022, the top 10 units receiving energy uplift credits received 26.4 percent of all credits and the top 10 organizations received 75.6 percent of all credits. The HHI for day-ahead operating reserves was 8770, the HHI for balancing operating reserves was 2372 and the HHI for lost opportunity cost was 4992, all of which are classified as highly concentrated.
- **Lost Opportunity Cost Credits.** Lost opportunity cost credits increased by $7.8 million, or 44.7 percent, in the first nine months of 2022, compared to the first nine months of 2021, from $17.5 million to $25.4 million.

  Some combustion turbines and diesels are scheduled day-ahead but not requested in real time, and receive day-ahead lost opportunity cost credits as a result. This was the source of 81.5 percent of the $25.4 million. The day-ahead generation paid LOC credits for this reason increased by 51.8 GWh or 16.4 percent during the first nine months of 2022, compared to the first nine months of 2021 from 315.4 GWh to 367.2 GWh.
- **Following Dispatch.** Some units are incorrectly paid uplift despite not meeting uplift eligibility requirements, including not following dispatch, not having the correct commitment status, or not operating with PLS offer parameters. Since 2018, the MMU has made cumulative resettlement requests for the most extreme overpaid units of $15.1 million, of which PJM has resettled only $1.5 million, or 9.7 percent.
- **Daily Uplift.** In the first nine months of 2022, balancing operating reserve charges would have been $31.3 million or 27.6 percent lower if they had been calculated on a daily basis rather than a segmented basis. In the first nine months of 2021, balancing operating reserve credits would have been $19.2 million or 19.7 percent lower if they had been calculated on a daily basis rather than a segmented basis. Uplift was designed to be charged on a daily basis and not on an intraday segmented basis.

Geography of Charges and Credits

- In the first nine months of 2022, 85.7 percent of all uplift charges allocated regionally (day-ahead operating reserves and balancing operating reserves) were paid by transactions at control zones, 6.2 percent by transactions at hubs and aggregates, and 8.0 percent by transactions at interchange interfaces.
- In the first nine months of 2022, generators in the Eastern Region received 50.6 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.
- In the first nine months of 2022, generators in the Western Region received 46.9 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.
- In the first nine months of 2022, external generators received 2.5 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 pay uplift to units not following dispatch, including uplift related to fast start pricing, and require refunds where it has made such payments. This includes units whose offers are flagged for fixed generation in Markets Gateway because such units are

not dispatchable. (Priority: Medium. First reported 2018. Status: Not adopted.)

- 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 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 uplift 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 uplift, the timing of commitment decisions and the commitment reasons. (Priority: High. First reported 2012. Status: Not adopted.)
- The MMU recommends that units not be paid lost opportunity cost uplift when PJM directs a unit to reduce output based on a transmission constraint or other reliability issue. There is no lost opportunity because the unit is required to reduce for the reliability of the unit and the system. (Priority: High. First reported 2021. 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.)
- 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.)
- 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 units with 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: Partially adopted.)
- The MMU recommends allocating the energy uplift payments to units scheduled as must run in the day-ahead energy market for reasons other than voltage/reactive or black start services as a reliability charge to real-time load, real-time exports and real-time wheels. (Priority: Medium. First reported 2014. Status: Not adopted. Stakeholder process.)
- The MMU recommends that the total cost of providing reactive support be categorized and allocated as reactive services. Reactive services credits should be calculated consistent with the balancing operating reserve credit calculation. (Priority: Medium. First reported 2012. Status: Not adopted. Stakeholder process.)

- The MMU recommends including real-time exports and real-time wheels in the allocation of the cost of providing reactive support to the 500 kV system or above, in addition to real-time load. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends modifications to the calculation of lost opportunity costs credits paid to wind units. The lost opportunity costs credits paid to wind units should be based on the lesser of the desired output, the estimated output based on actual wind conditions and the capacity interconnection rights (CIRs). The MMU recommends that PJM allow wind units to request CIRs that reflect the maximum output wind units want to inject into the transmission system at any time. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM clearly identify and classify all reasons for incurring uplift in the day-ahead and the real-time energy markets and the associated uplift 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 uplift. (Priority: Medium. First reported 2011. Status: Partially adopted.)
- The MMU recommends that PJM revise the current uplift (operating reserve) confidentiality rules in order to allow the disclosure of complete information about the level of uplift (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.)[82]
- The MMU recommends that PJM eliminate the exemption for 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.)

82 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 June 21, 2019. 166 FERC ¶ 61,210 (2019). PJM began posting unit specific uplift reports on May 1, 2019. 167 FERC ¶ 61,280 (2019).

Section 4 Conclusion

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

It is not appropriate to accept that inflexible units should be paid uplift based on inflexible offers. 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. But such modeling should not be used as an excuse to eliminate market power mitigation or an excuse to permit inflexible offers to be paid uplift.

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

Accurate short run price signals, equal to the short run marginal cost of generating power, provide market incentives for cost minimizing production to all economically dispatched resources and provide market incentives to load based on the marginal cost of additional consumption. The objective of efficient short run price signals is to minimize system production costs, not to minimize uplift. Repricing the market to reflect commitment costs will create a tradeoff between minimizing production costs and reduction of uplift. The tradeoff will 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 now exists based on PJM's recently implemented fast start pricing proposal (limited convex hull pricing). Fast start pricing was approved by FERC and implemented on September 1, 2021.[83] Fast start pricing affects uplift calculations by introducing a new category of uplift in the balancing market, and changing the calculation of uplift in the day-ahead market.

When units receive substantial revenues through energy uplift payments, these payments are not fully transparent to the market, in part 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. FERC Order No. 844 authorized the publication of unit specific uplift payments for credits incurred after July 1, 2019.[84] However, Order No. 844 failed to require the publication of unit specific uplift credits for the largest units receiving significant uplift payments, inflexible steam units committed for reliability in the day-ahead market.

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.

On July 16, 2020, following its investigation of the issue, the Commission ordered PJM to revise its rules so that UTCs are required to pay uplift on the withdrawal side (DEC) only.[85] The uplift payments for UTCs began on November 1, 2020.[86] This had been a longstanding recommendation of the MMU.

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. PJM pays uplift to units even when they do not operate as requested by PJM, i.e. they do not follow dispatch. PJM uses dispatcher logs as a primary screen to determine if units are eligible for uplift regardless of how they actually operate or if they followed the PJM dispatch signal. The reliance on dispatcher logs for this purpose is impractical, inefficient, and incorrect. PJM needs to define and implement systematic and verifiable rules for determining when units are following dispatch as a primary screen for eligibility for uplift payments. PJM should not pay uplift to units that do not follow dispatch.

The MMU notifies PJM and generators of instances in which, based on the PJM dispatch signal and the real-time output of the unit, it is clear that the unit did not operate as requested by PJM. The MMU sends requests for resettlements

83 See 173 FERC ¶ 61,244 (2020).

84 On June 21, 2019, FERC accepted PJM's Order No. 844 compliance filing. 166 FERC ¶ 61,210 (2019). 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. 167 FERC ¶ 61,280 (2019).

85 See 172 FERC ¶ 61,046 (2020).

86 On October 17, 2017, PJM filed a proposed tariff change at FERC to allocate uplift to UTC transactions in the same way uplift is allocated to other virtual transactions, as a separate injection and withdrawal deviation. FERC rejected the proposed tariff change. See 162 FERC ¶ 61,019 (2018).

to PJM to make the units with the most extreme overpayments ineligible for uplift credits. Since 2018, the MMU has requested that PJM require the return of $15.1 million of incorrect uplift credits of which PJM has resettled only $1.5 million or 9.7 percent. In addition, PJM has refused to accept the return of incorrectly paid uplift credits by generators when the MMU has identified such cases.

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. The result would also be to increase incentives for flexible operation and to decrease incentives for the continued operation of inflexible and uneconomic resources. PJM does not need a new flexibility product. PJM needs to provide incentives to existing and new entrant resources to unlock the significant flexibility potential that already exists, to end incentives for inflexibility and to stop creating new incentives for inflexibility.

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 a must buy requirement for load, with performance incentives, that includes clear market power mitigation rules and that permits the direct participation of demand-side resources.[87] Currently, intermittent and storage resources are exempt from the must offer requirement, although that is not a viable long term design element for the capacity market. The fundamental goal of the must offer requirement is to ensure that the capacity market works and therefore that the energy market works, given that LSEs have a must buy obligation.

Under RPM, capacity obligations are annual.[88] Base Residual Auctions (BRA) are held for delivery years that are three years in the future. First, Second and Third Incremental Auctions (IA) are held for each delivery year.[89] First, Second, and Third Incremental Auctions are conducted 20, 10, and three months prior to the delivery year.[90] 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.[91]

The 2022/2023 RPM Third Incremental Auction and the 2023/2024 RPM Base Residual Auction were conducted in the first nine months of 2022.

RPM prices are locational and may vary depending on transmission constraints and local supply and demand conditions.[92] Existing generation that qualifies as a capacity resource must be offered into RPM auctions, except for resources owned by entities that elect the fixed resource requirement (FRR) option, and, as a result of Capacity Performance rule changes, except for intermittent and capacity storage resources including hydro. 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

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

88 Effective for the 2020/2021 and subsequent delivery years, the RPM market design incorporated seasonal capacity resources. Summer period and winter period capacity must be matched either through commercial aggregation or through the optimization in equal MW amounts in the LDA or the lowest common parent LDA.
89 See 126 FERC ¶ 61,275 at P 86 (2009).
90 See Letter Order, FERC Docket No. ER10-366-000 (January 22, 2010).
91 See 126 FERC ¶ 61,275 at P 88 (2009). There have been no Conditional Incremental Auctions.
92 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 power mitigation rules that define structural market power, that define offer caps based on the marginal cost of capacity, and that have flexible criteria for competitive offers by new entrants. Market power mitigation is effective only when these definitions are up to date and accurate. Demand resources and energy efficiency resources may be offered directly into RPM auctions and receive the clearing price without mitigation.

Market Structure

- **RPM Installed Capacity.** In the first nine months of 2022, RPM installed capacity decreased 4,771.6 MW or 2.6 percent, from 186,117.4 MW on January 1, to 181,345.8 MW on September 30. Installed capacity includes net capacity imports and exports and can vary on a daily basis.
- **Reserves.** For the 2023/2024 RPM Base Residual Auction, the sum of cleared MW that were considered categorically exempt from the must offer requirement and the cleared MW of DR is 15,737.7 MW, or 92.8 percent of required reserves and 63.5 percent of total reserves. These results suggest that the required reserve margin and the actual reserve margin be considered carefully along with the obligations of the resources that the reserve margin assumes will be available.
- **RPM Installed Capacity by Fuel Type.** Of the total installed capacity on September 30, 2022, 48.5 percent was gas; 23.6 percent was coal; 17.6 percent was nuclear; 4.7 percent was hydroelectric; 2.9 percent was oil; 0.9 percent was wind; 0.4 percent was solid waste; and 1.5 percent was solar.
- **Market Concentration.** In the 2022/2023 RPM Third Incremental Auction and the 2023/2024 RPM Base Residual Auction, all participants in the total PJM market as well as the LDA RPM markets failed the three pivotal supplier (TPS) test.[93] 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.[94] [95] [96]
- **Imports and Exports.** Of the 1,528.0 MW of imports in the 2023/2024 RPM Base Residual Auction, 1,396.6 MW cleared. Of the cleared imports, 836.5 MW (59.9 percent) were from MISO.
- **Demand-Side and Energy Efficiency Resources.** Capacity in the RPM load management programs was 14,027.0 MW for June 1, 2022, as a result of cleared capacity for demand resources and energy efficiency resources in RPM auctions for the 2022/2023 Delivery Year (14,601.0 MW) less purchases of replacement capacity (574.0 MW).

Market Conduct

- **2023/2024 RPM Base Residual Auction.** Of the 1,003 generation resources that submitted Capacity Performance offers, the MMU calculated unit specific offer caps for 73 generation resources (7.3 percent).

Market Performance

- The 2022/2023 RPM Third Incremental Auction and 2023/2024 RPM Base Residual Auction were conducted in the first nine months of 2022. The weighted average capacity price for the 2022/2023 Delivery Year is $72.33 per MW-day, including all RPM auctions for the 2022/2023 Delivery Year. The weighted average capacity price for the 2023/2024 Delivery Year is $41.37 per MW-day, including all RPM auctions for the 2023/2024 Delivery Year held through the first nine months of 2022.
- For the 2022/2023 Delivery Year, RPM annual charges to load are $4.0 billion.
- In the 2023/2024 RPM Base Residual Auction, the market performance was determined to be competitive.

93 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).

94 See OATT Attachment DD § 6.5.

95 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).

96 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).

Part V Reliability Service

- Of the eight companies (24 units) that have provided service following deactivation requests, two companies (seven units) filed to be paid under the deactivation avoidable cost rate (DACR), the formula rate. The other six companies (17 units) filed to be paid under the cost of service recovery rate.

Generator Performance

- **Forced Outage Rates.** The average PJM EFORd in the first nine months of 2022 was 6.4 percent, a decrease from 6.8 percent in the first nine months of 2021.[97]
- **Generator Performance Factors.** The PJM aggregate equivalent availability factor in the first nine months of 2022 was 84.5 percent, an increase from 84.3 percent in the first nine months of 2021.

Section 5 Recommendations[98]

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.[99] [100] (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.)
- The MMU recommends that the implementation of the EE addback mechanism be modified to ensure that market clearing prices are not affected. (Priority: Medium. First reported 2016. Status: Adopted 2022.)[101]
- The MMU recommends that Energy Efficiency Resources (EE) not be included in the capacity market because PJM's load forecasts now account for EE, unlike the situation when EE was first added to the capacity market.[102] (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that intermittent resources, including storage, not be permitted to offer capacity MW based on energy deliveries that exceed their defined deliverability rights (CIRs). Only energy output for such resources below the designated CIR/deliverability level should be recognized in the definition of derated capacity (e.g. ELCC). Correctly defined derating factors will be lower than the CIRs required to meet those derating factors. (Priority: High. First reported 2021. Status: Not adopted.)
- The MMU recommends that PJM require all market participants to meet their deliverability requirements under the same rules. PJM should end the practice of giving away winter CIRs that appear to exist because other resources paid for the supporting network upgrades. (Priority: High. First reported 2017. Status: Not adopted.)[103]
- The MMU recommends that the must offer rule in the capacity market apply to all capacity resources. There is no reason to exempt intermittent and capacity storage resources, including hydro, and demand resources and energy efficiency resources from the must offer requirement. The same rules should apply to all capacity resources. (Priority: High. First reported 2021. Status: Not adopted.)

97 The generator performance analysis includes all PJM capacity resources for which there are data in the PJM generator availability data systems (GADS) database. Data was downloaded from the PJM GADS database on October 24, 2022. 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.

98 The MMU has identified serious market design issues with RPM and the MMU has made specific recommendations to address those issues. These recommendations have been made in public reports. See Table 5-2.

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

100 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).

101 This recommendation was first made in the 2019/2020 BRA report in 2016. 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).

102 "PJM Manual 19: Load Forecasting and Analysis," § 3.2 Development of the Forecast, Rev. 35 (Dec. 31, 2021).

103 This recommendation was first made in the 2020/2021 BRA report in 2017. See the "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).

- The MMU recommends elimination of the key remaining components of the CP model because they interfere with competitive outcomes in the capacity market and create unnecessary complexity and risk. (Priority: High. New recommendation. Status: Not adopted.)

Market Design and Parameters

- The MMU recommends that PJM reevaluate the shape of the VRR curve. The shape of the VRR curve directly results in load paying substantially more for capacity than load would pay with a vertical demand curve. More specifically, the MMU recommends that the VRR curve be rotated half way towards the vertical demand curve at the reliability requirement for the current Quadrennial Review. (Priority: High. First reported 2021. Status: Partially adopted.)
- The MMU recommends that the maximum price on the VRR curve be defined as net CONE. (Priority: Medium. First reported 2019. Status: Not adopted.)
- 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 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. Absent a fully nodal capacity market clearing process, the MMU recommends that PJM use a non-nested model with all LDAs modeled including VRR curves for all LDAs. 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 be allowed to price separate if that is the result of the LDA supply curves and the transmission constraints between LDAs. (Priority: Medium. First reported 2017. Status: Not adopted.)
- The MMU recommends the use of a forward looking energy and ancillary services (E&AS) net revenue offset rather than the backward looking E&AS net revenue offset currently in the tariff. Forward prices for energy prices and fuel costs are a better guide to market expectations of net revenues than an average of the actual net revenues for the last three years. (Priority: High. First reported 2014. Status: Not adopted.)[104]
- 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.[105] [106] 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: Adopted 2021.)
- The MMU recommends that PJM reduce the number of incremental auctions to a single incremental auction held three months prior to the start of the delivery year and reevaluate the triggers for holding conditional incremental auctions. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM not sell back any capacity in any IA procured in a BRA. If PJM continues to sell back capacity, 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 uplift (make whole) payments in the objective function. (Priority: Medium. First reported 2014. Status: Not adopted.)
- The MMU recommends that the Fixed Resource Requirement (FRR) rules, including obligations and performance requirements, be revised and updated to ensure that the rules reflect current market realities and that FRR entities do not unfairly take advantage of those customers paying for capacity in the PJM capacity market. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that the value of CTRs should be defined by the total MW cleared in the capacity market, the internal MW cleared and the

104 This recommendation was first made during the Quadrennial Review in 2014, including the PJM Capacity Senior Task Force (CSTF), t the MRC and the MC. <https://www.pjm.com/committees-and-groups/closed-groups/cstf>.
105 See PJM Interconnection, L.L.C., Docket No. ER12-513-000 (December 1, 2011) ("Triennial Review").
106 See the *2019 State of the Market Report for PJM*, Volume 2, Section 7: Net Revenue.

imported MW cleared, and not redefined later prior to the delivery year. (Priority: Medium. First reported 2021. Status: Not adopted.)

- The MMU recommends that the market clearing results be used in settlements rather than the reallocation process currently used, or that the process of modifying the obligations to pay for capacity be reviewed. (Priority: Medium. First reported 2021. Status: Not adopted.)
- The MMU recommends that PJM improve the clarity and transparency of its CETL calculations. The MMU also recommends that CETL for capacity imports into PJM be based on the ability to import capacity only where PJM capacity exists and where that capacity has a must offer requirement in the PJM Capacity Market. (Priority: Medium. First reported 2021. Status: Partially adopted 2022.)
- The MMU recommends that the value of CTRs be defined by the total MW cleared in the capacity market, the internal MW cleared and the imported MW cleared, and not redefined later prior to the delivery year. Capacity Transfer Rights (CTRs) are used to return capacity market congestion revenues to load, but the CTRs that result from market clearing prices and quantities are not included in final settlements for individual LDAs. MMU also recommends that the market clearing results be used in settlements rather than the reallocation process currently used or that the process of modifying the obligations to pay for capacity be reviewed. (Priority: High. First reported 2022. Status: Not adopted.)[107]

Offer Caps, Offer Floors, and Must Offer

- The MMU recommends using the lower of the cost or price-based energy market offer to calculate energy costs in the calculation of the historical net revenues which are an offset to gross ACR in the calculation of unit specific capacity resource offer caps based on net ACR. (Priority: Medium. First reported 2021. Status: Not adopted.)
- The MMU recommends use of the Sustainable Market Rule (SMR) in order to protect competition in the capacity market from nonmarket revenues.[108] (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.[109] (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that modifications to existing resources be subject to market power related offer caps or MOPR offer floors and not be treated as new resources and therefore exempt. (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 uplift (make whole) payments for seasonal products. (Priority: Medium. First reported 2017. Status: Not adopted.)
- The MMU recommends that any combined seasonal resources be required to be in the same LDA and preferably at the same location, in order for the energy market and capacity market to remain synchronized and reliability metrics correctly calculated. (Priority: Medium. First reported 2021. 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: Adopted 2021.)

107 This recommendation first made in the 2023/2024 BRA report in 2022. See "Analysis of the 2023/2024 RPM Base Residual Auction Revised,"<http://www.monitoringanalytics.com/reports/Reports/2022/IMM_Analysis_of_the_20232024_RPM_Base_Residual_Auction_20221028.pdf> (October 28, 2022).

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

109 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 the definition of avoidable costs in the tariff be corrected to be consistent with the economic definition. Avoidable costs are costs that are neither short run marginal costs, like fuel or consumables, nor fixed costs like depreciation and rate of return. Avoidable costs are the marginal costs of capacity and therefore the competitive offer level for capacity resources and therefore the market seller offer cap. Avoidable costs are the marginal costs of capacity whether a new resource or an existing resource. (Priority: Medium. First reported 2017. Status: Not adopted.)[110]
- The MMU recommends that capacity market sellers be required to explicitly request and support the use of minimum MW quantities (inflexible sell offer segments) and that the requests only be permitted for defined physical reasons. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that relatively small proposed increases in the capability of a Generation Capacity Resource be treated as an existing resource and subject to the corresponding market power mitigation rules and no longer be treated as planned and exempt from offer capping. (Priority: Medium. First reported 2012. Status: Not adopted.)[111]

Performance Incentive Requirements of RPM

- The MMU recommends that any unit not capable of supplying energy equal to its day-ahead must offer requirement (ICAP) be required to 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 PAI 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.)
- The MMU recommends that Capacity Performance resources be required to perform without excuses. Resources that do not perform should not be paid regardless of the reason for nonperformance. (Priority: High. First reported 2019. Status: Not adopted.)
- The MMU recommends that the market data posting rules be modified to allow the disclosure of expected performance, actual performance, shortfall and bonus MW during a PAI by area without the requirement that more than three market participants' data be aggregated for posting. (Priority: Low. First reported 2019. Status: Not adopted.)
- The MMU recommends that PJM require actual seasonal tests as part of the Summer/Winter Capability Testing rules, that the number of tests be limited, and that the ambient conditions under which the tests are performed be defined. (Priority: Medium. First reported Q1 2022. Status: Not adopted.)
- The MMU recommends that PJM select the time and day that a unit undergoes Net Capability Verification Testing, not the unit owner, and that this information not be communicated in advance to the unit owner. (Priority: Medium. First reported Q2 2022. Status: Not adopted.)

Capacity Imports and Exports

- The MMU recommends that all capacity imports be required to be deliverable to PJM load in an identified LDA, zonal or smaller, or explicit combinations of specific zones, e.g. MAAC, 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 to PJM load. (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

110 This recommendation was first made in the 2023/2024 BRA report in 2022. See "Analysis of the 2023/2024 RPM Base Residual Auction Revised," <http://www.monitoringanalytics.com/reports/Reports/2022/IMM_Analysis_of_the_20232024_RPM_Base_Residual_Auction_20221028.pdf> (October 28, 2022).
111 This recommendation was first made in the 2014/2015 BRA report in 2012. See "Analysis of the 2014/2015 RPM Base Residual Auction," <http://www.monitoringanalytics.com/reports/Reports/2012/Analysis_of_2014_2015_RPM_Base_Residual_Auction_20120409.pdf> (April 9, 2012).

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: Partially adopted.)
- The MMU recommends that units recover all and only the incremental costs, including incremental investment costs, required by the Part V reliability 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, that Part V reliability service should be provided under the deactivation avoidable cost rate in Part V, and that the cap on investment under the avoidable cost rate option be eliminated. 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. In a market with endemic structural market power, effective market power mitigation rules are required in order to constrain market participants to behave competitively. The analysis examines market performance, measured by price and the relationship between price and marginal cost, that results from the interaction of market structure and participant behavior.

The capacity market is, by design, always tight in the sense that total supply is generally only slightly larger than demand. The PJM Capacity Market is a locational market and local markets can and do have different supply demand balances than the aggregate market. While the market may be long at times, that is not the equilibrium state. Capacity in excess of demand is not sold and, if it does not earn or does not expect to earn adequate revenues in future capacity markets, or in other markets, or does not have value as a hedge, may be expected to retire, provided the market sets appropriate price signals to reflect the availability of excess supply. The demand for capacity includes expected peak load plus a reserve margin, and points on the demand curve, called the Variable Resource Requirement (VRR) curve, exceed peak load plus the reserve margin. The shape of the VRR curve results in the purchase of excess capacity and higher payments by customers. The impact of the VRR curve shape used in the 2023/2024 BRA compared to a vertical demand curve was a significant increase in customer payments for load as a result of buying more capacity than needed for reliability and paying a price above the competitive level as a result. The defined reliability goal is to have total supply greater than or equal to the defined demand for capacity. The level of purchased demand under RPM has generally exceeded expected peak load plus the target reserve margin, resulting in reserve margins that exceed the target. Demand for capacity is almost entirely inelastic because the market rules require loads to purchase their share of the system capacity requirement.

The VRR demand curve is everywhere inelastic. The result is that any supplier that owns more capacity than the typically small difference between total supply and the defined demand is individually pivotal and therefore has structural market power. Any supplier that, jointly with two other suppliers, owns more capacity than the difference between supply and demand either in aggregate or for a local market is jointly pivotal and therefore has structural market power.

For the 2023/2024 RPM Base Residual Auction, the level of committed demand resources (8,203.3 MW UCAP) exceeds the entire level of excess capacity (7,835.3 MW). This is consistent with PJM effectively not relying on demand response for reliability in actual operations. The excess is a result of the flawed rules permitting the participation of inferior demand side resources in the capacity market. Maintaining the persistent excess has meant that PJM markets have never experienced the results of reliance on demand side resources as part of the required reserve margin, rather than as excess above the required reserve margin. PJM markets have never experienced the implications of the definition of demand side resources as a purely emergency capacity resource that triggers a PAI whenever called.

The market design for capacity leads to structural market power in the capacity market. The capacity market is unlikely ever to approach a competitive market structure in the absence of a substantial and unlikely structural change that results in much greater diversity of ownership. 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. Detailed market power mitigation rules are included in the PJM Open Access Transmission Tariff (OATT or Tariff). Reliance on the RPM design for competitive outcomes means reliance on the market power mitigation rules. Attenuation of those rules means that market participants are not able to rely on the competitiveness of the market outcomes. The market power rules applied in the 2021/2022 BRA and the 2022/2023 BRA were significantly flawed, as illustrated by the results of the 2021/2022 BRA and the 2022/2023 BRA.[112] [113]

Competitive outcomes require continued improvement of the rules and ongoing monitoring of market participant behavior and market performance. The incorrect definition of the offer caps in the 2021/2022 BRA and the 2022/2023 BRA resulted in noncompetitive offers and a noncompetitive outcome. The market power rules were corrected by the Commission in an order issued on September 2, 2021, but the modified market power rules were not implemented in the 2022/2023 BRA.[114] [115] [116] The result was that capacity market prices were above the competitive level in the 2022/2023 BRA. In addition, the inclusion of offers that were not consistent with the defined terms of the Minimum Offer Price Rule (MOPR) based on the MMU's review, but were accepted by PJM, had a significant impact on the auction results in the 2022/2023 BRA.

The implementation of the market power mitigation rules that corrected the definition of the market seller offer cap in the 2023/2024 BRA resolved the market power issues from the prior two BRAs. The results of the 2023/2024 BRA were competitive.

In the capacity market, as in other markets, market power is the ability of a market participant to increase the market price above the competitive level or to decrease the market price below the competitive level. In order to evaluate whether actual prices reflect the exercise of market power, it is necessary to evaluate whether market offers are consistent with competitive offers.

The definition of the market seller offer cap was changed with the introduction of the Capacity Performance (CP) rules, from offer caps based on the marginal cost of capacity to offer caps based on Net CONE. But the CP market seller offer cap was based on strong assumptions that are not correct. The derivation of the CP market seller offer cap was based on PJM's assertion that the target price of the capacity market should be Net CONE, and simply assumed the answer. The CP market seller offer cap was incorrectly and significantly overstated as a result.

PJM's filing of the CP design made clear that PJM was abandoning offer caps that were based on verifiable calculations of the marginal cost of providing

112 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).

113 See "Analysis of the 2022/2023 RPM Base Residual Auction," <https://www.monitoringanalytics.com/reports/Reports/2022/IMM_Analysis_of_the_20222023_RPM_BRA_20220222.pdf> (February 22, 2022).

114 Complaint of the Independent Market Monitor for PJM, Docket No. EL19-47 (February 21, 2019) ("IMM MSOC Complaint").

115 176 FERC ¶ 61,137 (2021).

116 178 FERC ¶ 61,121 (2022).

capacity in favor of an approach that explicitly relied on wishful thinking about competitive forces resulting in competitive offers, despite the fact that the filing elsewhere recognized the high levels of concentration and the need to protect against market power in the capacity market.[117] PJM ignored the economic logic of marginal cost. PJM simply asserted that Net CONE was the target clearing price of the capacity market. PJM's filing explicitly stated that "By design, over time the marginal offer needed to clear the market will be priced at Net CONE, and all other resources that clear the market will be compensated at that Net CONE price."[118] PJM did not include a derivation of the offer cap in its CP filing, but simply asserted that Net CONE was the definition of a competitive offer.[119] There was not a single reference to opportunity cost as the basis for the market seller offer cap in the PJM filing.

In subsequent filings, PJM included the mathematical derivation of the market seller offer cap.[120] But the circular logic of the derivation inevitably concluded that Net CONE times B was the competitive offer. There were two key assumptions that led to that result. The derivation started by assuming that Net CONE was the target clearing price for the capacity market. PJM stated, in explaining the penalty rate, "Net CONE is the proper measure of the value of capacity."[121] That assumption/assertion was the basis for using Net CONE as the penalty rate. The penalty rate, adjusted for the reduced obligation defined by B, became the market seller offer cap. In addition to assuming the answer by setting the penalty rate based on Net CONE, the second key counterfactual assumption was that capacity resources have the ability to costlessly switch between capacity resource status and energy only status.

The mathematical derivation also included some additional unsupported and incorrect assumptions: there are a reasonably expected number of PAI; the number of PAI used in the calculation of the nonperformance charge rate is the same as the expected PAI (360); the number of performance intervals that define the total payments must equal the denominator of the performance penalty rate; the bonus payment rate for units that overperform equals the penalty rate for units that underperform; and penalties are imposed by PJM for all cases of noncompliance as defined in the tariff and there are no excuses.

Those assumptions were not even close to being correct for the 2022/2023 BRA and Net CONE times B was not the correct offer cap as a result.

The MMU supported the modified CP filing and prepared the mathematical appendix.[122] But, after evaluating the offer behavior and results of the capacity market auctions under CP and the actual PAI evidence and the failure to include updated PAI data in the definition of the offer cap, it became clear to the MMU that the CP model was a mistake.[123] The market seller offer cap of Net CONE times B was ultimately a failed experiment based on the third demonstrably false assumption that competitive forces in the PJM Capacity Market would produce competitive outcomes despite an offer cap that was above the competitive level. The structure of the PJM Capacity Market is not competitive and the purpose of market power mitigation is to produce competitive results despite that fact. The Net CONE times B offer cap assumed competition where it did not exist and led to noncompetitive outcomes and led to customers being overcharged by a combined $1.454 billion in the 2021/2022 and 2022/2023 BRAs.[124] The logical circularity of the argument as well as the fact that key assumptions are incorrect, means that the CP market seller offer cap was not based on economics or logic or math.

The correct definition of a competitive offer is the marginal cost of capacity, net ACR, where ACR includes an explicit accounting for the costs of mitigating risk, including the risk associated with capacity market nonperformance penalties, and the relevant costs of acquiring fuel, including natural gas. In response to a complaint filed by the MMU, the Commission replaced the Net

117 See "Reforms to the Reliability Pricing Market ("RPM") and Related Rules in the PJM Open Access Transmission Tariff ("Tariff") and Reliability Assurance Agreement Among Load Serving Entities ("RAA")," ("CP Filing"), Docket No. ER15-623, December 12, 2014; See, for example, page 54 and page 58.
118 See page 55 of CP Filing.
119 PJM did not multiply Net CONE by B in its CP filing of December 12, 2014.
120 For a detailed derivation, *see* Errata to February 25, 2015 Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM Interconnection, L.L.C., Docket No. ER15-623, et al. (February 27, 2015).
121 See page 43 of CP Filing.
122 See PJM Response to Deficiency Notice, ER15-623-001, et al. (April 10, 2015); Comments of the Independent Market Monitor for PJM, Docket No. ER15-623-001, et al. (April 15, 2015).
123 Brief of the Independent Market Monitor for PJM, EL19-47-000 (April 28, 2021); see also Comments of the Independent Market Monitor, Docket No. ER15-623, EL15-29 and EL19-47 (December 13, 2019); Comments of the Independent Market Monitor, Docket No. ER15-623, EL15-29 and EL19-47 (December 17, 2020).
124 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) and "Analysis of the 2022/2023 RPM Base Residual Auction," <http://www.monitoringanalytics.com/reports/Reports/2022/IMM_Analysis_of_the_20222023_RPM_BRA_20220222.pdf>.

CONE times B market seller offer cap with an ACR offer cap in the September 2nd Order.[125] [126]

The MMU recommends elimination of the key remaining components of the CP model because they interfere with competitive outcomes in the capacity market and create unnecessary complexity and risk. The use of Net CONE as the basis for the penalty rate is unsupported by economic logic. The use of Net CONE to establish penalties is a form of arbitrary administrative pricing that creates arbitrarily high risk for generators, creates complexity in the calculation of CPQR and ultimately raises the price of capacity. Rather than penalizing capacity resources for nonperformance, capacity resources should be paid the daily price of capacity only to the extent that they are available to produce energy or provide reserves, as required by PJM on a daily/hourly basis, based on their cleared capacity (ICAP). This is a positive performance incentive based on the market price of capacity rather than a penalty based on an arbitrary assumption. This would mean that capacity resources are paid to provide energy and reserves based on their full ICAP and are not paid a bonus for doing so. The reduced payments for capacity would directly reduce customers' bills for capacity. This would also end the pretense that there will be penalty payments to fund bonus payments. This would also end the need for complex CPQR calculations based on the penalty rate and assumptions about the number and timing of PAI. CP has not worked as the theory suggested. There have been only de minimis and generally very local PAI, largely excused nonperformance and de minimis bonus payments.

The MMU concludes that the results of the 2023/2024 RPM Base Residual Auction were competitive. A competitive offer in the capacity market is equal to net ACR.[127] The ACR values were based on data provided by the participants and were consistent with competitive offers for the relevant capacity.

The MMU also concludes that market prices were significantly affected by flaws in the capacity market rules and in the application of the capacity market rules by PJM, including the shape of the VRR curve; the overstatement of intermittent MW offers; the inclusion of sell offers from DR; and capacity imports.

The MMU also concludes that, although not an issue in the 2023/2024 auction, the rules permit the exercise of market power without mitigation for seasonal products through uplift payments for noncompetitive offers, rather than through higher prices.[128] Although the impact did not arise in the 2023/2024 auction, the issue should be addressed immediately in order to prevent the impact from increasing and because the solution is simple.

Changes to the capacity market design have addressed some but not all of the significant recommendations made by the MMU in prior reports. The MMU had recommended the elimination of the 2.5 percent demand adjustment (Short-Term Resource Procurement Target). The MMU had recommended that the performance incentives in the capacity market design be strengthened. The MMU had recommended that generation capacity resources pay penalties if they fail to produce energy when called upon during any of the hours defined as critical. The MMU had recommended 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. The MMU had recommended that all capacity imports be required to be pseudo tied in order to ensure that imports are as close to full substitutes for internal, physical capacity resources as possible. The MMU had recommended that the definition of demand side resources be modified in order to ensure that such resources are full substitutes for and provide the same value in the capacity market as generation resources, although this recommendation has not been incorporated in PJM rules. The MMU had recommended that both the Limited and the Extended Summer DR products be eliminated and that the restrictions on the availability of Annual DR be eliminated in order to ensure that the DR product has the same unlimited obligation to provide capacity year round as Generation Capacity Resources. The MMU had recommended that the EE addback calculation be corrected. The MMU had recommended

125 Complaint of the Independent Market Monitor for PJM, Docket No. EL19-47, February 21, 2019 ("IMM MSOC Complaint").
126 174 FERC ¶ 61,212; 176 FERC ¶ 61,137; *order on reh'g*, 178 FERC ¶ 61,121.
127 174 FERC ¶ 61,212 ("March 18th Order") at 65.

128 PJM uses various terms for uplift including make whole payments (often used in the capacity market) and operating reserve payments (often used in the energy market). The term uplift is used in this report to refer to out of market payments made by PJM to market participants in addition to market revenues.

that the default Avoidable Cost Rate (ACR) escalation method be modified in order to ensure accuracy and eliminate double counting.

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 has identified serious market design issues with RPM and the MMU has made specific recommendations to address those issues.[129] [130] [131] [132] [133] [134] [135] [136] In 2021 and 2022, the MMU prepared a number of RPM related reports and testimony, shown in Table 5-2.

The PJM markets have worked to provide incentives to entry and to retain capacity. PJM had excess reserves of 6,596.3 ICAP MW on June 1, 2022, and will have excess reserves of 8,246.0 ICAP MW on June 1, 2023, based on current positions.[137] A majority of capacity investments in PJM were financed by market sources.[138] Of the 46,697.0 MW of additional capacity that cleared in RPM auctions for the 2007/2008 through 2022/2023 Delivery Years, 34,853.8 MW (74.6 percent) were based on market funding. Of the 3,775.0 MW of additional capacity that cleared in RPM auctions for the 2023/2024 Delivery Years, 3,572.3 MW (94.6 percent) were 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.

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.

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.

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.

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

129 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).
130 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).
131 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).
132 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).
133 See "Analysis of the 2022/2023 RPM Base Residual Auction," <https://www.monitoringanalytics.com/reports/Reports/2022/IMM_Analysis_of_the_20222023_RPM_BRA_20220222.pdf> (February 22, 2022).
134 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).
135 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).
136 See "Analysis of the 2023/2024 RPM Base Residual Auction Revised," <http://www.monitoringanalytics.com/reports/Reports/2022/IMM_Analysis_of_the_20232024_RPM_Base_Residual_Auction_20221028.pdf> (October 28, 2022).
137 The calculated reserve margin for June 1, 2023, does not account for cleared buy bids that have not been used in replacement capacity transactions.
138 "2020 PJM Generation Capacity and Funding Sources 2007/2008 through 2021/2022 Delivery Years," <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_2020_PJM_Generation_Capacity_and_Funding_Sources_20072008_through_20212022_DY_20200915.pdf> (September 15, 2020).

market. Emergency and pre-emergency demand response participates in the capacity market and energy market.[139] Demand response resources participate in the synchronized reserve market. Demand response resources participate in the regulation market.

Total demand response revenue decreased by $3.8 million, 1.1 percent, from $354.0 million in the first nine months of 2021 to $350.2 million in the first nine months of 2022. Emergency demand response revenue accounted for 93.3 percent of all demand response revenue, economic demand response for 1.6 percent, demand response in the synchronized reserve market for 3.5 percent and demand response in the regulation market for 1.6 percent.

Total emergency demand response revenue decreased by $21.4 million, 6.1 percent, from $348.0 million in the first nine months of 2021 to $326.6 million in the first nine months of 2022.[140]

Economic demand response revenue increased by $4.7 million, 513.9 percent, from $0.9 million in the first nine months of 2021 to $5.6 million in the first nine months of 2022.[141] Demand response revenue in the synchronized reserve market increased by $8.5 million, 222.1 percent, from $3.8 million in the first nine months of 2021 to $12.3 million in the first nine months of 2022. Demand response revenue in the regulation market increased by $4.4 million, 335.1 percent, from $1.3 million in the first nine months of 2021 to $5.7 million in the first nine months of 2022.

- **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.[142]

- **Demand Response Market Concentration.** The ownership of economic load response resources was highly concentrated in the first nine months of 2021 and 2022. The HHI for economic resource reductions decreased by 923 points from 8674 for the first nine months of 2021 to 7751 for the first nine months of 2022. The ownership of emergency load response resources is highly concentrated. The HHI for emergency load response committed MW was 2070 for the 2021/2022 Delivery Year. In the 2021/2022 Delivery Year, the four largest CSPs owned 85.3 percent of all committed demand response UCAP MW. The HHI for emergency demand response committed MW is 2051 for the 2022/2023 Delivery Year. In the 2022/2023 Delivery Year, the four largest CSPs own 82.8 percent of all committed demand response UCAP MW.

- **Limited Locational Dispatch of Demand Resources.** With full implementation of the Capacity Performance rules in the capacity market in the 2020/2021 Delivery Year, PJM should be able to individually dispatch any capacity performance resource, including demand resources. But PJM cannot dispatch demand resources by node with the current rules because demand resources are not registered to a node. Demand resources can be dispatched by subzone only if the subzone is defined before dispatch. Aggregation rules allow a demand resource that incorporates many small end use customers to span an entire zone, which is inconsistent with nodal dispatch.

Section 6 Recommendations

- 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.)

139 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.

140 The total credits and MWh numbers for demand resources were downloaded as of October 6, 2022 and may change as a result of continued PJM billing updates.

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

142 "PJM Manual 28: Operating Agreement Accounting," § 11.2.2, Rev. 88 (Oct. 1, 2022).

- The MMU recommends that the option to specify a minimum dispatch price (strike price) for demand resources be eliminated and that participating resources receive the hourly real-time LMP less any generation component of their retail rate. (Priority: Medium. First reported 2010. Status: Not adopted.)
- The MMU recommends that the maximum offer for demand resources be the same as the maximum offer for generation resources. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that the demand resources be treated as economic resources, responding to economic price signals like other capacity resources. The MMU recommends that demand resources not be treated as emergency resources, not trigger a PJM emergency and not trigger a Performance Assessment Interval. (Priority: High. First reported 2012. Status: Not adopted.)
- The MMU recommends that the Emergency Program Energy Only option be eliminated because the opportunity to receive the appropriate energy market incentive is already provided in the economic program. (Priority: Low. First reported 2010. Status: Not adopted.)
- The MMU recommends that, if demand resources remain in the capacity market, a daily energy market must offer requirement apply to demand resources, comparable to the rule applicable to generation capacity resources.[143] (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. The MMU recommends that, if PJM continues to use subzones for any purpose, PJM clearly define the role of subzones in the dispatch of demand response. (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.[144] (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends demand response event compliance be calculated 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.)

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

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

- The MMU recommends that shutdown cost be defined as the cost to curtail load for a given period that does not vary with the measured reduction or, for behind the meter generators, be the start cost defined in Manual 15 for generators. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that the Net Benefits Test be eliminated and that demand response resources be paid LMP less any generation component of the applicable retail rate. (Priority: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that the tariff rules for demand response clarify that a resource and its CSP, if any, must notify PJM of material changes affecting the capability of the resource to perform as registered and must terminate or modify registrations that are no longer capable of responding to PJM dispatch directives at defined levels because load has been reduced or eliminated, as in the case of bankrupt and/or out of service facilities. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that there be only one demand response product in the capacity market, with an obligation to respond when called for any hour of the delivery year. (Priority: High. First reported 2011. Status: Partially adopted.[145])
- The MMU recommends that the lead times for demand resources be shortened to 30 minutes with a one 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, regardless of whether the real-time LMP at the applicable location meet or exceeds the PRD strike price, to be consistent with all CP resources. (Priority: High. First reported 2017. Status: Adopted 2022.)
- 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 resources not be included in the 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: Partially adopted.)
- The MMU recommends that, if energy efficiency resources remain in the capacity market, PJM codify eligibility requirements to claim the capacity rights to energy efficiency installations in the tariff and that PJM institute a registration system to track claims to capacity rights to energy efficiency installations and document installation periods of energy efficiency installations. (Priority: Medium. First reported Q2 2022. 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 2019. Status: Not adopted.)
- The MMU recommends that all demand resources register as Pre-Emergency Load Response and that the Emergency Load Response Program be eliminated. (Priority: High. First reported 2020. Status: Not adopted.)
- The MMU recommends that EDCs not be allowed to participate in markets as DER aggregators in addition to their EDC role. (Priority: High. First reported 2021. Status: Not adopted.)

145 PJM's Capacity Performance design requires resources to respond when called for any hour of the delivery year, but demand resources still have a limited mandatory compliance window.

- The MMU recommends that PJM include a 5.0 MW maximum size cap on DER aggregations. (Priority: Medium. First reported 2021. Status: Not adopted.)
- The MMU recommends that PJM use a nodal approach for DER participation in PJM markets. (Priority: Medium. First reported Q2 2022. Status: Partially adopted.)

Section 6 Conclusion

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

In the energy market, if there is to be a demand side program, demand resources should be paid the value of energy, which is LMP less any generation component of the applicable retail rate. There is no reason to have the net benefits test. The necessity for the net benefits test is an illustration of the illogical approach to demand side compensation embodied in paying full LMP to demand resources. The benefit of demand side resources is not that they suppress market prices, but that customers can choose not to consume at the current price of power, that individual customers benefit from their choices and that the choices of all customers are reflected in market prices. If customers face the market price, customers should have the ability to not purchase power and the market impact of that choice does not require a test for appropriateness.

If demand resources are to continue competing directly with generation capacity resources in the PJM Capacity Market, the product must be defined such that it can actually serve as a substitute for generation. This is a prerequisite to a functional market design. 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, and inappropriately, 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 (DR) 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, Actual Performance of demand resources during a Performance Assessment Event should be determined consistent with that of generation and should not be netted across the Emergency Action Area (EAA). The Capacity Market Seller's Performance Shortfalls for Demand Resources in the EAA are netted to determine a net EAA Performance Shortfall for the Performance Assessment Interval. Any net positive EAA Performance Shortfall is allocated to the Capacity Market Seller's demand resources that under complied within the EAA on a prorata basis based on the under compliance MW, and such seller's demand resources will be assessed a Performance Shortfall for the Performance Assessment Interval. Any net negative EAA Performance Shortfall is allocated to the Market Seller's Demand Resources that over complied within the EAA on a prorata basis based on over compliance MW, and such Market Seller's Demand Resources will be assessed Bonus Performance. Netting of performance of Demand Resources across the EAA is inconsistent with the performance measurement of other Capacity Performance resources.

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 to being a substitute for generation in the capacity and energy markets, 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.[146] The MMU proposal was based on the BGE load forecasting program and the Pennsylvania Act 129 Utility Program.[147] [148] 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 is be measured under the current economic demand response CBL rules which means relying on load estimates rather than actual metered load.[149] 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, accounting for market prices in any way they like, and that usage will determine the amount of capacity and energy for which each customer pays. There would be no counterfactual measurement and verification.

146 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>.
147 *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 April 28, 2022).
148 *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 April 28, 2022).
149 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 measurement and verification estimates are required. No promises of future reductions which can only be verified by inaccurate and biased measurement and verification methods are required. To the extent that customers enter into contracts with CSPs or LSEs to manage their payments, measurement and verification can be negotiated as part of a bilateral commercial contract between a customer and its CSP or LSE. But the system would be paid for actual, metered usage, regardless of which contractual party takes that obligation.

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. 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.[150] 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.

150 577 U.S. 260 (2016).

Overview: Section 7, Net Revenue

Net Revenue

- Energy market net revenues are significantly affected by energy prices and fuel prices. Energy prices and fuel prices were significantly higher in the first nine months of 2022 than in the first nine months of 2021.
- In the first nine months of 2022 both spark spreads and dark spreads increased compared to the first nine months of 2021. The volatility of both spark spreads and dark spreads increased for BGE, PSEG, and Western Hub.
- In the first nine months of 2022, compared to the first nine months of 2021, average energy market net revenues increased by 161 percent for a new combustion turbine (CT), 148 percent for a new combined cycle (CC), 44 percent for a new coal plant (CP), 117 percent for a new nuclear plant, 110 percent for a new diesel (DS), 122 percent for a new onshore wind installation, 122 percent for a new offshore wind installation and 148 percent for a new solar installation.
- The price of eastern natural gas and coal and CSAPR NOX Group 3 increased in the first nine months of 2022. The marginal costs of a new CC were greater than the marginal costs of a new CP in January 2022, and the marginal costs of a new CT were greater than the marginal cost of a new CP in January, February, and May 2022.
- All existing PJM nuclear plants are expected to more than cover their avoidable costs from energy and capacity market revenues in 2022, 2023, and 2024.

Section 7 Recommendations

- The MMU recommends that the net revenue calculation used by PJM to calculate the net Cost of New Entry (CONE) and net ACR be based on a forward looking estimate of expected energy and ancillary services net revenues using forward prices for energy and fuel. (Priority: Medium. First reported 2019. Status: Not adopted.)

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.

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.[151] On May 22, 2020, the EPA published its determination that MATS is not appropriate and necessary based on a cost-benefit analysis.[152] The list of coal steam units subject to MATS, however, remains in place.[153] All coal steam units in PJM are compliant with the state and federal emissions limits established by MATS. On January 31, 2022, the EPA proposed to reaffirm that it remains appropriate and necessary to regulate hazardous air pollutants (HAP), including mercury, from power plants after considering cost. This action revokes a 2020 finding that it was not appropriate and necessary to regulate coal and oil fired power plants under CAA § 112, and would restore the basis for the MATS rule.
- **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.[154] On March 15, 2021, the EPA finalized decreases to allowable emissions under the Cross-State Air Pollution Rule (CSAPR) and the 2008 ozone NAAQS for 10 PJM states.[155] On February 28, 2022, the EPA proposed a Federal Implementation Plan (FIP), to be known as the "Transport Rule," for 26 states that addresses the contribution of those states to problems in other states in attaining and maintaining the 2015 Ozone NAAQS.[156] The proposed FIP requirements

151 *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).
152 *See National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units—Reconsideration of Supplemental Finding and Residual Risk and Technology Review*, Docket No. EPA–HQ–OAR–2018–0794, 85 Fed. Reg. 31286.
153 *Id.* at 31291.
154 CAA § 110(a)(2)(D)(i)(I).
155 *Revised Cross-State Air Pollution Rule Update for the 2008 Ozone NAAQS*, Docket No. EPA–HQ–OAR–2020–0272; FRL–10013–42– OAR, 85 Fed. Reg. 23054 (Apr. 30, 2021).
156 See *Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard*, Docket No. EPA–HQ–OAR–2021–0668; FRL 8670–01–OAR, 87 Fed. Reg. 20036 (April 6, 2022).

would establish ozone season NOX emissions budgets for electric generating units in the PJM states, excluding North Carolina and the District of Columbia.

- **NSR.** On August 1, 2019, the EPA proposed to reform the New Source Review (NSR) permitting program.[157] NSR requires new projects and existing projects receiving major overhauls that significantly increase emissions to obtain permits. Recent EPA proposals would reduce the number of projects that require permits.

- **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.[158] RICE do not have to meet the same emissions standards if they are emergency stationary RICE. Environmental regulations allow emergency stationary RICE participating in demand response programs to operate for up to 100 hours per calendar year when providing emergency demand response when there is a PJM declared NERC Energy Emergency Alert Level 2 or there are five percent voltage/frequency deviations.

  PJM does not prevent emergency stationary RICE that cannot meet its capacity market obligations as a result of EPA emissions standards from participating in PJM markets as DR. Some emergency stationary RICE that cannot meet its capacity market obligations as a result of emissions standards are now included in DR portfolios. Emergency stationary RICE should be prohibited from participation as DR either when registered individually or as part of a portfolio if it cannot meet its capacity market obligations as a result of emissions standards.

- **Greenhouse Gas Emissions.** On June 30, 2022, the Supreme Court held that Section 111(d) of the CAA did not provide authority under the major questions doctrine to regulate carbon emissions in the manner proposed.[159] Both the EPA's Affordable Clean Energy (ACE) rule and the Clean Power Plan (CPP), which were promulgated under Section 111(d) of the CAA, can be expected to be vacated on remand.

- **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.[160]

- **Waters of the United States.** On November 18, 2021, the EPA and the Department the Army announced the signing of a proposed rule to revise the definition of "waters of the United States" to restore the pre 2015 definition of "waters of the United States." The proposed rule, if adopted, would make permanent the pre 2015 regulatory regime for interpreting WOTUS that is now effective.

- **Effluents.** Under the CWA, the EPA regulates (National Pollutant Discharge Elimination System (NPDES)) discharges from and intakes to power plants, including water cooling systems at steam electric power generating stations. The EPA has recently been strengthening certain discharge limits applicable to steam generating units, and some plant owners have already indicated an intent to close certain generating units as a result.

- **Coal Ash.** The EPA administers the Resource Conservation and Recovery Act (RCRA), which governs the disposal of solid and hazardous waste.[161] The EPA has adopted significant changes to the implementing regulations that will require closing noncompliant impoundments, and, potentially, the host power plant. The EPA is implementing a process for extensions to as late as October 17, 2028. The EPA is reviewing applications received from PJM plant owners. So far, the EPA has proposed to reject applications for Gavin and Clifty Creek, and proposed to grant, with conditions, an application from Spurlock.

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 Jersey, New York, Rhode Island, Vermont and Virginia that applies

157 *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).
158 See 40 CFR § 63.6640(f).
159 *West Virginia v. EPA*, No. 20-1530 (S. Ct. of the U.S.).
160 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).
161 42 U.S.C. §§ 6901 *et seq.*

to power generation facilities. New Jersey rejoined on January 1, 2020.[162] Virginia joined RGGI on January 1, 2021. Pennsylvania took action to join RGGI on April 23, 2022, but such action has been enjoined by court order on appeal.[163] [164] [165] A decision on the merits of the appeal is pending. The auction price in the September 1, 2022 auction was $13.45 per short ton, or $14.83 per metric tonne.

- **Illinois Climate and Equitable Jobs Act (CEJA).** On September 16, 2021, the Climate and Equitable Jobs Act (CEJA) became effective. CEJA created an expanded nuclear subsidy program. CEJA mandates that all fossil fuel plants close by 2045. CEJA established emissions caps for investor owned, gas-fired units with three years of operating history, effective October 1, 2021, on a rolling 12 month basis going forward. More than 10,000 MW of capacity are currently affected.
- **Carbon Price.** If the price of carbon were $50.00 per metric tonne, short run marginal costs would increase by $24.45 per MWh or 35.2 percent for a new combustion turbine (CT) unit, $16.66 per MWh or 36.2 percent for a new combined cycle (CC) unit and $43.09 per MWh or 58.1 percent for a new coal plant (CP) for 2022.

State Renewable Portfolio Standards

- **RPS.** In PJM, ten 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, 2022, Delaware, Illinois, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Virginia and Washington, DC have renewable portfolio standards. Virginia had a voluntary RPS in 2020, but a new mandatory RPS became effective on January 1, 2021. Indiana has voluntary renewable portfolio standards. Kentucky, Tennessee and West Virginia do not have renewable portfolio standards.
- **RPS Cost.** The cost of complying with RPS, as reported by the states, is $7.2 billion over the seven year period from 2014 through 2020, an average annual RPS compliance cost of $1.0 billion. The compliance cost for 2020, the most recent year with almost complete data, was $1.5 billion.[166]

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.** In PJM, as of September 30, 2022, 96.0 percent of coal steam MW had some type of flue-gas desulfurization (FGD) technology to reduce SO_2 emissions, while 99.8 percent of coal steam MW had some type of particulate control, and 99.8 percent of fossil fuel fired capacity had NO_X emission control technology. All coal steam units in PJM are compliant with the state and federal emissions limits established by MATS.

Renewable Generation

- **Renewable Generation.** Wind and solar generation was 4.6 percent of total generation in PJM in the first nine months of 2022. RPS Tier I generation was 5.8 percent of total generation in PJM and RPS Tier II generation was 2.2 percent of total generation in PJM in the first nine months of 2021. Only Tier I generation is defined to be renewable but Tier 1 includes some carbon emitting generation. RPS programs in the PJM states are heavily dependent upon imports. In the first nine months of 2022, Tier I generation in PJM was sufficient to meet 43.7 percent of the Tier I RPS requirements.

162 "Statement on New Jersey Greenhouse Gas Rule," RGGI Inc., (June 17, 2019) <https://www.rggi.org/sites/default/files/Uploads/Press-Releases/2019_06_17_NJ_Announcement_Release.pdf>.

163 "Statement on Virginia Greenhouse Gas Rule," RGGI, (July 8, 2020) <https://www.rggi.org/news-releases/rggi-releases>.

164 CO2 Budget Trading Program, 52 Pa.B. 2471 (April 23, 2022), codified 25 Pa. Code Ch. 145; *see also* 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/>.

165 See *Ramez Ziadeh, et al. v. Pennsylvania Legislative Reference Bureau*, Memorandum Opinion, Commonwealth Court of Pennsylvania Case No. No. 41 M.D. 2022 (July 8, 2022); *Ramez Ziadeh, et al. v. Pennsylvania Legislative Reference Bureau*, Order Granting Application to Vacate, Commonwealth Court of Pennsylvania Case No. No. 41 M.D. 2022 (July 25, 2022).

166 The 2020 compliance cost value for PJM states does not include Illinois, Michigan or North Carolina. Based on past data these states generally account for 3.0 percent of the total RPS compliance cost of PJM states.

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. The MMU recommends that there be a single PJM operated forward market for RECs, for a single product based on a common set of state definitions of renewable technologies, with a single clearing price, trued up to real time delivery. (Priority: High. First reported 2010. Status: Not adopted.)
- The MMU recommends that PJM provide a full analysis of the impact of carbon pricing on PJM generating units and carbon pricing revenues to the PJM states in order to permit the states to consider a potential agreement on the development of a multistate framework for carbon pricing and the distribution of carbon revenues. (Priority: High. 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 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: Low. First reported 2018. Status: Not adopted.)
- The MMU recommends that load and generation located at separate nodes be treated as separate resources in order to ensure that load and generation face consistent incentives throughout the markets. (Priority: High. First reported 2019. Status: Not adopted.)
- The MMU recommends that emergency stationary RICE be prohibited from participation as DR either when registered individually or as part of a portfolio if it cannot meet the capacity market requirements to be DR as a result of emissions standards that impose environmental run hour limitations. (Priority: Medium. First reported 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.

Environmental requirements and initiatives at both the federal and state levels, and state renewable energy mandates and associated incentives have resulted in the construction of substantial amounts of renewable capacity in the PJM footprint, especially wind and solar resources and the retirement of emitting resources. Renewable energy credit (REC) markets created by state programs, and federal tax credits have significant impacts on PJM wholesale markets. But state renewables programs in PJM are not coordinated with one another, are generally not consistent with the PJM market design or PJM prices, have widely differing objectives, including supporting some emitting resources, have widely differing implied prices of carbon and are not transparent on pricing and quantities. The effectiveness of state renewables programs would be enhanced if they were coordinated with one another and with PJM markets, and if they increased transparency. States could evaluate the impacts of a range of carbon prices if PJM would provide a full analysis of the impact of carbon pricing on PJM generating units and carbon pricing revenues to the PJM states in order to permit the states to consider a potential agreement on the development of a multistate framework for carbon pricing and the distribution of carbon revenues. A single carbon price across PJM, established by the states, would be the most efficient way to reduce carbon output, if that is the goal.

But in the absence of a PJM market carbon price, a single PJM market for RECs would contribute significantly to market efficiency and to the procurement of renewable resources in a least cost manner. Ideally, there would be a single PJM operated forward market for RECs, for a single product based on a common set of state definitions of renewable technologies, with a single clearing price, trued up to real-time delivery. States would continue to have the option to create separate RECs for additional products that did not fit the product definition, e.g. waste coal, trash incinerators, or black liquor.

RECs are an important mechanism used by PJM states to implement environmental policy. 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 on behalf of the states that would meet the standards and requirements of all states in the PJM footprint. 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.

Existing 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 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 $17.14 per tonne in Ohio to $27.65 per tonne in Maryland. The price of carbon implied by SREC prices ranges from $84.74 per tonne in Pennsylvania to $847.59 per tonne in Washington, DC. The effective prices for carbon compare to the RGGI clearing price in September 2022 of $14.83 per tonne and to the social cost of carbon which is estimated in the range of $50 per tonne.[167] The impact on the cost of generation from a new combined cycle unit of a $50 per tonne carbon price would be $16.66 per MWh.[168] The impact of an $800 per tonne carbon price would be $266.50 per MWh. This wide range of implied carbon prices is not consistent with an efficient, competitive, least cost approach to the reduction of carbon emissions.

In addition, even the explicit environmental goals of RPS programs are not clear. While RPS is frequently considered to target carbon emissions, Tier 1 resources include some carbon emitting generation and Tier 2 resources include additional carbon emitting generation.

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.

If the states chose this policy option, PJM markets could also provide a flexible mechanism to limit carbon output, for example by incorporating a consistent carbon price in unit offers which would be reflected in PJM's economic dispatch. If there is a social decision to limit carbon output, a consistent carbon price would be the most efficient way to implement that decision. The states in PJM could agree, if they decided it was in their interests, with the appropriate information, on a carbon price and on how to allocate the revenues from a carbon price that would make all states better off. A mechanism like RGGI leaves all decision making with the states. The carbon price would not be FERC jurisdictional or subject to PJM decisions. The MMU continues to recommend that PJM provide a full analysis of the impact of carbon pricing on PJM generating units and carbon pricing revenues to the PJM states in order to permit the states to consider a potential agreement on the development of a multistate framework for carbon pricing and the distribution of carbon revenues. The results of the analysis would include the

167 "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>.

168 The cost impact calculation assumes a heat rate of 6.296 MMBtu per MWh and a carbon emissions rate of 0.05290995 tonne per MMBtu. The $800 per tonne carbon price represents the approximate upper end of the carbon prices implied by the 2022 REC and SREC prices in the PJM jurisdictions with RPS. Additional cost impacts are provided in Table 8-7.

impact on the dispatch of every unit, the impact on energy prices and the carbon pricing revenues that would flow to each state.

For example, states receiving high levels of revenue could shift revenue to states disproportionately hurt by a carbon price if they believed that all states would be better off as a result. 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 seven year period from 2014 through 2020 for the nine jurisdictions that had RPS was $1.0 billion, or a total of $7.2 billion over seven years. The RPS compliance cost for 2020, the most recent year for which there is almost complete data, was $1.5 billion.[169] RPS costs are payments by customers to the sellers of qualifying resources. The revenues from carbon pricing flow to the states.

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 $3.8 billion per year if the carbon price were $13.45 per short ton and emissions levels were five percent below 2021 emission levels. 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 $14.1 billion if the carbon price were $50 per short ton and emission levels were five percent below 2021 levels. If only the current RPS states participated in a regional carbon market, the estimated revenue returned to the states/customers from selling carbon allowances at $13.45 per short ton would be about $2.5 billion. The costs of a carbon price are the impact on energy market prices, net of the revenue returned to states/customers.

169 The 2020 compliance cost value for PJM states does not include Illinois, Michigan or North Carolina. Based on past data these states generally account for 3.0 percent of the total RPS compliance cost of PJM states.

Overview: Section 9, Interchange Transactions

Interchange Transaction Activity

- **Aggregate Imports and Exports in the Real-Time Energy Market.** In the first nine months of 2022, PJM was a monthly net exporter of energy in the real-time energy market in all months.[170] In the first nine months of 2022, the real-time net interchange was -26,304.3 GWh. The real-time net interchange in the first nine months of 2021 was -29,504.6 GWh.
- **Aggregate Imports and Exports in the Day-Ahead Energy Market.** In the first nine months of 2022, PJM was a monthly net exporter of energy in the day-ahead energy market in all months. In the first nine months of 2022, the total day-ahead net interchange was -20,229.1 GWh. The day-ahead net interchange in the first nine months of 2021 was -19,496.3 GWh.
- **Aggregate Imports and Exports in the Day-Ahead and the Real-Time Energy Market.** In the first nine months of 2022, gross imports in the day-ahead energy market were 109.4 percent of gross imports in the real-time energy market (126.0 percent in the first nine months of 2021). In the first nine months of 2022, gross exports in the day-ahead energy market were 86.4 percent of the gross exports in the real-time energy market (74.4 percent in the first nine months of 2021).
- **Interface Imports and Exports in the Real-Time Energy Market.** In the first nine months of 2022, there were net scheduled exports at 15 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 2022, there were net scheduled exports at five of PJM's eight interface pricing points eligible for real-time transactions in the real-time energy market.

170 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.

- **Interface Imports and Exports in the Day-Ahead Energy Market.** In the first nine months of 2022, there were net scheduled exports at 15 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 2022, there were net scheduled exports at seven of PJM's seven interface pricing points eligible for day-ahead transactions in the day-ahead energy market.[171]
- **Up To Congestion Interface Pricing Point Imports and Exports in the Day-Ahead Energy Market.** In the first nine months of 2022, up to congestion transactions were net exports at five of PJM's seven interface pricing points eligible for day-ahead transactions in the day-ahead energy market.[172]
- **Inadvertent Interchange.** In the first nine months of 2022, net scheduled interchange was - 26,304.3 GWh and net actual interchange was -26,204.7 GWh, a difference of 99.6 GWh. In the first nine months of 2021, the difference was 69.7 GWh. This difference is inadvertent interchange.
- **Loop Flows.** In the first nine months of 2022, the Northern Indiana Public Service (NIPS) Interface had the largest loop flows of any interface with 566.0 GWh of net scheduled interchange and -8,681.3 GWh of net actual interchange, a difference of 8,115.3 GWh. In the first nine months of 2022, the SOUTH interface pricing point had the largest loop flows of any interface pricing point with 2,129.3 GWh of net scheduled interchange and 6,644.4 GWh of net actual interchange, a difference of 4,515.1 GWh.

Interactions with Bordering Areas

PJM Interface Pricing with Organized Markets

- **PJM and MISO Interface Prices.** In the first nine months of 2022, 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 54.3 percent of the hours.
- **PJM and New York ISO Interface Prices.** In the first nine months of 2022, 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 60.5 percent of the hours.
- **Neptune Underwater Transmission Line to Long Island, New York.** In the first nine months of 2022, 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 85.7 percent of the hours.
- **Linden Variable Frequency Transformer (VFT) Facility.** In the first nine months of 2022, 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 78.0 percent of the hours.
- **Hudson DC Line.** In the first nine months of 2022, 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 75.1 percent of the hours.

Interchange Transaction Issues

- **PJM Transmission Loading Relief Procedures (TLRs).** PJM issued one TLR of level 3a or higher in the first nine months of 2022, and two such TLRs in the first nine months of 2021.
- **Up To Congestion.** The average number of up to congestion bids submitted in the day-ahead energy market increased by 45.3 percent, from 25,930 bids per day in the first nine months of 2021 to 37,667 bids per day in the first nine months of 2022. The average cleared volume of up to congestion bids submitted in the day-ahead energy market increased by 49.1 percent, from 175,524 MWh per day in the first nine months of 2021, to 261,668 MWh per day in the first nine months of 2022.

171 On April 15, 2021, PJM retired the Southeast interface pricing point from the day-ahead market. The Southeast interface pricing point could still be assigned to transactions under the VACAR reserve sharing agreement in the real-time market. Following the termination of the VACAR reserve sharing agreement on October 1, 2022, PJM retired the Southeast and Southwest interface pricing points.
172 Id.

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.)
- 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 SOUTH interface pricing point. (Priority: High. First reported 2013. Status: Adopted, Q3 2022.)[173]
- The MMU recommends that transactions sourcing in the Western Interconnection be priced at either the MISO interface pricing point or the SOUTH interface pricing point based on the locational price impact of flows between the DC tie line point of connection with the Eastern Interconnection and PJM. (Priority: High. First reported 2020. 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 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

173 The grandfathered agreements associated with the Southwest interface pricing point expired in 2012. The Southwest interface pricing point is no longer an eligible pricing point in the day-ahead or real-time energy markets. Effective June 1, 2020, PJM retired the NIPSCO interface pricing point. Following the termination of the VACAR reserve sharing agreement on October 1, 2022, PJM retired the Southeast and Southwest interface pricing points.

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 modifications to the FFE calculation to ensure that FFE calculations reflect the current capability of the transmission system as it evolves. The MMU recommends that the Commission set a deadline for PJM and MISO to resolve the FFE freeze date and related issues. (Priority: Medium. First reported 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 of an energy market including 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.

It is not appropriate to have special pricing agreements between PJM and any external entity. The same market pricing should apply to all transactions. External entities wishing to receive the benefits of the PJM LMP market should join PJM.

In 2020, PJM terminated a number of interface pricing points, consistent with longstanding MMU recommendations. Following the termination of the Northwest pricing point on October 1, 2020, PJM failed to correctly map the pricing points to transactions that had been mapped to the Northwest pricing point to pricing points that are consistent with electrical impacts on the PJM system. On October 1, 2022, PJM terminated the Southeast and Southwest interface pricing points. The MMU recommends that transactions sourcing in the Western Interconnection be priced at either the MISO interface pricing point or the SOUTH interface pricing point based on the electrical impact of flows between the DC tie line point of connection with the Eastern Interconnection and PJM. The MMU continues to recommend the termination of the Ontario interface pricing point. The Ontario interface pricing point is noncontiguous to the PJM footprint that creates opportunities for market participants to engage in sham scheduling activities.

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.[174]

PJM determines the primary reserve requirement based on the largest single contingency plus 190 MW in every approved RT SCED case. The required synchronized reserve and nonsynchronized reserve are calculated and dispatched in every real-time market solution, and there are associated clearing prices (SRMCP and NSRMCP) assigned every five minutes. Scheduled resources are credited based on a dispatched assignment and a five minute 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

174 See PJM. "PJM Manual 10: Pre-Scheduling Operations," § 3.1.1 Day-ahead Scheduling (Operating) Reserve, Rev. 42 (Oct. 1, 2022).

currently off line but available to start and provide energy within 10 minutes).

- **Demand.** The PJM primary reserve requirement is 150 percent of the largest single contingency plus 190 MW. In the first nine months of 2022, the average primary reserve requirement was 2,419.4 MW in the RTO Zone and 2,418.1 in the MAD Subzone.

Tier 1 Synchronized Reserve

Synchronized reserve is provided by generators and 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. Before the reserve market changes implemented on October 1, 2022, 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. Every real-time market solution calculates the available tier 1 synchronized reserve. There is no formal market for tier 1 synchronized reserve prior to October 1, 2022.

- **Supply.** No offers are made for tier 1 synchronized reserves. The market solution estimated tier 1 synchronized reserve as available 10 minute ramp from the energy dispatch. In the first nine months of 2022, there was an average hourly supply of 1,531.4 MW of tier 1 available in the RTO Zone and an average hourly supply of 693.6 MW of tier 1 synchronized reserve available within the MAD Subzone.
- **Demand.** The synchronized reserve requirement is calculated for each real-time dispatch solution as the largest single contingency plus 190 MW within both the RTO Zone and the MAD Subzone.
- **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.[175] 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 the 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 rule has a significant impact on the cost of tier 1 synchronized reserves, resulting in a windfall payment of more than $150 million since 2014. In the first nine months of 2022, the nonsynchronized reserve market clearing price was above $0 in 609 intervals, none of which were during a spinning event. Both the synchronized reserve premium price and the payment when the nonsynchronized reserve price is above zero will be removed on October 1, 2022.

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. Tier 2 synchronized reserve, along with tier 1, will be replaced by the new consolidated synchronized reserve on October 1, 2022, which behaves similarly to tier 2. In PJM, the required amount of synchronized reserve is defined to be no less than the largest single contingency, and 10 minute primary reserve as no less than 150 percent of the largest single contingency, plus 190 MW. This is stricter than the NERC standard of the greater of 80 percent of the largest single contingency or 900 MW.[176]

175 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.2.10 Settlements, Rev. 122 (Oct. 1, 2022).
176 NERC (June 2, 2020) <NERC Reliability Standard BAL 002-2 Glossary_of_Terms.pdf>.

When the synchronized reserve requirement cannot be met with tier 1 synchronized reserve, PJM uses the tier 2 synchronized reserve market to satisfy the balance of the requirement. 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 of 2022, the average supply of daily offered and eligible tier 2 synchronized reserve was 35,042.6 MW in the RTO Zone of which 5,478.1 MW was located in the MAD Subzone.
- **Demand.** The average hourly synchronized reserve requirement was 1,676.2 MW in the RTO Reserve Zone and 1,675.5 in the Mid-Atlantic Dominion Reserve Subzone. The hourly average cleared tier 2 synchronized reserve was 234.5 MW in the MAD Subzone and 706.4 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 of 2022.

  The average HHI for tier 2 synchronized reserve in the RTO Zone was 2898 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. The $7.50 per MWh will be reduced to the expected value of the synchronized reserve nonperformance penalty on October 1, 2022. PJM automatically enters an offer of $0 for tier 2 synchronized reserve when an offer is not entered by the owner. Demand resources offering into the tier 2 market are also subject to an offer cap of $7.50 plus costs. Cost may include shutdown costs for demand response.[177]

177 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.2.1 Synchronized Reserve Market Eligibility, Rev. 122 (Oct. 1, 2022).

Market Performance

- **Price.** The weighted average price for tier 2 synchronized reserve for all cleared hours in the MAD Subzone was $18.14 per MW in the first nine months of 2022. The weighted average price for tier 2 synchronized reserve for all cleared intervals in the RTO Synchronized Reserve Zone was $16.16 per MW in the first nine months of 2022.

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 2022, the average supply of eligible and available nonsynchronized reserve was 2,015.6 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.[178]
- **Market Concentration.** The MMU calculates that the three pivotal supplier test would have been failed in 96.3 percent of intervals in which the price was above $0.01 in the first nine months of 2022.

178 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.1 Overview of the PJM Reserve Markets, Rev. 122 (Oct. 1, 2022).

Market Conduct

- **Offers.** Generation owners do not submit supply offers for nonsynchronized reserve. 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. The reserve market design implemented on October 1, 2022, removes the approximated nonsynchronized reserve opportunity cost calculation that PJM currently uses, because offline resources do not have an opportunity cost for the market intervals when they are scheduled to be offline because PJM cannot dispatch them for energy in those intervals.[179]

Market Performance

- **Price.** The nonsynchronized reserve price is determined by the opportunity cost of the marginal nonsynchronized reserve unit. The nonsynchronized reserve weighted average price for all intervals in the RTO Reserve Zone was $0.32 per MW in the first nine months of 2022.

Secondary Reserve (DASR)

There is no NERC standard for secondary reserve. PJM defines secondary reserve in the day-ahead market as reserves (online or offline available for dispatch) that can be converted to energy in 30 minutes. PJM defines a secondary reserve requirement but is not required to maintain this level of secondary reserve in real time. Effective on October 1, 2022, a secondary reserve product will exist in both the real-time and day-ahead markets.

PJM maintains a day-ahead, offer-based market for 30 minute day-ahead secondary reserve. The PJM 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.[180] If DASR units are on an outage in real time or cleared DASR MW are not available, the DASR payment is not made. Effective October 1, 2022, PJM will have both day-ahead and real-time 30 minute reserves markets using only lost opportunity costs to determine price, not submitted offers.

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 resources that can provide energy within 30 minutes of a request from PJM Dispatch.
- **Demand.** The DASR requirement is the sum of the PJM requirement and the Dominion requirement based on the VACAR reserve sharing agreement. It is calculated every year for the period November 1 through October 31. For November 1, 2021, through October 31, 2022, the DASR requirement was 4.40 percent of forecast peak load. The average hourly DASR MW purchased in the first nine months of 2022 was 4,820.4 MW, a decrease from the 5,094.2 hourly MW in the first nine months of 2021. Effective October 1, 2022, the 30-minute reserve requirement will be the maximum of: 150 percent of the synchronized reserve requirement (the same as for primary reserve); the largest active gas contingency; or 3,000 MW.

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 2022, 43.7 percent of daily unit offers were above $0.00 and 16.9 percent of daily unit offers were above $5. Effective with the reserve market changes, the offer price of secondary reserve will be $0.00.
- **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 2022.

179 See *PJM Interconnection, L.L.C.*, "Enhanced Price Formation in Reserve Markets of PJM Interconnection, L.L.C.," Docket No. EL19-58 (March 29, 2019) at 84.

180 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 11.2.7 Day-Ahead Scheduling Reserve Performance, Rev. 122 (Oct. 1, 2022).

Market Performance

- **Price.** In the first nine months of 2022, the MW weighted average DASR price for all hours when the DASRMCP was above $0.00 was $2.28. The MW weighted average for all hours including hours when the price was $0 was $0.37.

Regulation Market

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

Market Structure

- **Supply.** In the first nine months of 2022, the average hourly offered supply of regulation for nonramp hours was 757.5 performance adjusted MW (765.8 effective MW). This was an increase of 4.1 performance adjusted MW (an increase of 13.1 effective MW) from the first nine months of 2021. In the first nine months of 2022, the average hourly offered supply of regulation for ramp hours was 1,124.4 performance adjusted MW (1,127.6 effective MW). This was an increase of 47.9 performance adjusted MW (an increase of 25.9 effective MW) from the first nine months of 2021, when the average hourly offered supply of regulation was 1,076.5 performance adjusted MW (1,101.7 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 cleared RegA and RegD resources equal to 464.4 hourly average performance adjusted actual MW in the first nine months of 2022. This is an increase of 21.0 performance adjusted actual MW from the first nine months of 2021, when the average hourly total regulation cleared performance adjusted actual MW for nonramp hours were 485.4 performance adjusted actual MW. The ramp regulation requirement of 800.0 effective MW was provided by a combination of cleared RegA and RegD resources equal to 719.2 hourly average performance adjusted actual MW in the first nine months of 2022. This is an increase of 12.4 performance adjusted actual MW from the first nine months of 2021, where the average hourly regulation cleared MW for ramp hours were 706.8 performance adjusted actual MW.

  The ratio of the average hourly offered supply of regulation to average hourly regulation demand (performance adjusted cleared MW) for nonramp hours was 1.63 in the first nine months of 2022 (1.55 in the first nine months of 2021). The ratio of the average hourly offered supply of regulation to average hourly regulation demand (performance adjusted cleared MW) for ramp hours was 1.56 in the first nine months of 2022 (1.52 in the first nine months of 2021).
- **Market Concentration.** In the first nine months of 2022, the three pivotal supplier test was failed in 88.8 percent of hours. In the first nine months of 2022, the effective MW weighted average HHI of RegA resources was 2458 which is highly concentrated and the effective MW weighted average HHI of RegD resources was 1670 which is moderately concentrated. The effective MW weighted average HHI of all resources was 1433, 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.[181] In the first nine months of 2022, there were 183 resources following the RegA signal and 52 resources following the RegD signal.

Market Performance

- **Price and Cost.** The weighted average clearing price for regulation was $51.04 per MW of regulation in the first nine months of 2022, an increase of $30.13 per MW, or 144.1 percent, from the weighted average clearing price of $20.91 per MW in the first nine months of 2021. The weighted average cost of regulation in the first nine months of 2022 was $63.46 per MW of regulation, an increase of 150.1 percent, from the weighted average cost of $25.37 per MW in the first nine months of 2021.
- **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 and competitively, RegD and RegA resources would be paid the same price per effective MW.
- **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. 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 an inefficient market signal about the value of RegD in every hour.

181 See the *2021 State of the Market Report for PJM*, Vol. II, Appendix F "Ancillary Services Markets."

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).[182]

In the first nine months of 2022, total black start charges were $51.7 million, including $51.4 million in revenue requirement charges and $0.35 million in uplift 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 payment. Black start uplift 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 first nine months of 2022 ranged from $0 in the OVEC and REC Zones to $14.7 million in the AEP Zone.

CRF values are a key determinant of total payments to black start units. The CRF values in PJM tariff tables should have been changed for both black start and the capacity market when the tax laws changed in December 2017. As a result of the failure to change the CRF values, black start units have been and continue to be significantly overcompensated since the changes to the tax code.

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). The same equipment provides both MVAr and MW. The current rules permit over recovery of capital costs.

Reactive capability charges are based on FERC approved filings that permit recovery based on an outdated cost of service approach.[183] All capacity costs of generators should be incorporated in the capacity market. The nonmarket

182 OATT Schedule 1 § 1.3BB. There are no ALR units currently providing black start service.
183 OATT Schedule 2.

cost of service approach to reactive capability payments should be eliminated. 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. Total reactive charges in the first nine months of 2022 increased 6.44 percent from $272.3 million in 2021 to $289.9 million in 2022. In the first nine months of 2022, reactive capability charges increased 6.27 percent from $271.6 million in the first nine months of 2021 to $288.6 million in 2022. Total reactive service charges in in the first nine months of 2022 ranged from $0 in the REC and OVEC Zones, to $39.4 million in the AEP Zone.

Frequency Response

The PJM Tariff requires that all new generator interconnection customers, both synchronous and nonsynchronous, have hardware and/or software that provides primary frequency responsive real power control with the ability to sense changes in system frequency and autonomously adjust real power output to correct for frequency deviations.[184] Primary frequency response begins within a few seconds and extends up to a minute. The purpose of primary frequency response is to arrest and stabilize the system until other measures (secondary and tertiary frequency response) become active. This includes a governor or equivalent controls capable of operating with a maximum five percent droop and a +/- 36 mHz deadband.[185] In addition to resource capability, resource owners must comply by setting control systems to autonomously adjust real power output in a direction to correct for frequency deviations.

The response of generators within PJM to NERC identified frequency events remains under evaluation. A frequency event is declared whenever the system frequency goes outside of 60 Hz by +/- 40 mHz and stays there for 60 continuous seconds. The NERC BAL-003-2 requirement for balancing authorities (PJM is a balancing authority) uses a threshold value (L_{10}) equal to -259.3 MW/0.1 Hz and has selected twelve frequency events between December 1, 2020, and November 30, 2021, to evaluate.

184 Nuclear Regulatory Commission (NRC) regulated facilities are exempt from this provision. Behind the meter generation that is sized to load is also exempt.
185 OATT Attachment O § 4.7.2 (Primary Frequency Response).

As a balancing authority, PJM requires all generators to be capable of providing primary frequency response and to operate with primary frequency response controls enabled.[186] PJM does monitor primary frequency response during NERC identified frequency events for all resources 50 MW or greater. Exclusions to PJM monitoring include nuclear plants, offline units, units with no available headroom, units assigned to regulation, and units with a current outage ticket in eDART.

Market Procurement of Real-Time Ancillary Services

PJM uses market mechanisms to varying degrees in the procurement of ancillary services, including primary reserves and regulation. Ideally, all ancillary services would be procured taking full account of the interactions with the energy market. When a resource is used for an ancillary service instead of providing energy in real time, the cost of removing the resource, either fully or partially, from the energy market should be weighed against the benefit the ancillary service provides. The degree to which PJM markets account for these interactions depends on the timing of the product clearing and software limitations and the accuracy of unit parameters and offers.

The synchronized reserve market clearing is more integrated with the energy market clearing than the other ancillary services. Resources categorized as flexible tier 2 reserve, those that can provide reserves by backing down according to their ramp rate, are jointly cleared along with energy in every real-time market solution. Given the joint clearing of energy and flexible tier 2, the synchronized reserve market clearing price should always cover the opportunity cost of providing flexible tier 2. PJM should never need to pay uplift to flexible tier 2. The uplift paid to flexible tier 2 results from issues with the dispatch and pricing software timing. Inflexible tier 2 reserves, provided by resources that require longer notice to take actions to prepare for reserve deployment, are not cleared along with energy in the real-time market solution. Inflexible tier 2 reserves are cleared hourly by the Ancillary Service Optimizer (ASO). The ASO uses forward looking information about the energy market, flexible tier 2, tier 1, and regulation to estimate the costs and benefits of using a resource for inflexible tier 2 synchronized reserves.

186 *Id.*; see also "PJM Manual 12: Balancing Operations, Rev. 47 (Oct. 1, 2022). § 3.6 (Primary Frequency Response).

Nonsynchronized reserves are cleared with every real-time energy market solution, but their costs are not fully known by the real-time energy market software (RT SCED) because the resources are offline. PJM uses an estimate of the cost of using a resource for nonsynchronized reserve instead of energy from a previously solved IT SCED solution. IT SCED runs every 15 minutes looking ahead at target dispatch times up to two hours in the future. The energy commitment decisions for the offline resources have already been made when the RT SCED clears the nonsynchronized reserve market. RT SCED compares the IT SCED estimated cost of nonsynchronized reserve clearing to the RT SCED determined cost of synchronized reserve clearing in satisfying the primary reserve requirement. Nonsynchronized reserve clearing indirectly interacts with energy clearing through both products' substitutability with synchronized reserves.

Prices for the regulation and reserve markets are set by the pricing calculator (LPC), which uses the RT SCED solution as an input. The RT SCED partially, but not fully, clears the reserve market. The software determining the prices is not clearing the regulation market. Since the implementation of fast start pricing on September 1, 2021, the pricing calculations in LPC are not the same prices that result from the market clearing in RT SCED.

Section 10 Recommendations

- The MMU recommends that all data necessary to perform the regulation market three pivotal supplier test be saved by PJM so that the test can be replicated. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that the total regulation (TReg) signal sent on a fleet wide basis be eliminated and replaced with individual regulation signals for each unit. (Priority: Low. First reported 2019. Status: Not adopted.)
- The MMU recommends that the ability to make dual offers (to make offers as both a RegA and a RegD resource in the same market hour) be removed from the regulation market. (Priority: High. First reported 2019. 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.[187])
- 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.[188] FERC rejected.[189])
- 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.[190])
- 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.[191])
- The MMU recommends enhanced documentation of the implementation of the regulation market design. (Priority: Medium. First reported 2010. Status: Not adopted. FERC rejected.[192])
- The MMU recommends that PJM be required to save data elements necessary for verifying the performance of the regulation market. (Priority: Medium. First reported 2010. Status: Not adopted.)
- The MMU recommends that the $12.00 margin adder be eliminated from the definition of the cost based regulation offer because it is a markup and not a cost. (Priority: Medium. First reported 2021. Status: Not adopted.)

187 162 FERC ¶ 61,295 (2018), *reh'g denied*, 170 FERC ¶ 61,259 (2020).
188 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.
189 162 FERC ¶ 61,295 (2018), *reh'g denied*, 170 FERC ¶ 61,259 (2020).
190 *Id.*
191 *Id.*
192 *Id.*

- The MMU recommends that the ramp rate limited desired MW output be used in the regulation uplift calculation, to reflect the physical limits of the unit's ability to ramp and to eliminate overpayment for opportunity costs when the payment uses an unachievable MW. (Priority: Medium. First reported Q1, 2022. Status: Not adopted.)
- The MMU recommends that PJM replace the static MidAtlantic/Dominion Reserve Subzone with a reserve zone structure consistent with the actual deliverability of reserves based on current transmission constraints. (Priority: High. First reported 2019. Status: Not adopted.)
- The MMU recommends that the $7.50 margin be eliminated from the definition of the cost of tier 2 synchronized reserve because it is a markup and not a cost. (Priority: Medium. First reported 2018. Status: Adopted October 1, 2022.)
- The MMU recommends that the variable operating and maintenance cost be eliminated from the definition of the cost of tier 2 synchronized reserve and that the calculation of synchronized reserve variable operations and maintenance costs be removed from Manual 15. (Priority: Medium. First reported 2019. Status: Adopted October 1, 2022.)
- The MMU recommends that the components of the cost-based offers for providing regulation and synchronous condensing be defined in Schedule 2 of the Operating Agreement. (Priority: Low. First reported 2019. Status: Not adopted.)
- The MMU recommends that the rule requiring that tier 1 synchronized reserve resources be 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: Adopted October 1, 2022.)
- 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: Adopted October 1, 2022.)
- The MMU recommends that, for calculating the penalty for a tier 2 resource failing to meet its scheduled obligation during a spinning event, the penalty should be based on the actual time since the last spinning event of 10 minutes or longer during which the resource performed because performance is only measured for events 10 minutes or longer and that the tier 2 shortfall penalty should include LOC payments as well as SRMCP and MW of shortfall. (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: Adopted October 1, 2022.)
- The MMU recommends that the details of VACAR Reserve Sharing Agreement (VRSA) be made public, including any responsibilities assigned to PJM and including the amount of reserves that Dominion commits to meet its obligations under the VRSA. (Priority: Medium. First reported 2020. Status: Not adopted.)
- The MMU recommends that the VRSA be terminated and, if necessary, replaced by a reserve sharing agreement between PJM and VACAR South, similar to agreements between PJM and other bordering areas. (Priority: Medium. First reported 2020. Status: Adopted October 1, 2022.)
- 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: Adopted October 1, 2022.)
- 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: Adopted October 1, 2022.)

- The MMU recommends that, in order to mitigate market power, offers in the DASR market be based on opportunity cost only. (Priority: Low. First reported 2009. Modified, 2018. Status: Adopted October 1, 2022.)
- 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. The PJM capacity and energy markets already compensate resources for frequency response capability and any marginal costs. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that new CRF rates for black start units, incorporating current tax code changes, be implemented immediately. The new CRF rates should apply to all black start units. The black start units should be required to commit to providing black start service for the life of the unit. (Priority: High. First reported 2020. 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: Adopted 2021.)
- 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, if payments for reactive are continued, 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. First reported 2019.[193] Status: Partially adopted.)
- The MMU recommends that Schedule 2 to OATT be revised to state explicitly that only generators that provide reactive capability to the transmission system that PJM operates and has responsibility for are eligible for reactive capability compensation. Specifically, such eligibility should be determined based on whether a generation facility's point of interconnection is on a transmission line that is a Monitored Transmission Facility as defined by PJM and is on a Reportable Transmission Facility as defined by PJM.[194] (Priority: Medium. First reported 2020. Status: Not adopted.)

Section 10 Conclusion

The design of the PJM Regulation Market is significantly flawed.[195] 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. The current market design allows regulation units that have the capability to provide both RegA and RegD MW to submit an offer for both signal types in the same market hour. However, the method of clearing the regulation market for an hour in which one or more units has a dual offer incorrectly accounts for the amount of RegD and the effective MW of the RegD that it clears. The result of the flaw is that the MBF in the clearing phase is incorrectly low compared to the MBF in the solution phase and the actual amount of effective MW procured is higher than the regulation requirement. 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

193 The MMU has discussed this recommendation in state of the market reports since 2016 but Q3, 2019 was the first time it was reported as a formal MMU recommendation.

194 *See* PJM Transmission Facilities (note that this requires you first log into a PJM Tools account. If you do not, then the link sends you to an Access Request page, <https://pjm.com/markets-and-operations/ops-analysis/transmission-facilities>.

195 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. Order No. 755, 137 FERC ¶ 61,064 at PP 197–200 (2011).

FERC on October 17, 2017.[196] 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.[197] The MMU and PJM separately filed requests for rehearing, which were denied by order issued March 26, 2020.[198]

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 economic withholding and is therefore not consistent with a competitive outcome. The $7.50 margin should be eliminated. The variable operating and maintenance component of the synchronized reserve offer should also be eliminated. All variable operating and maintenance costs are incurred to provide energy and to make units available to provide energy. There are no variable operating and maintenance costs associated with providing synchronized reserve. Reserve market design changes approved by FERC and scheduled for implementation on October 1, 2022 will eliminate the $7.50 per MW margin and the variable operations and maintenance costs.[199]

Participant performance has not been adequate for tier 2 synchronized reserve. Compliance with calls to respond to actual synchronized reserve events remains significantly less than 100 percent. Actual participant performance means that the penalty structure is not an adequate incentive for performance. The October 1, 2022, reserve market design changes do not respond to the MMU's recommendations to increase the penalties for nonperformance. 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 to a synchronized reserve event. Tier 1 resources require no additional payment. Overpayment of tier 1 resources based on this rule has added more than $150 million to the cost of primary reserve since 2014. The reserve market design changes approved by FERC and implemented on October 1, 2022, consolidate Tier 1 and Tier 2 reserves into a single synchronized reserve product, with a stronger must offer requirement and a single clearing price.[200] This eliminates the payment of Tier 1 based on the nonzero nonsynchronized reserve price.

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 not competitive, and 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 continued to affect prices. The MMU recognizes that significant reserve market design changes were implemented on October 1, 2022, and these new rules will be addressed in detail in the *2022 Annual State of the Market Report for PJM*.

196 18 CFR § 385.211.
197 162 FERC ¶ 61,295 (2018).
198 170 FERC ¶ 61,259 (2020).
199 See FERC Docket No. EL19-58.
200 See FERC Docket No. EL19-58.

Overview: Section 11, Congestion and Marginal Losses

Congestion Cost

- **Total Congestion.** Total congestion costs increased by $1,248.6 million or 203.2 percent, from $614.6 million in the first nine months of 2021 to $1,863.2 million in the first nine months of 2022.
- **Day-Ahead Congestion.** Day-ahead congestion costs increased by $1,494.0 million or 189.2 percent, from $789.5 million in the first nine months of 2021 to $2,283.5 million in the first nine months of 2022.
- **Balancing Congestion.** Negative balancing congestion costs increased by $245.4 million, from -$174.9 million in the first nine months of 2021 to -$420.3 million in the first nine months of 2022. Negative balancing explicit charges increased by $136.7 million, from -$80.6 million in the first nine months of 2021 to -$217.3 million in the first nine months of 2022.
- **Real-Time Congestion.** Real-time congestion costs increased by $1,971.8 million, from $988.7 million in the first nine months of 2021 to $2,960.5 million in the first nine months of 2022.
- **Monthly Congestion.** Monthly total congestion costs in the first nine months of 2022 ranged from $74.5 million in March to $354.2 million in May.
- **Geographic Differences in CLMP.** Differences in CLMP between southern and eastern control zones in PJM were primarily a result of binding constraints on the Brambleton - Evergreen Mills Line, the Nottingham Series Reactor, the Cumberland - Juniata Line, the Beaumeade Circuit Breaker, and the Idylwood - Clark Line.
- **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 2022. The number of congestion event hours in the day-ahead energy market was about twice the number of congestion event hours in the real-time energy market.

  Day-ahead congestion frequency increased by 19.5 percent from 41,946 congestion event hours in the first nine months of 2021 to 50,120 congestion event hours in the first nine months of 2022.

  Real-time congestion frequency increased by 34.6 percent from 15,401 congestion event hours in the first nine months of 2021 to 20,728 congestion event hours in the first nine months of 2022.
- **Congested Facilities.** Day-ahead, congestion event hours increased on all types of facilities except transformers.

  The Brambleton - Evergreen Mills Line was the largest contributor to congestion costs in the first nine months of 2022. With $230.1 million in total congestion costs, it accounted for 12.3 percent of the total PJM congestion costs in the first nine months of 2022.
- **CT Price Setting Logic and Closed Loop Interface Related Congestion.** PJM's use of CT pricing logic officially ended with the implementation of fast start pricing on September 1, 2021. While CT pricing logic was officially discontinued by PJM on September 1, 2021, PJM continues to use a related logic to force inflexible units and demand response to be on the margin in both real time and day ahead. None of the PJM defined closed loop interfaces were binding in the first nine months of 2021 or 2022.
- **Zonal Congestion.** DOM had the highest zonal congestion costs among all control zones in the first nine months of 2022. DOM had $337.0 million in zonal congestion costs, comprised of $420.2 million in day-ahead congestion costs and -$83.2 million in balancing congestion costs.

Marginal Loss Cost

- **Total Marginal Loss Costs.** Total marginal loss costs increased by $801.8 million or 119.6 percent, from $670.2 million in the first nine months of 2021 to $1,472.0 million in the first nine months of 2022. The loss MWh in PJM increased by 776.6 GWh or 6.7 percent, from 11,668.2 GWh in the first nine months of 2021 to 12,444.8 GWh in the first nine months of 2022. The loss component of real-time LMP in the first nine months of 2022 was $0.06, compared to $0.02 in the first nine months of 2021.

- **Day-Ahead Marginal Loss Costs.** Day-ahead marginal loss costs increased by $878.2 million or 126.3 percent, from $695.4 million in the first nine months of 2021 to $1,573.6 million in the first nine months of 2022.
- **Balancing Marginal Loss Costs.** Negative balancing marginal loss costs increased by $76.4 million or 303.2 percent, from -$25.2 million in the first nine months of 2021 to -$101.5 million in the first nine months of 2022.
- **Total Marginal Loss Surplus.** The total marginal loss surplus increased by $250.6 million or 105.7 percent, from $237.0 million in the first nine months of 2021, to $487.6 million in the first nine months of 2022.
- **Monthly Total Marginal Loss Costs.** Monthly total marginal loss costs in the first nine months of 2022 ranged from $85.7 million in March to $257.4 million in August.

System Energy Cost

- **Total System Energy Costs.** Total system energy costs decreased by $548.4 million or 127.3 percent, from -$430.7 million in the first nine months of 2021 to -$979.1 million in the first nine months of 2022.
- **Day-Ahead System Energy Costs.** Day-ahead system energy costs decreased by $641.3 million or 134.9 percent, from -$475.4 million in the first nine months of 2021 to -$1,116.7 million in the first nine months of 2022.
- **Balancing System Energy Costs.** Balancing system energy costs increased by $101.4 million or 246.1 percent, from $41.2 million in the first nine months of 2021 to $142.6 million in the first nine months of 2022.
- **Monthly Total System Energy Costs.** Monthly total system energy costs in the first nine months of 2022 ranged from -$168.6 million in August to -$60.0 million in March.

Section 11 Conclusion

Congestion is defined as the total payments by load in excess of the total payments to generation, excluding marginal losses. The level and distribution of congestion reflects the underlying characteristics of the power system, including the nature and defined 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 costs in the first nine months of 2022 were the highest for any comparable period since 2008 due to higher fuel prices, especially higher gas and coal prices; cold weather in January; higher frequency of transmission constraint violations in the day-ahead market; and increased load in the Data Center Alley area of Northern Virginia.

Monthly total congestion costs ranged from $74.5 million in March to $354.2 million in May in the first nine months of 2022.

The current ARR/FTR design does not ensure that load receives the rights to all congestion revenues. The congestion offset provided by ARRs and self scheduled FTRs in the first four months of the 2022/2023 planning period was 62.9 percent. The cumulative offset of congestion by ARRs for the 2011/2012 planning period through the first four months of the 2022/2023 planning period, using the rules effective for each planning period, was 67.6 percent. Load has received $3.8 billion less than load should have received from the 2011/2012 planning period through the first four months of the 2022/2023 planning period.

Overview: Section 12, Planning

Generation Interconnection Planning

Existing Generation Mix

- As of September 30, 2022, PJM had a total installed capacity of 196,245.9 MW, of which 44,332.7 MW (22.6 percent) are coal fired steam units, 54,253.2 MW (27.6 percent) are combined cycle units and 33,452.6 MW (17.0 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.

- Of the 196,245.9 MW of installed capacity, 70,380.3 MW (35.9 percent) are from units older than 40 years, of which 34,642.3 MW (49.2 percent) are coal fired steam units, 191.0 MW (0.3 percent) are combined cycle units and 18,460.6 MW (26.2 percent) are nuclear units.

Generation Retirements[201]

- There are 53,167.6 MW of generation that have been, or are planned to be, retired between 2011 and 2024, of which 40,627.1 MW (76.4 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 natural gas.
- In the first nine months of 2022, 6,069.6 MW of generation retired. The largest generator that retired in the first nine months of 2022 was the 638.0 MW Avon Lake Unit 9 coal fired steam unit located in the ATSI Zone. Of the 6,069.6 MW of generation that retired, 1,300.0 MW (21.4 percent) were located in the DUKE Zone.
- As of September 30, 2022, there are 5,770.3 MW of generation that have requested retirement after September 30, 2022, of which 1,520.7 MW (26.4 percent) are located in the ATSI Zone. Of the generation requesting retirement in the ATSI Zone, 1,490.0 MW (98.0 percent) are coal fired steam units.

Generation Queue[202]

- There were 254,998.8 MW in generation queues, in the status of active, under construction or suspended, at the end of 2021. In the first nine months of 2022, the AH2 queue window closed and the AI1 queue window opened. 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, 2022, there were 277,040.0 MW in generation queues, in the status of active, under construction or suspended, an increase of 22,041.2 MW (8.6 percent) from the end of 2021.[203]
- As of September 30, 2022, 7,562 projects, representing 795,209.6 MW, have entered the queue process since its inception in 1998. Of those, 1,033 projects, representing 78,472.1 MW, went into service. Of the projects that entered the queue process, 3,425 projects, representing 439,697.6 MW (55.3 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, 2022, 277,040.0 MW were in generation request queues in the status of active, under construction or suspended. Based on historical completion rates, 37,918.7 MW (13.7 percent) of new generation in the queue are expected to go into service.
- In the first nine months of 2022, 1,515.5 MW from the queue went in service. Of the 1,515.5 MW that went in service, 1,200.9 MW (79.2 percent) were combined cycle units, 221.1 MW (14.6 percent) were solar units and 93.5 MW (6.2 percent) were combustion turbine natural gas units.
- The number of queue entries increased during the past several years, primarily renewable projects. Of the 4,938 projects entered from January 2015 through September 2022, 3,665 projects (74.2 percent) were renewable. Of the 407 projects entered in the first nine months of 2022, 284 projects (69.8 percent) were renewable. Renewable projects make up 75.5 percent of all projects in the queue and those projects account for 75.4 percent of the nameplate MW currently active, suspended or under construction in the queue as of September 30, 2022.

  But of the 209,039.6 MW of renewable projects in the queue, only 11,631.3 MW (5.6 percent) of capacity resources are expected to go into service, based on both historical completion rates and ELCC derate factors for battery, wind and solar.

201 See PJM. Planning. "Generator Deactivations," (Accessed on September 30, 2022) <http://www.pjm.com/planning/services-requests/gen-deactivations.aspx>.
202 See PJM. Planning. "New Services Queue," (Accessed on September 30, 2022) <https://www.pjm.com/planning/services-requests/interconnection-queues.aspx>.
203 The queue totals in this report are the winter net MW energy for the interconnection requests ("MW Energy") as shown in the queue.

Regional Transmission Expansion Plan (RTEP)

Market Efficiency Process

- There are significant issues with PJM's cost/ benefit analysis that should be addressed prior to approval of additional projects. PJM's cost/benefit analysis does not correctly account for the costs of increased congestion associated with market efficiency projects.
- Through September 30, 2022, PJM has completed four market efficiency cycles under Order No. 1000.[204]

PJM MISO Interregional Market Efficiency Process (IMEP)

- PJM and MISO developed a process to facilitate the construction of interregional projects in response to the Commission's concerns about interregional coordination along the PJM-MISO seam. This process, called the Interregional Market Efficiency Process (IMEP), operates on a two year study schedule and is designed to address forward looking congestion.

  But the use of an inaccurate cost/benefit method by PJM and the correct method by MISO results in an over allocation of the costs associated with joint PJM/MISO projects to PJM participants and in some cases approval of projects that do not pass an accurate cost-benefit test.

PJM MISO Targeted Market Efficiency Process (TMEP)

- PJM and MISO developed the Targeted Market Efficiency Process (TMEP) to facilitate the resolution of historic congestion issues that could be addressed through small, quick implementation projects.

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."[205] Supplemental projects are exempt from the competitive planning process.
- The average number of supplemental projects in each expected in service year increased by 860.0 percent, from 20 for years 1998 through 2007 (pre Order No. 890) to 192 for years 2008 through 2022 (post Order 890).[206]

End of Life Transmission Projects

- An end of life transmission project is a project submitted for the purpose of replacing existing infrastructure that is at, or is approaching, the end of its useful life. End of life transmission projects 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. Under the current approach, end of life projects are excluded from competition.

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, as well as scope changes and project cancellations, but exclude supplemental and end of life projects, are periodically presented to the PJM Board of Managers for authorization.[207] In the first nine months of 2022, the PJM Board approved $597.5 million in upgrades. As of September 30, 2022, the PJM Board has approved $39.5 billion in system enhancements since 1999.

Transmission Competition

- The MMU makes several recommendations related to the competitive transmission planning process. The recommendations include improved process transparency, incorporation of competition between transmission and generation alternatives and the removal of barriers to competition from nonincumbent transmission. These recommendations would help

204 See *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, FERC Stats. & Regs. ¶ 31,323 (2011) (Order No. 1000), *order on reh'g*, Order No. 1000-A, 139 FERC ¶ 61,132 (2012).

205 See PJM. "Transmission Construction Status," (Accessed on September 30, 2022) <http://www.pjm.com/planning/rtep-upgrades-status/construct-status.aspx>.

206 See *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 118 FERC ¶ 61,119, *order on reh'g*, Order No. 890-A, 121 FERC ¶ 61,297 (2007), *order on reh'g*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g*, Order No. 890-C, 126 FERC ¶ 61,228, *order on clarification*, Order No. 890-D, 129 FERC ¶ 61,126 (2009).

207 Supplemental Projects, including the end of life subset of supplemental projects, do not require PJM Board of Managers authorization.

ensure that the process is an open and transparent process that results in the most competitive solutions.

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

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, 2022, no QTUs have cleared a Base Residual Auction or an Incremental Auction.

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.[208]
- There were 6,155 transmission outage requests submitted in the first four months of 2022/2023 planning period. Of the requested outages, 73.8 percent of the requested outages were planned for less than or equal to five days and 13.1 percent of requested outages were planned for greater than 30 days. Of the requested outages, 42.0 percent were late according to the rules in PJM's Manual 3.

208 See "PJM Manual 03: Transmission Operations," Rev. 62 (June 1, 2022).

Section 12 Recommendations

Generation Retirements

- The MMU recommends that the question of whether Capacity Interconnection Rights (CIRs) should persist after the retirement of a unit be addressed. The rules need to ensure that incumbents cannot exploit control of CIRs to block or postpone entry of competitors.[209] (Priority: Low. First reported 2013. Status: Partially adopted, 2012.)

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. (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.[210] (Priority: Medium. First reported 2013. Status: Partially adopted.)
- The MMU recommends continuing analysis of the study phase of PJM's transmission planning to reduce the need for postponements of study results, to decrease study completion times, and to improve the likelihood that a project at a given phase in the study process will successfully go into service.[211] (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

209 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>.
210 Once implemented, the approved solutions from PJM's Interconnection Process Reform Task Force (IPRTF) should result in improvements in these areas.
211 Ibid.

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. First reported 2019. Status: Not adopted.)
- The MMU recommends that, if the market efficiency process is retained, PJM modify the rules governing cost/benefit 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 in order to ensure that the correct metrics are used for defining benefits. (Priority: Medium. First reported 2018. Status: Not adopted.)

Comparative Cost Framework

- The MMU recommends that PJM modify the project proposal templates to include data necessary to perform a detailed project lifetime financial analysis. The required data includes, but is not limited to: capital expenditure; capital structure; return on equity; cost of debt; tax assumptions; ongoing capital expenditures; ongoing maintenance; and expected life. (Priority: Medium. First reported 2020. 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. Rejected by FERC.)[212]
- 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 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 2019. Status: Not adopted. Rejected by FERC.)[213]
- 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

212 The FERC accepted tariff provisions that exclude supplemental projects from competition in the RTEP. 162 FERC ¶ 61,129 (2018), *reh'g denied*, 164 FERC ¶ 61,217 (2018).

213 In recent decisions addressing competing proposals on end of life projects, the Commission accepted a transmission owner proposal excluding end of life projects from competition in the RTEP process, 172 FERC ¶ 61,136 (2020), *reh'g denied*, 173 FERC ¶ 61,225 (2020), and rejected a proposal from PJM stakeholders that would have included end of life projects in competition in the RTEP process, 173 FERC ¶ 61,242 (2020).

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

- The MMU recommends that storage resources not be includable as transmission assets for any reason. (Priority: High. First reported 2020. Status: Not adopted.)

Cost Allocation

- The MMU recommends a comprehensive review of the ways in which the solution based dfax is implemented. The goal for such a process would be to ensure that the most rational and efficient approach to implementing the solution based dfax method is used in PJM. Such an approach should allocate costs consistent with benefits and appropriately calibrate the incentives for investment in new transmission capability. No replacement approach should be approved until all potential alternatives, including the status quo, are thoroughly reviewed. (Priority: Medium. First reported 2020. Status: Not adopted.)
- The MMU recommends consideration of changing the minimum distribution factor in the allocation from 0.01 to 0.00 and adding a threshold minimum usage impact on the line.[214] (Priority: Medium. First reported 2015. Status: Not adopted.)

Transmission Line Ratings

- The MMU recommends that all PJM transmission owners use the same methods to define line ratings and that all PJM transmission owners implement dynamic line ratings (DLR), subject to NERC standards and guidelines, subject to review by NERC, PJM and the MMU, and approval by FERC. (Priority: Medium. First reported 2019. 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 core element of all 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 or even permit 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 MMU recognizes that the Commission has issued orders that are inconsistent with the recommendations of the MMU and that PJM cannot unilaterally modify those directives. It remains the recommendation of the MMU that 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 the reasons for that policy should be reevaluated.

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

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. 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.

Managing the generation queues is a complex process. The PJM queue evaluation process has been incrementally improved in recent years. In 2020, PJM conducted interconnection process workshops and in 2021, the Interconnection Process Reform Task Force (IPRTF) was created to explore ways to improve overall queue management. The proposal endorsed by the IPRTF in 2022 includes significant modifications to the interconnection process designed to address some of the key underlying issues and significantly improve the efficiency of the process. These modifications include process efficiency enhancements, recognition of project clusters affecting the same transmission facilities, incentives to reduce the entry of speculative projects in the queue, and incentives to remove projects that are not expected to reach commercial operation. The proposed solution should help to reduce backlog and to remove projects that are not viable earlier to help improve the overall efficiency of the queue process. On June 14, 2022, PJM filed tariff changes to incorporate the endorsed modifications to the interconnection queue process.[215]

The proposed modifications to the queue process will need to be evaluated to determine if they successfully remove projects from the queue if they are not viable, and allow commercially viable projects to advance in the queue ahead of projects which have failed to make progress. The behavior of project developers also creates issues with queue management. When developers put multiple projects in the queue to maintain their own optionality while planning to build only one they also affect all the projects that follow them in the queue. Project developers may also enter speculative projects in the queue and then put the project in suspended status while they address financing. The impacts of such behavior and the incentives for such behavior are addressed in the new process which includes nonrefundable fees, credit requirements, enhanced site control, elimination of the ability to suspend a project and milestone requirements. These aspects of the proposed interconnection process should continue to be evaluated to ensure that they are having the desired effect on project developer behavior. 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 and whether transmission owners should perform interconnection studies.

The roles and efficiency of PJM, TOs and developers in the queue process all need to be examined and enhanced in order to help ensure that the queue process can function effectively and efficiently as the gateway to competition in the energy and capacity markets and not as a barrier to competition.

The Commission should require PJM, for example, to 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.

215 See *PJM*, Docket No. ER22-2110 (June 14, 2022).

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

The current market efficiency process does exactly the opposite by permitting transmission projects to be approved without competition from generation. The broader issue is that the market efficiency project approach explicitly allows transmission projects to compete against future generation projects, but without allowing the generation projects to compete. Projecting speculative transmission related benefits for 15 years based on the existing generation fleet and existing patterns of congestion eliminates the potential for new generation to respond to market signals. The market efficiency process allows assets built under the cost of service regulatory paradigm to displace generation assets built under the competitive market paradigm. In addition, there are significant issues with PJM's current cost/benefit analysis which cause it to consistently overstate the potential benefits of market efficiency projects. The market efficiency process is misnamed. The MMU recommends that the market efficiency process be eliminated.

In addition, the use of an inaccurate cost-benefit method by PJM and the correct method by MISO results in an over allocation of the costs associated with joint PJM/MISO projects to PJM participants and in some cases approval of projects that do not pass an accurate cost-benefit test.

If it is retained, there are significant issues with PJM's cost/benefit analysis that should be addressed prior to approval of additional projects. The current cost/benefit 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 cost/benefit 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 plan, 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 and that have large and unnecessary impacts on the PJM 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. The PJM process for evaluating the congestion impact of transmission outages needs to be clearly defined and upgraded to provide for management of transmission outages to minimize market impacts. The MMU continues to recommend that PJM draft a clear definition of the congestion analysis required for transmission outage requests that is incorporated in the PJM Market Rules.

The treatment by PJM and Dominion Virginia Power of the outage for the Lanexa – Dunnsville Line illustrates some of the issues with the current process. The outage was submitted and delayed more than once. PJM's analysis of expected congestion did not highlight the magnitude of the issue. Dominion Virginia Power did not stage the outage so as to minimize market disruption and congestion.

Overview: Section 13, FTRs and ARRs

Auction Revenue Rights

Market Structure

- **ARR Ownership.** In the 2022/2023 planning period ARRs were allocated to 1,563 individual participants, held by 133 parent companies. ARR ownership for the 2022/2023 planning period was unconcentrated with an HHI of 584.

Market Behavior

- **Self Scheduled FTRs.** For the 2022/2023 planning period, 26.0 percent of eligible ARRs were self scheduled as FTRs.

Market Performance

- **ARRs as an Offset to Congestion.** ARRs have not served as an effective mechanism to return all congestion revenues to load. For the first four months of the 2022/2023 planning period, ARRs and self scheduled FTRs offset 77.9 percent of total congestion. Congestion payments by load in some zones were more than offset and congestion payments in some zones were less than offset. Load has been underpaid congestion revenues by $3.8 billion from the 2011/2012 planning period through the first four months of the 2022/2023 planning period. The cumulative offset for that period was 67.6 percent of total congestion.
- **ARR Payments.** For the first four months of the 2022/2023 planning period, the ARR target allocations, which are based on the nodal price differences from the Annual FTR Auction, were $1,320.8 million, while PJM collected $1,626.6 million from the combined Long Term, Annual and Monthly Balance of Planning Period FTR Auctions. For the 2021/2022 planning period, the ARR target allocations were $634.2 million while PJM collected $812.6 million from the combined Annual and Monthly Balance of Planning Period FTR Auctions.
- **Residual ARRs.** Residual ARRs are only available on contract 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 2022/2023 planning period, PJM allocated a total of 11,699.9 MW of residual ARRs with a total target allocation of $8.6 million, up from 11,518.2 MW, with a total target allocation of $7.0 million, in the same period of the 2020/2021 planning period.
- **ARR Reassignment for Retail Load Switching.** There were 32,935 MW of ARRs associated with $568,200 of revenue that were reassigned in the 2021/2022 planning period. There were 17,787 MW of ARRs associated with $659,700 of revenue that were reassigned for the first four months of the 2022/2023 planning period.

Financial Transmission Rights

Market Design

- **Monthly Balance of Planning Period FTR Auctions.** The design of the Monthly Balance of Planning Period FTR Auctions includes auctions for each remaining month in the planning period.

Market Structure

- **Patterns of Ownership.** For the Monthly Balance of Planning Period Auctions, financial entities purchased 80.9 percent of prevailing flow and 89.7 percent of counter flow FTRs for January through September, 2022. Financial entities owned 75.3 percent of all prevailing and counter flow FTRs, including 64.9 percent of all prevailing flow FTRs and 86.7 percent of all counter flow FTRs during the period from January through September 2022. Self scheduled FTRs account for 4.9 percent of all FTRs held.
- **Market Concentration.** For prevailing flow obligation FTRs in the Monthly Balance of Planning Period Auctions for the first four months of the 2022/2023 planning period, ownership of cleared prevailing flow bids was unconcentrated in 88.1 percent of periods and moderately concentrated in 11.9 percent of periods. Ownership of cleared counter flow bids was unconcentrated in 42.9 percent of periods and moderately concentrated

in 57.1 percent of periods, in the first four months of the 2022/2023 planning period.

Market Behavior

- **Sell Offers.** In a given auction, market participants can sell FTRs 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 2022/2023 planning period, total participant FTR sell offers were 6,912,176 MW.
- **Buy Bids.** The total FTR buy bids from the Monthly Balance of Planning Period FTR Auctions for the first four months of the 2022/2023 planning were 11,774,680 MW.
- **FTR Forfeitures.** Total FTR forfeitures were $1.3 million for the first four months of the 2022/2023 planning period.
- **Credit.** There were five collateral defaults and ten payment defaults in the first nine months of 2022. There were two collateral defaults and five payment defaults not involving Hill Energy Resource & Services. All of Hill Energy's FTR positions were liquidated by the April 2022 Monthly FTR auction, and no default costs were distributed to the PJM members through the default allocation assessment procedures.

  On December 21, 2021, PJM submitted a change to their credit rules to institute the use of a 97 percent confidence interval. On February 28, 2022, FERC rejected PJM's filing and instituted a Section 206 proceeding. On June 3, 2022, PJM submitted a Section 205 filing with the same change to the credit rules with further analysis of the 97 percent confidence interval. On August 2, 2022, FERC accepted and suspended PJM's June 3 filing to become effective August 3, 2022, subject to refund and subject to the outcome of a paper hearing.

Market Performance

- **Quantity.** In the first four months of the 2022/2023 planning period, Monthly Balance of Planning Period FTR Auctions cleared 2,140,740 MW (18.2 percent) of FTR buy bids and 1,209,278 MW (17.5 percent) of FTR sell offers. For the same period of the 2021/2022 planning period, Monthly Balance of Planning Period FTR Auctions cleared 4,054,686 MW (26.0 percent) of FTR buy bids and 1,629,121 MW (20.5 percent) of FTR sell offers.
- **Price.** The weighted average buy bid cleared FTR price in the Monthly Balance of Planning Period FTR Auctions for all periods in the first four months of the 2022/2023 planning period was $0.33 per MWh.
- **Revenue.** The Monthly Balance of Planning Period FTR Auctions resulted in net revenue of $68.4 million in the first four months of the 2022/2023 planning period, up from $36.6 million for the same time period in the 2021/2022 planning period.
- **Revenue Adequacy.** FTRs were paid 100.0 percent of the target allocations for the first four months of the 2022/2023 planning period, including distribution of the current surplus revenue.
- **Profitability.** FTR profitability is the difference between the revenue received directly from holding an FTR plus any revenue from the sale of an FTR, and the cost of buying the FTR. In the first four months of the 2022/2023 planning period, profits for all participants were $318.3 million, the highest level since the 2013/2014 planning period. In the first four months of the 2022/2023 planning period, physical entities received $93.2 million in profits on FTRs purchased directly (not self scheduled), up from $23.5 million in profits in the same time period in the 2021/2022 planning period. Financial entities received $225.1 million in profits, up from $100.3 million profits in the same time period in the 2021/2022 planning period.

Section 13 Recommendations

Market Design

- The MMU recommends that the current ARR/FTR design be replaced with defined congestion revenue rights (CRRs). A CRR is the right to actual congestion that is paid by physical load at a specific bus, zone or aggregate. (Priority: High. First reported 2015. Status: Not adopted.)

ARR

- The MMU recommends that the ARR/FTR design be modified to ensure that the rights to all congestion revenues are assigned to load. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that all historical generation to load paths be eliminated as a basis for assigning ARRs. The MMU recommends that the current design be replaced with a design in which the rights to actual congestion paid are assigned directly to the load that paid that congestion by node. (Priority: High. First reported 2015. Status: Partially adopted.)
- The MMU recommends that, under the current FTR design, the rights to all congestion revenue 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 IARRs be eliminated from PJM's tariff, but that if IARRs are not eliminated, IARRs should be subject to the same proration rules that apply to all other ARR rights. (Priority: Low. First reported 2018. Status: Not adopted.)

FTR

- The MMU recommends that FTR funding be based on total congestion, including day-ahead and balancing congestion. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends that bilateral transactions be eliminated and that all FTR transactions occur in the PJM market. (Priority: High. First reported Q1 2022. Status: Not adopted.)[216]
- The MMU recommends a requirement that the details of all bilateral FTR transactions be reported to PJM. (Priority: High. First reported 2020. Status: Replaced.)
- The MMU recommends that PJM continue to evaluate the bilateral indemnification rules and any asymmetries they may create. (Priority: Low. First reported 2018. Status: Replaced.)
- The MMU recommends that PJM reduce FTR sales on paths with persistent overallocation of FTRs, including a clear definition of 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 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 Long Term FTR product be eliminated. If the Long Term FTR product is not eliminated, the Long Term FTR Market should 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 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.)

Surplus

- 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 by PJM to buy counter flow FTRs for the purpose of improving FTR payout ratios.[217] (Priority: High. First reported 2015. Status: Not adopted.)

FTR Subsidies

- 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.)

216 If adopted, this recommendation would replace the next two recommendations.

217 See "PJM Manual 6: Financial Transmission Rights," Rev. 29 (Sep. 1, 2022).

- 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.)

FTR Liquidation

- The MMU recommends that the FTR portfolio of a defaulted member be canceled rather than liquidated or allowed to settle as a default cost on the membership. (Priority: High. First reported 2018. Status: Not adopted.)

Credit

- The MMU recommends the use of a 99 percent confidence interval when calculating initial margin requirements for FTR market participants, in order to assign the cost of managing risk to the FTR holders who benefit or lose from their FTR positions. (Priority: High. First reported 2021. Status: Not adopted.)

Section 13 Conclusion

Solutions

The annual ARR allocation should be designed to ensure that the rights to all congestion revenues are assigned to load, without requiring contract path or point to point physical or financial transmission rights that are inconsistent with the network based delivery of power and the actual way congestion is generated in security constrained LMP markets. When there are binding transmission constraints and locational price differences, load pays more for energy than generation is paid to produce that energy. The difference is congestion. As a result, congestion belongs to load and should be returned to load.

The current contract path based design should be replaced with a design in which the rights to actual congestion paid are assigned directly to the load that paid that congestion by node. The assigned right is to the actual difference between load payments, both day-ahead and balancing, and revenues paid to the generation used to serve that load. The load can retain the right to the congestion revenues or sell the rights through auctions. The correct assignment of congestion revenues to load is fully consistent with retaining FTR auctions for the sale by load of their congestion revenue rights.

Issues

If the original PJM FTR approach had been designed to return congestion revenues to load without use of the generation to load contract paths, and if the distortions subsequently introduced into the FTR design not been added, many of the subsequent issues with the FTR design and complex redesigns would have been avoided. PJM would not have had to repeatedly intervene in the functioning of the FTR system in an effort to meet the artificial and incorrectly defined goal of revenue adequacy.

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 including so called revenue adequacy. 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.[218] The FERC order of September 15, 2016, introduced a subsidy to FTR holders at the expense of ARR holders.[219] The order requires PJM to ignore balancing congestion when calculating total congestion dollars available to fund FTRs. As a result, balancing congestion and M2M payments are assigned to load, rather than to FTR holders, as of the 2017/2018 planning period. When combined with the direct assignment of both surplus day-ahead congestion and surplus FTR auction revenues to FTR holders, the Commission's order shifted substantial revenue from load to the holders of FTRs and further reduced the offset to congestion payments by load. This approach ignores the fact that load pays 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 total congestion and pays negative balancing congestion again. The fundamental reasons that there has been a significant and persistent difference between day-ahead and balancing congestion include inadequate transmission modeling in the FTR auction and the role of UTCs in taking advantage of these modeling differences and creating negative balancing congestion. There is no reason to impose these costs on load.

These changes were made in order to increase the payout to holders of FTRs who are not loads. Increasing the payout to FTR holders at the expense of the load is not a supportable market objective. PJM should implement an FTR design that calculates and assigns congestion rights to load rather than continuing to modify the current, fundamentally flawed, design.

218 Such subsidies have been suggested repeatedly. See FERC Dockets Nos. EL13-47-000 and EL12-19-000.
219 See 156 FERC ¶ 61,180 (2016), *reh'g denied*, 156 FERC ¶ 61,093 (2017).

Load was made significantly worse off as a result of the changes made to the FTR/ARR process by PJM based on the FERC order of September 15, 2016. ARR revenues were significantly reduced for the 2017/2018 FTR Auction, the first auction under the new rules. ARRs and self scheduled FTRs offset only 49.5 percent of total congestion costs for the 2017/2018 planning period rather than the 58.0 percent offset that would have occurred under the prior rules, a difference of $101.4 million.

A subsequent rule change was implemented that modified the allocation of surplus auction revenue to load. Beginning with the 2018/2019 planning period, surplus day-ahead congestion and surplus FTR auction revenue are assigned to FTR holders only up total target allocations, and then distributed to ARR holders.[220] ARR holders will only be allocated this surplus after full funding of FTRs is accomplished. While this rule change increased the level of congestion revenues returned to load, the rules do not recognize ARR holders' rights to all congestion revenue, and only improves congestion payouts to load when there is a surplus. There was no surplus for the 2020/2021 or 2021/2022 planning years. With this rule in effect for the 2021/2022 planning period, ARRs and self scheduled FTRs offset 31.5 percent of total congestion. Load has been underpaid congestion revenues by $3.8 billion from the 2011/2012 planning period through the first four months of the 2022/2023 planning period. The cumulative offset for that period was 67.6 percent of total congestion.

The complex process related to what is termed the overallocation of Stage 1A ARRs is entirely an artificial result of reliance on the contract path model in the assignment of FTRs. For example, there is a reason that transmission is not built to address the Stage 1A overallocation issue. The Stage 1A overallocation issue is a fiction based on the use of outdated and irrelevant generation to load contract paths to assign Stage 1A rights that have nothing to do with actual power flows.

PJM proposed, and on March 11, 2022, FERC accepted, to increase Stage 1A ARR allocations to 60 percent of Network Service Peak Load (NSPL) ("Stage 1A Proposal").[221] While PJM's proposal will increase Stage 1A rights, this will

220 163 FERC ¶61,165 (2018).
221 See 178 FERC ¶61,170.

come at the cost of Stage 1B and Stage 2 ARR allocations. More importantly, PJM's proposal will not improve the alignment of congestion property rights to load, but will exacerbate the current misalignment.

Under the current rules, Stage 1A allocations are limited to 50 percent of Network Service Base Load. In the 2022/2023 planning period there were infeasibilities on 45 internal PJM constraints totaling 3,385 MW. These MW already result in revenue inadequacy because they are physically infeasible, but must be granted under the rules. In order to grant infeasible Stage 1A ARR allocations, PJM artificially increases the capacity of the constraint, which results in the over allocation issues of FTRs in the FTR auction. Increasing the amount of Stage 1 ARR allocations will exacerbate this issue and result in higher revenue inadequacy.

PJM's proposal is not internally consistent and does not follow its own logic. PJM's proposal does not extend the proposed changes beyond year one in the long term auction. The result is that buyers of long term FTRs can continue to purchase and hold capacity on the system before ARRs even have access to it. This increases over allocations and reduces load's access to ARRs.

PJM continues to fail to recognize the actual underlying issue. The only effective way to address the underlying issue identified by PJM's consultant, the fact that load does not actually get the rights to all congestion, is to modify the market design to assign congestion revenue rights to load.

Proposed Design

To address the issues with the current contract path based ARR/FTR market design, the MMU recommends that the current design be replaced with a design in which the rights to actual congestion paid are assigned directly to the load that paid that congestion by node. The assigned right would be the actual difference between load payments, both day-ahead and balancing, and revenues paid to the generation used to serve that load. The load could retain the right to the network congestion or sell the right through auctions. The correct assignment of congestion revenues to load is fully consistent with retaining FTR auctions for the sale by ARR holders of their congestion revenue rights.

With a network assignment of actual congestion, there would be no cross subsidies among rights holders and no over or under allocation of rights relative to actual network market solutions. There would be no revenue shortfalls as congestion payments equal congestion collected. The risk of default would be isolated to the buyer and seller of the right, and any default would not be socialized to other right holders. In the case of a defaulting buyer, the rights to the congestion revenues would revert to the load. There would be no risk of a network right flipping in value from positive to negative, because congestion is always the positive difference between what load pays for energy, and generation is paid for energy as a result of transmission constraints.

The MMU proposal requires the calculation of constraint specific congestion and the calculation of that specific constraint's congestion related charges to each physical load bus downstream of that constraint. Under the MMU proposal, the constraint specific congestion calculated by hour, from both the day-ahead and balancing market would be paid directly to the physical load as a credit against the associated load serving entity's (LSE) energy bill. This right to the congestion is defined as the congestion revenue right (CRR) that belongs to the physical load at a defined bus, zone or aggregate. The LSE could choose to sell all or a portion of the CRR through auctions.

A CRR is the right to actual, realized network related congestion that is paid by physical load at a specific bus, zone or aggregate. Under the MMU proposal a bus, zone or aggregate specific CRR could be sold as a defined share of the actual congestion. For example, an LSE could sell 50 percent of its congestion revenue right for the planning period to a third party. The third party buyer would then be entitled to 50 percent of the congestion that will be credited to that specific bus, zone or aggregate for the planning period. The remaining 50 percent of the congestion credit for the specified bus, zone or aggregate would be paid to the LSE along with auction clearing price for the 50 percent of CRR that was sold to the third party. Depending on actual congestion, an LSE selling its congestion revenue rights could be better or worse off than if it retained its rights.

Under the MMU proposal, the LSE would be able to set reservation prices in the auction for the sale of portions or all of its CRR. Third parties would have an opportunity to bid for the offered portions of the CRR, and the market for the congestion revenue associated with the specified bus, zone or aggregate would clear at a price. If the reservation price of an identified portion of the offered CRR was not met at the clearing price, that portion of the offered CRR would remain with the load. Auctions could be annual and/or monthly.

Under the MMU proposal, point to point rights (FTRs) could exist as a separate, self-funded hedging product based on simultaneously feasible prevailing and counter flows in a PJM managed network based auction. The only supply and the only source of revenues in the point to point market for prevailing flow FTRs would be counter flow offers and direct payments for specific rights.